NEPOOL
NEW ENGLAND POWER POOL
Sebastian Lombardi
Secretary

June 17, 2024

VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of June 25-27, 2024 NEPOOL Participants Committee Summer Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the NEPOOL Participants Committee Summer Meeting will be held on June 25-27, 2024 at The Omni Mount Washington Hotel in Bretton Woods, NH. Please see the attached meeting agenda and Sector meeting schedule, which are also posted with the meeting materials. A list of currently registered attendees is posted on the Summer Meeting information page. If you cannot make the meeting in person, telephone participation will be available for the plenary sessions (and to a more limited extent for the separate meetings of the Sectors) if you contact us for the dial-in information.

As reflected on the meeting agenda:

- ***Tuesday (Jun 25)***: General NEPOOL business will be conducted on Tuesday, with a planned 10:00 a.m. start. Note that Tuesday's agenda includes the annual markets presentation by the ISO's External Market Monitor.
- ***Wednesday (Jun 26)***: As detailed in the attached agenda, Wednesday morning has been set aside for a plenary session with guest speakers (including a panel discussion). Wednesday afternoon is set aside for separate meetings or participation in networking events.
- ***Thursday (Jun 27)***: Thursday's session is for modified Sector group meetings, scheduled to begin at 8:30 a.m., with times set aside for each group to meet separately with ISO Board members, State Officials and FERC representatives. ***Please note when and where your modified Sector group is scheduled to meet.***

The NEPOOL reservations block at The Omni Mount Washington is quite full, but should you still need overnight accommodations, please contact Jaki Sloan (jsloan@daypitney.com), who may be able to assist getting you into The Mount Washington or an alternative venue/inn if possible. **For those staying at The Omni Mount Washington, please note that the check-in time is 4:00 p.m. and the check-out time is 11:00 a.m.**

Dress for the Summer Meeting is business casual. Additional information regarding the Summer Meeting is available on the Summer Meeting information page. Many have signed up for activities on Wednesday afternoon. While a couple of the activities did not generate sufficient interest to be held, registration remains open for many others. Please sign up now if you are interested and have not already registered for an activity.

We very much look forward to seeing you in New Hampshire.

Respectfully yours,

/s/
Sebastian Lombardi, Secretary

FINAL AGENDA

TUESDAY, JUNE 25, 2024
10:00 a.m. – 5:00 p.m. General Session**
(Grand Ballroom)

1. To approve the draft minutes of the Participants Committee meeting held on May 5, 2024. A copy of the draft May 5 meeting minutes, marked to show the changes from the draft circulated with the initial notice, are included with this supplemental notice and posted on the NEPOOL and ISO websites.

2. To adopt and approve all actions recommended by the Technical Committees set forth on the Consent Agenda included with this initial notice and posted on the NEPOOL website. The Consent Agenda is included with this supplemental notice and posted on the NEPOOL and ISO websites.

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

4. To receive a Chief Operations Officer (COO) Update from Dr. Vamsi Chadalavada, ISO New England. A copy of the June Report, reflecting a full set of May 2024 operations data, was included with the initial notice and is posted on the NEPOOL and ISO websites.

5. To receive a report on the ISO's preliminary 2025 and 2026 Operating and Capital Budgets by Chief Financial & Compliance Officer Robert Ludlow, ISO New England. The 2025 Budget Presentation is included with this supplemental notice and posted on the NEPOOL and ISO websites.

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

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

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

8. FERC Staff Introductions.

9. To receive an External Market Monitor Report by Dr. David Patton, President, Potomac Economics. A presentation with highlights of the EMM's 2023 Annual Assessment of the ISO New England Electricity Markets will be circulated and posted following receipt.

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

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

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

WEDNESDAY, JUNE 26, 2024
9:30 a.m. – 12:00 p.m.**
(Grand Ballroom)

11. To receive welcome/opening remarks.

12. ***Energy Transition: Trends, Evolving Challenges and Collaborative Solutions.***

    a. American Energy Transformation: Tracking Market & Policy Trends and Looking Forward

    - Lisa Jacobson, President,
      Business Council for Sustainable Energy (BCSE)

    - Tara Narayanan, Lead Analyst, US Regional Trends,
      Bloomberg New Energy Finance (NEF)

    b. Panel Discussion – Energy Sector Perspectives & Reflections "Beyond New England"

    - Moderator: Lisa Jacobson, President, BCSE

    - Panelists:

      - Sapna Gheewala Dowla, Associate Vice President, Policy & Research,
        Alliance to Save Energy

      - Rob Mosher, Vice President of Government Affairs,
        Interstate Natural Gas Association of America (INGAA)

      - Anthony Fratto, Senior Director, Research & Analytics,
        American Clean Power Association (ACP)

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

THURSDAY, JUNE 27, 2025
8:30 a.m. – 12:45 p.m.**

The last day of the Summer Meeting has been set aside for
separate, modified Sector meetings with individual ISO Board Members,
State Officials and FERC Representatives,
as detailed in the Sector meeting schedule included with this agenda.

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

21st Annual
Participants Committee Summer Meeting
Bretton Woods, NH
June 27 Schedule

SECTOR/GROUP	8:30 – 9:45 a.m.	10:00 – 11:15 a.m.	11:30 a.m. – 12:45 p.m.	12:15 – 2:00 p.m.
Generation / Long	ISO Board Panel 2 ***(Madison)***	*FERC Staff (10:45-11:15)* ***(Jefferson)***	State Officials Panel 1 ***(Monroe)***	Lunch (All) ***(Sun Dining Room)***
Transmission	ISO Board Panel 1 ***(Adams)***	*FERC Staff (10:00-10:30)* ***(Jefferson)***	State Officials Panel 2 ***(Reagan)***	
Supplier / Short (LSE)	*FERC Staff (9:15-9:45)* ***(Jefferson)***	State Officials Panel 1 ***(Monroe)***	ISO Board Panel 1 ***(Adams)***	
Publicly Owned Entity	State Officials Panel 2 ***(Reagan)***	ISO Board Panel 1 ***(Adams)***	*FERC Staff (12:15-12:45)* ***(Jefferson)***	
AR	State Officials Panel 1 ***(Monroe)***	ISO Board Panel 2 ***(Madison)***	*FERC Staff (11:30-12:00)* ***(Jefferson)***	
End User	*FERC Staff (8:30-9:00)* ***(Jefferson)***	State Officials Panel 2 ***(Reagan)***	ISO Board Panel 2 ***(Madison)***	
ISO Board Panel 1	Transmission ***(Adams)***	Publicly Owned Entity ***(Adams)***	Supplier / Short (LSE) ***(Adams)***	
ISO Board Panel 2	Generation / Long ***(Madison)***	AR ***(Madison)***	End User ***(Madison)***	
State Officials Panel 1	AR ***(Monroe)***	Supplier / Short (LSE) ***(Monroe)***	Generation / Long ***(Monroe)***	
State Officials Panel 2	Publicly Owned Entity ***(Reagan)***	End User ***(Reagan)***	Transmission ***(Reagan)***	
FERC Staff	*End User (8:30-9:00)* Supplier/Short (LSE) *(9:15-9:45)* ***(Jefferson)***	*Transmission (10:00-10:30)* *Generation/Long (10:45-11:15)* ***(Jefferson)***	*AR (11:30-12:00)* *Publicly Owned (12:15-12:45)* ***(Jefferson)***	

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

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

State Officials Panel 1: NH DOE Commissioner Jared Chicoine, CT DEEP Staff Bruce Ho, ME PUC Commissioner Carolyn Gilbert, ME PUC Staff Michael Haskell, MA EOEEA Deputy Secretary Jason Marshall, VT PUC Staff Mary Jo Krolewski, NESCOE Staff Jeff Bentz, NESCOE Staff Nathan Forster, NESCOE Staff Shannon Beale, NECPUC Exec. Dir. George Twigg.

State Officials Panel 2: NH PUC Staff Dan Phelan, NH State Rep. Mike Harrington, CT DEEP Deputy Commissioner Joseph DeNicola, CT DEEP Staff Josh Walters, ME PUC Chair Phil Bartlett, ME PUC Commissioner Patrick Scully, MA EOEEA Assistant Secretary Weezie Nuara, VT PUC Chair Ed McNamara, VT DPS Staff Lou Cecere, NESCOE Staff Sheila Keane, NESCOE Exec. Dir. Heather Hunt.

FERC Staff: Emma Brin, Eric Jacobi, Aaron Siskind, Brandon Ward, and Mary Wierzbicki.

v. 2024.06.18

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Thursday, May 2, 2024, at the Renaissance Boston Waterfront Hotel, Boston, MA. A quorum, determined in accordance with the Second Restated NEPOOL Agreement, was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the meeting, either in person or by telephone/Webex.

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

EXECUTIVE SESSION

VOTE ON SLATE OF CANDIDATES FOR ISO BOARD

Ms. Bresolin indicated that discussion of the proposed slate of candidates for the ISO Board would proceed in executive session. She then introduced Mr. Brook Colangelo, ISO Board Member and Chairman of the Joint Nominating Committee (JNC), who joined this portion of the meeting to present and answer any questions regarding the JNC-recommended slate and the process undertaken to identify that slate. Following general comments on the JNC process, Mr. Colangelo identified the candidates, referring to the materials that were circulated to the members and alternates of the Committee in advance of the meeting. Mr. Colangelo then left the meeting.

The slate was then discussed in executive session among members and alternates, with initial comments offered by the NEPOOL representatives of the JNC. Following discussion, the following motion was duly made, seconded and approved by more than the 70% Vote required for NEPOOL endorsement, with the vote accomplished by confidential written ballot:

> RESOLVED, that the Participants Committee endorses the slate of candidates for the ISO Board that has been recommended by the Joint Nominating Committee and presented to the Participants Committee in executive session at this meeting.

Members were advised that the ISO Board's final election of the slate would occur at the Board's next regularly-scheduled meeting, with the results of that final election to be announced publicly promptly thereafter.

GENERAL SESSION

Following a short recess, the Committee came out of executive session at 10:30 a.m. and was joined by ISO representatives, State officials and guests. Ms. Bresolin welcomed the members, alternates, State officials, and guests who were present.

APPROVAL OF APRIL 4, 2024 MEETING MINUTES

The Chair referred the Committee to the preliminary minutes of the April 4, 2024 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of that meeting were unanimously approved as circulated, with abstentions by the Connecticut Office of Consumer Counsel and Mr. Jon Lamson noted.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summary of the one ISO New England Board Committee meeting that had occurred since the April 4 meeting, which had been circulated and posted in advance of this meeting. There were no questions or comments on the summary.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by referring the Committee to his May operations report (May Report), which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the May Report was through April 24, 2024. The May Report highlighted: (i) that the Peak Hour for April, with 15,657 MW of Revenue Quality Metered (RQM) Data (including settlement-only generation), occurred on April 3, 2024 during the hour ending at 7:00 pm; (ii) April averages for Day-Ahead Hub LMP ($25.93/MWh), Real-Time Hub LMP ($25.27/MWh), and natural gas prices ($1.56/MMBtu); (iii) Energy Market value was $197.2 million, down from $275.6 million in April 2023 and down from the updated March Energy Market value of $255.7 million; (iv) Ancillary Markets value ($5.6 million) was down from April 2023 ($6.3 million); (v) average Day-Ahead cleared physical energy during peak hours as a percentage of forecasted load was 96.93% during April (down from 97.3% reported for March 2024); (vi) Daily Net Commitment Period Compensation (NCPC) payments for April totaled $1.2 million, comprised completely first contingency payments, including $208,000 in Dispatch Lost Opportunity Costs and $160,000 in Rapid Response Pricing Opportunity Costs (there were no second contingency, distribution or voltage NCPC payments in April); and (vii) Forward Capacity Market (FCM) value was $86.4 million.

Commenting on those highlights, Dr. Chadalavada noted behind-the-meter (BTM) solar in April reached an all-time record contribution of 6,000 MW on April 25, hour ending 13:00. This directly contributed to April’s low average Real-Time load -- approximately 11,000 MW. The BTM solar output in April, he explained, was approximately 1,000 MW greater than April 2023. In response to questions, Dr. Chadalavada confirmed that the annual growth of BTM solar was meeting, if not exceeding, the projections for annual increases of approximately 700 MW, and this growth was pushing the ISO to improve its methodologies for solar forecasting. He reported that a number of intended improvements were under development. With the 7.5 GW of installed solar predicted to nearly double in the next 8-9 years, he added that smaller investments in additional synchronous devises to control high voltage would be required. He also expected the market to respond to the increasing opportunities to arbitrage between the windows of low and high prices that installed solar was opening.

Dr. Chadalavada reported that a new minimum system load -- 6,590 MW -- was also set in April, at hour ending 14:00 on April 27. He said that, with most of the ISO's transmission studies having assumed a minimum system load of 6,500 MW, and now having reached those levels, attention would need to focus on system voltage control, as loads continue to dip into these low mid-afternoon levels.

Dr. Chadalavada also drew attention to the level of imports experienced in April, down 60% from 2023, and the lowest level of imports for the month of April experienced in the last 10 years. He attributed the reduced imports largely to draught conditions in the Quebec region.

Turning to scheduled transmission outages, Dr. Chadalavada identified two for the month of May: (i) Line 391 (Scobie Pond - Buxton) from May 13 to May 17 and (ii) Line 390 (Orrington - Point Lepreau) from May 16 to 26. The Line 390 outage would impact the New England-New Brunswick interface and Orrington South limit, which would be reduced to 500 MW during the duration of the outage. In response to a question on further outage updates, Dr. Chadalavada reminded the Committee that Line 312 (Berkshire - Northfield Mountain), which had come back in service for one day, on April 8, specifically to support Eclipse efforts, would be out until May 10. He also identified an overlapping outage impacting Line 398 (Pleasant Valley – Long Mountain) that would extend a little beyond May 10. He noted the significant amount of work being conducted on, and the variability in transfer capability of, the New York – New England AC interface, encouraging members to look at transfer limits daily because the limits were changing from 0-900 MW frequently, even hourly.

April 8th Solar Eclipse

Dr. Chadalavada then reported on the impact of the April 8 solar eclipse (Eclipse). He said that, as expected, operators were prepared, the Eclipse's effects on the system were completely met by market resources, and supplemental, out-of-market commitments had not been necessary. He noted that, just prior to the Eclipse, the majority of the system's energy was being produced by a near-record high of solar resources (approximately 5,650 MW from BTM photovoltaic (PV), 730 MW from commercial PV). The Eclipse reduced solar output by approximately 4,000 MW (reductions of 3,300 MW of BTM PV and 700 MW of commercial PV). As solar output ramped down, he explained, imports (which increased by approximately 1,200 MW during the peak of the Eclipse), natural gas and hydro resources compensated for the reduction in solar production. He reported that LMPs spiked to more than $100/MWh as load ramped up during the Eclipse. System load ramped up by more than 4,000 MW, which was the largest load ramp recorded in the past 20 years. The steep load ramp, averaging 60 MW per minute, far exceeded the maximum load ramp of 2,000-2,200 MW typically experienced. In response to a question as to whether or not there was any data evidencing the emissions effects of the Eclipse, Dr. Chadalavada stated that the phenomenon was too transitional and of short duration to produce any meaningful data to that end, and speculated that any incremental emissions savings that might have resulted from additional consumer actions to reduce load would have been negligible.

A member, commending the ISO's efforts to improve its solar forecasting more generally, requested that Dr. Chadalavada consider adding information to future COO reports on solar forecasting, including percentage error measurements. Dr. Chadalavada, acknowledging with appreciation the forecasting work completed to date by ISO personnel, assured the Committee that the ISO was committed to continued consideration of ways to improve the compilation and granularity of data, and that he would include, if possible, exhibits or information related to solar forecasting in his future reports.

New Brunswick Security Energy Transactions

In response to a question asked prior to the meeting, Dr. Chadalavada explained that, infrequently, but from time-to-time, security energy transactions are necessary because New Brunswick has a specific topology configuration that leaves it vulnerable to a single generation source loss under certain circumstances. Specifically, when transfer capability between New England and New Brunswick is reduced due to transmission lines being out of service, there is a minimum flow required to protect against a loss of generation in New Brunswick, which would otherwise cause power, exceeding the transfer capability of the remaining lines, to rush from New England to New Brunswick. To protect against this kind of transfer capability exceedance, the ISO and the New Brunswick System Operator coordinate (ahead of any such loss) to establish a pre-contingency flow, typically in the 100 MW range. If the flow is scheduled outside the market, through Control Area-to-Control Area administration, the costs are split evenly between New Brunswick and New England, and within New England, the costs allocated pool-wide based on Network Load. However, Dr. Chadalavada noted that when the ISO calls for security energy transactions (through energy security notifications), the market almost always fills those transactions, obviating the need for the control room to schedule additional, out-of-market transactions.

In response to questions, Dr. Chadalavada clarified that, directionally, security energy flows from New Brunswick to New England, but when there is a generation source loss in New Brunswick, energy rushes from New England to New Brunswick. He also reiterated that this phenomenon happens infrequently during the year, and typically only when transfer capability is reduced due to transmission lines being out of service and a minimum flow is required to protect against a loss of generation in New Brunswick.

ORDER 2023-A REVISIONS

Mr. Nick Gangi, the new Transmission Committee (TC) Chair, referred the Committee to the materials circulated in advance of the meeting regarding revisions to the ISO-NE Tariff in response to the requirements of *Order 2023-A* (the *Order No. 2023-A* Revisions). Mr. Gangi provided an overview of the background of the *Order 2023-A* Revisions, noting that, between August 2023 and February 2024, the Transmission Committee had reviewed proposed Tariff provisions in order to respond to the requirements of *Order 2023* (which adopted significant reforms to interconnection procedures, including the move to a first-ready, first-served queue framework that required projects to be clustered and studied together). The changes were primarily in the Open Access Transmission Tariff (Section II of the Tariff) (the OATT), incorporated a number of stakeholder-proposed revisions, and were broadly supported at the March 7 Participants Committee meeting. He further explained that, as a result of *Order 2023-A* issued on March 21, the ISO had proposed additional, incremental reforms, including the allowance of surety bonds for commercial readiness deposits (beginning with the first regular

Order 2023 cluster study process in 2025), the allowance for options to build in the case of shared network upgrades, and an extension of the late-stage System Impact Study completion deadlines. At its April 25 meeting, the TC unanimously recommended Participants Committee support for the incremental changes proposed by the ISO, with two additional conceptual changes that the ISO agreed to include in the final package presented to the Participants Committee for its consideration. Those additional changes were (i) the use of surety bonds for post-transition Commercial Readiness Deposits, once the ISO is prepared to accept such bonds, and (ii) the forfeiture by an Interconnection Customer (IC) of only $5,000 of its application fee should the IC fail to complete all of the Interconnection Request requirements before the close of the Cluster Request Window.

In response to a clarifying question, Mr. Al McBride, ISO Executive Director, Transmission Services & Resource Qualification, confirmed that it will be possible for a Participant that participates in the transitional cluster study to convert its Commercial Readiness Deposit to a surety bond no later than the opening of the first regular Order 2023 Cluster Study process in 2025 should it so choose, and potentially sooner should the ISO be able to get in place earlier the appropriate processes and controls.

The following motion was then duly made and seconded:

> RESOLVED, that the Participants Committee supports revisions to Section II of the Tariff, as proposed by ISO-NE in response to FERC Order No. 2023-A and recommended by the Transmission Committee at its April 25, 2024 meeting, and as reflected in the materials distributed to the Participants Committee in advance of this meeting (including the specific changes to Sections 3.1 and 3.4.4 of Schedules 22, 23 and 25 finalized after the April 25 TC meeting), together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Transmission Committee.

Participants thanked the ISO for its efforts, particularly its willingness to receive and reflect stakeholder feedback in its proposed changes. Without further discussion, the motion was voted and ~~unanimously~~ approved unanimously, with an abstention recorded for Mr. Lamson.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the May 1, 2024 Litigation Report that had been circulated and posted before the meeting. He highlighted the following:

(i) FERC's special open meeting scheduled for May 13 at which the FERC was expected to issue two final rules -- one on electric regional transmission planning and cost allocation and generator interconnection and one on transmission siting;

(ii) revisions to delay New England's nineteenth Forward Capacity Auction (FCA19) until February 2028 remained pending, with an order expected on or about May 20;

(iii) the FERC's April 11 order conditionally accepting ISO-NE's January 31 further *Order 2222* compliance filing, subject to an additional, relatively straight-forward compliance filing, due on or before June 10, 2024, that explicitly includes meter data submission deadlines in the Tariff, rather than just in ISO-NE's Manuals; and

(iv) that changes to the NEPOOL and Participants Agreements, which modify the allocation of any unused Provisional Member Group Seat voting share to all six Sectors, had been approved unanimously in the balloting authorized at the April meeting, with the requisite filing of those changes with the FERC being prepared for submission. The filing and status of the changes would be summarized in future Litigation Reports.

COMMITTEE REPORTS

Markets Committee (MC). Mr. Bill Fowler reported that the next MC meeting was scheduled for May 7-8, 2024, in person both days, at the DoubleTree in Milford, MA. The agenda and most of the materials for that meeting had been posted to the ISO website. He added that the MC's summer meeting was scheduled for July 9-10. The invitation for that meeting had been issued and he encouraged all those interested to book overnight arrangements and to attend.

Reliability Committee (RC). Mr. Bob Stein, the RC Vice-Chair, reported that the next RC meeting was scheduled for May 14, 2024, also at the DoubleTree in Milford, MA. Topics for consideration would be discussion of changes to planning procedures related to *Order 2023* and *Order 2023-A* compliance, a new planning procedure to address data collection on distributed energy resources, and continued discussion of components of the regional energy shortage threshold (REST).

Transmission Committee. Mr. Dave Burnham, the TC Vice-Chair, reported that the next TC meeting was scheduled to be held virtually on May 16, 2024. The agenda would include a vote on a definitional change associated with the Day-Ahead Ancillary Services Initiative (DASI), a presentation by NEPOOL counsel on the expected May 13 FERC final rules, and a potential discussion related to the FERC's notice of proposed rulemaking (NOPR) on compensation for reactive power within the standard power factor range.

Budget & Finance Subcommittee (B&F). Mr. Tom Kaslow, B&F Chair, reported that the next B&F Subcommittee meeting was scheduled for Friday, May 10, 2024 at 9:30 a.m. (one-half hour earlier than usual) to continue discussion on the topic of FCM Delivery Financial Assurance.

Membership Subcommittee. Mr. Brad Swalwell, Subcommittee Chair, reported that the next Membership Subcommittee meeting was scheduled to be held by Zoom on May 13. Those interested in participating were encouraged to reach out to NEPOOL counsel, Pat Gerity, for the Zoom information.

ADMINISTRATIVE MATTERS

Mr. Lombardi reminded the Committee of NECPUC's annual symposium that would be held May 19-21, 2024 at the Omni Mount Washington Hotel in Bretton Woods, New Hampshire. He highlighted the June 25-27 Participants Committee Summer Meeting, which would also be held at the Omni Mount Washington, and encouraged folks to register for the Summer meeting, if they hadn't already. He announced that the Participants Committee's previously scheduled June 6 meeting was cancelled and could be removed from members' calendars. A formal notice of that cancellation would also be circulated by e-mail.

There being no further business, the meeting was then adjourned at 11:30 a.m.

Respectfully submitted,

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Sebastian Lombardi, Secretary

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN MAY 2, 2024 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Ashburnham Municipal Light Plant	Publicly Owned Entity			Brian Forshaw (tel)
AVANGRID: CMP/UI	Transmission		Jason Rauch (tel)	
Bath Iron Works Corporation	End User			Bill Short
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
BlueWave Ppublic Benefit Corp.	AR-DG	Mike Berlinski (tel)		
Boylston Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
BP Energy Company (BP)	Supplier			José Rotger (tel)
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity			Brian Forshaw (tel)
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield (tel)		
Clearway Power Marketing LLC	Supplier			Pete Fuller
Competitive Energy Services	Supplier		Eben Perkins (tel)	
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop. (CMEEC)	Publicly Owned Entity	Brian Forshaw (tel)	Richard Gaudet (tel)	
Connecticut Office of Consumer Counsel (CT OCC)	End User		Jamie Talbert-Slagle	Chelsea Mattioda
Conservation Law Foundation (CLF)	End User	Phelps Turner (tel)		
Constellation Energy Generation	Supplier	Gretchen Fuhr (tel)	Bill Fowler	
CPV Towantic, LLC (CPV)	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger (tel)	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dominion Energy Generation Marketing	Generation	Wes Walker (tel)		
DTE Energy Trading, Inc. (DTE)	Supplier			José Rotger (tel)
Durgin and Crowell Lumber Co., Inc.	End User			Bill Short
Dynegy Marketing and Trade, LLC	Supplier	Ryan McCarthy		Bill Fowler
ECP Companies Calpine Energy Services, LP (Calpine) New Leaf Energy	Generation	Andy Gillespie	Brett Kruse (tel) Alex Chaplin (tel)	Bill Fowler
EDF Trading North America, LLC	Supplier	Eric Osborn		
Elektrisola, Inc.	End User			Bill Short
Emera Energy Companies	Supplier			Bill Fowler
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission	James Daly (tel)	Dave Burnham	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc. (Galt)	Supplier	José Rotger (tel)		
Garland Manufacturing Company	End User			Bill Short
Generation Bridge Companies	Generation		Bill Fowler	
Generation Group Member	Generation		Abby Krich (tel)	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Granite Shore Companies	Generation			Bob Stein
Groton Electric Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQ US)	AR-RG	Louis Guibault (tel)	Bob Stein	
Hammond Lumber Company	End User			Bill Short
Hanover, NH	End User			Bill Short
High Liner Foods (USA) Incorporated	End User		William P. Short III	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN MAY 2, 2024 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Holyoke Gas & Electric Department	Publicly Owned Entity			Brian Forshaw (tel)
Hull Municipal Lighting Plant	Publicly Owned Entity			Brian Forshaw (tel)
Icetec Energy Services, Inc. (Icetec)	AR-LR	Doug Hurley		
Ipswich Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths	Nancy Chafetz (tel)	
Jupiter Power	AR-RG		Ron Carrier (tel)	
Lamson, Jon	End User	John Lamson		
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Long Island Power Authority (LIPA)	Supplier	Bill Kilgoar (tel)		
Maine Power LLC	Supplier	Jeff Jones (tel)		
Maine Public Advocate’s Office (Maine OPA)	End User			Chelsea Mattioda
Mansfield Municipal Electric Department	Publicly Owned Entity			Brian Forshaw (tel)
Marble River, LLC	Supplier		John Brodbeck (tel)	
Marblehead Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Mass. Attorney General’s Office (MA AG)	End User	Jacquelyn Bihrle		Jamie Donovan
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Department of Capital Asset Management	End User			Nancy Chafetz (tel)
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity			Brian Forshaw (tel)
Mercuria Energy America, LLC	Supplier			José Rotger (tel)
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Moore Company	End User			Bill Short
Narragansett Electric Co. (d/b/a RI Energy)	Transmission	Brian Thomson	Lindsay Orphanides (tel)	
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw (tel)
New Hampshire Office of Consumer Advocate (NHOCA)	End User	Matthew Fossum		
New England Power (d/b/a National Grid)	Transmission	Tim Brennan	Tim Martin	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson		
NextEra Energy Resources, LLC	Generation	Michelle Gardner	Nick Hutchings	
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Business Marketing, LLC	Supplier		Pete Fuller	
Nylon Corporation of America	End User			Bill Short
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Pawtucket Power Holding Company LLC	Generation			Bill Fowler
Paxton Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Peabody Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
PowerOptions, Inc.	End User			Chelsea Mattioda
Princeton Municipal Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
RI Division (DPUC)	End User	Paul Roberti		
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity			Brian Forshaw (tel)
Saint Anselm	End User			Bill Short
Shipyard Brewing LLC	End User			Bill Short

.

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN MAY 2, 2024 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Shrewsbury Electric & Cable Operations	Publicly Owned Entity			Brian Forshaw (tel)
Sierra Club	End User	Casey Roberts (tel)		
South Hadley Electric Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Sterling Municipal Electric Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Pete Fuller
Tangent Energy Inc.	AR-LR	Brad Swalwell (tel)		
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity			Brian Forshaw (tel)
The Energy Consortium	End User		Mary Smith (tel)	
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw (tel)
Versant Power	Transmission	Dave Norman (tel)		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Vineyard Offshore	Generation	Carrie Hitt (tel)		
Vitol Inc.	Supplier	Seth Cochran		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity			Brian Forshaw (tel)
Walden Renewables Development LLC	Generation			Abby Krich (tel)
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity			Brian Forshaw (tel)
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	
ZTECH, LLC	End User			Bill Short

CONSENT AGENDA

Day-Ahead Ancillary Services Initiative (DASI) Conforming Changes

Markets Committee (MC)

From the previously-circulated notice of actions of the MC's ***May 7-8, 2024 meeting****, dated May 9, 2024.*[1]

1. **MC-Recommended Changes to Tariff §§ III (Market Rule 1) and I.2.2 (Definitions)**

   Support the proposed revisions to (i) Market Rule 1, including Appendix F, to include modifications to Day-Ahead Net Commitment Period Compensation (NCPC) and Special Case NCPC, clarifications to Self-Scheduled External Transactions, modifications to Day-Ahead excess energy conditions, clarifications to Demand Response Resource Day-Ahead Ancillary Service obligations; and (ii) to Section I.2.2 of the Tariff,[2] as recommended by the MC at its May 7-8 meeting, together with such further non-material changes as the Chair and Vice-Chair of the MC may approve.

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

Reliability Committee (RC)

From the previously-circulated notice of actions of the RC's ***May 14, 2024 meeting****, dated May 14, 2024.*[3]

2. **RC-Recommended Changes to Tariff § I.2.2**

   Support DASI-conforming revisions to Tariff Section I.2.2,[4] as recommended by the RC at its May 14, 2024 meeting, together with such other non-material changes as the Chair and Vice-Chair of the RC may approve.

   The motion to recommend Participants Committee support was approved unanimously.

Transmission Committee (TC)

From the previously-circulated notice of actions of the TC's ***May 16, 2024 meeting****, dated May 16, 2024.*[5]

3. **TC-Recommended Changes to Tariff § I.2.2**

   Support DASI-conforming revisions to Tariff Section I.2.2,[6] as recommended by the TC at its May 16, 2024 meeting, together with such other non-material changes as the Chair and Vice-Chair of the TC may approve.

   The motion to recommend Participants Committee support was approved unanimously.

Budget & Finance Subcommittee (B&F)

The same changes to the definitions of "Block", "Day-Ahead Ancillary Services Offer Block-Hours" and "Energy ETUs", that will flow through the existing ISO Self-Funding Tariff framework in Tariff Section IV.A, were also considered without objection by B&F.

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

[2] Proposed revisions to § I.2.2 considered by the MC are to the following definitions: "Block", "Day-Ahead Ancillary Services Offer Block-Hours", "Day-Ahead Market NCPC Credit", "Effective Offer", "Energy Transaction Units (Energy TUs)", and "Self-Schedule".

[3] 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.

[4] The RC considered the change to the definition of "Block" as that term is used in § III.9.5.3.1.

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

[6] The TC considered the change to the definition of "Self-Schedule" as that term is used in § II.44.

Additional MC Recommendations

*Also from the previously-circulated notice of actions of the MC's **May 7-8, 2024 meeting**.*

4. **Changes to the NEPOOL Generation Information System (GIS) and GIS Operating Rules (Clean Peak Standard Data Batch Uploads)**

Approve changes to the GIS to support the batch upload of Clean Peak Resource data, as recommended by the MC at its May 7-8, 2024 meeting, together with such further non-material changes as the Chair and Vice-Chair of the MC may approve.

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

5. **Changes to Appendix A to Market Rule 1 (MW-Dependent Fuel Price Adjustments)**

Support the proposed revisions to Appendix A to Market Rule 1 (Market Monitoring, Reporting and Market Power Mitigation) to allow Market Participants the ability to reflect up to two different prices in their Resource's cost-based Reference Levels, as recommended by the MC at its May 7-8, 2024 meeting, together with such further non-material changes as the Chair and Vice-Chair of the MC may approve.

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

6. **Change to Market Rule 1 § 6.4(f) (Further *Order 2222* Compliance – Addition of Meter Data Submission Deadline to Tariff)**

Support the proposed revisions to Market Rule 1 to include in the Tariff the meter data submission deadline applicable to Distributed Energy Resource Aggregators, as recommended by the MC at its May 7-8, 2024 meeting, with such further non-material changes as the Chair and Vice-Chair of the MC may approve.

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

Additional RC Recommendation

*Also from the previously-circulated notice of actions of the RC's **May 7-8, 2024 meeting**.*

7. **Revisions to OP-14 (Automatic Voltage Regulator Requirement Clarifications)**

Support revisions to ISO New England Operating Procedure No. 14 (Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources),[7] as recommended by the RC at its May 14, 2024 meeting, together with such further non-material changes as the Chair and Vice-Chair of the MC may approve.

The motion to recommend Participants Committee approval was approved unanimously.

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[7] The recommended revisions to OP-14 include changes to: (i) apply only to generators interconnected at 69 kV or higher voltage existing Automatic Voltage Regulator (AVR) and governor requirements; and (ii) add direction for AVR and governor control for new generators connecting at voltages below 69 kV and for existing generators that had AVR and governor control per prior OP-14 requirements.

Summary of ISO New England Board and Committee Meetings

June 25, 2024 Participants Committee Meeting

Since the last update, the Audit and Finance Committee, Markets Committee, and the Nominating and Governance Committee met on May 15. The Board of Directors met on May 15 and 16. All of the meetings were held in Boston, Massachusetts.

The Audit and Finance Committee reviewed the Company's financial performance against the 2024 budget, and approved the first quarter's unaudited financial statements after management confirmed that all relevant disclosures were included in the financial statements. Next, the Committee discussed the preliminary 2025 operating and capital budgets, and potential costs related to the clean energy transition. The Committee reviewed a draft of the Company's 2023 tax return on Form 990, and received an update on an ongoing office workspace study to assess future workspace needs. Finally, the Committee considered a proposal for $75 million of private placement funding to support the Company's capital budget. The Committee reflected on why private placement is the most advantageous financing vehicle, discussed other alternatives and the cost of each, and reviewed the cash flow analysis that supports the $75 million borrowing amount. The Committee discussed the factors contributing to the increased capital budget, including the complexity of projects and longer lead times before depreciation expense can be collected, and agreed that the private placement serves a useful function in disciplining spending. The Committee emphasized to management the importance of transparency regarding the capital budget amounts and the inputs into arriving at the annual budget and agreed to recommend that the Board approve the private placement funding arrangement.

The Markets Committee was provided with a market monitoring review of market performance in winter 2023-2024, and received reports from both the Internal and External Market Monitors. In addition, the Committee also discussed the Inventoried Energy Program for winter 2023-2024. Next, the Committee provided final comments on the Internal Market Monitor's draft annual markets report, which assesses the competitiveness of the wholesale markets and reviews market pricing outcomes. The Committee then received an update on the Resource Capacity Accreditation project, and discussed stakeholder feedback and highlights of the key findings related to a market impact analysis.

The Nominating and Governance Committee received an update on Joint Nominating Committee activities and formally nominated the incumbent directors who are eligible for re-election in 2024 (Caren Anders, Mike Curran, and Steve Corneli). The Committee also held a preliminary discussion regarding assignments to Board committees and succession planning for board leadership positions. The Committee discussed the proposed scope for a "deep dive" in September regarding the Company's compliance activities. Next, the Committee reviewed potential topics for discussion with the NEPOOL sectors in June, and discussed the logistics and format for the 2024 open Board meeting. The Committee also discussed recent correspondence with the Consumer Liaison Group Coordinating Committee, and concurred with management's response. In executive session, the Committee reviewed the Board and committees' self-evaluation responses.

The Board of Directors received a report from the Chief Executive Officer, and conducted an in-depth review of the Company's strategic plan. The Board reviewed detailed reports on a variety of key strategic issues. The Board also considered initiatives and related resource requirements for 2025, the impact of trends on the 2040 scenario plan, and related impacts on the "four pillar" trajectories. The Board also discussed the future of significant infrastructure in New England, and the impact of Order No. 1920. On the second day of its meeting, the Board received a presentation by Fintan Slye, Executive Director of the Electricity System Operator for the UK, and discussed his view on opportunities and challenges presented by the Climate Change Act and decarbonization in the UK. Following the session with Mr. Slye, the Board of Directors held its annual meeting of members and elected Ms. Anders and Messrs. Curran and Corneli to the Board of Directors for three-year terms, noting that the slate was previously approved by the NEPOOL Participants Committee at its May 2nd meeting. The Board also prepared for upcoming meetings at the IRC Board Conference and the NECPUC Symposium. The Board then received reports from the standing committees. During the Audit and Finance Committee report, the Board discussed and then approved the private placement funding request. The Board concluded its meeting with an executive session.

NEPOOL Participants Committee Report

June 2024

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Highlights: May 2024

- **Peak Hour** on May 22
  - 17,328 MW system peak (Revenue Quality Metered/RQM); hour ending 7:00 pm
- **Average Pricing**
  - Day Ahead (DA) Hub Locational Marginal Price (LMP): $27.23/MWh
  - Real Time (RT) Hub LMP: $26.25/MWh
  - Natural Gas: $1.60/Mmbtu (MA Natural Gas Avg)
- **Energy Market** value $260M up from $232M in May 2023
  - Ancillary Markets* value $6.9M up from $6.6M in May 2023
  - Average DA cleared physical energy** during the peak hours as percent of forecasted load was 98.5% during May, up from 97.5% during April
  - Updated April Energy Market value: $239M
- **Net Commitment Period Compensation (NCPC)** total $1.6M
  - First Contingency $1.6M
    - Dispatch Lost Opportunity Cost (DLOC) - $318K; Rapid Response Pricing (RRP) Opportunity Cost - $176K; Posturing - $0K; Generator Performance Auditing (GPA) - $0K
    - $121K paid to resources at external locations, down $127K from April
      - $32K charged to Day Ahead Load Obligation (DALO) at external locations, $89K to RT Deviations
  - 2nd Contingency, Distribution and Voltage were zero
- **Forward Capacity Market (FCM)** market value $86.4M
  - FCM peak for 2024 is currently 17,971 MWh (preliminary); hour ending 6:00 P.M. on Wednesday, January 17

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

*Ancillaries = Reserves, Regulation, NCPC, less Marginal Loss Revenue Fund

**DA cleared physical energy is the sum of Generation and Net Imports cleared in the DA Energy Market

Highlights

- On May 20, FERC issued an order accepting the additional delay to FCA 19
- 2024 Economic Study stakeholder-requested scenario proposals will be reviewed and discussed at the June PAC meeting
- EPCET Pilot Study report will be issued in Q3 2024

Forward Capacity Market (FCM) Highlights

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

CCP – Capacity Commitment Period

FCM Highlights, cont.

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

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (1.3°F) Max: 89°F, Min: 43°F Precipitation: 4.82" – Above Normal Normal: 3.25"	Hartford	Temperature: Above Normal (5.2°F) Max: 93°F, Min: 41°F Precipitation: 3.19" - Below Normal Normal: 3.79"

Peak Load:	16,896 MW	May 22, 2024	19:00 (ending)

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

Procedure	Declared	Cancelled	Note
M/LCC 2	05/10/2024 20:30	05/12/2024 22:00	Geomagnetic Disturbance

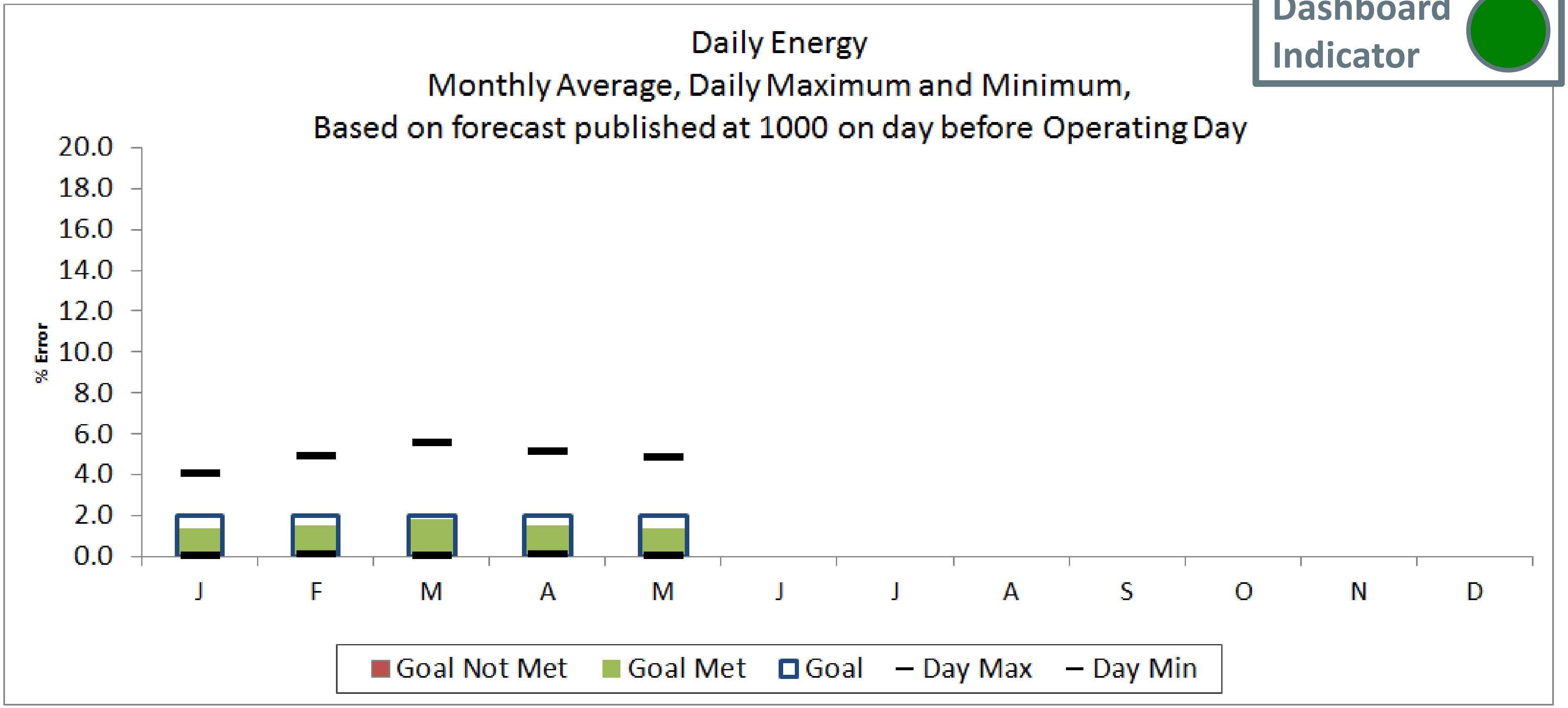
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
05/22/2024	ISO-NE	550

2024 System Operations - Load Forecast Accuracy cont.

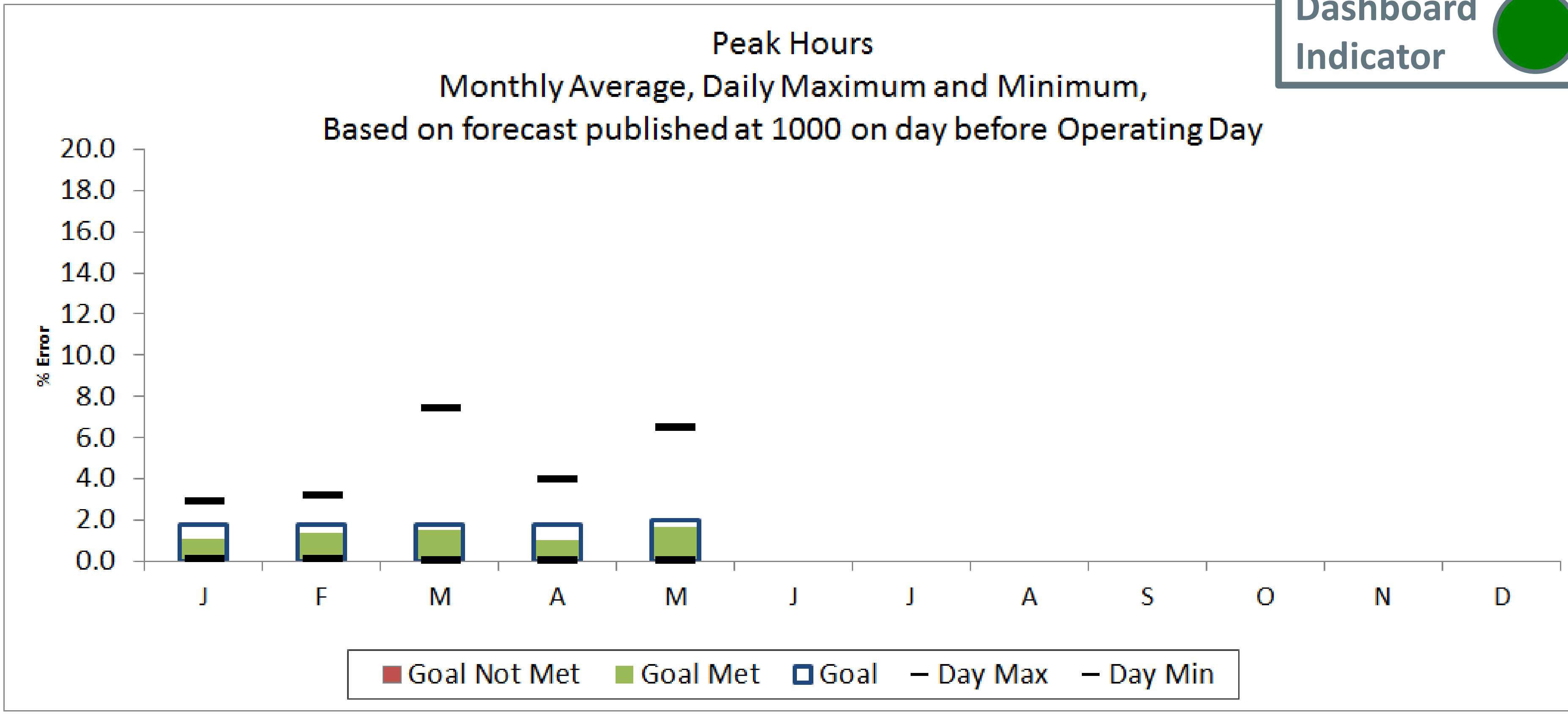
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.02	4.89	5.56	5.09	4.84								5.56
Day Min	0.00	0.12	0.02	0.09	0.07								0.00
MAPE	1.38	1.54	1.83	1.52	1.40								1.53
Goal	2.00	2.00	2.00	2.00	2.00								

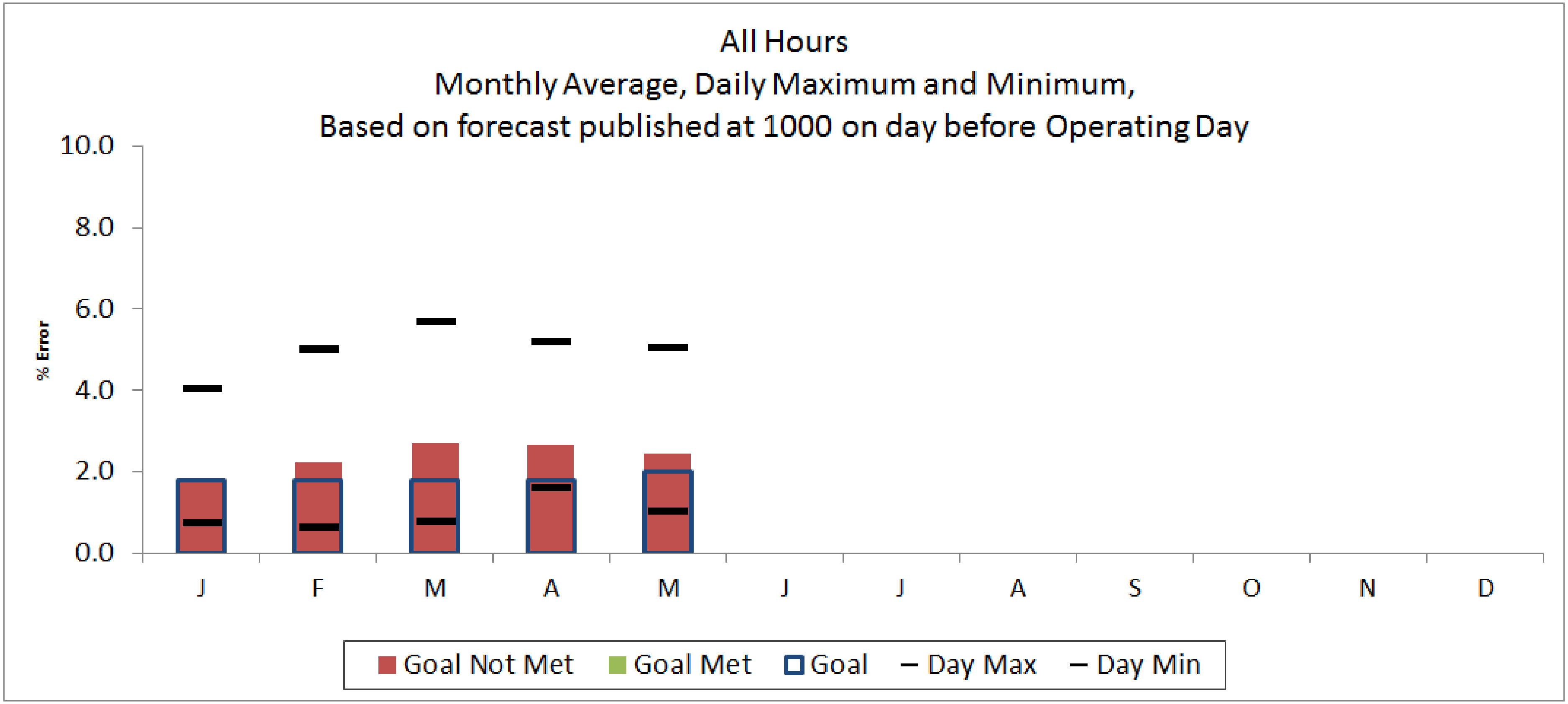
2024 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



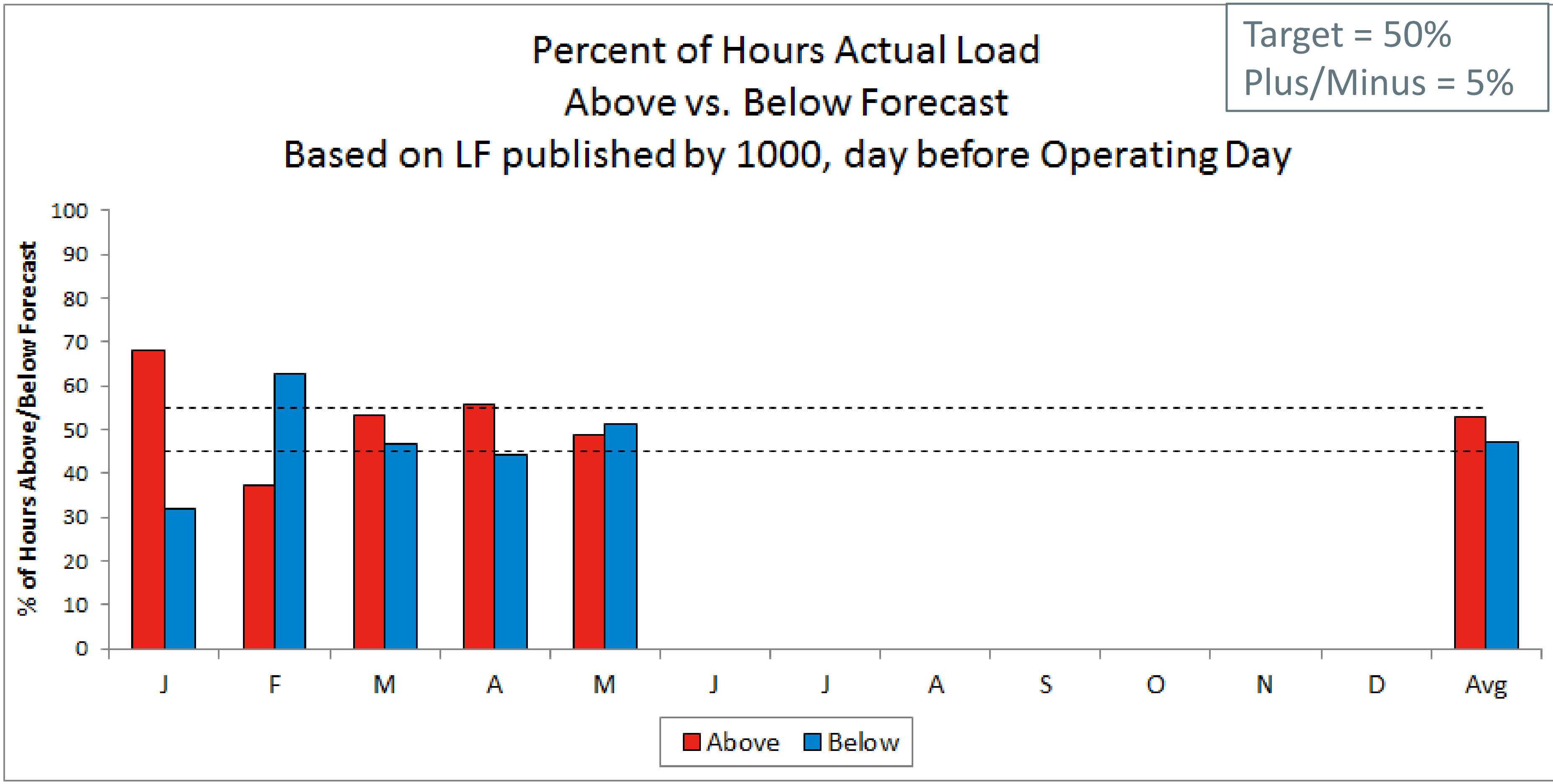
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	2.90	3.17	7.45	3.99	6.46								7.45
Day Min	0.08	0.10	0.02	0.03	0.01								0.01
MAPE	1.10	1.39	1.54	1.02	1.65								1.34
Goal	1.80	1.80	1.80	1.80	2.00								

2024 System Operations - Load Forecast Accuracy



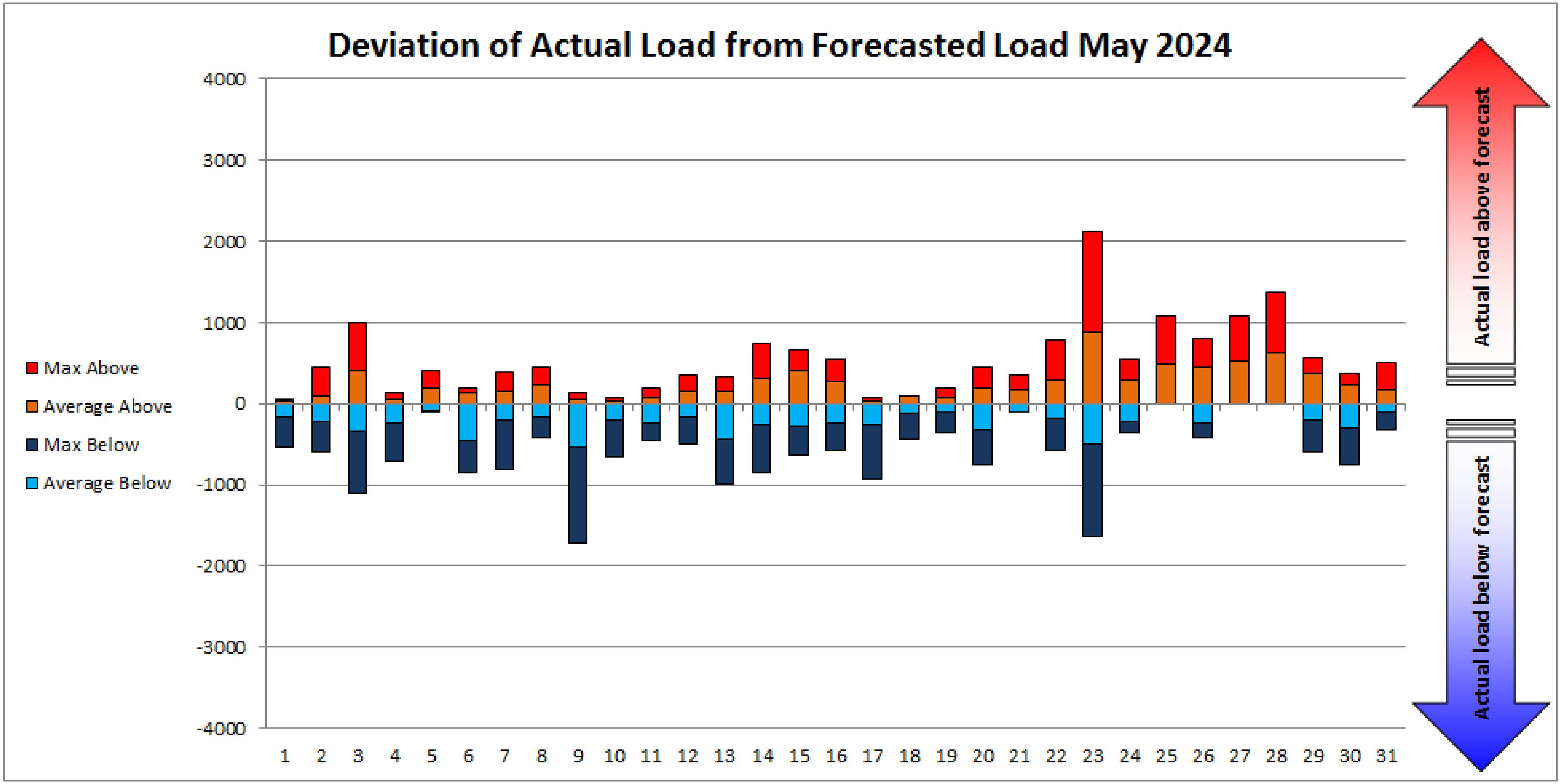
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.03	5.00	5.67	5.18	5.04								5.67
Day Min	0.73	0.64	0.76	1.59	1.00								0.64
MAPE	1.83	2.24	2.72	2.66	2.46								2.38
Goal	1.80	1.80	1.80	1.80	2.00								

2024 System Operations - Load Forecast Accuracy cont.

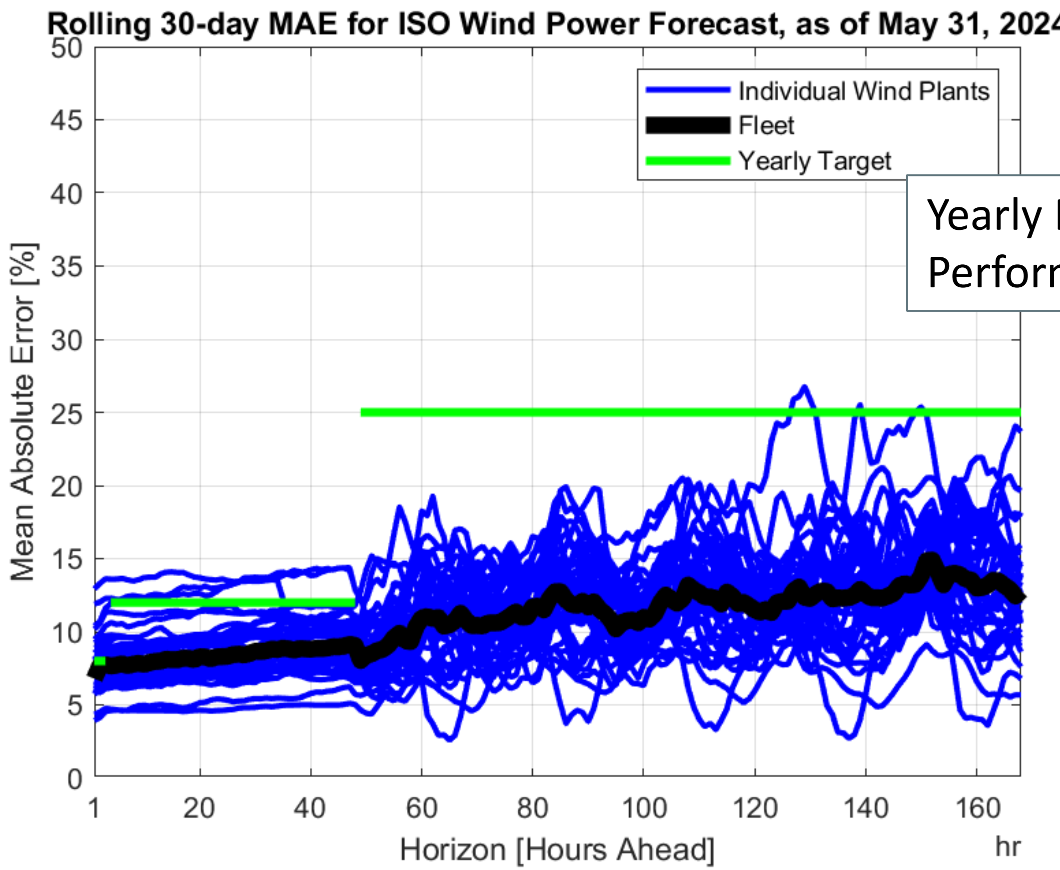


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	67.9	37.4	53.3	55.8	48.7								53
Below %	32.1	62.6	46.7	44.2	51.3								47
Avg Above	260.5	155.2	254.6	254.9	245.5								261
Avg Below	-155.5	-292.3	-253.5	-239.2	-223.2								-292
Avg All	132	-130	39	38	11								20

2024 System Operations - Load Forecast Accuracy cont.



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

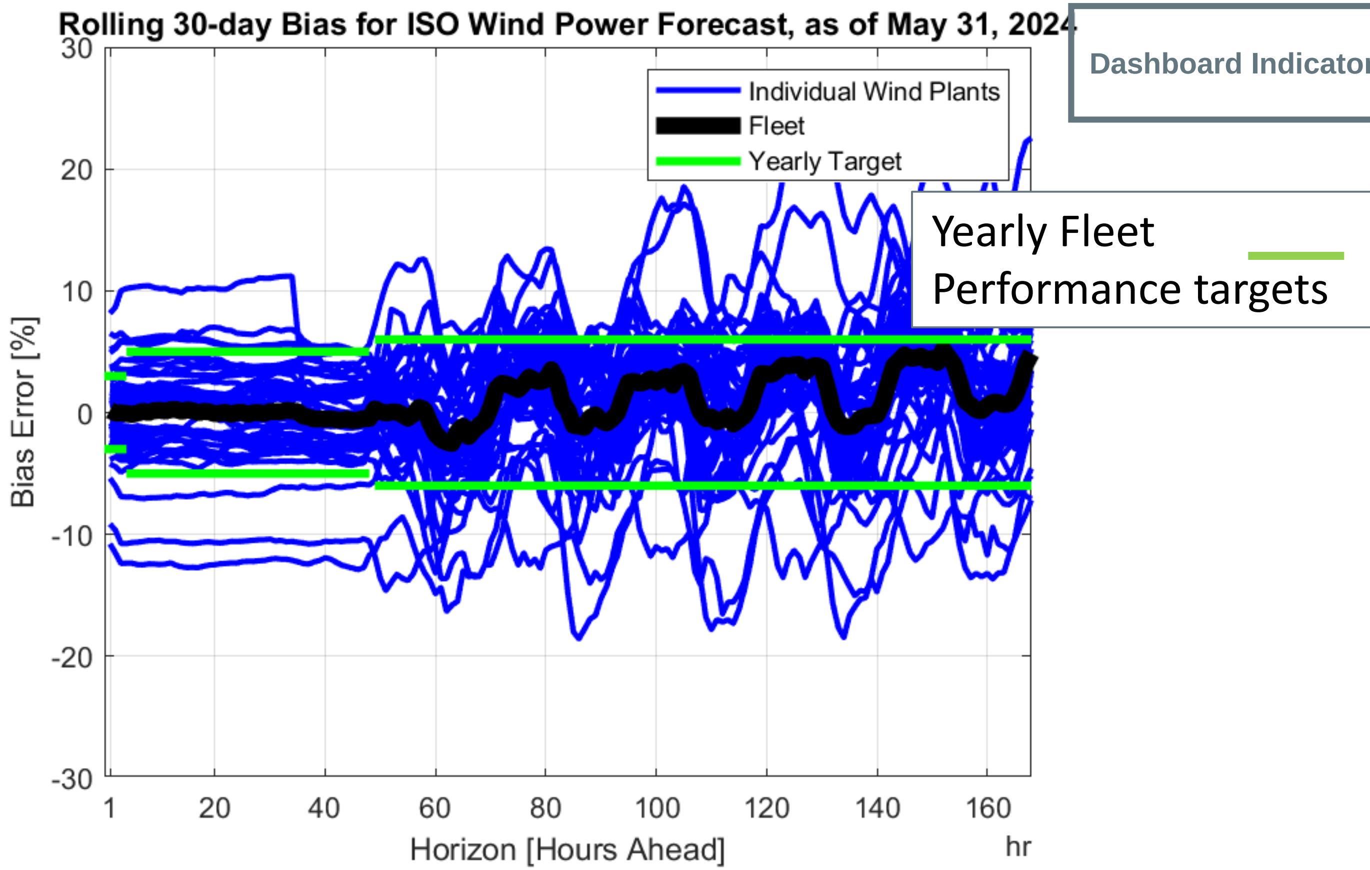


Dashboard Indicator

Yearly Fleet Performance targets

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

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

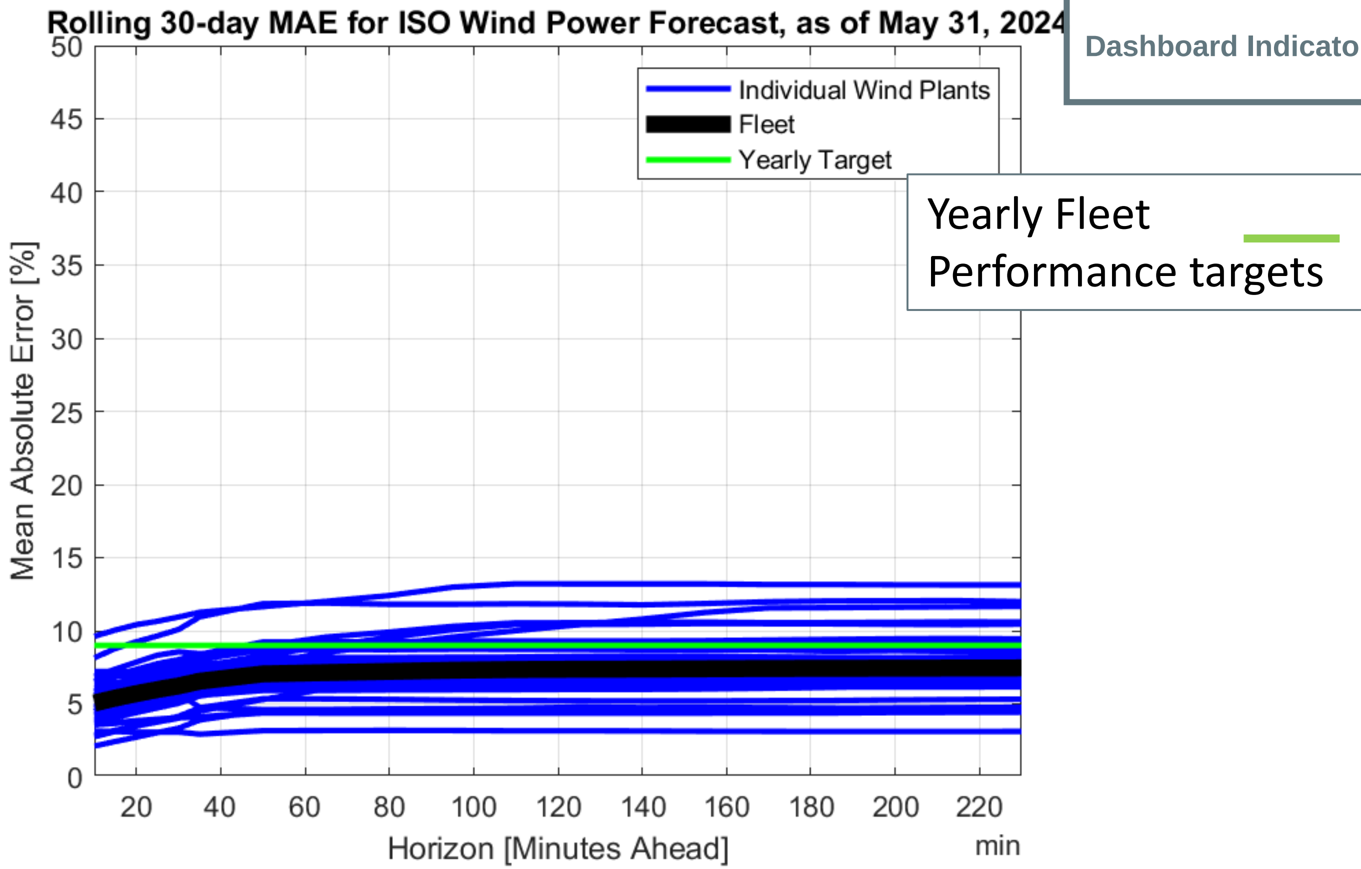


Dashboard Indicator

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

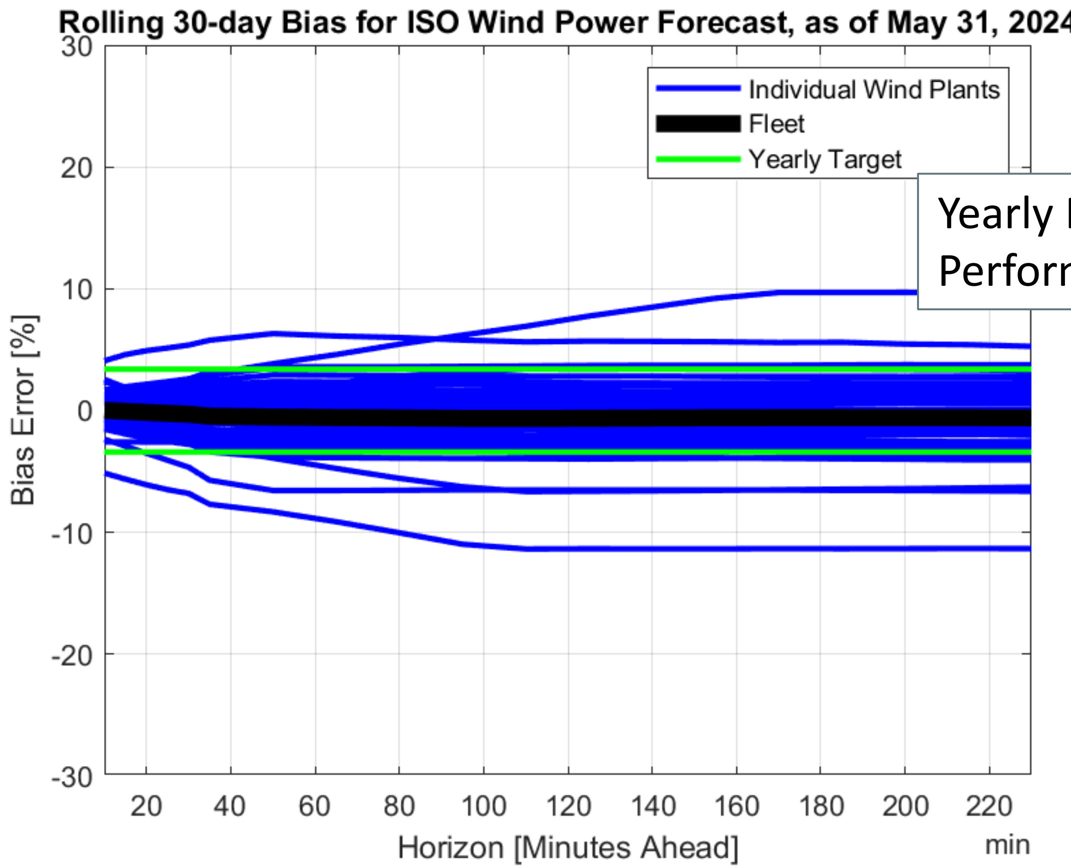
Wind Power Forecast Error Statistics: Short Term Forecast MAE

Dashboard Indicator



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

Wind Power Forecast Error Statistics: Short Term Forecast Bias



Dashboard Indicator

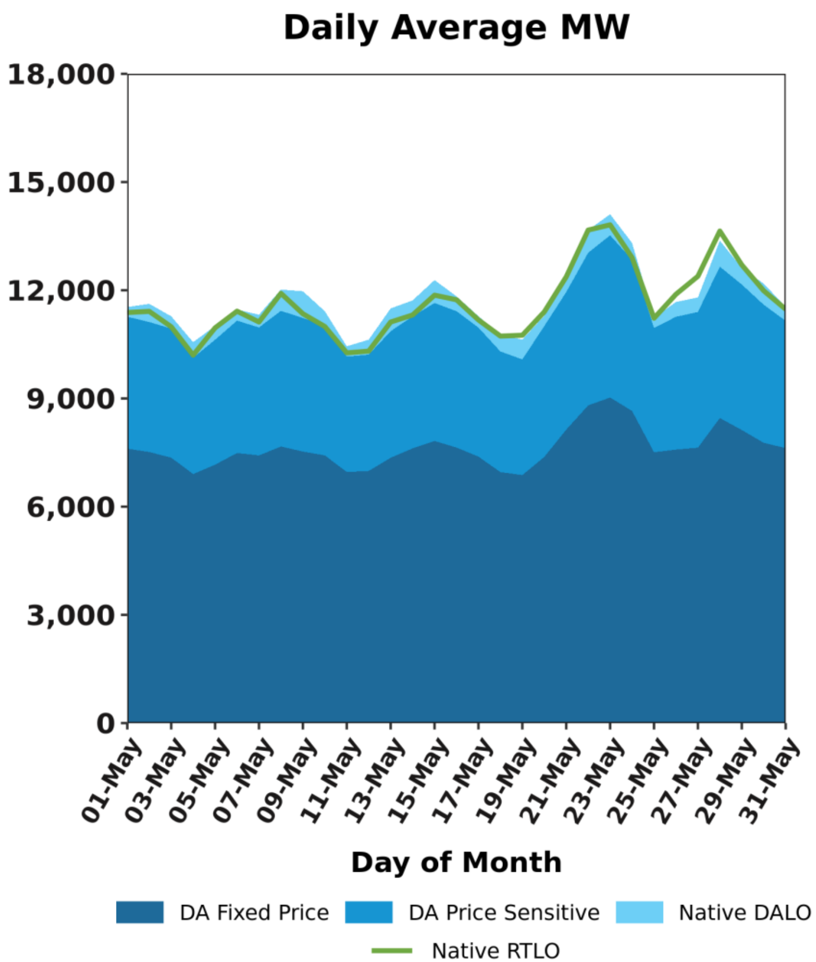
Yearly Fleet Performance targets

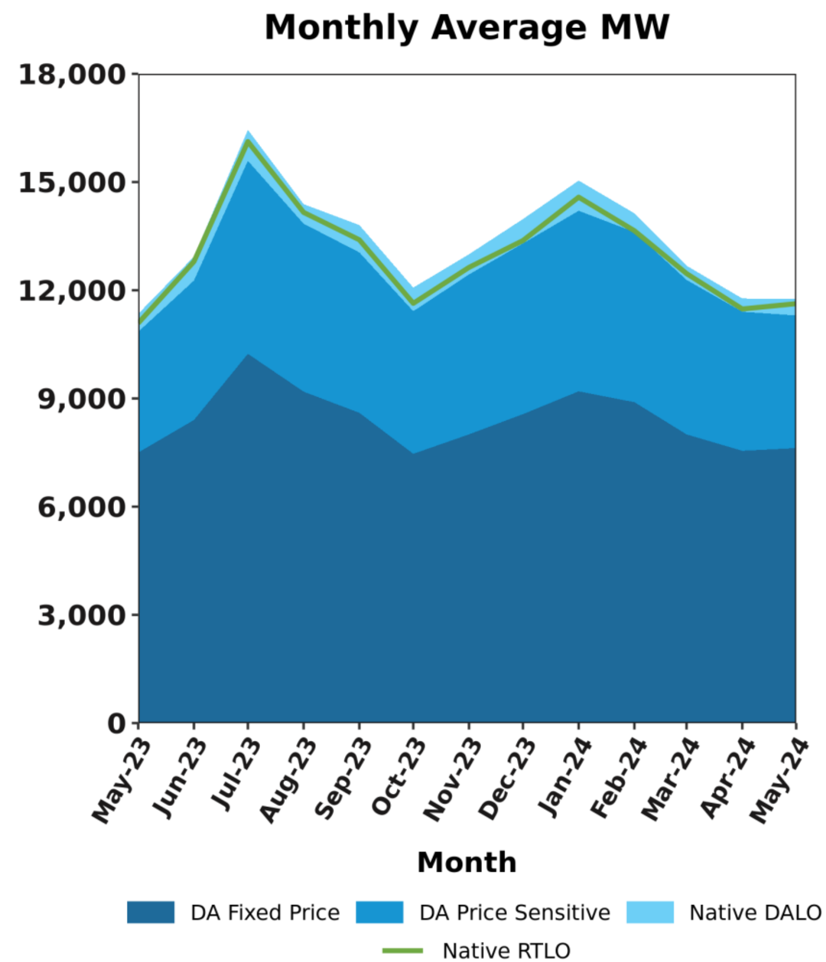
Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV forecast compares well with industry standards, and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

MARKET OPERATIONS

SUPPLY AND DEMAND VOLUMES

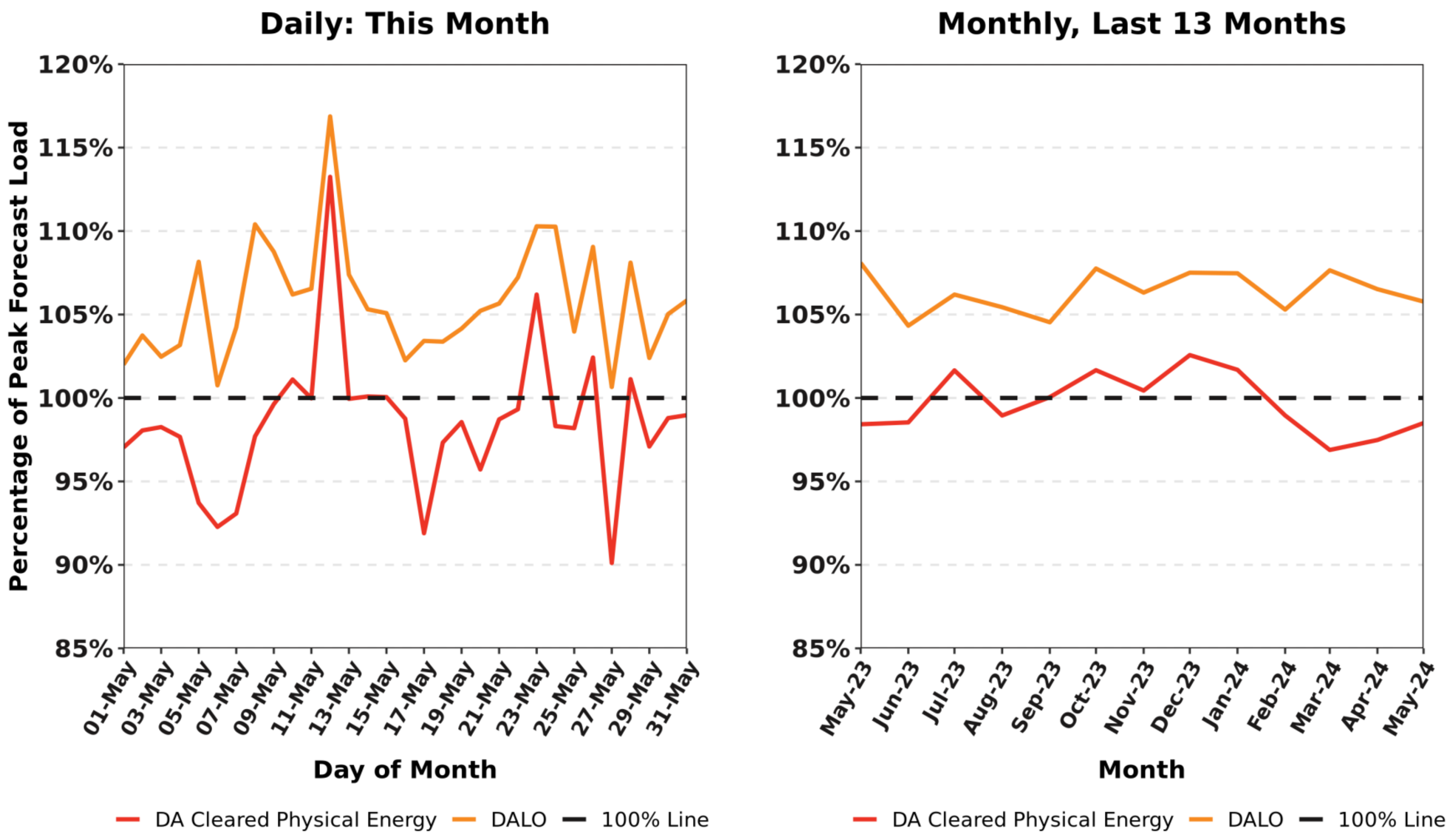
DA Cleared Native Load by Composition Compared to Native RT Load





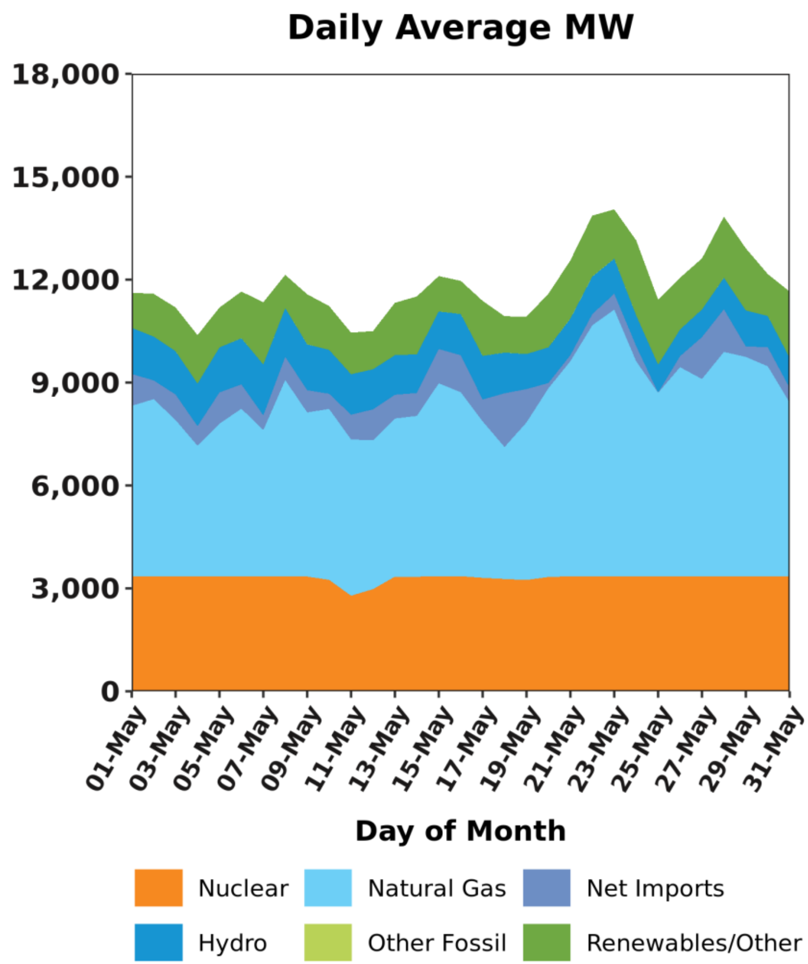
Native Day-Ahead Load Obligation (DALO) is the sum of all day-ahead cleared load, excluding modeled transmission losses and exports
Native Real-Time Load Obligation (RTLO) is the sum of all real-time load, excluding exports

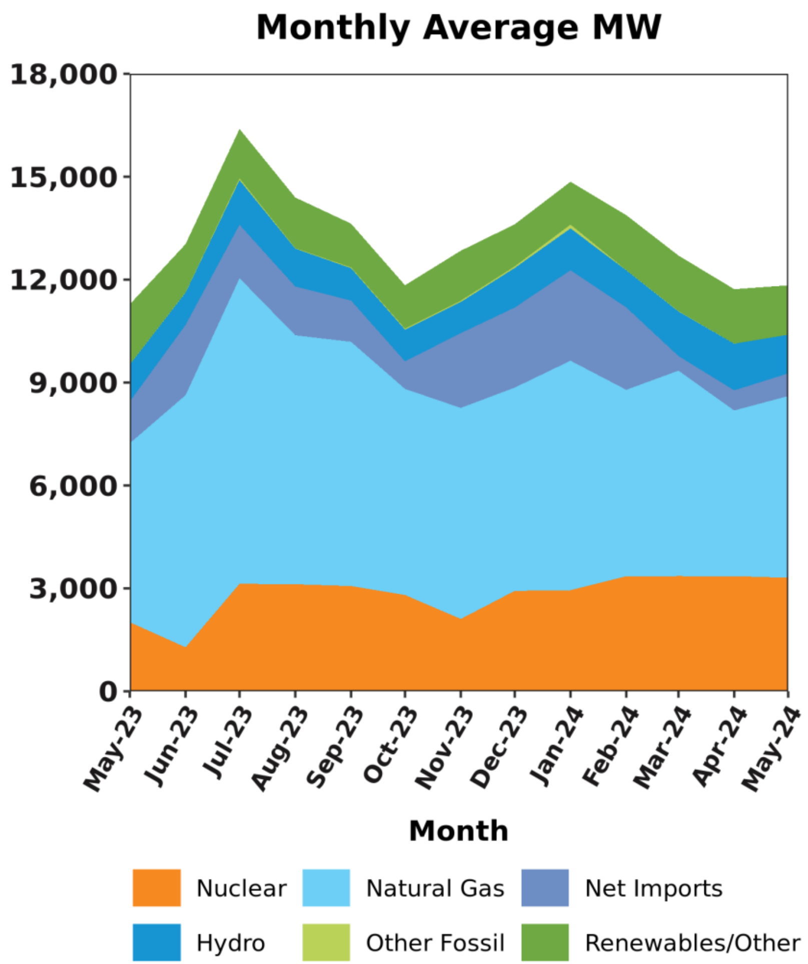
DA Volumes as % of Forecast in Peak Hour



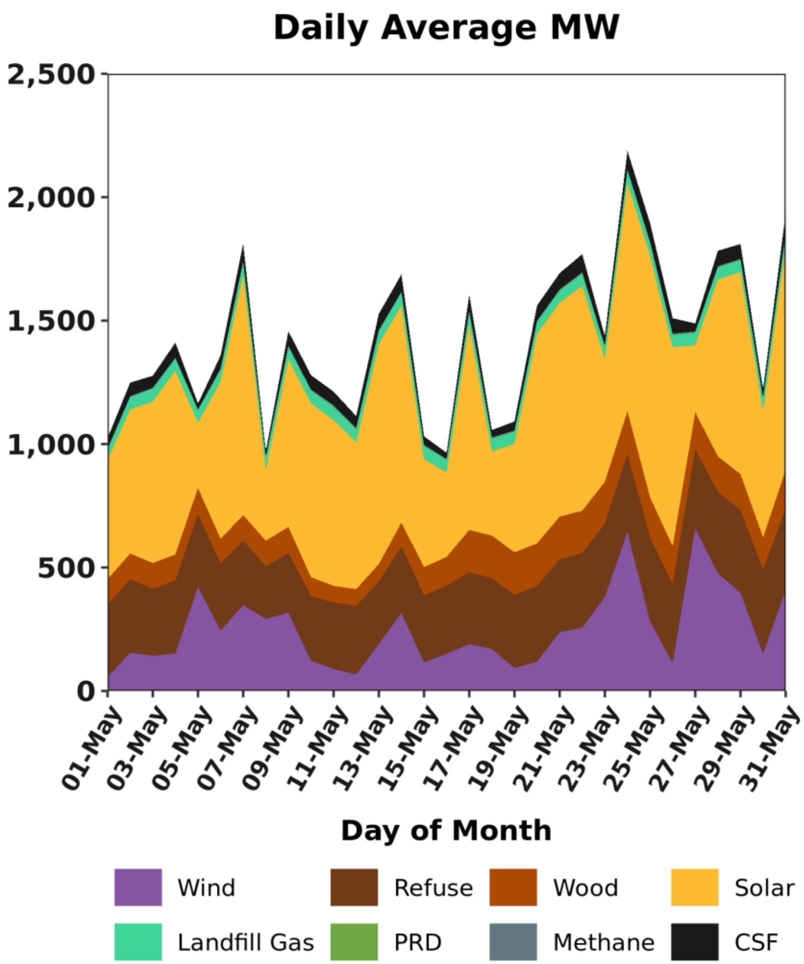
The number of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month was: none

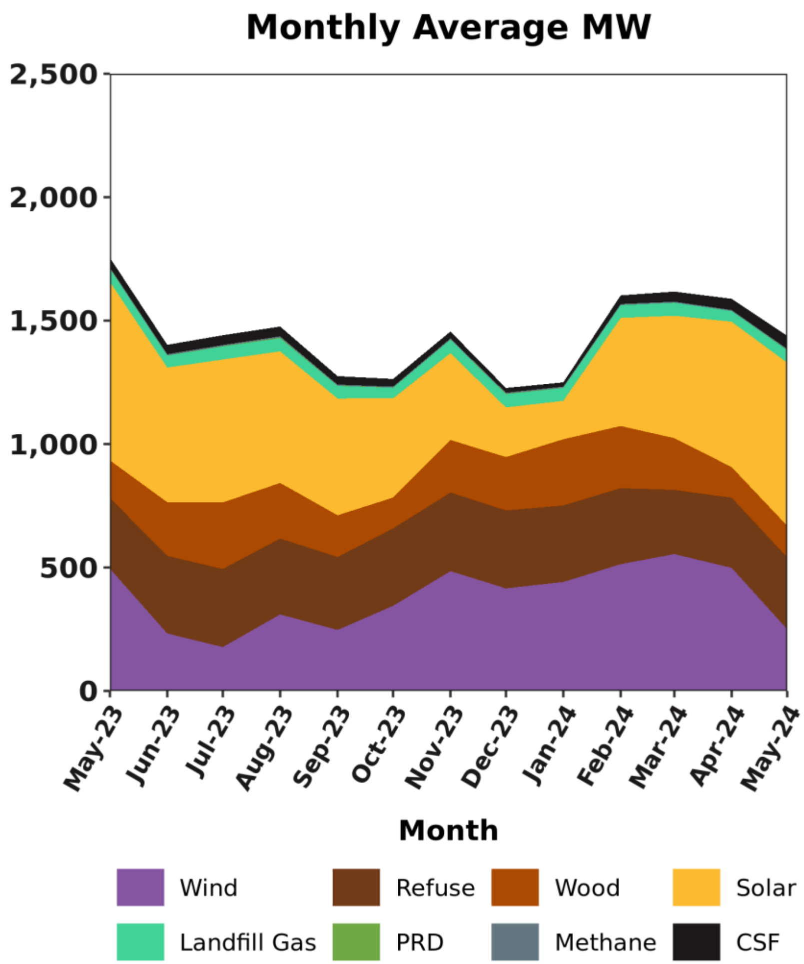
Resource Mix





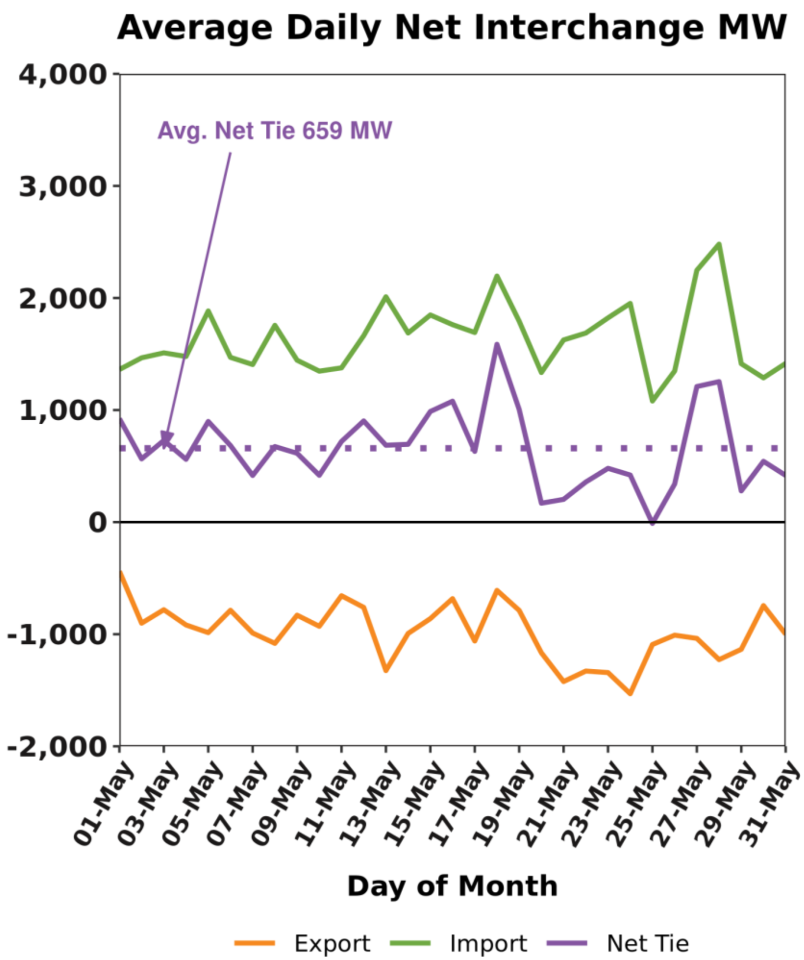
Renewable Generation by Fuel Type

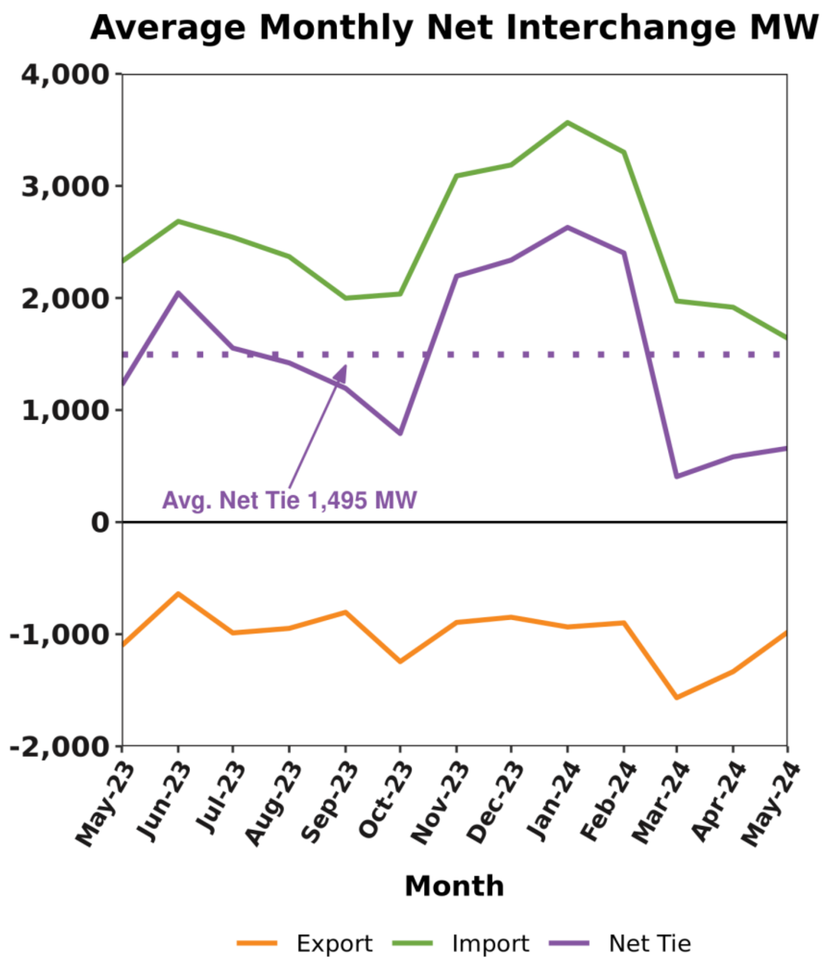




CSF = Continuous Storage Facilities (a.k.a. Batteries)

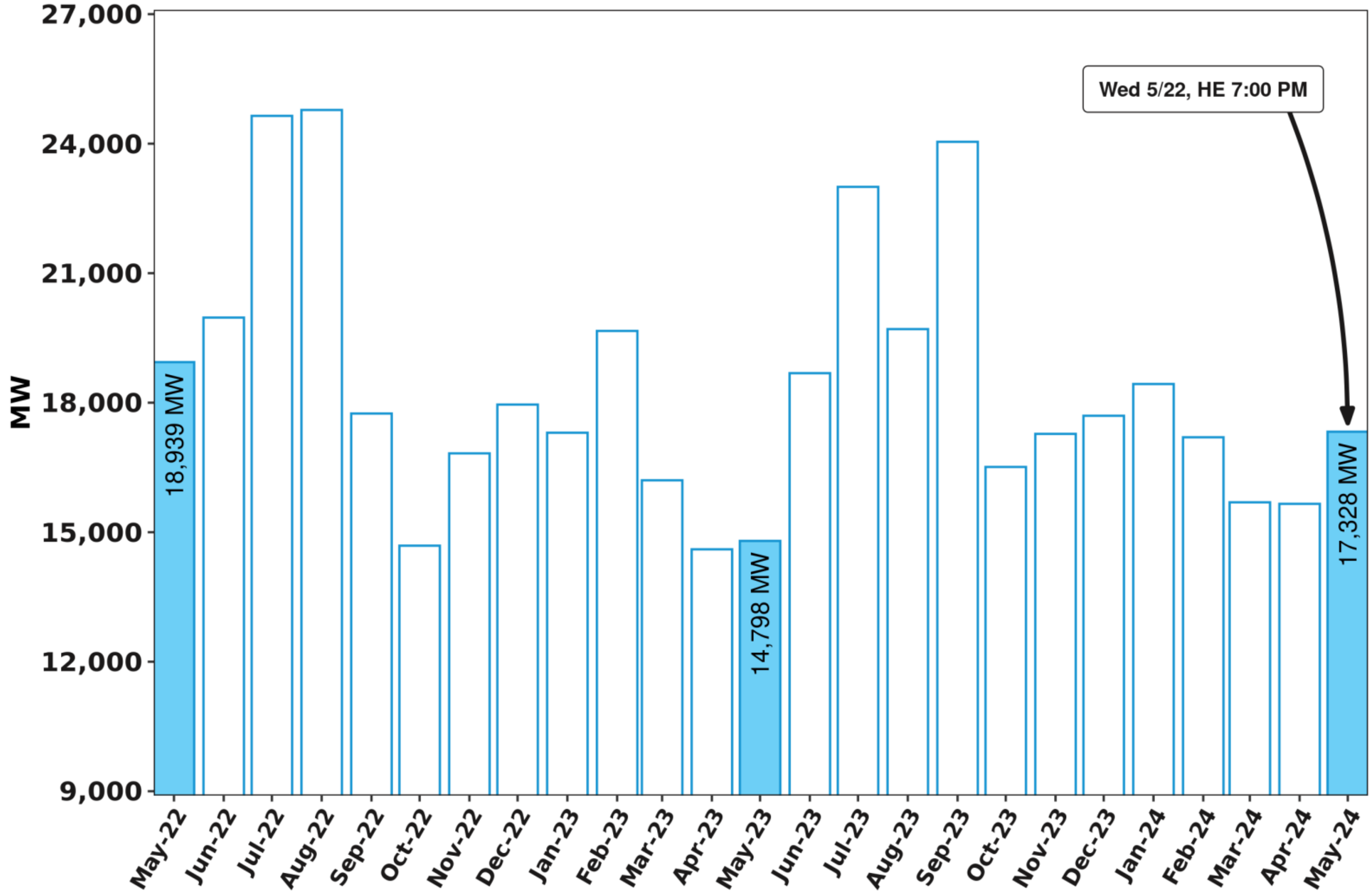
RT Net Interchange





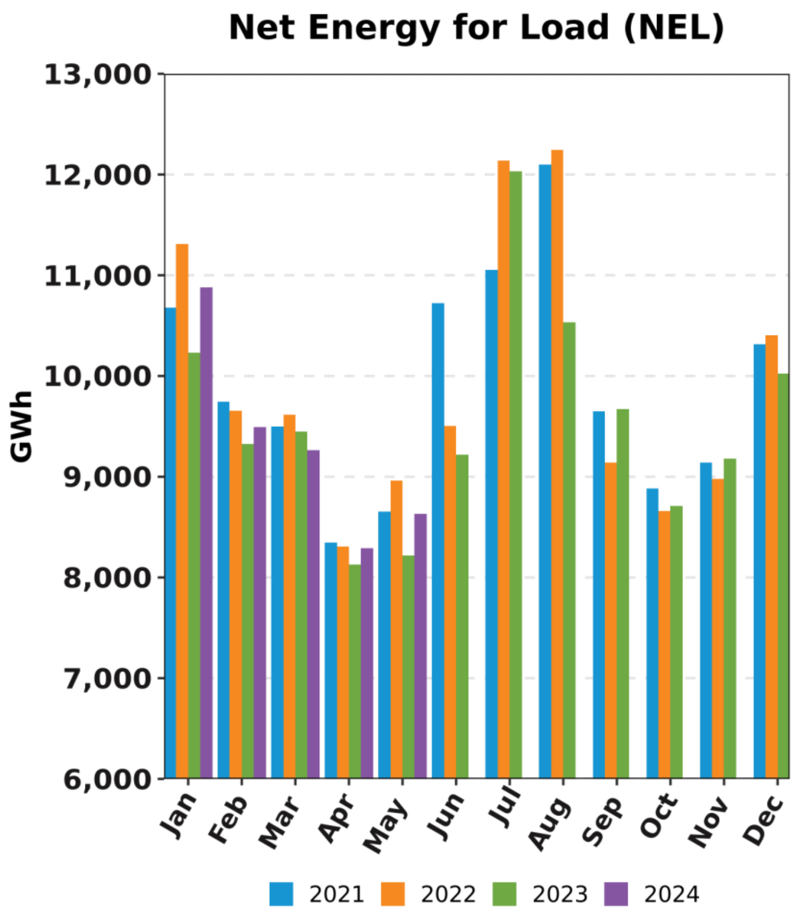
Net Interchange is the participant sum of daily imports minus the sum of daily exports; positive values are net imports

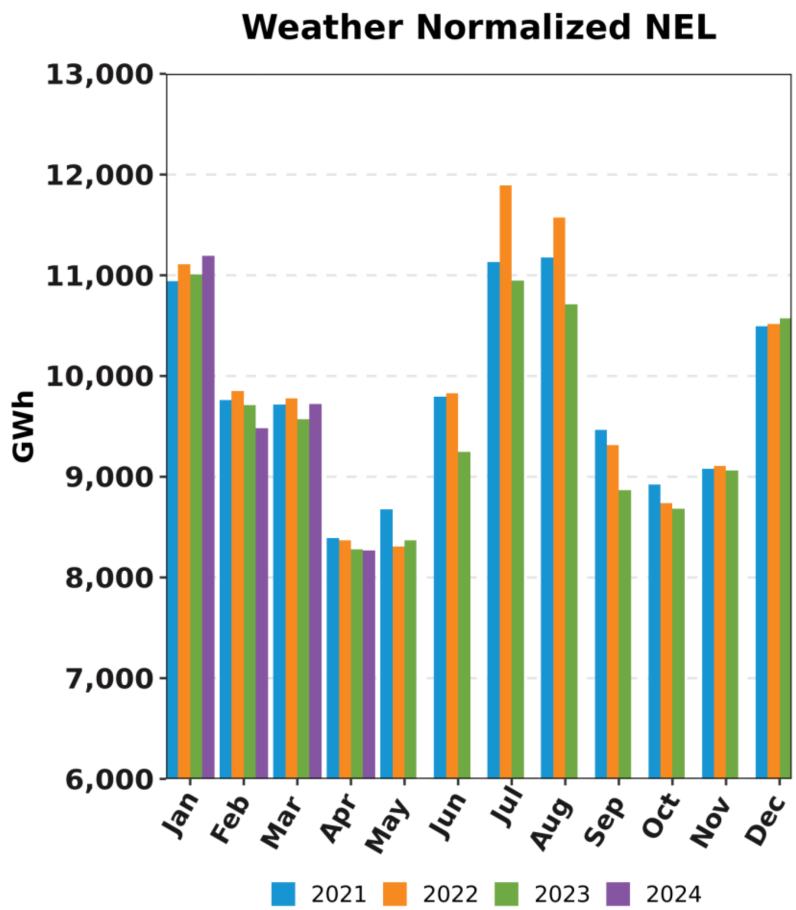
RQM System Peak Load MW by Month



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

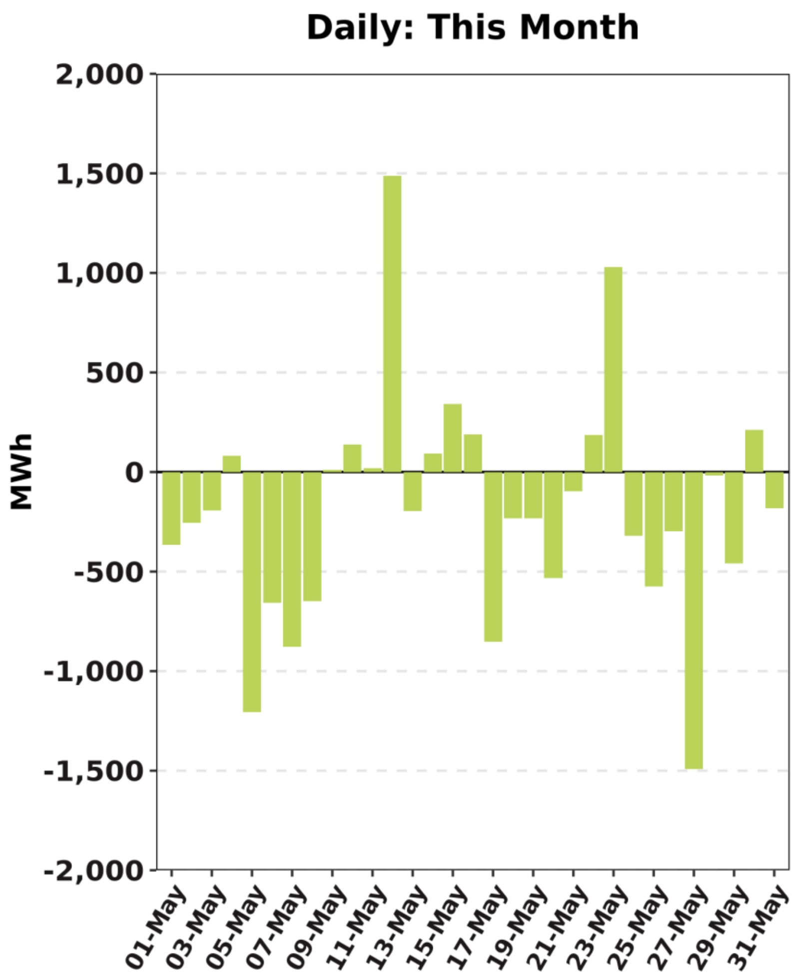
Monthly Recorded Net Energy for Load (NEL) and Weather Normalized NEL

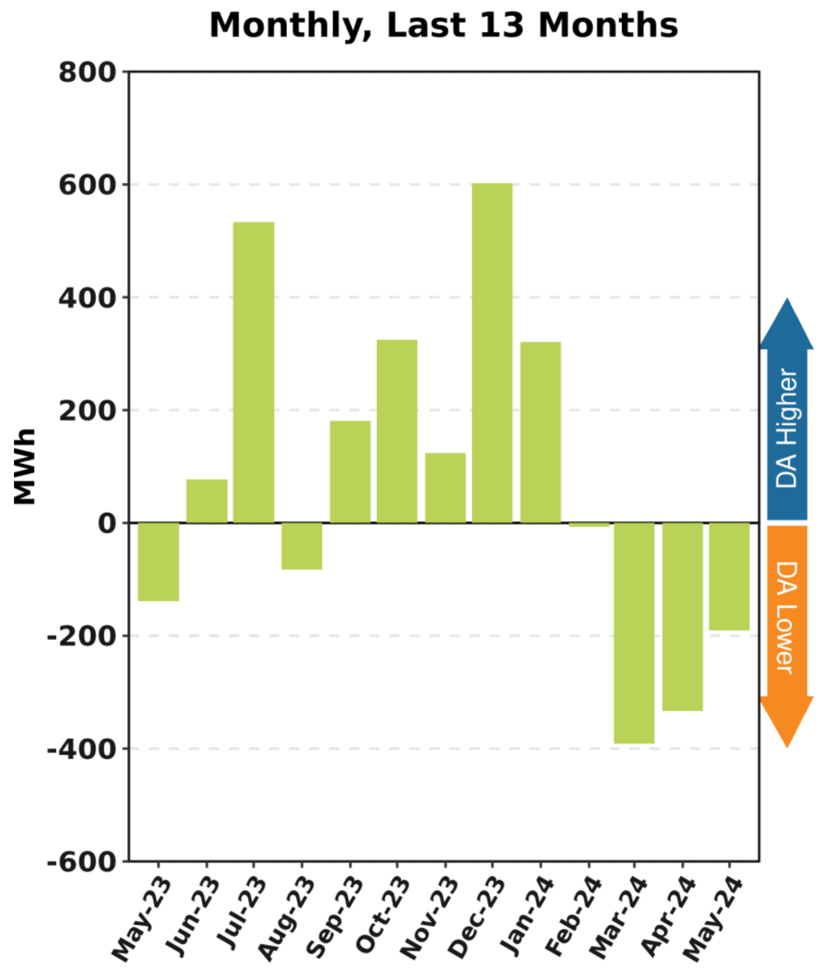




NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation + Demand Response Resource output - pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather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

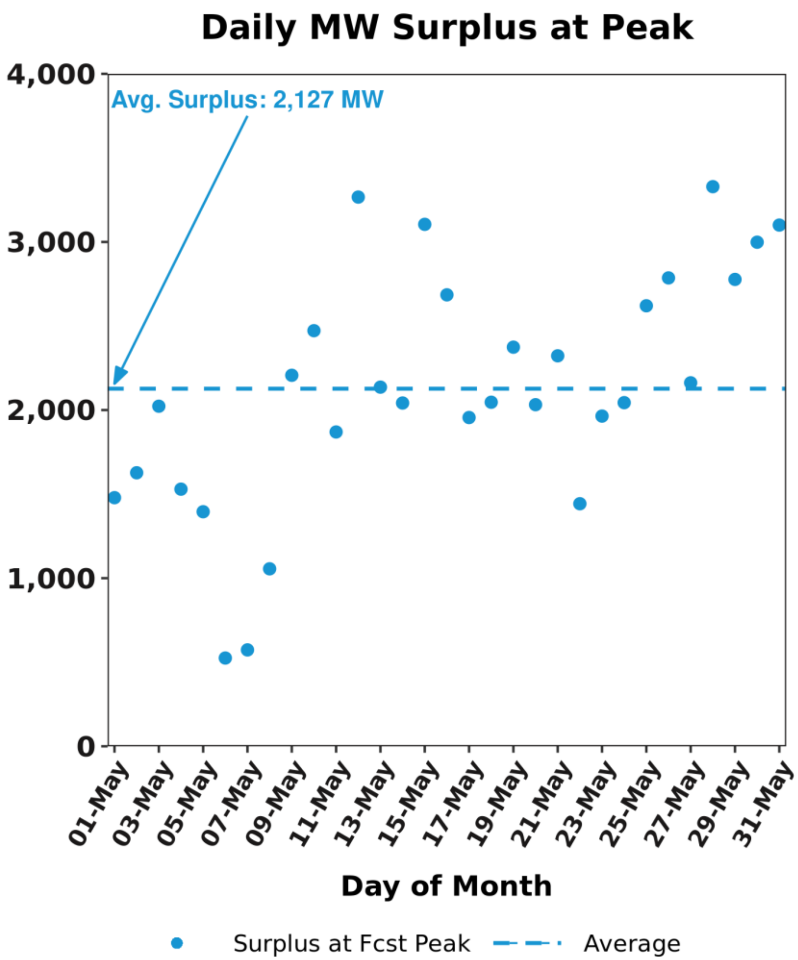
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour

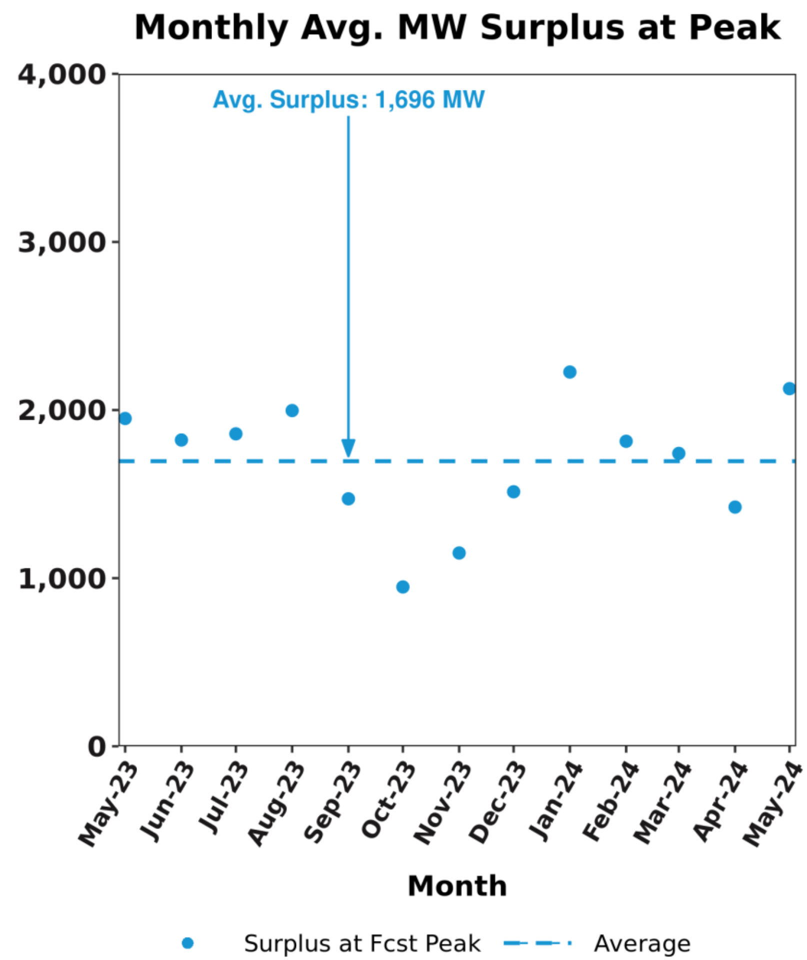




Negative values indicate DA Cleared Physical Energy value below its RT counterpart.

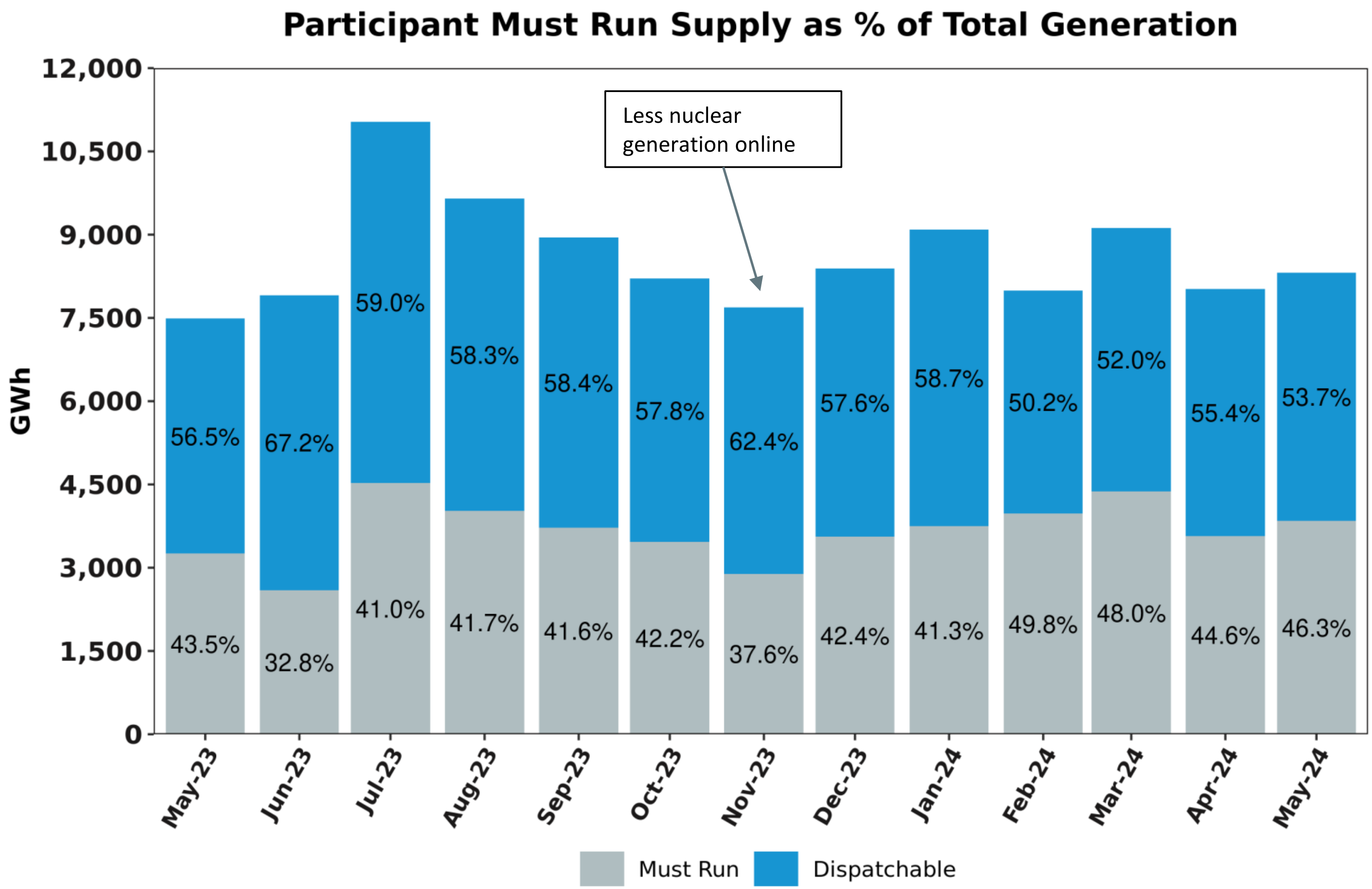
Capacity Surplus* Cleared in the DA Market Relative to Forecasted Peak-Hour Requirements





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

RT Generation Output Offered as Must Run vs Dispatchable



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

MARKET PRICING

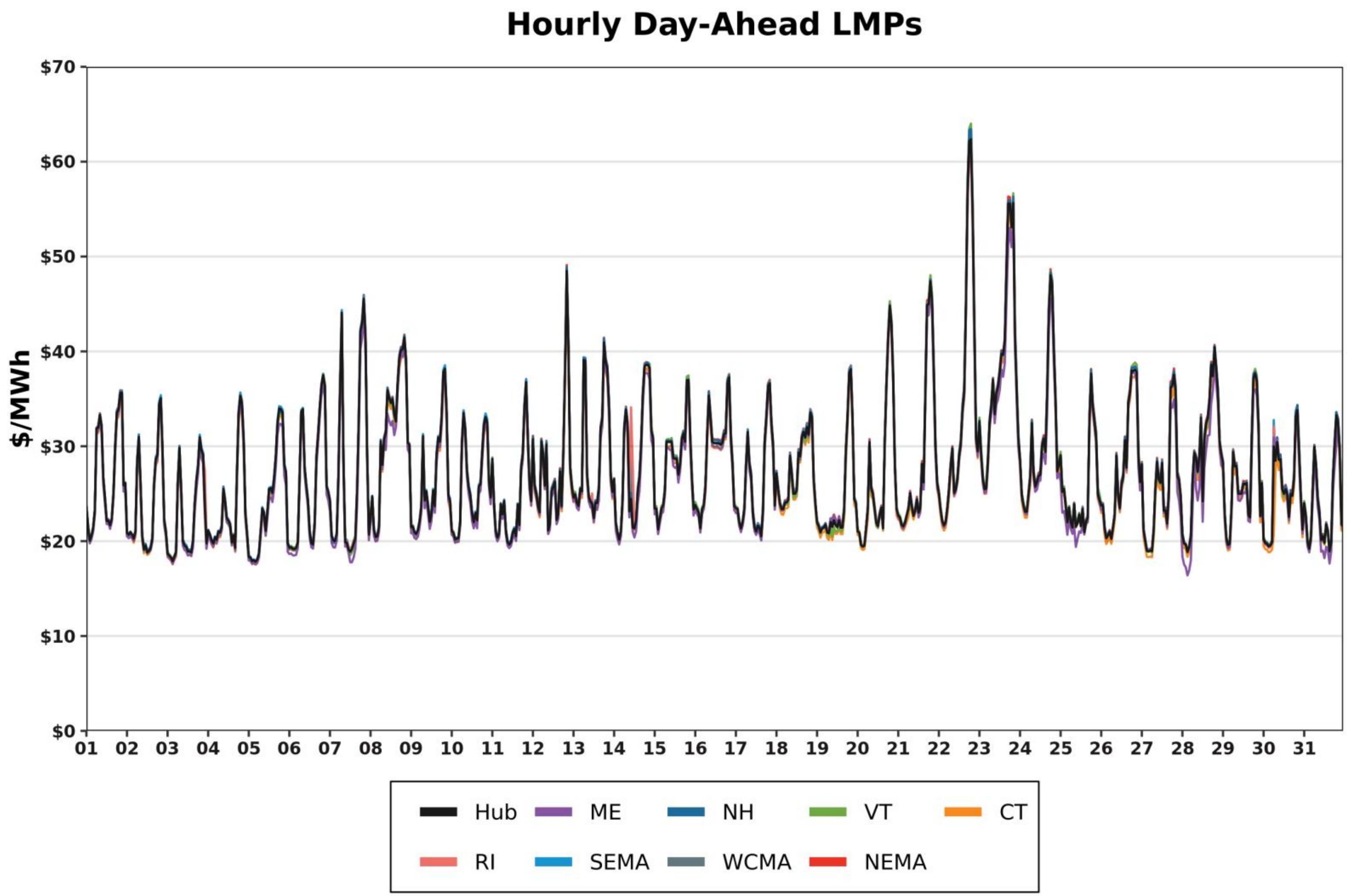
DA vs. RT LMPs ($/MWh)

Arithmetic Average

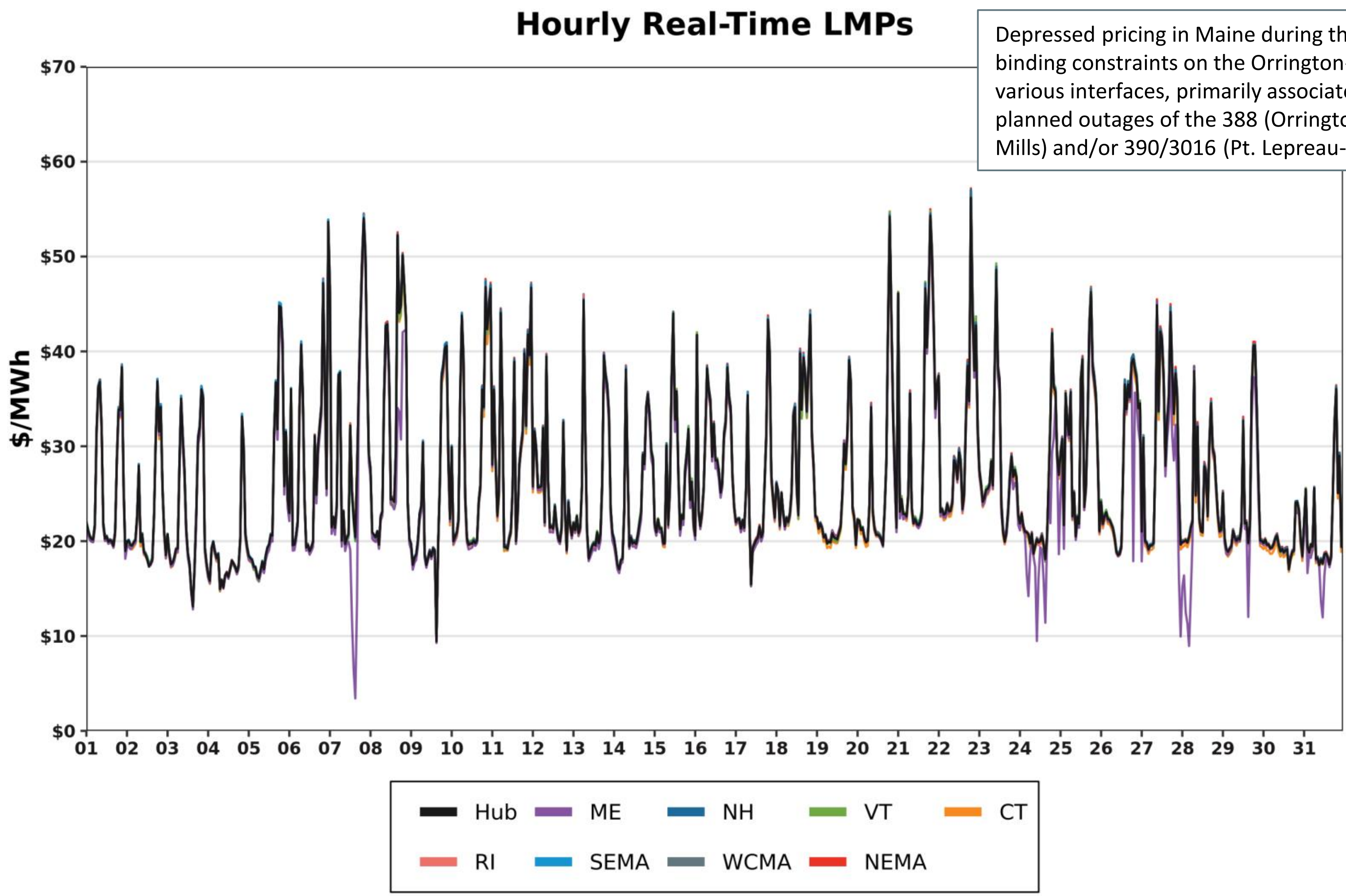
Year 2023	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$85.59	$84.20	$85.77	$84.48	$84.07	$85.39	$86.05	$85.69	$86.12
Real-Time	$84.89	$83.06	$85.05	$83.64	$83.80	$84.69	$85.35	$84.97	$85.40
RT Delta %	-0.82%	-1.35%	-0.84%	-0.99%	-0.32%	-0.82%	-0.81%	-0.84%	-0.84%
Year 2022	**Hub**	**ME**	**NH**	**VT**	**CT**	**RI**	**SEMA**	**WCMA**	**NEMA**
Day-Ahead	$37.04	$36.59	$37.22	$36.78	$36.25	$36.89	$37.34	$37.07	$37.35
Real-Time	$35.91	$35.36	$36.05	$35.55	$35.26	$35.71	$36.17	$35.92	$36.21
RT Delta %	-0.82%	-1.35%	-0.84%	-0.99%	-0.32%	-0.82%	-0.81%	-0.84%	-0.84%

May-23	Hub	ME	NH	VT	CT	RI	SEMA	WCMA	NEMA
Day-Ahead	$25.03	$24.50	$25.06	$24.98	$24.92	$24.77	$25.06	$25.08	$25.10
Real-Time	$23.12	$22.59	$23.12	$23.05	$22.94	$22.88	$23.17	$23.14	$23.23
RT Delta %	-7.63%	-7.80%	-7.74%	-7.73%	-7.95%	-7.63%	-7.54%	-7.74%	-7.45%
May-24	**Hub**	**ME**	**NH**	**VT**	**CT**	**RI**	**SEMA**	**WCMA**	**NEMA**
Day-Ahead	$27.23	$26.56	$27.30	$27.22	$26.66	$27.00	$27.36	$27.23	$27.47
Real-Time	$26.25	$25.32	$26.33	$26.22	$25.78	$25.99	$26.35	$26.23	$26.48
RT Delta %	-3.60%	-4.67%	-3.55%	-3.67%	-3.30%	-3.74%	-3.69%	-3.67%	-3.60%
Annual Diff.	**Hub**	**ME**	**NH**	**VT**	**CT**	**RI**	**SEMA**	**WCMA**	**NEMA**
Yr over Yr DA	8.79%	8.41%	8.94%	8.97%	6.98%	9.00%	9.18%	8.57%	9.44%
Yr over Yr RT	13.54%	12.08%	13.88%	13.75%	12.38%	13.59%	13.72%	13.35%	13.99%

Hourly DA LMPs, May 1-31, 2024

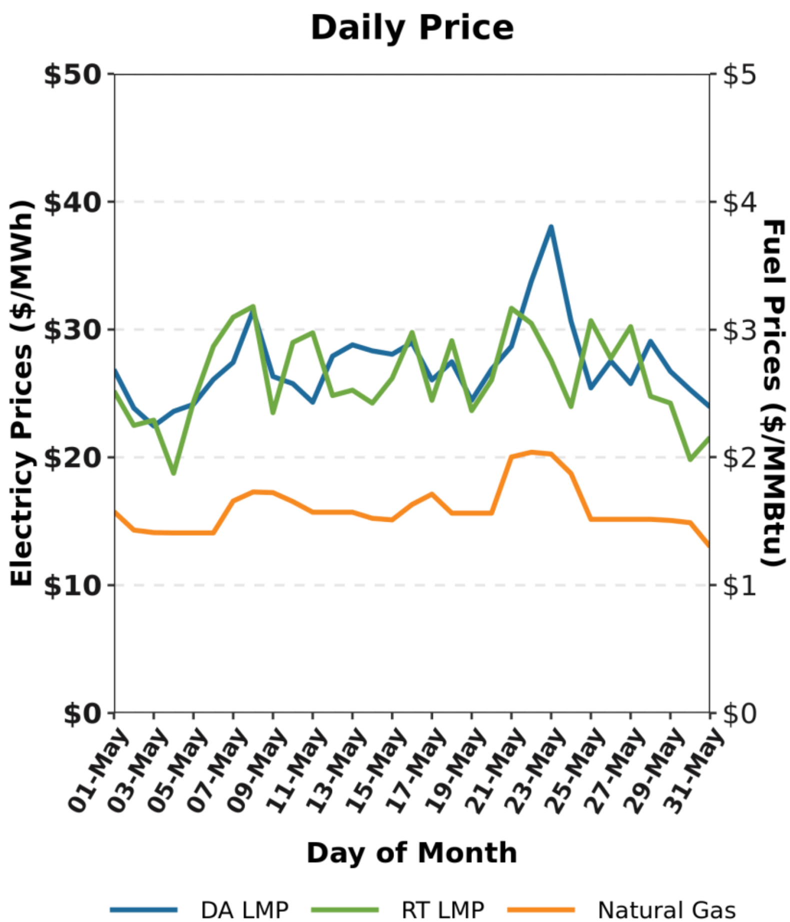


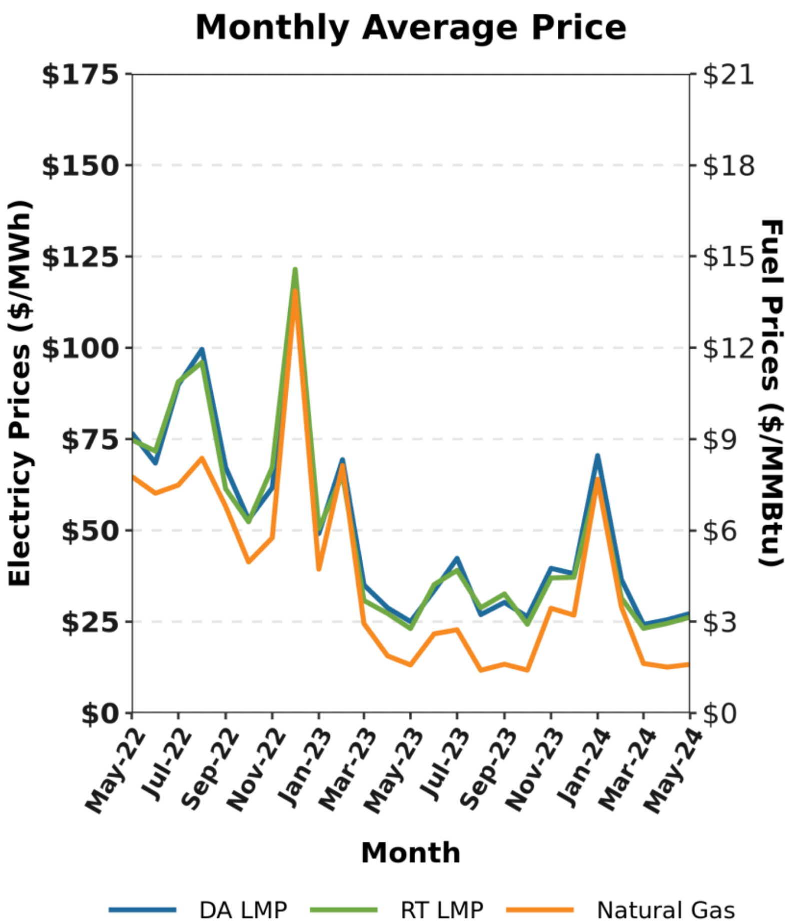
Hourly RT LMPs, May 1-31, 2024



Depressed pricing in Maine during the month due to binding constraints on the Orrington-South and other various interfaces, primarily associated with the planned outages of the 388 (Orrington – Coopers Mills) and/or 390/3016 (Pt. Lepreau-Orrington) lines

Wholesale Electricity vs Natural Gas Prices by Month

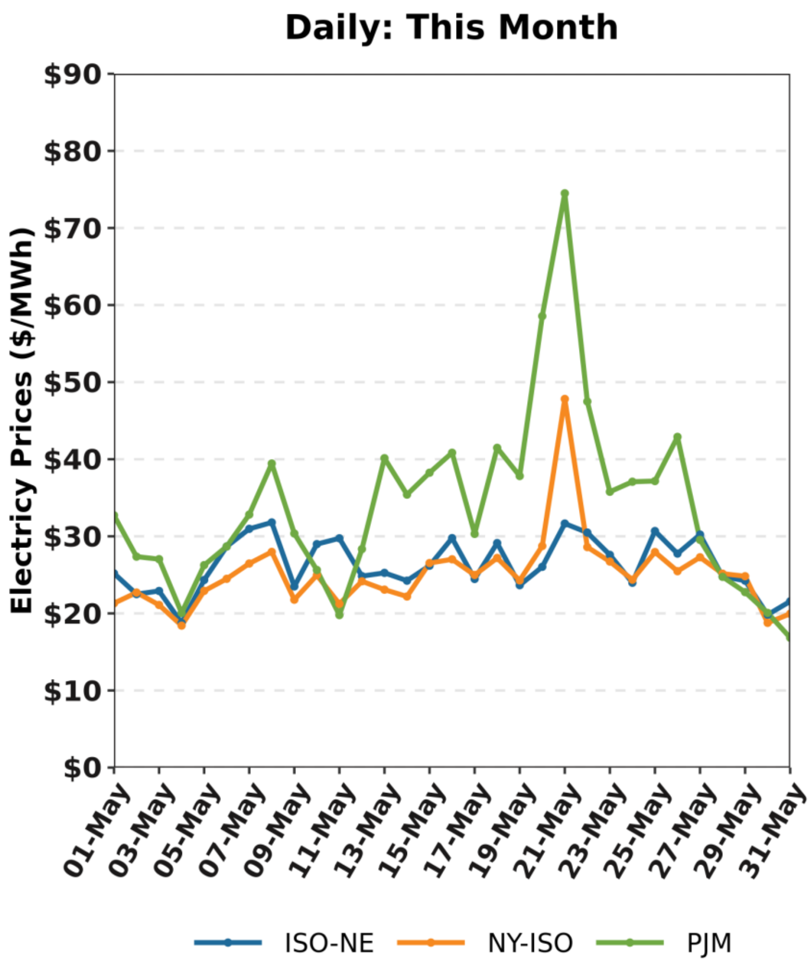


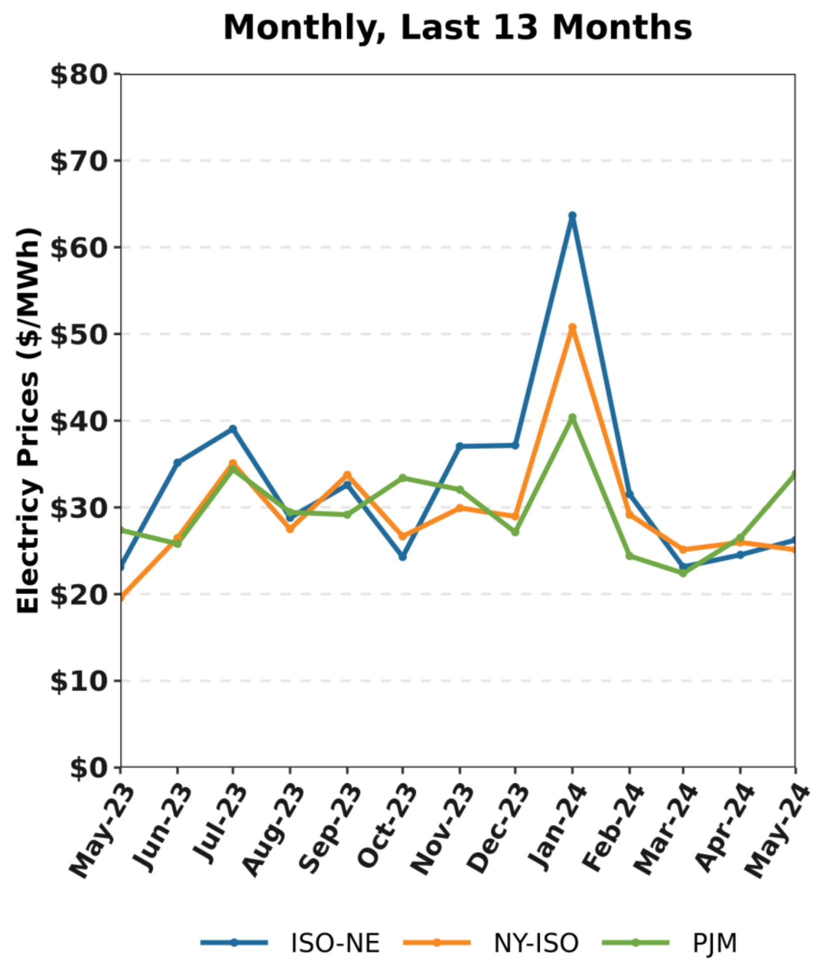


Underlying natural gas data furnished by: ICE Global markets in clear view

Gas price is average of Massachusetts delivery points

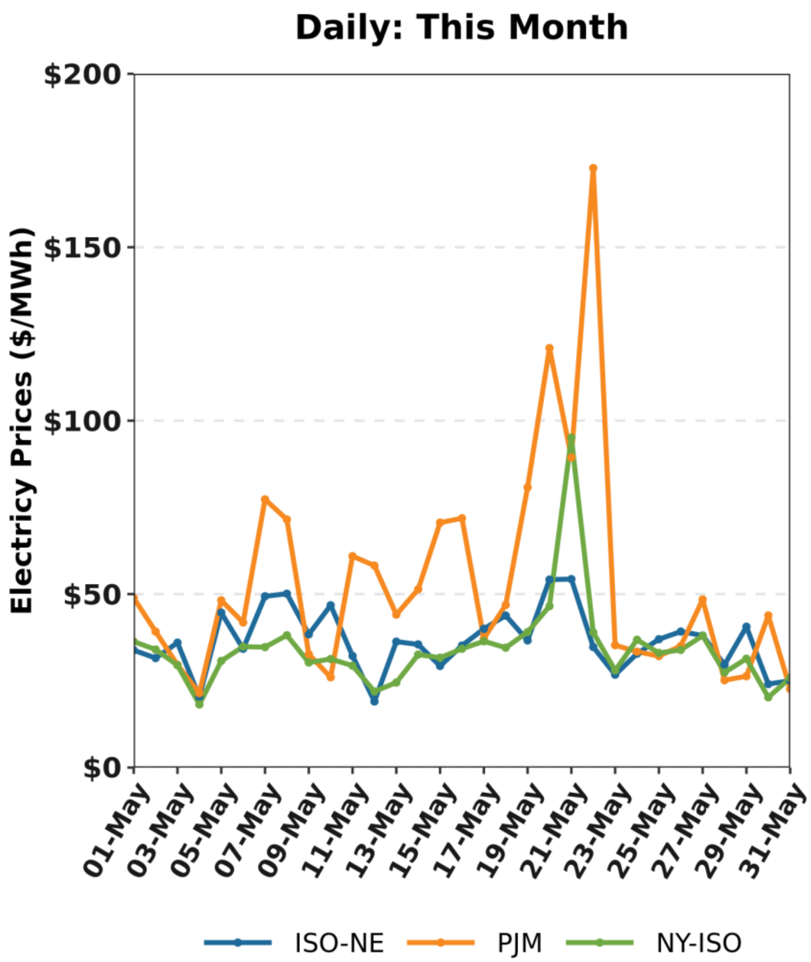
New England, NY, and PJM Hourly Average RT Prices by Month

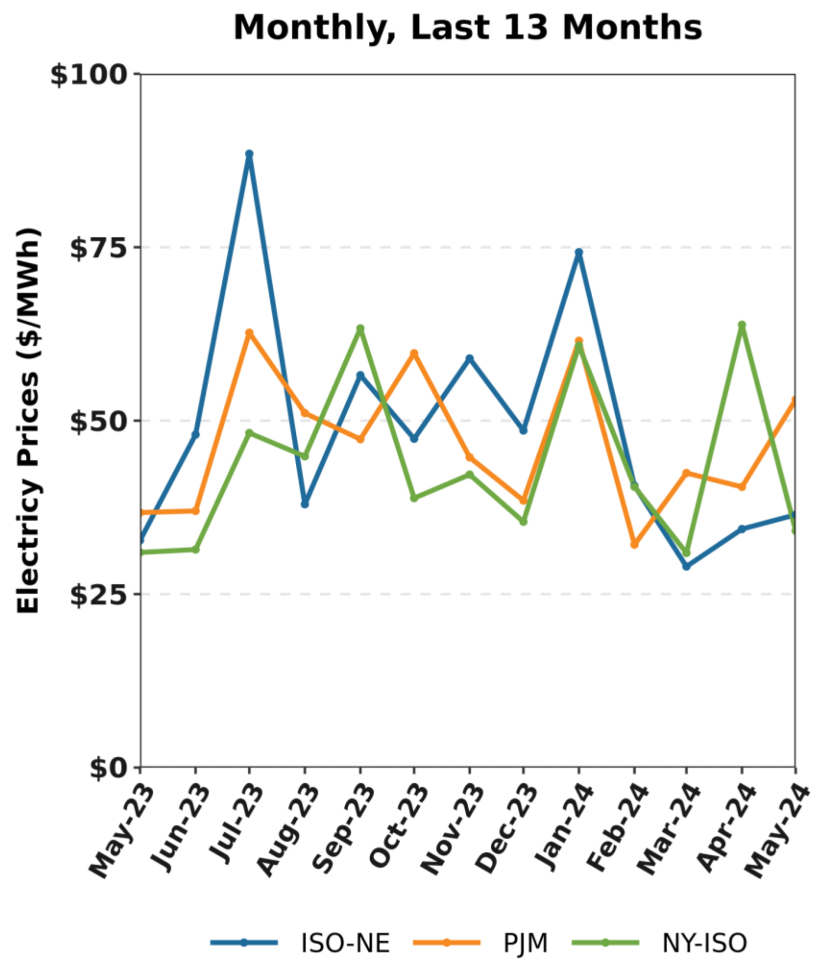




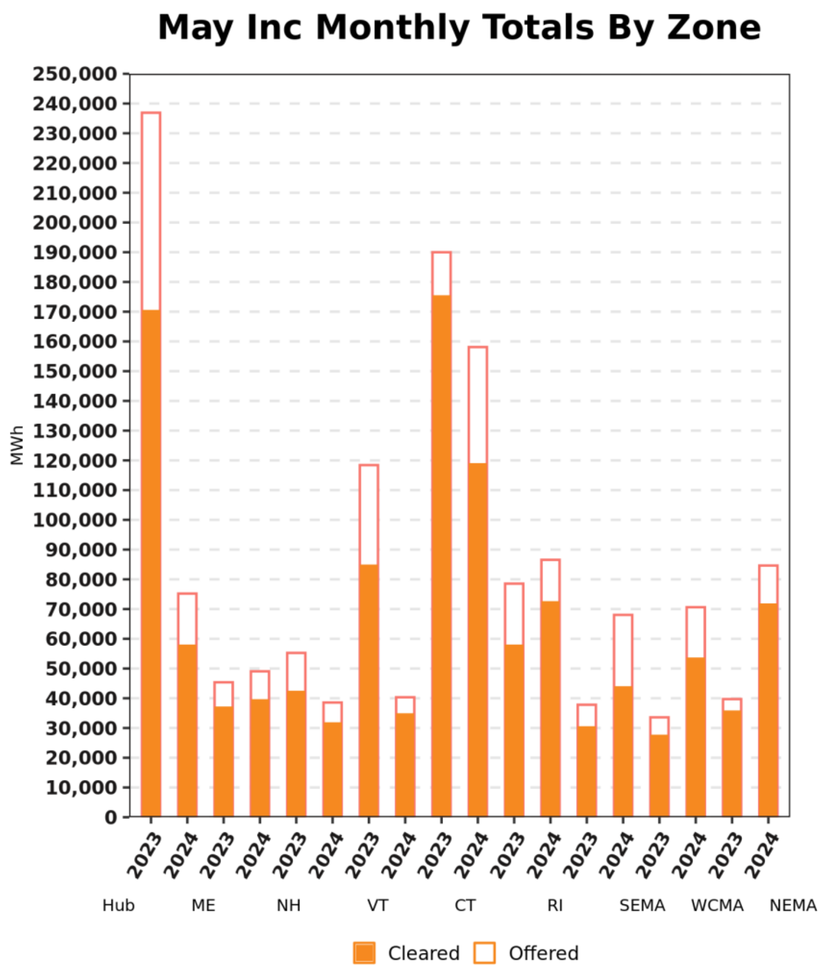
Hourly average prices are shown

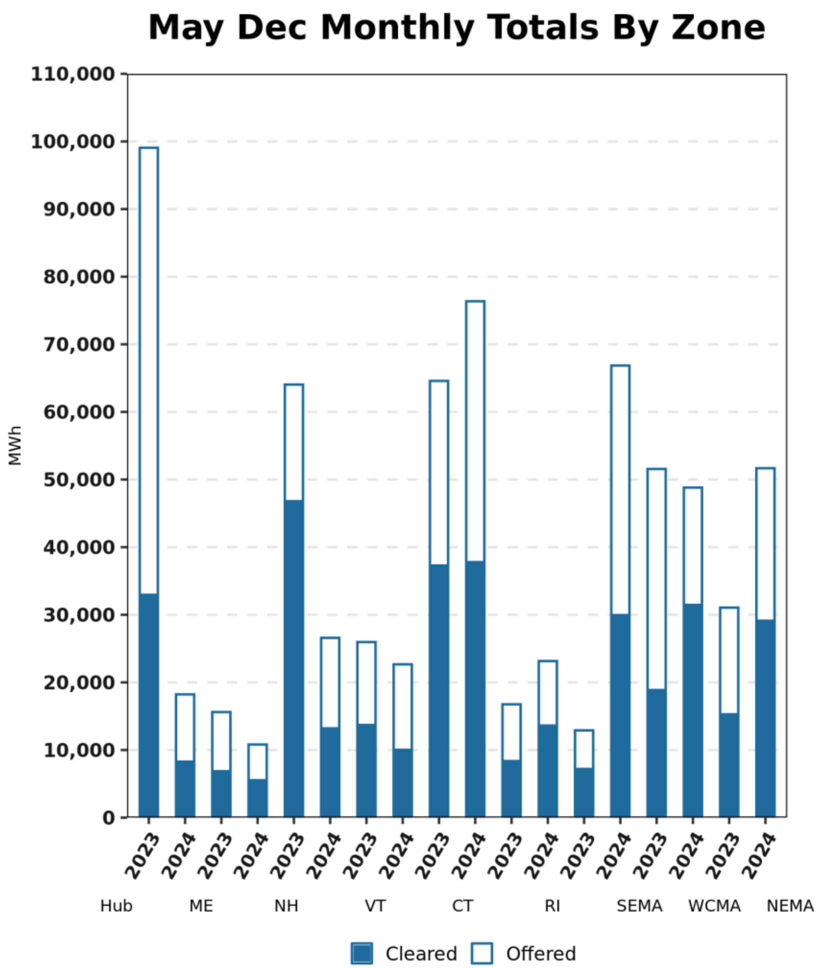
New England, NY, and PJM Average Forecasted Peak Hour RT Prices





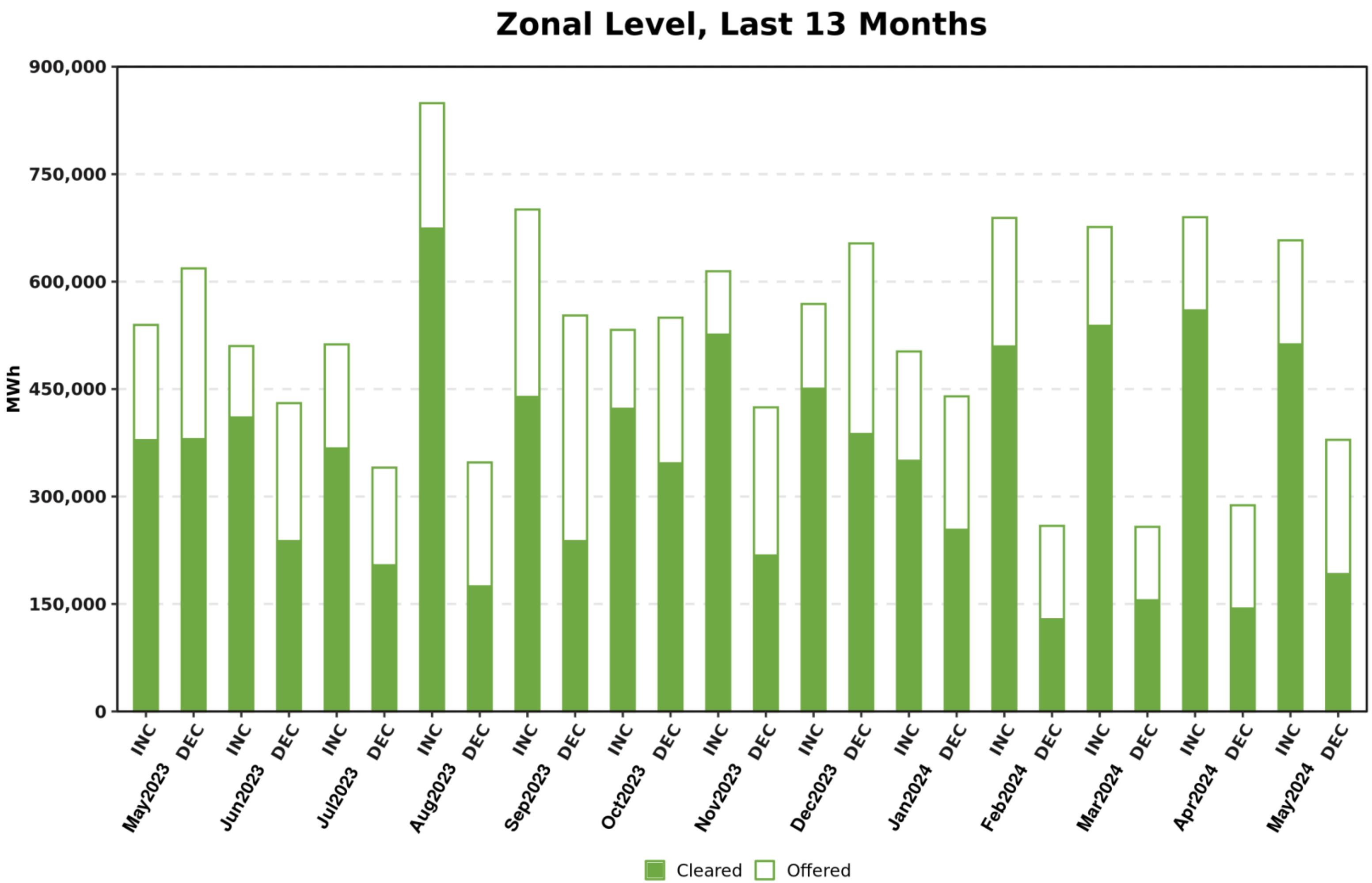
Zonal Increment Offers and Decrement Bid Amounts





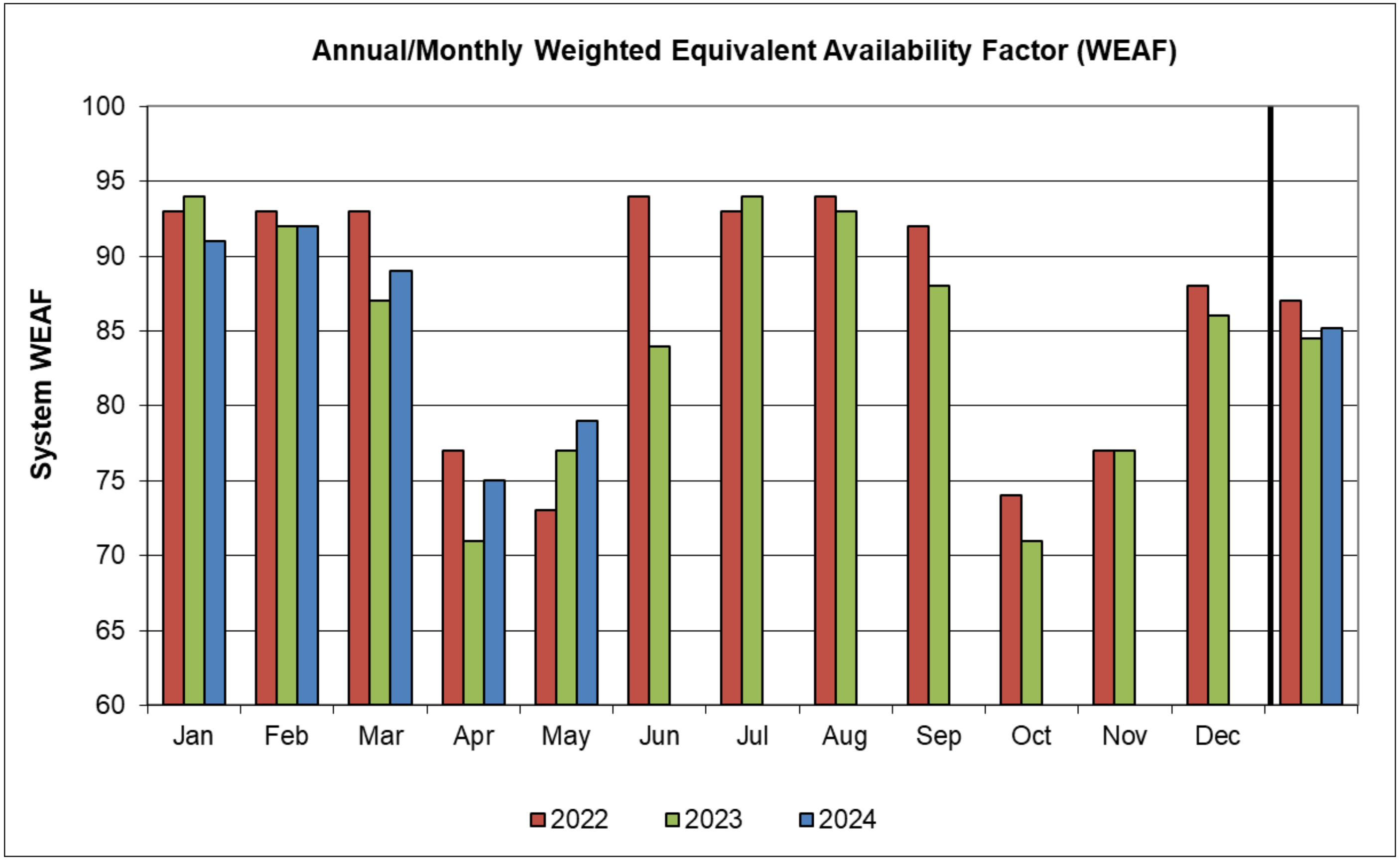
Includes nodal activity within the zone; excludes external nodes

Total Increment Offers and Decrement Bids



Includes nodal activity within the zone; excludes external nodes

System Unit Availability



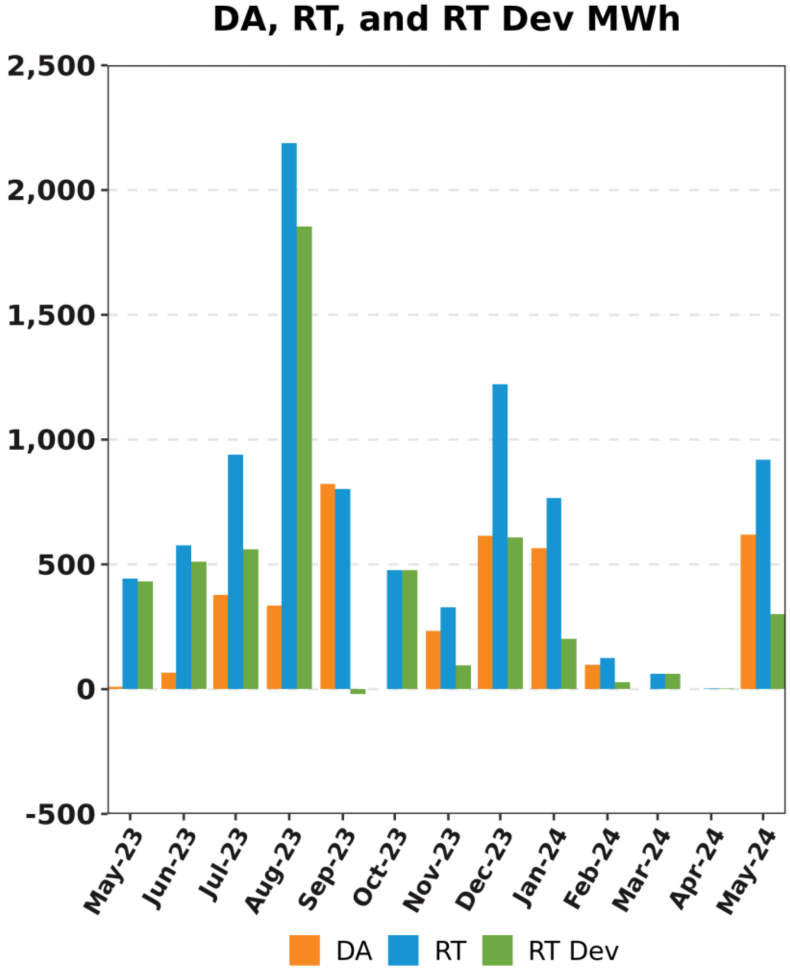
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2024	91	92	89	75	79								85
2023	94	92	87	71	77	84	94	93	88	71	77	86	85
2022	93	93	93	77	73	94	93	94	92	74	77	88	87

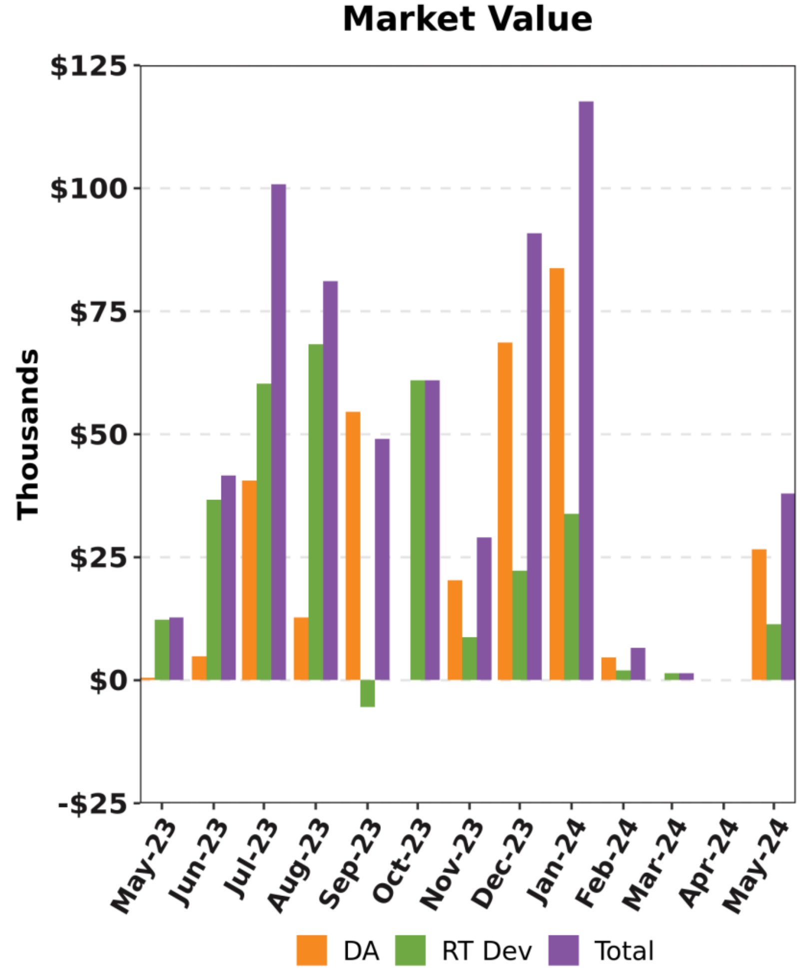
Data as of 6/3/24

BACK-UP DETAIL

DEMAND RESPONSE

Price Responsive Demand (PRD) Energy Market Activity by Month





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

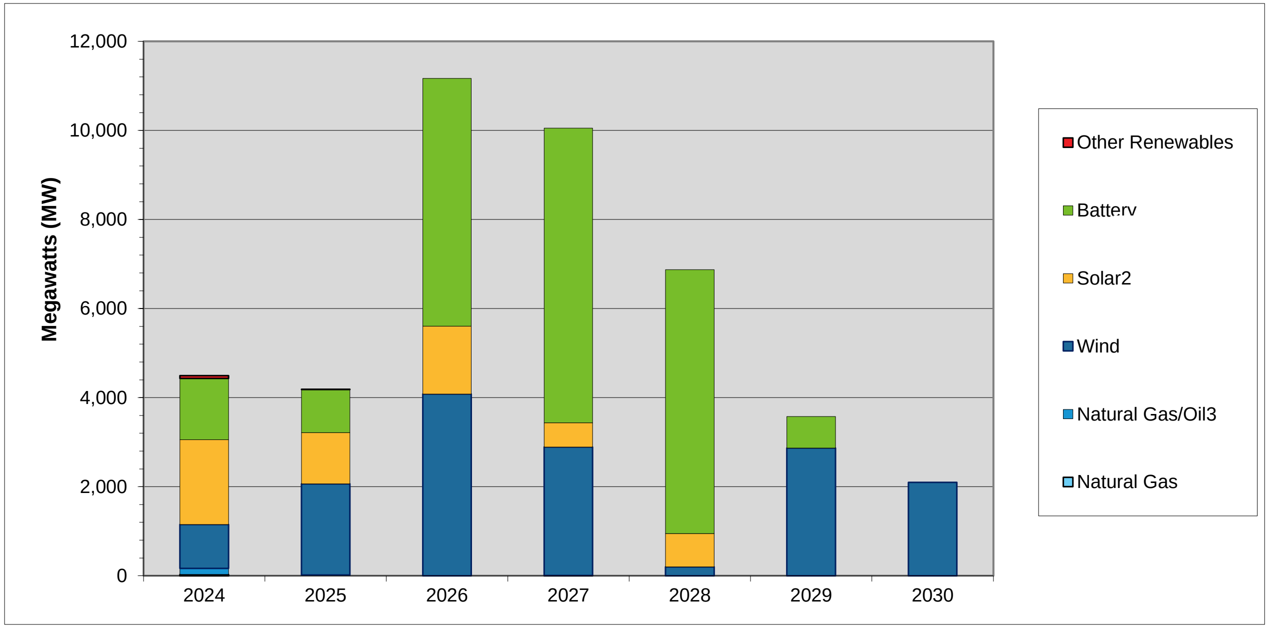
NEW GENERATION

New Generation Update
Based on Queue as of 05/29/24

- Eighteen projects totaling 832 MW were added to the interconnection queue since the last update
  - Ten battery and eight solar paired with battery projects with in-service dates between 2024 and 2029
- In total, 428 generation projects are currently being tracked by the ISO, totaling approximately 47,314 MW

Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2024	2025	2026	2027	2028	2029	2030	Total MW	% of Total[1]
Other Renewables	58	2	0	0	0	0	0	60	0.1
Battery	1,376	970	5,562	6,617	5,925	704	0	21,154	49.8
Solar[2]	1,905	1,146	1,527	545	750	0	0	5,873	13.8
Wind	989	2,049	4,079	2,887	197	2,870	2,100	15,171	35.7
Natural Gas/Oil[3]	135	16	0	0	0	0	0	151	0.4
Natural Gas	26	0	0	4	0	0	0	30	0.1
Totals	4,489	4,183	11,168	10,053	6,872	3,574	2,100	42,439	100.0

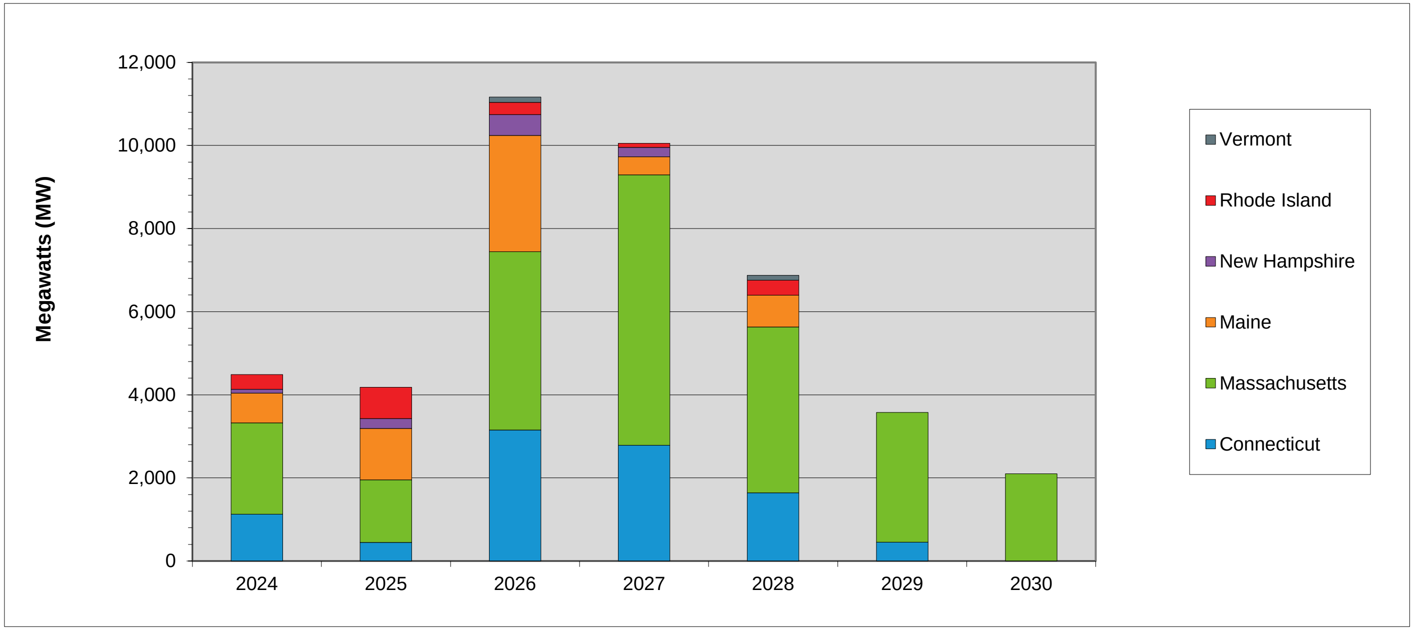
[1] Sum may not equal 100% due to rounding

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

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

Projected Annual Generator Capacity Additions

By State



	2024	2025	2026	2027	2028	2029	2030	Total MW	% of Total[1]
Vermont	0	0	128	0	115	0	0	243	0.6
Rhode Island	360	758	295	102	360	0	0	1,875	4.4
New Hampshire	88	239	504	226	0	0	0	1,057	2.5
Maine	720	1,236	2,799	433	764	0	0	5,952	14.0
Massachusetts	2,196	1,506	4,287	6,510	3,995	3,120	2,100	23,714	55.9
Connecticut	1,125	444	3,155	2,782	1,638	454	0	9,598	22.6
Totals	**4,489**	**4,183**	**11,168**	**10,053**	**6,872**	**3,574**	**2,100**	**42,439**	**100.0**

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

New Generation Projection

By Fuel Type

Unit Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	139	21,154	1	150	138	21,004
Fuel Cell	3	32	1	20	2	12
Hydro	1	28	1	28	0	0
Natural Gas	4	30	0	0	4	30
Natural Gas/Oil	3	151	1	62	2	89
Nuclear	0	0	0	0	0	0
Solar	249	5,873	14	323	235	5,550
Wind	29	20,046	2	926	27	19,120
Total	428	47,314	20	1,509	408	45,805

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

New Generation Projection

By Operating Type

	Total		Green		Yellow	
Operating Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	6	73	2	48	4	25
Intermediate	2	89	0	0	2	89
Peaker	391	27,106	16	535	375	26,571
Wind Turbine	29	20,046	2	926	27	19,120
Total	428	47,314	20	1,509	408	45,805

- 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	139	21,154	0	0	0	0	139	21,154	0	0
Fuel Cell	3	32	3	32	0	0	0	0	0	0
Hydro	1	28	1	28	0	0	0	0	0	0
Natural Gas	4	30	2	13	0	0	2	17	0	0
Natural Gas/Oil	3	151	0	0	2	89	1	62	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	249	5,873	0	0	0	0	249	5,873	0	0
Wind	29	20,046	0	0	0	0	0	0	29	20,046
Total	428	47,314	6	73	2	89	391	27,106	29	20,046

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 14

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

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2023-2027 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 15

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

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2023-2027 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 16

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	765.35	589.882	-175.468				
	Passive Demand	2,557.256	2,579.120	21.864				
Demand Total		**3,322.606**	**3,169.002**	**-153.604**				
Generator	*Non-Intermittent*	26,805.003	26,643.379	-161.624				
	Intermittent	1,178.933	1,146.783	-32.15				
Generator Total		**27,983.936**	**27,790.162**	**-193.774**				
Import Total		**1,503.842**	**1,247.601**	**-256.241**				
Grand Total*		**32,810.384**	**32,206.765**	**-603.619**				
Net ICR (NICR)		**31,645**	**30,585**	**-1,060**				

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2023-2027 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 17

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	622.854						
	Passive Demand	2,316.815						
Demand Total		**2,939.669**						
Generator	*Non-Intermittent*	26,507.420						
	Intermittent	1,356.084						
Generator Total		**27,863.504**						
Import Total		**566.998**						
Grand Total*		**31,370.171**						
Net ICR (NICR)		**30,305**						

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2023-2027 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 18

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	543.580						
	Passive Demand	2,070.498						
Demand Total		**2,614.078**						
Generator	*Non-Intermittent*	27,026.635						
	Intermittent	1,450.872						
Generator Total		**28,477.507**						
Import Total		**464.835**						
Grand Total*		**31,556.420**						
Net ICR (NICR)		**30,550**						

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

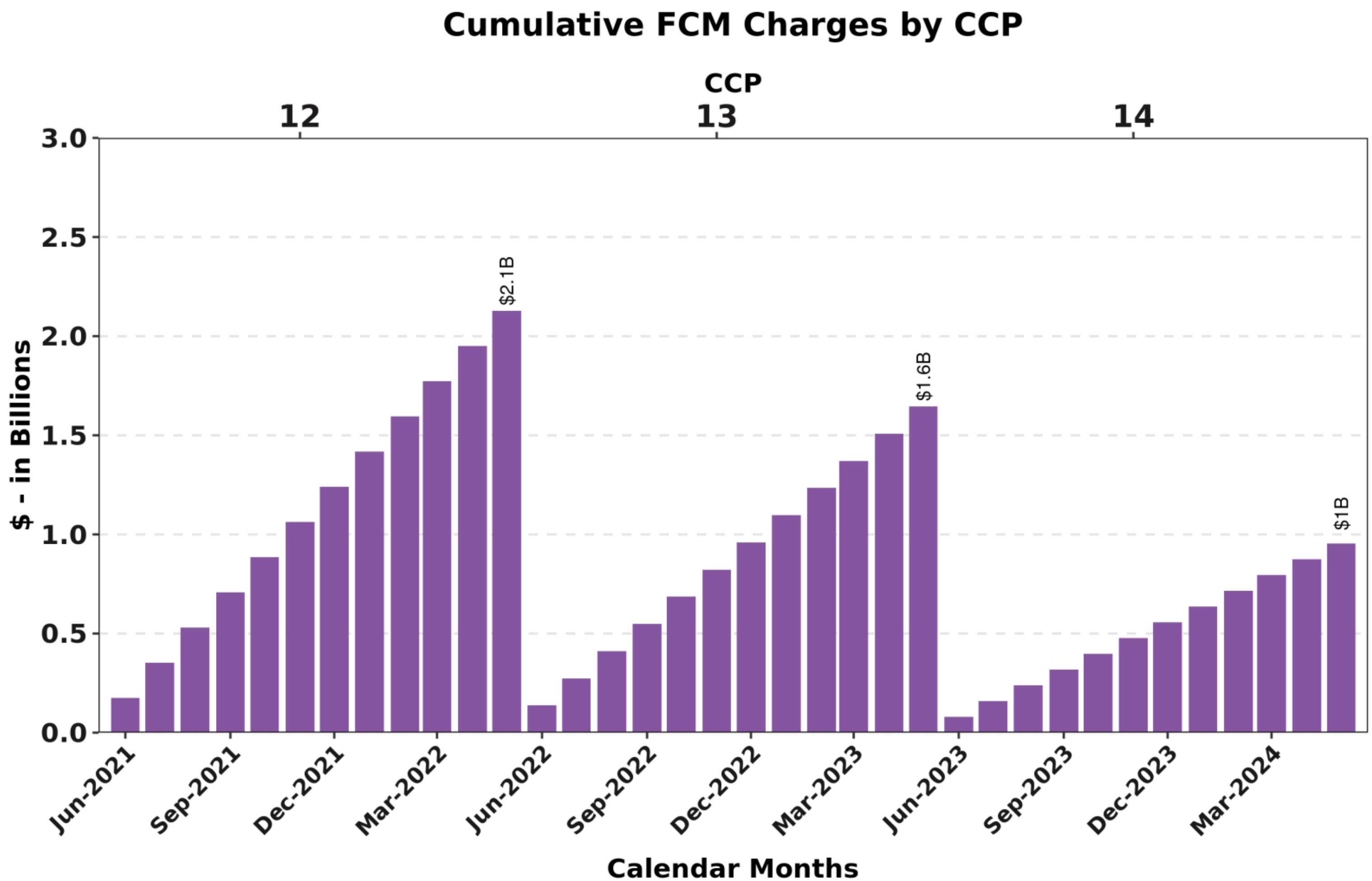
Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2023-2027 CCP Month Capacity Supply Obligation Changes report on the ISO New England website.

Active/Passive Demand Response

CSO Totals by Commitment Period

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

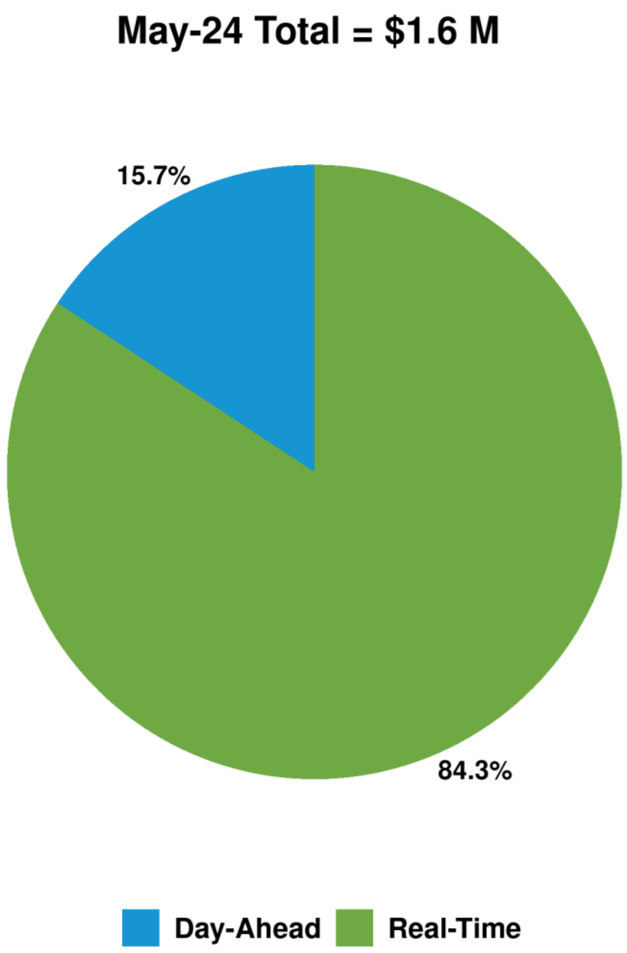
Forward Capacity Market Auctions

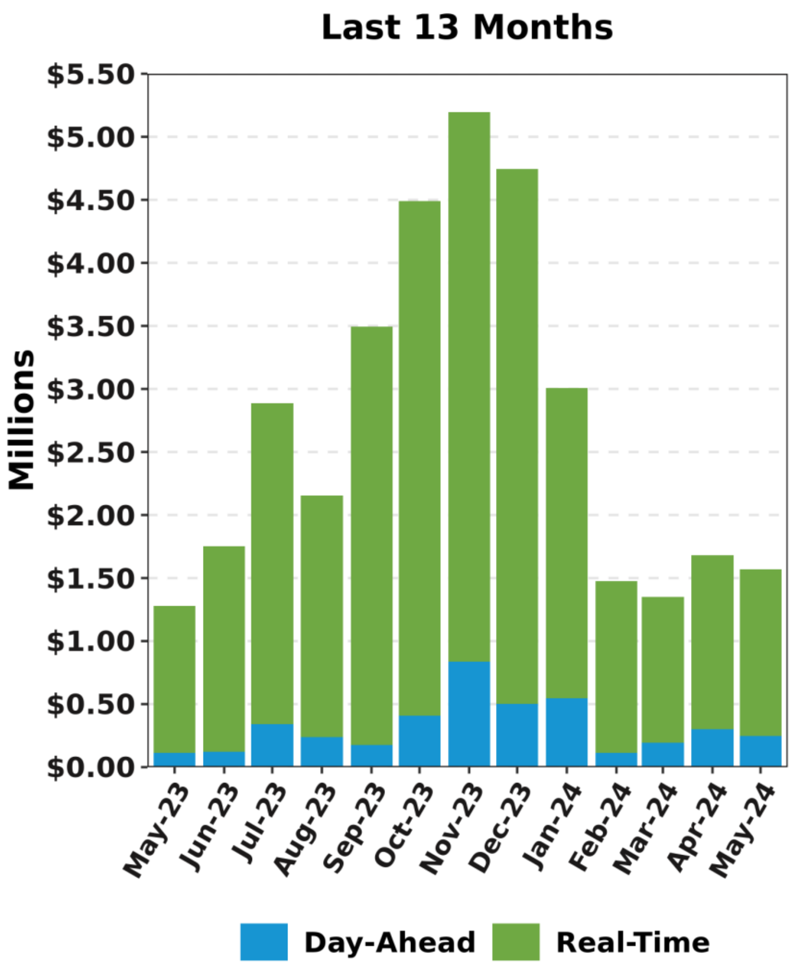


The items in the graph shaded in a lighter color represent the forecast for future months in the Capacity Commitment Period (CCP)

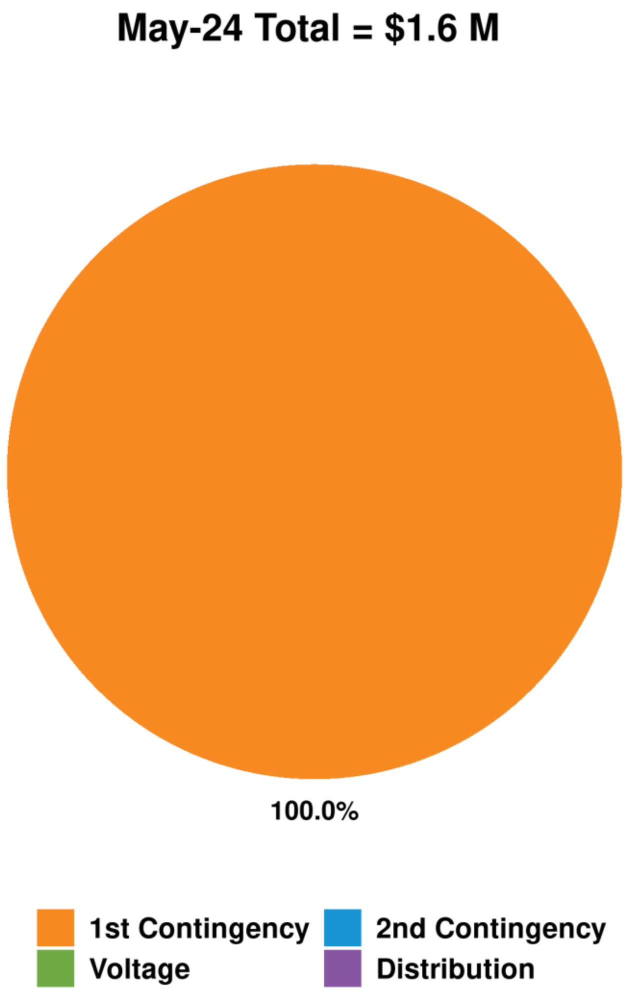
NET COMMITMENT PERIOD COMPENSATION

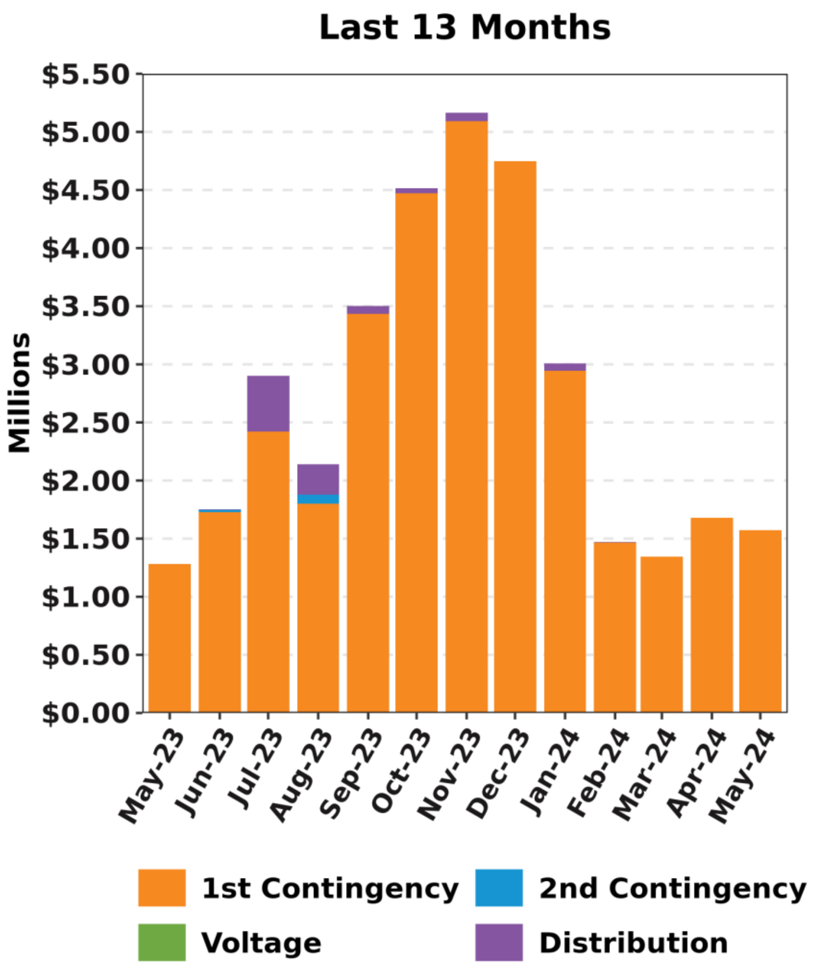
DA and RT NCPC Charges



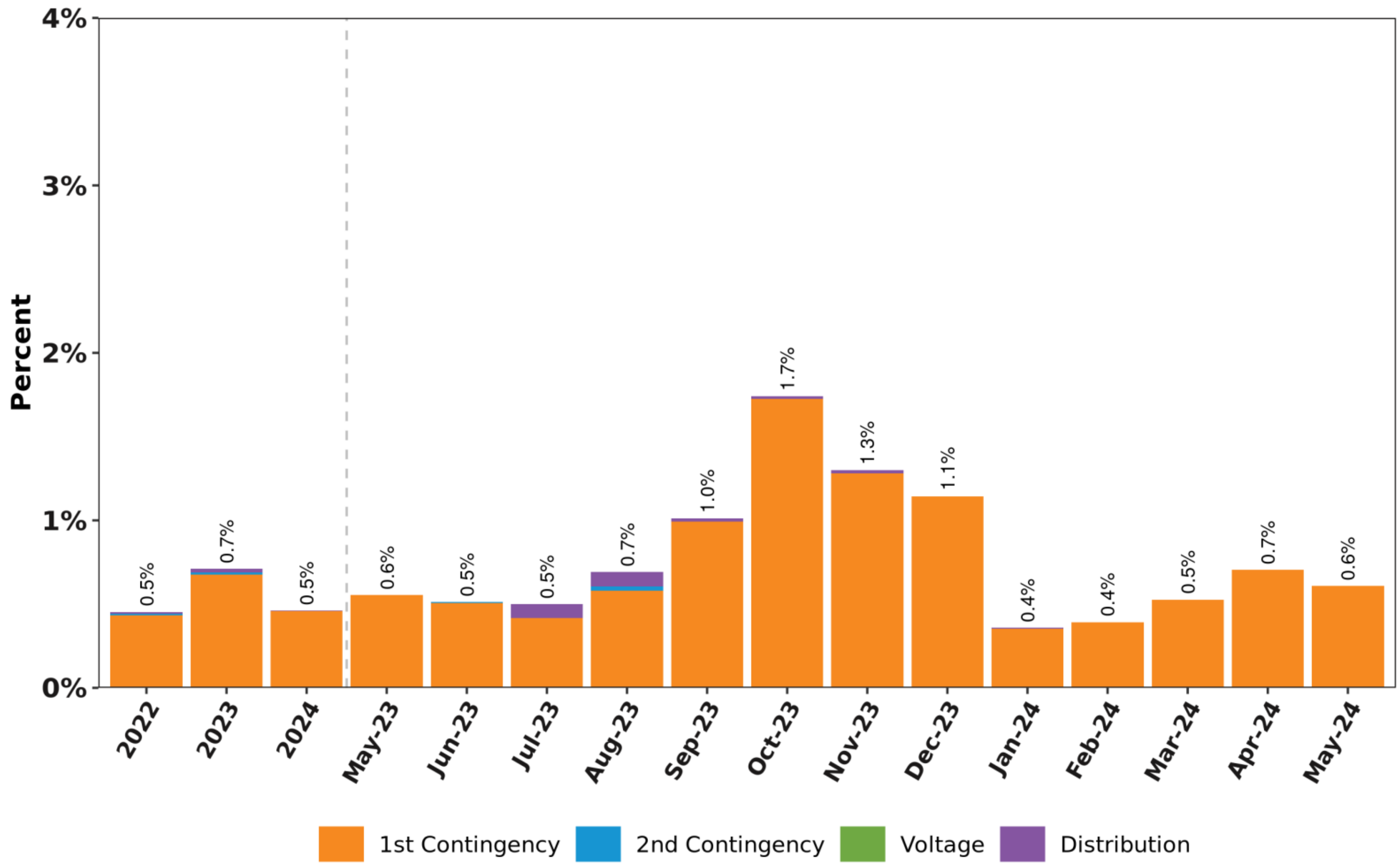


NCPC Charges by Type

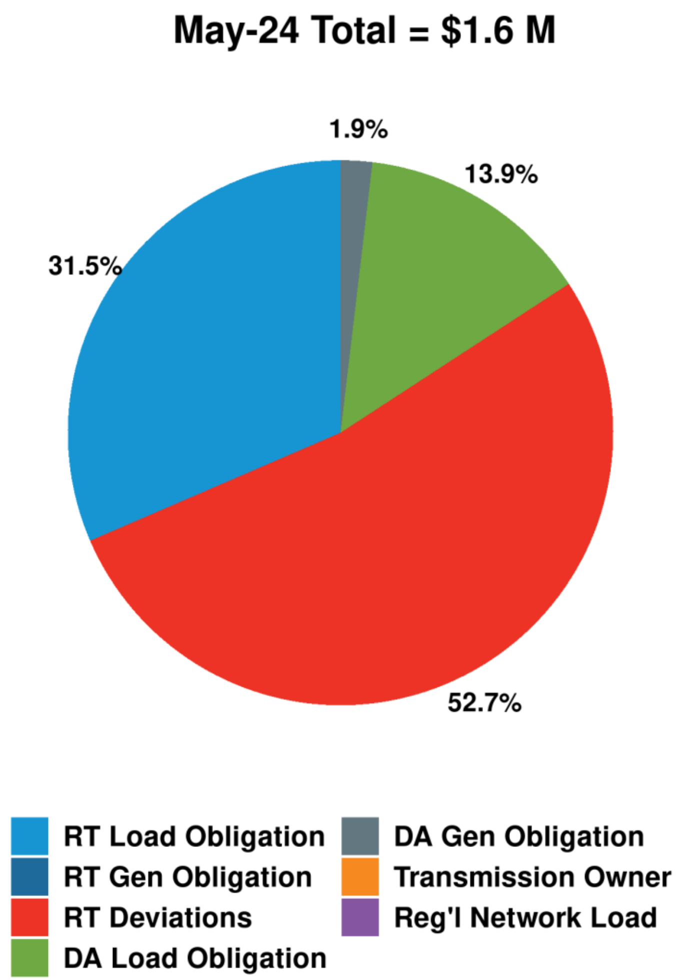


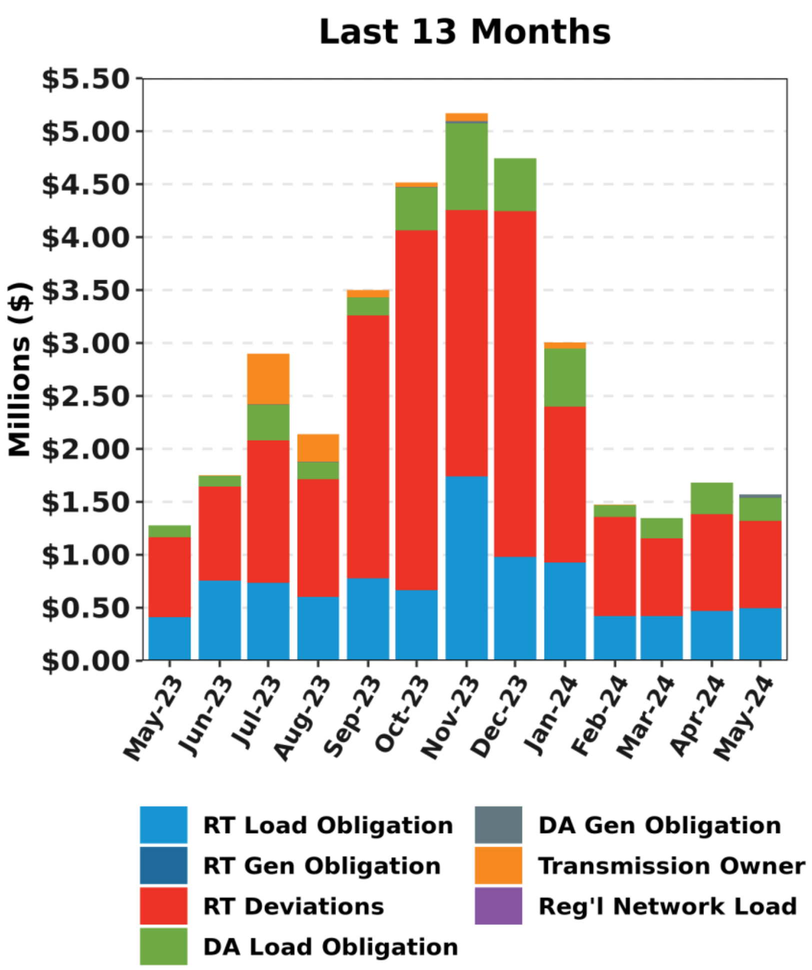


NCPC Charges by Type as Percent of Energy Market Value

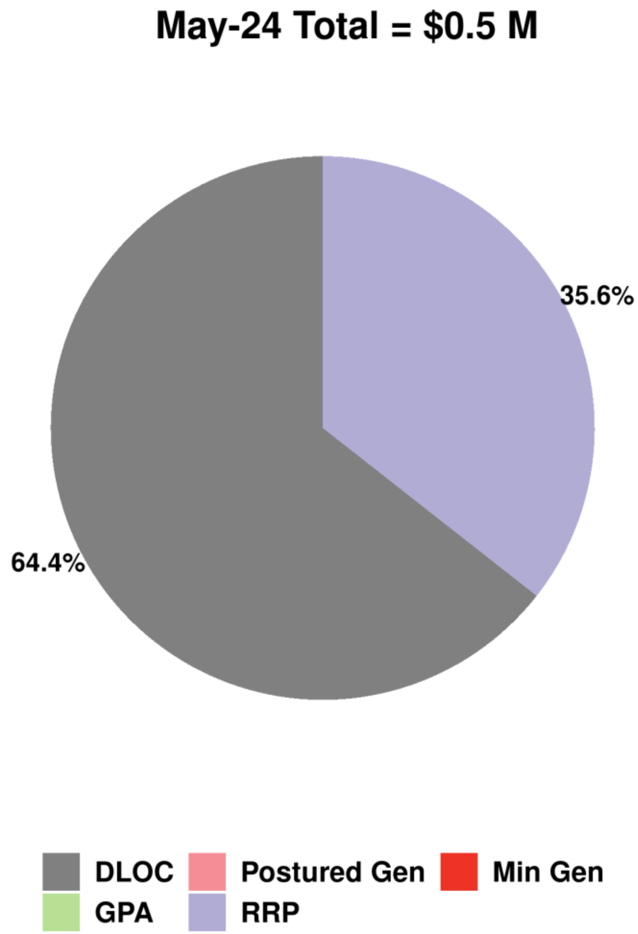


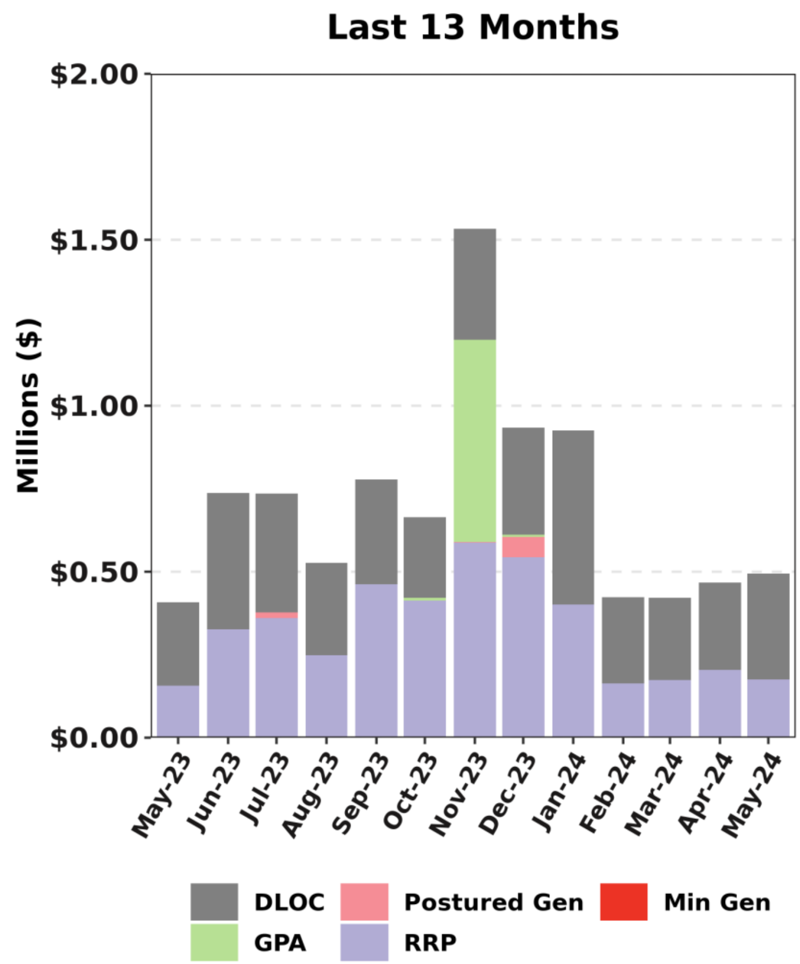
NCPC Charge Allocations





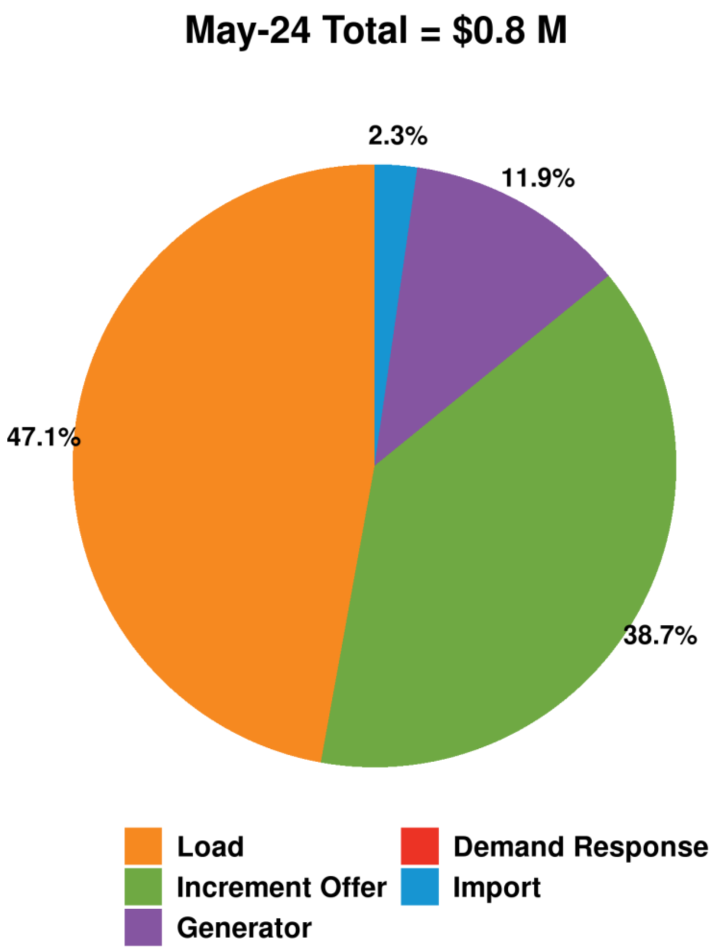
RT First Contingency NCPC Paid to Units and Allocated to RTLO and/or RTGO

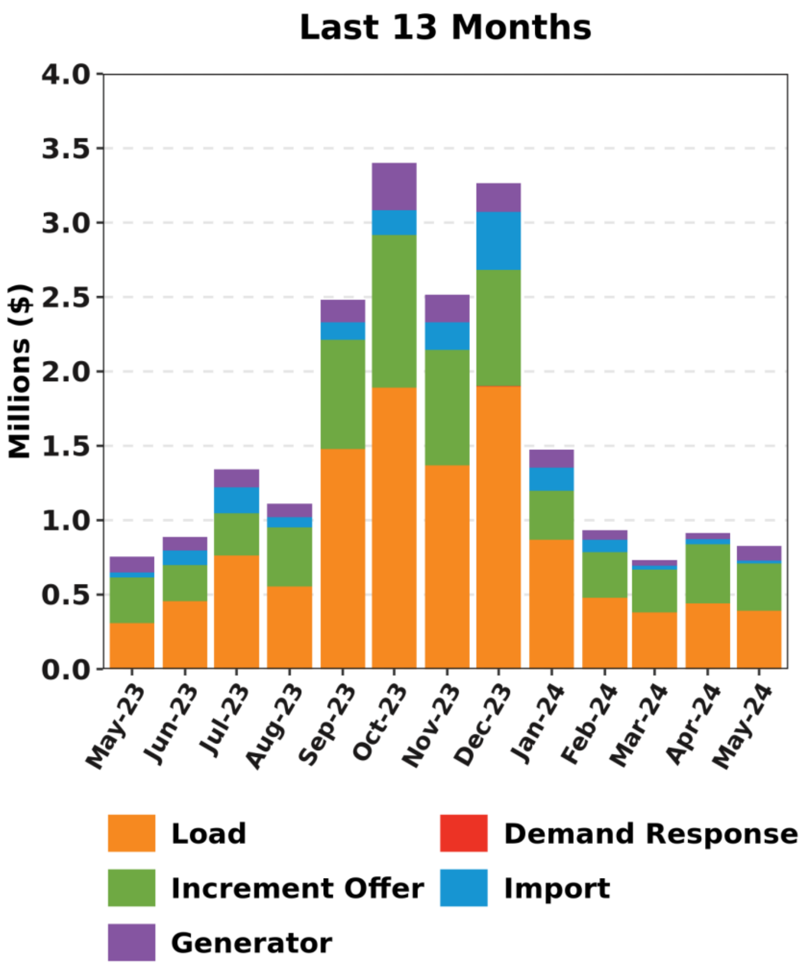




The categories shown above are a subset of those reflected in First Contingency NCPC throughout this report. The above categories are allocated to RTLO, except for Min Gen Emergency credits, which are allocated to RTGO.

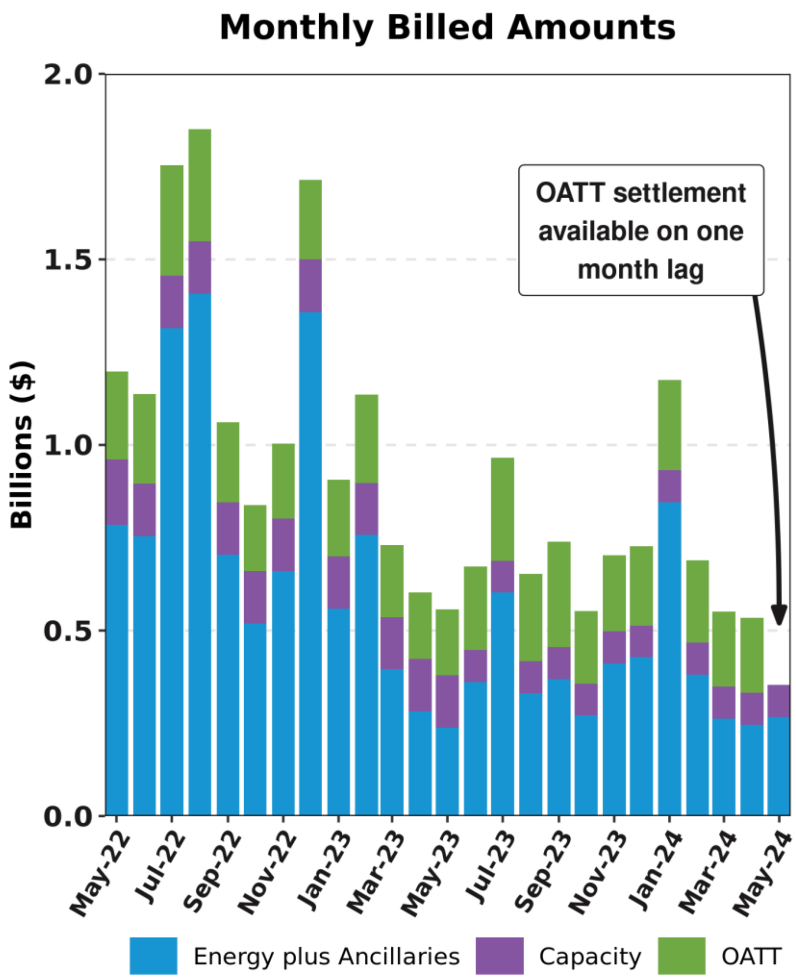
RT First Contingency Charges by Deviation Type

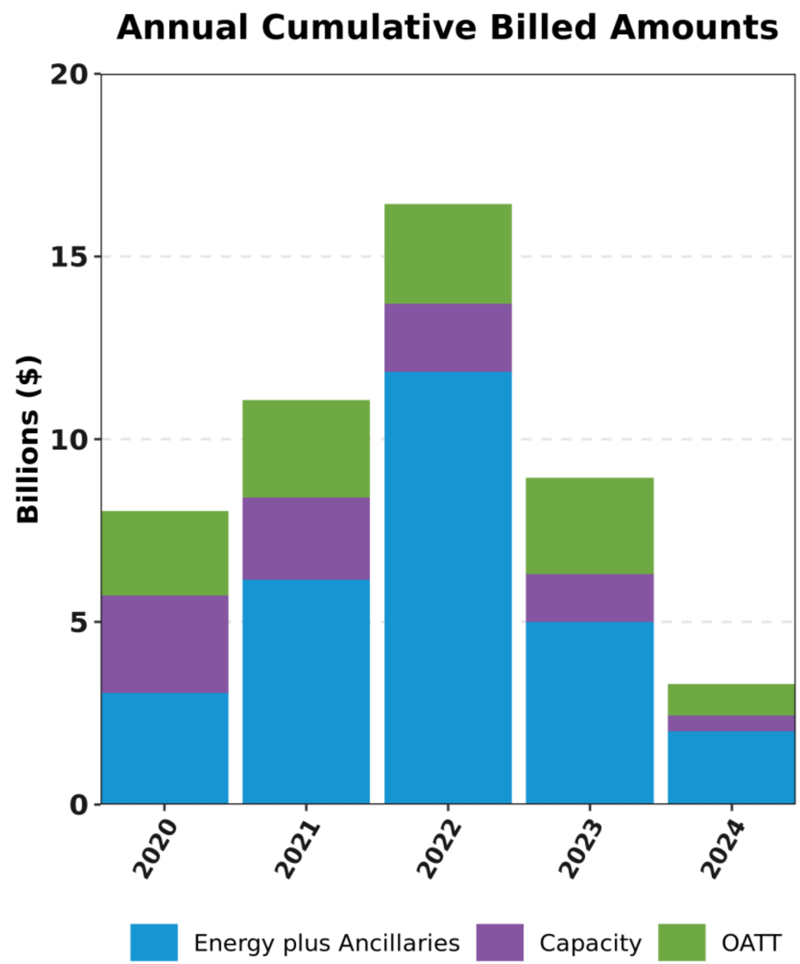




ISO BILLINGS

Total ISO Billings





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

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- June 20 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - MEPCO Sections 396 and 3001 End of Life Strategy – Avangrid
    - Campville 115 kV Substation Relay Upgrades – Eversource
    - Line 1670/1771 – Reservoir Road Junction to Berlin Rebuild – Eversource
    - Line N133 Structure Replacement Project – Eversource
    - Line X-178 115 kV Line Rebuild – Eversource
  - Third Maine Resource Integration Study
  - 2024 Economic Study – Benchmark Results & Review of Stakeholder Requested Scenario Proposals
  - RSP Project List and Asset Condition List June 2024 Update
  - Maine Transfer Limit Updates

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

2050 Transmission Study

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

Economic Studies: EPCET

- Economic Planning for the Clean Energy Transition (EPCET) Pilot Study
  - An effort to review all assumptions in economic planning and perform a test study consistent with the changes to the Tariff
  - PAC presentations began in April 2022. To date, the ISO has presented results from the Benchmark, Market Efficiency Need, and Policy scenarios and is now in the process of finalizing the study. The last set of results was presented in April 2024.
    - A report will be issued in Q3 2024

Economic Studies: 2024 Study

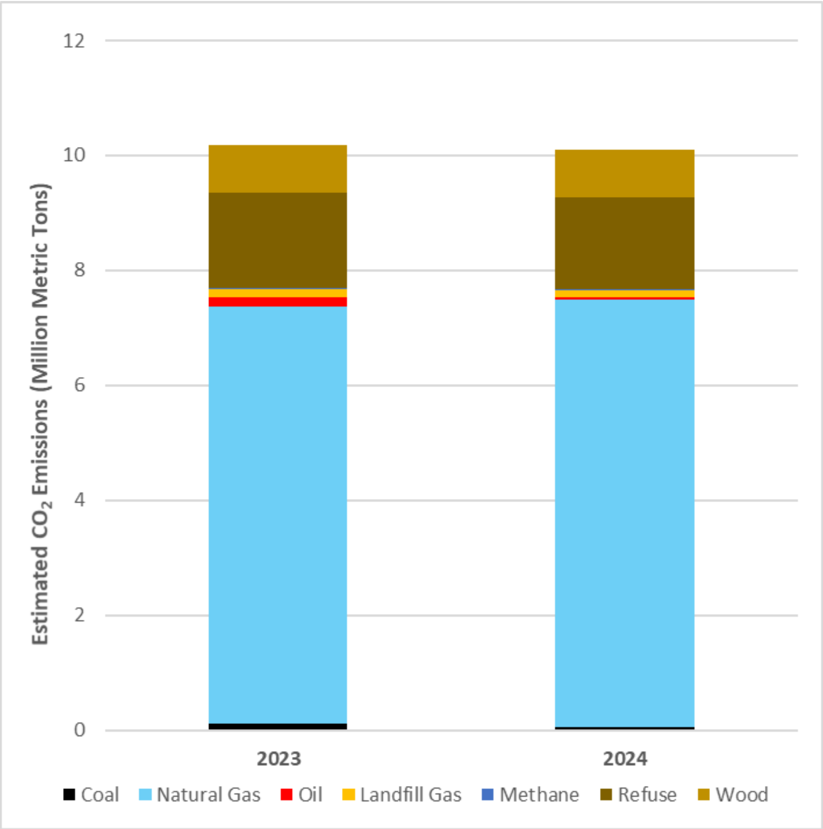
- 2024 Economic Study
  - First use of new Tariff language
    - Study was initiated at the January PAC meeting
  - Study will begin with Benchmark Scenario in Q1-Q2 2024, followed by Policy Scenario in Q3-Q4 2024
  - Stakeholder-Requested Scenario proposals will be reviewed and discussed at the June PAC meeting
  - Market Efficiency Needs Scenario will be studied in 2025

ISO-NE Tie Benefits Evaluation

- The ISO started the tie benefits evaluation at the October 19 PSPC meeting. The third presentation was given at a special March 15 PSPC meeting and topics included:
  - Responses to stakeholder questions from January
  - A deeper dive into the MARS model methodology
  - Review of flows within MARS replications during tie benefits analyses
- The next PSPC meeting is scheduled for June 21
  - The ISO reviewed the 2024 PSPC cycle in greater detail at the May RC meeting

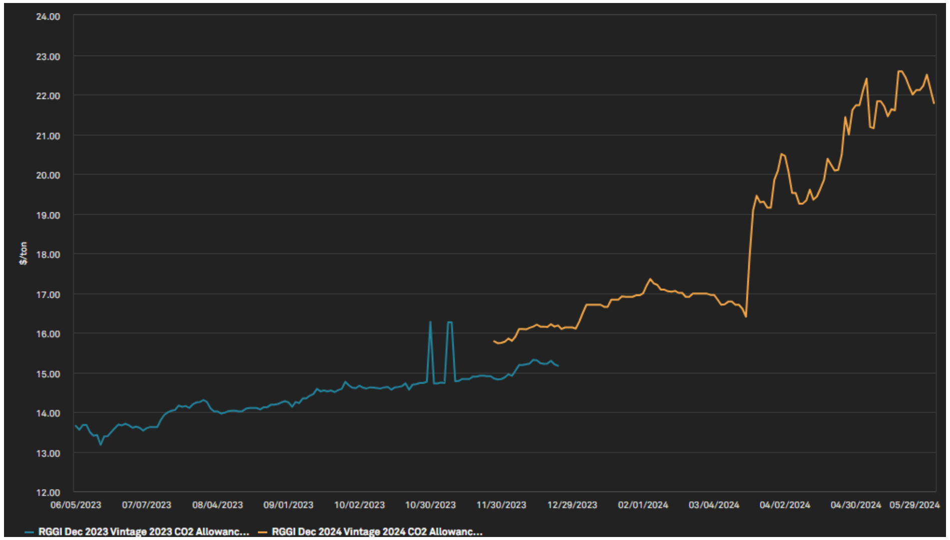
New England Power System Carbon Emissions

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



Data as of 5/19/24

Regional Greenhouse Gas Initiative (RGGI) Allowance Prices



- 5/31/24: RGGI allowance spot price - $21.78
- The 64th RGGI auction was held on June 5
  - Cost Containment Reserve (CCR) allowances for 2024 were depleted in Auction 63 and are not available in Auction 64
  - CCR trigger price for 2024 is $15.92 per CO_2 allowance

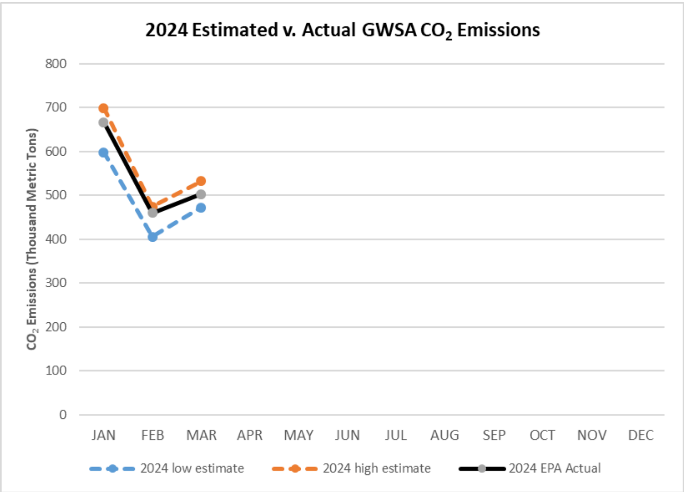
Massachusetts CO_2 Generator Emissions Cap

2024 Estimated Emissions Under CO_2 Cap

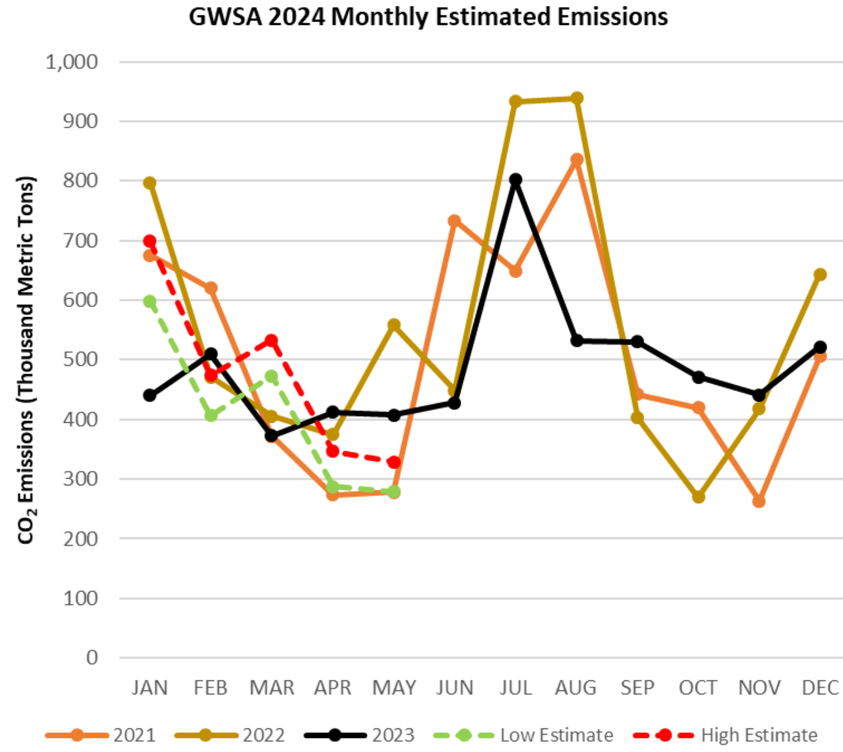
- As of 5/31/24, May estimated GWSA CO_2 emissions range between **278,692** and **328,903** metric tons
  - Year-to-date 2024 estimated emissions range between **26.8%** and **31.3%** of the 2024 cap of 7.61 MMT

2024 Q1 Actual Emissions Under CO_2 Cap

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



2021-2024 Estimated Monthly Emissions (Thousand Metric Tons)



GWSA – Global Warming Solutions Act
MMT – Million Metric Tons

Source: ISO-NE (estimated emissions)

RSP Project Stage Descriptions

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

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

Greater Boston Projects

Status as of 5/24/2024

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

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

Greater Boston Projects, cont.

Status as of 5/24/2024

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

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

Greater Boston Projects, cont.

Status as of 5/24/2024

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

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

Greater Boston Projects, cont.

Status as of 5/24/2024

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

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

Greater Boston Projects, cont.

Status as of 5/24/2024

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

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

SEMA/RI Reliability Projects

Status as of 5/24/2024

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

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

SEMA/RI Reliability Projects, cont.

Status as of 5/24/2024

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Mar-22	4
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	Mar-27	2
1721	Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor	Aug-23	4
1722	Extend the Line 114 from the Dartmouth town line (Eversource-National Grid border) to Bell Rock substation	Dec-25	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Cancelled*	N/A

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

SEMA/RI Reliability Projects, cont.

Status as of 5/24/2024

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1725	Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	May-24	4
1726	Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	4
1727	Retire the Barnstable SPS	Nov-21	4
1728	Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Aug-23	4
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Aug-23	4
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-25	2

SEMA/RI Reliability Projects, cont.

Status as of 5/24/2024

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

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

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

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

SEMA/RI Reliability Projects, cont.

Status as of 5/24/2024

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

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

Eastern CT Reliability Projects

Status as of 5/24/2024

Project Benefit: Addresses system needs in the Eastern Connecticut area

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

Eastern CT Reliability Projects, cont.

Status as of 5/24/2024

Project Benefit: Addresses system needs in the Eastern Connecticut area

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

Eastern CT Reliability Projects, cont.

Status as of 5/24/2024

Project Benefit: Addresses system needs in the Eastern Connecticut area

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

New Hampshire Solution Projects

Status as of 5/24/2024

Project Benefit: Addresses system needs in the New Hampshire area

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

Upper Maine Solution Projects

Status as of 5/24/2024

Project Benefit: Addresses system needs in the Upper Maine area

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

Upper Maine Solution Projects, cont.

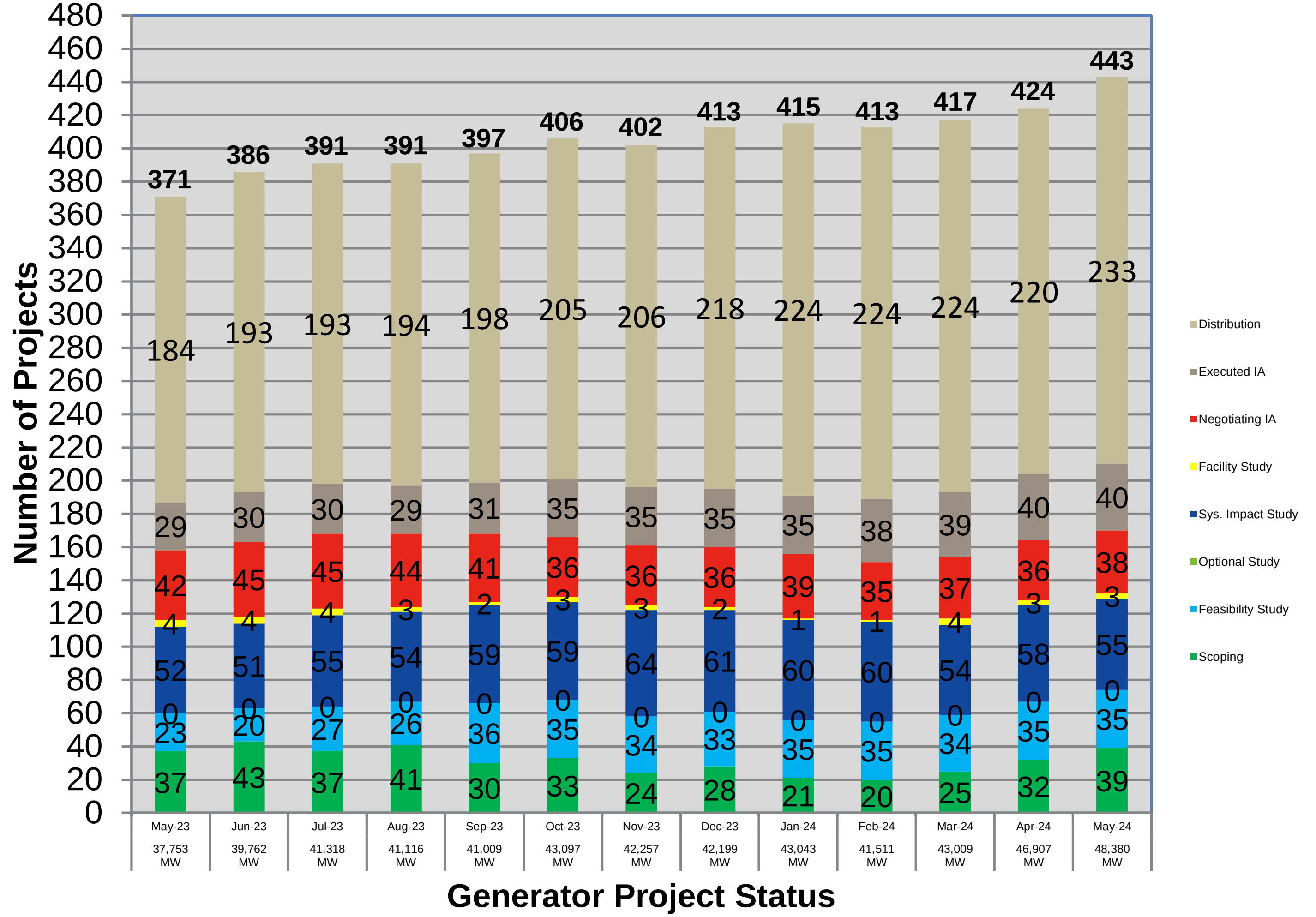
Status as of 5/24/2024

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1887	Install 25 MVAR reactor at Boggy Brook 115 kV substation	Aug-24	3
1888	Install 10 MVAR reactor at Keene Road 115 kV substation	Jun-24	3
1889	Install three remotely monitored and controlled switches to split the existing Orrington reactors between the two Orrington 345/115 kV autotransformers	Cancelled *	N/A
1914	Install a new 80 MVAR reactor, reconfigure the existing two reactors at the 345 kV Orrington substation	Dec-25	2

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

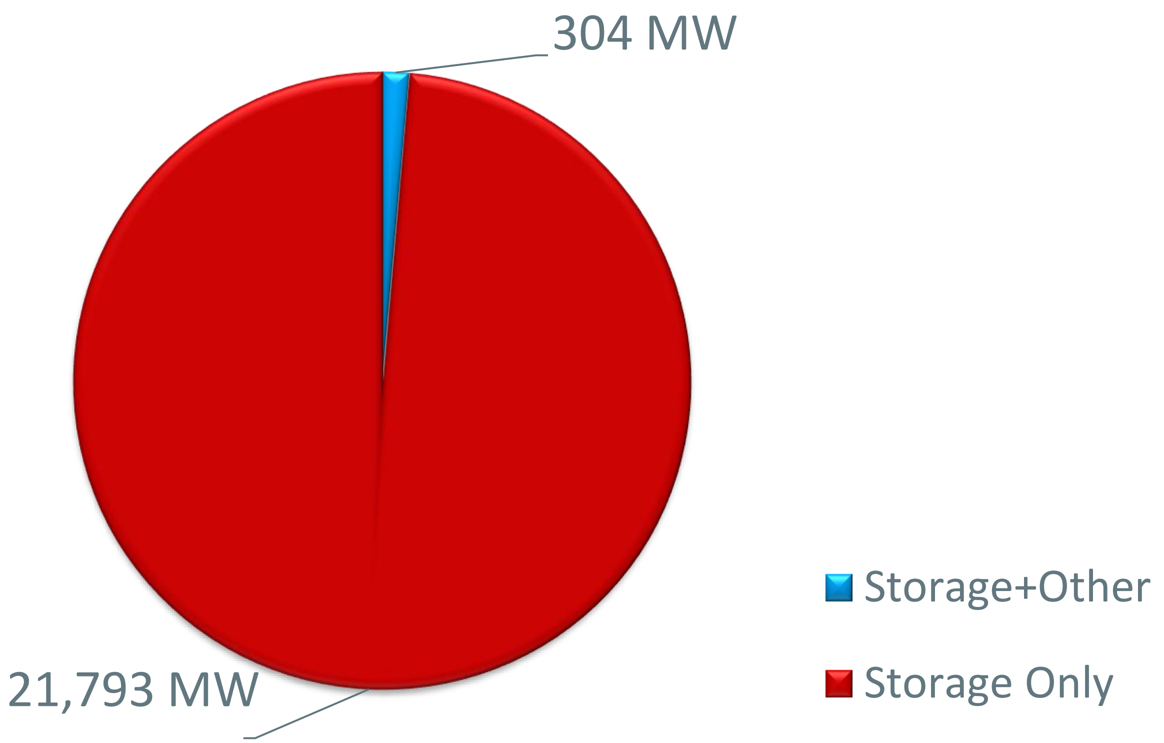
Status of Tariff Studies as of June 1, 2024



7 ETUs in Scoping, 3 in FS, 3 in SIS, 0 in OIS, 0 in FAC, 1 Negotiating IA, and 4 with Executed IA
Transmission Service Requests needing study: 1 in SIS
https://irtt.iso-ne.com/external.aspx

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

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



OPERABLE CAPACITY ANALYSIS

Summer 2024 Analysis

Summer 2024 Operable Capacity Analysis

50/50 Load Forecast (Reference)	June - 2024[2] CSO (MW)	June - 2024[2] SCC (MW)
Operable Capacity MW [1]	27,204	27,747
Active Demand Capacity Resource (+) [5]	396	369
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,188	1,188
Non Commercial Capacity (+)	255	255
Non Gas-fired Planned Outage MW (-)	417	502
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	25,826	26,257
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	24,553	24,553
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	26,858	26,858
Operable Capacity Margin	-1,032	-601

[1]Operable Capacity is based on data as of **June 3, 2024** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **June 3, 2024.**

[2] Load forecast that is based on the 2024 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 22, 2024.**

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

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

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

Summer 2024 Operable Capacity Analysis

90/10 Load Forecast	June - 2024[2] CSO (MW)	June - 2024[2] SCC (MW)
Operable Capacity MW [1]	27,204	27,747
Active Demand Capacity Resource (+) [5]	396	369
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,188	1,188
Non Commercial Capacity (+)	255	255
Non Gas-fired Planned Outage MW (-)	417	502
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	25,826	26,257
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	26,383	26,383
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	28,688	28,688
Operable Capacity Margin	-2,862	-2,431

[1]Operable Capacity is based on data as of **June 3, 2024** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **June 3, 2024.**

[2] Load forecast that is based on the 2024 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 22, 2024.**

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

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

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

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

ISO-NE OPERABLE CAPACITY ANALYSIS

June 3, 2024 - 50-50 FORECAST using CSO MW

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

Report created: 6/3/2024

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
6/22/2024	27204	396	1188	255	417	0	2800	0	25826	24553	2305	26858	-1032	Y	Summer 2024
6/29/2024	27186	390	1274	173	293	0	2100	0	26630	24553	2305	26858	-228	N	Summer 2024
7/6/2024	27186	390	1274	173	421	0	2100	0	26502	24553	2305	26858	-356	N	Summer 2024
7/13/2024	27186	390	1274	173	430	0	2100	0	26493	24553	2305	26858	-365	N	Summer 2024
7/20/2024	27186	390	1274	173	421	0	2100	0	26502	24553	2305	26858	-356	N	Summer 2024
7/27/2024	27186	390	1274	173	269	0	2100	0	26654	24553	2305	26858	-204	N	Summer 2024
8/3/2024	27303	419	1194	313	400	0	2100	0	26729	24553	2305	26858	-129	N	Summer 2024
8/10/2024	27303	419	1194	313	339	0	2100	0	26790	24553	2305	26858	-68	N	Summer 2024
8/17/2024	27303	419	1194	313	330	0	2100	0	26799	24553	2305	26858	-59	N	Summer 2024
8/24/2024	27303	419	1194	313	338	0	2100	0	26791	24553	2305	26858	-67	N	Summer 2024
8/31/2024	27303	419	1194	313	312	31	2100	0	26786	24553	2305	26858	-72	N	Summer 2024
9/7/2024	27303	419	1194	313	351	41	2100	0	26737	24553	2305	26858	-121	N	Summer 2024
9/14/2024	27303	419	1194	313	368	10	2100	0	26751	24553	2305	26858	-107	N	Summer 2024

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).

2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.

3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.

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

5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.

6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.

7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.

8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.

9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)

10. Peak Load Forecast MW: Provided in the annual 2024 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).

11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.

12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)

13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)

14. Operable Capacity Season Label: Applicable season and year.

15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Summer 2024 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

June 3, 2024 - 90/10 FORECAST using CSO MW

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

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7/20/2024	27186	390	1274	173	421	0	2100	0	26502	26383	2305	28688	-2186	N	Summer 2024
7/27/2024	27186	390	1274	173	269	0	2100	0	26654	26383	2305	28688	-2034	N	Summer 2024
8/3/2024	27303	419	1194	313	400	0	2100	0	26729	26383	2305	28688	-1959	N	Summer 2024
8/10/2024	27303	419	1194	313	339	0	2100	0	26790	26383	2305	28688	-1898	N	Summer 2024
8/17/2024	27303	419	1194	313	330	0	2100	0	26799	26383	2305	28688	-1889	N	Summer 2024
8/24/2024	27303	419	1194	313	338	0	2100	0	26791	26383	2305	28688	-1897	N	Summer 2024
8/31/2024	27303	419	1194	313	312	31	2100	0	26786	26383	2305	28688	-1902	N	Summer 2024
9/7/2024	27303	419	1194	313	351	41	2100	0	26737	26383	2305	28688	-1951	N	Summer 2024
9/14/2024	27303	419	1194	313	368	10	2100	0	26751	26383	2305	28688	-1937	N	Summer 2024

Column Definitions

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15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

Possible Relief Under OP4: Appendix A

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

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

Possible Relief Under OP4: Appendix A

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

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

ISO New England 2025 and 2026 Preliminary Operating and Capital Budgets

NEPOOL Participants Committee 2024 Summer Meeting

Robert Ludlow
CHIEF FINANCIAL OFFICER | ISO NEW ENGLAND

Contents of Presentation

EXECUTIVE SUMMARY

Executive Summary

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

Executive Summary *(cont.)*

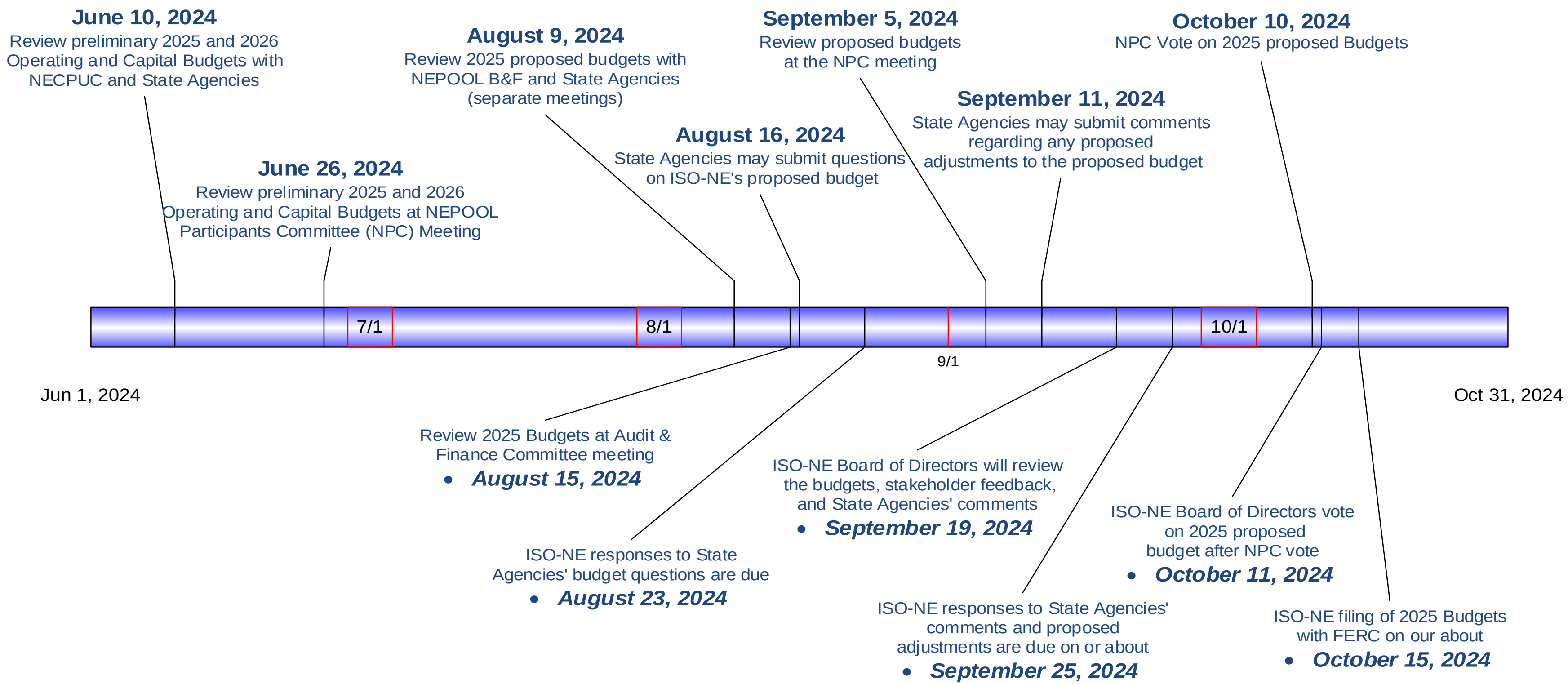
- In order to carry out ISO-NE's mission of planning the transmission system, administering the region's wholesale markets, and operating the power system to ensure reliable and competitively priced wholesale electricity, it is necessary to develop new capabilities for supporting the grid of the future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

Executive Summary *(cont.)*

- For the 2025 budget, ISO is proposing adding an additional 16 FTEs over the 30 FTEs that were projected in last year's budget presentation; this increase is driven primarily by:
  - IT support to operationalize internally developed software for market simulation and situational awareness
  - Support the increasingly complex information to stakeholders and the public and to assist the growing and distributed workforce
  - Additions in system planning for modeling, forecasting, longer-term transmission planning, and addressing and supporting current FERC orders; this is the first iteration of a budget to support the scaling up of our capabilities in our System Planning department to support the proposed Longer-Term Transmission Studies (LTTS) and necessary tariff changes, and the issuance of state supported transmission RFPs that require extensive economic analyses
    - There are still many unknowns, including the volume of RFPs to be supported and the FERC requirements in the rulemaking on transmission planning, which is expected on May 13, 2024; it is our expectation that the resource requirements will be refined over time as we gain experience with the new processes
- The proposed 2025 revenue requirement before true-up is $306.1M, an increase of 10.5% over 2024; when including the net true-up, an increase of $7.8M, the total revenue requirement increase is 13.5% year over year

2025 Budget Process – Key Dates

2025 Budget Process Key Dates

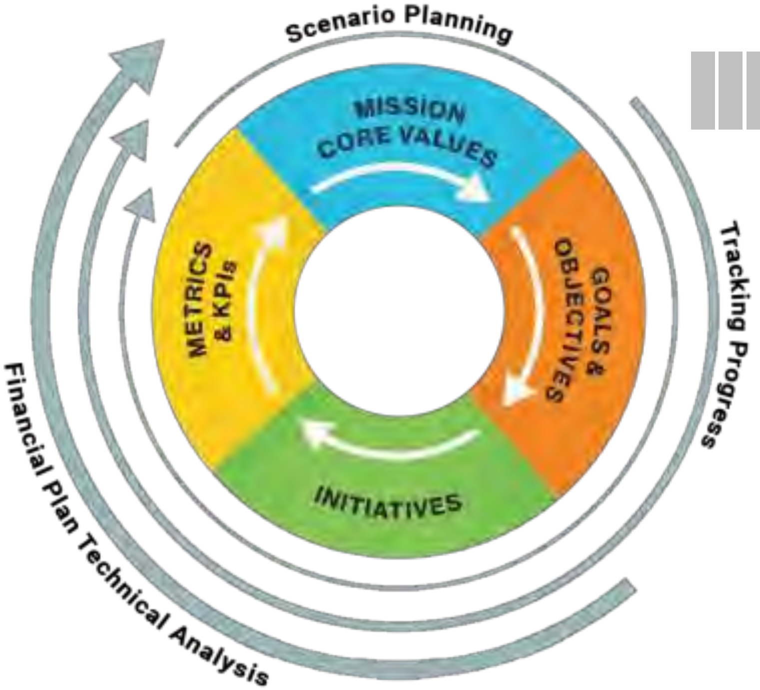


STRATEGIC PLANNING PROCESS OVERVIEW

ISO-NE's integrated business and strategic planning framework

Strategic Planning Framework

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



Strategic Planning Framework – Five-Step Project Approach

STEP 1	STEP 2	STEP 3	STEP 4
Situation Analysis	Strategy Formulation	Operating Model Review	Implementation Plan Development

STEP 5
(High Level) **Economic/Financial Modeling** (Detailed)

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

Annual Process – Business and Strategic Planning

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

Our Guidepost: The ISO New England Vision Statement

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

Vision Statement:

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

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

Our Responsibility to the Region: ISO's Mission

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

Mission Statement:

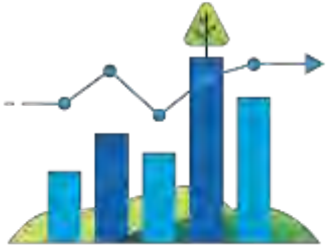
Through collaboration and innovation, ISO New England plans the transmission system, administers the region's wholesale markets, and operates the power system to ensure reliable and competitively priced wholesale electricity

Four Pillars of Supporting a Successful Energy Transition

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

1

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



2

Balancing resources that keep electricity supply and demand in equilibrium

3

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

4

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

CLEAN ENERGY TRANSITION & 2040 OUTLOOK

The path to the 2040 (and beyond) decarbonized grid outlined by the MA decarbonization roadmap

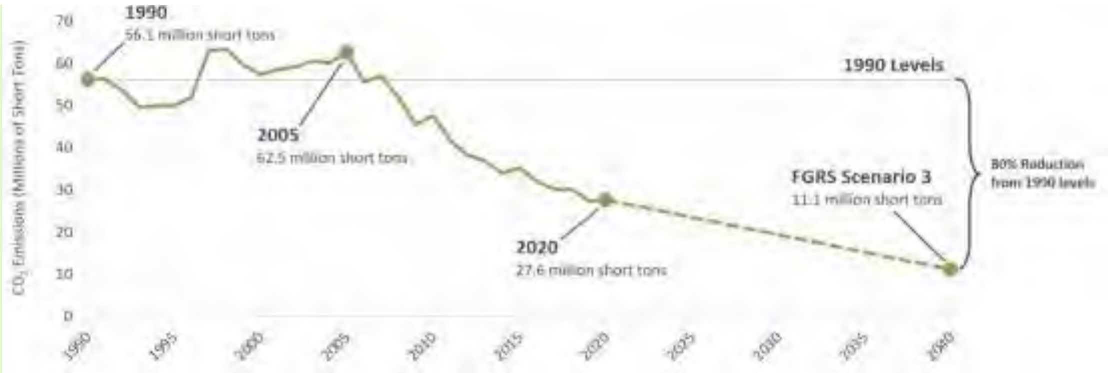
Overview of 2040 Outlook

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

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

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

Historical and Extrapolated New England CO_2 Emissions

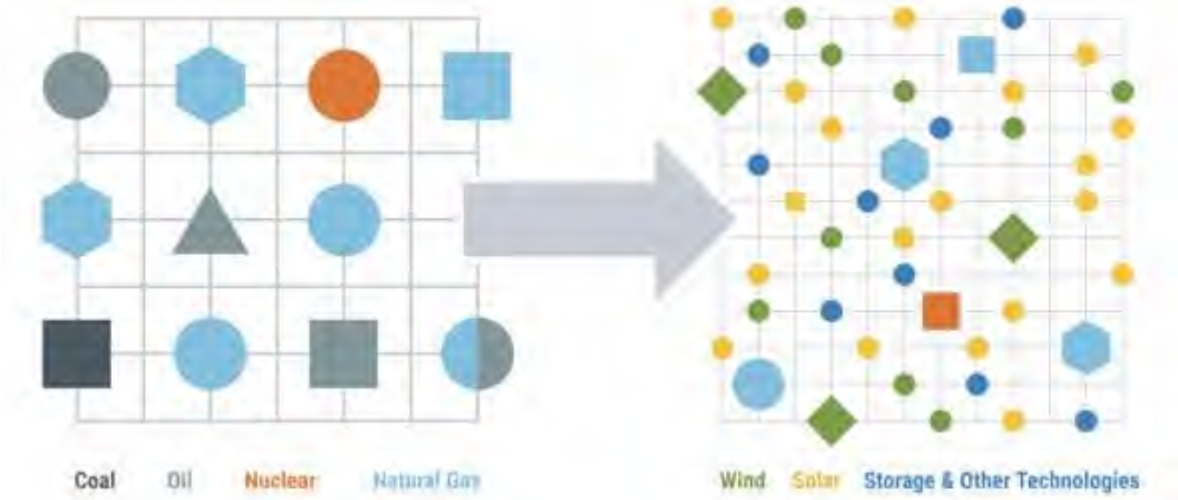


- State policies to address climate change through emissions reduction mandate an 80% reduction from 1990 levels
- These mandates will result in a drastically different generation profile for the region compared to today

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

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

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



1. A shift from centrally dispatched generation to distributed resources

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

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

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

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

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

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

ISO needs to plan to administer, operate, and make market design changes for a power system that by 2030 is projected to be very different than the grid of today.

- **Double the installed capacity of solar resources**
  - Substantial increase in number of BTM PV and possibly BTM storage
- **Thousands of MW of planned offshore wind**
- **Substantial new transmission investment**
  - Supporting inter- and intra-regional transfers, upgrading condition of existing assets, and addressing increasing interaction between transmission and distribution system
- **Enhanced market structures** – accounting for resource mix with different operating characteristics

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

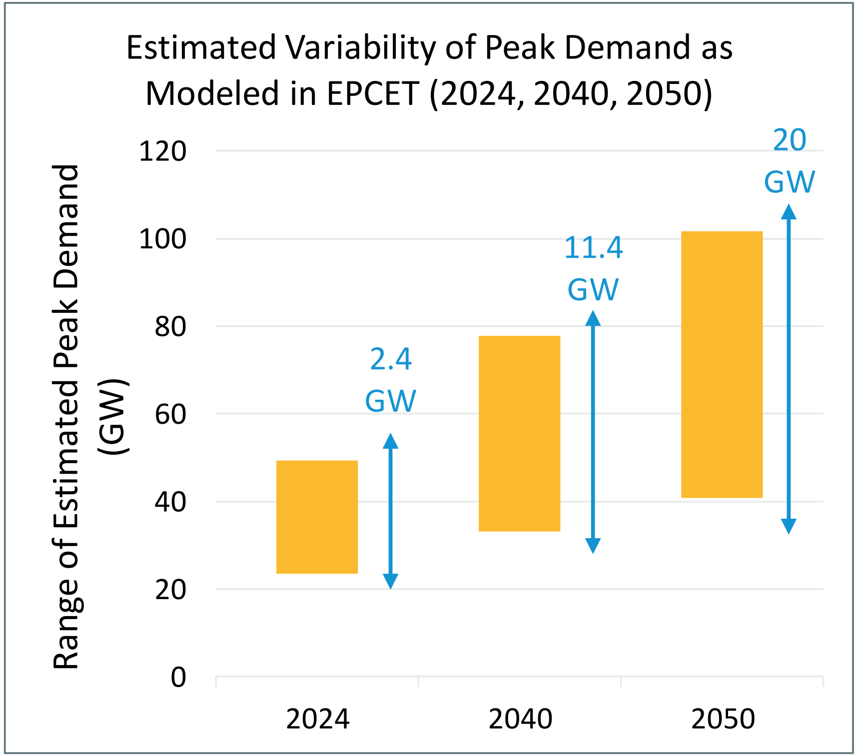
Supporting Decarbonization of the New England Power System Will be the Primary Driver of ISO Work Over the Next Decade

- Decarbonization will change the composition of the power system
  - Increasing numbers of inverter-based resources looking to connect to the New England grid
  - Additional resources are connecting to the distribution system, outside of the ISO’s current visibility, that contribute to load variability and forecasting challenges
- Changing load characteristics will exacerbate operational complexity
  - Increased load anticipated through electrification of heating and transportation
  - Increased variability through proliferation of behind-the-meter (BTM) generation
  - Increasing load-dependence on weather at a time when weather is becoming more erratic

Escalating Variability in Supply and Demand

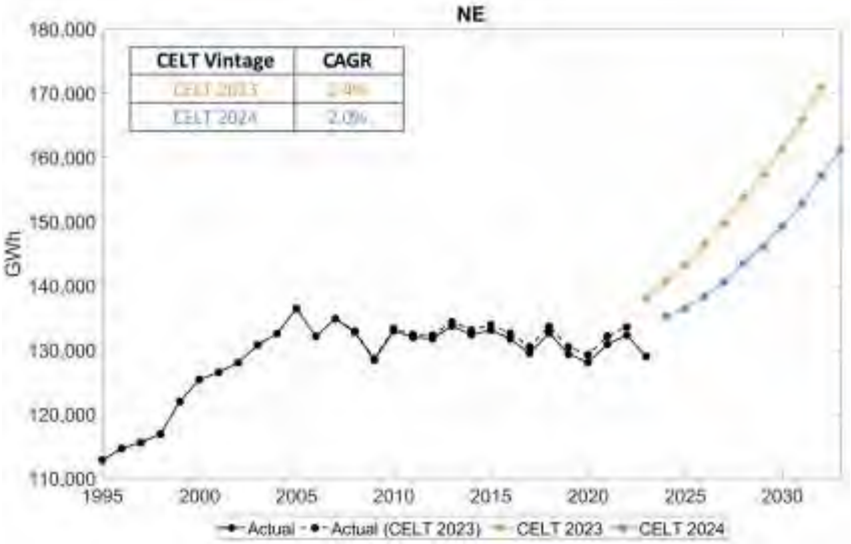
Most pathways to a low-carbon grid involve high variability in both supply and demand, which will result in either reliability challenges or higher costs

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



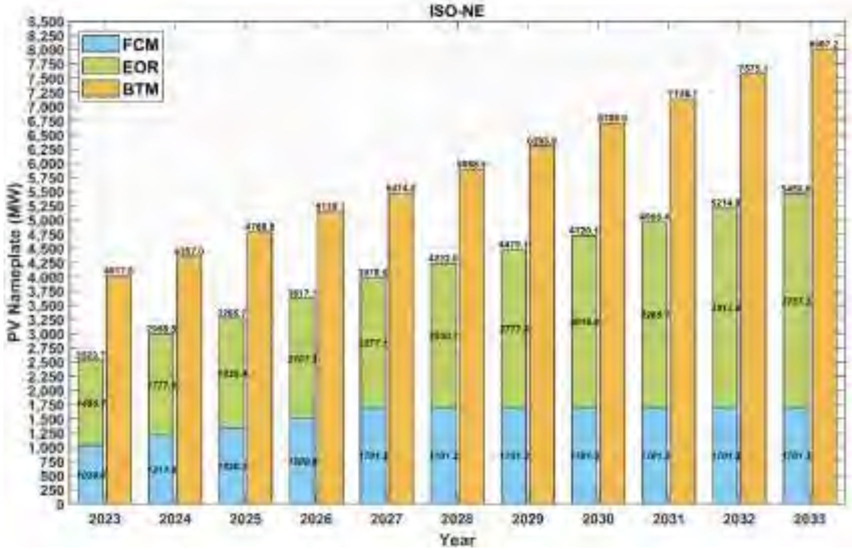
Continued Growth in PV and Peak-Load Estimates Through 2030

Peak load is projected to grow through 2030s



Source: March 2024, Load Forecast Committee: [2024 Final Draft Energy and Seasonal Peak Forecasts]()

ISO projects PV growth to approximately double over next 10 years

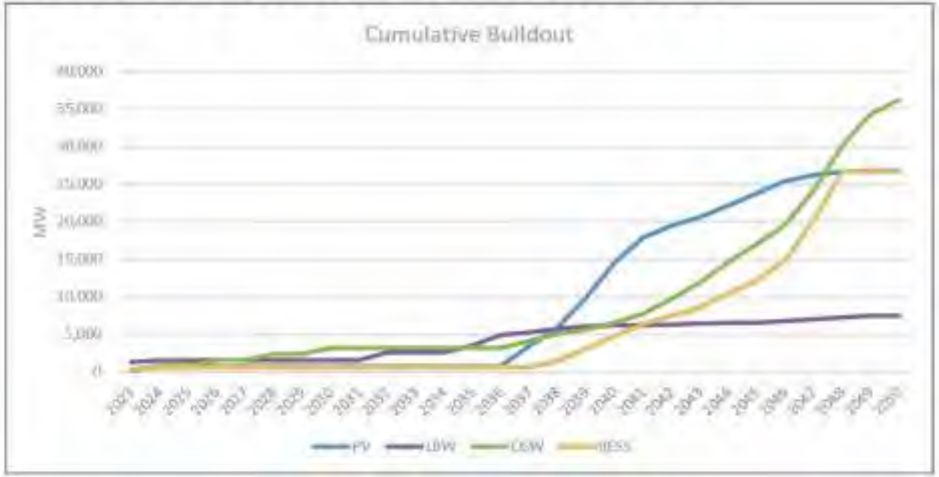


Source: March 2024, Distributed Generation Forecast Working Group: [Final 2024 PV Forecast]()

Grid-level Renewable Capacity Expected to Take Off in the 2030's

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

Carbon Constrained Buildout

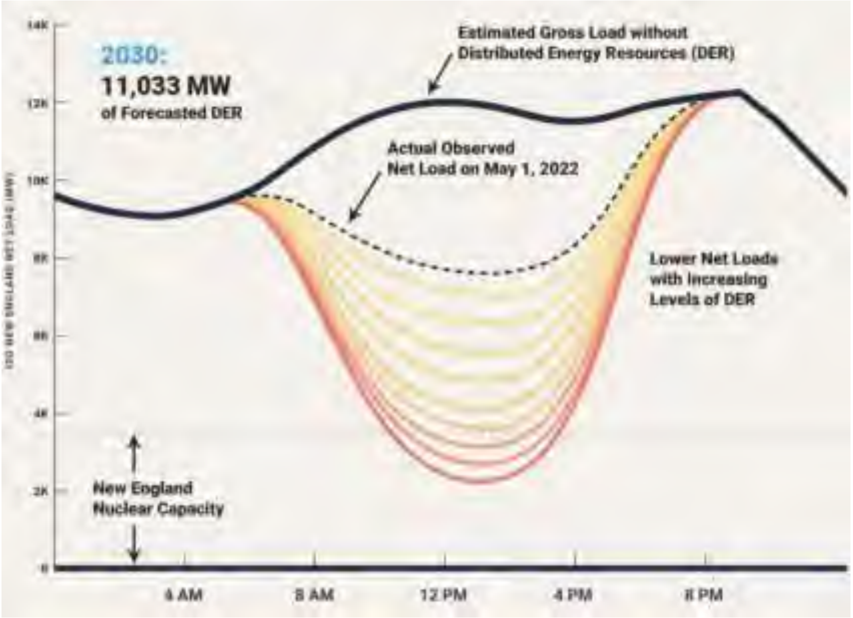


Source: [Economic Planning for the Clean Energy Transition]

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

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

Behind-the-Meter Solar Reduces Grid Demand



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

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

Timing of Shift to Winter-Peaking System

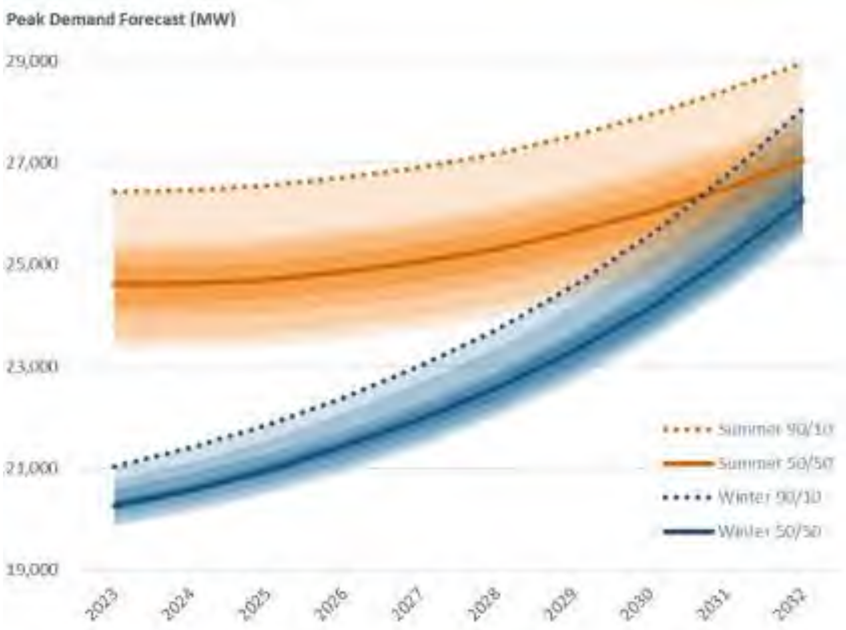
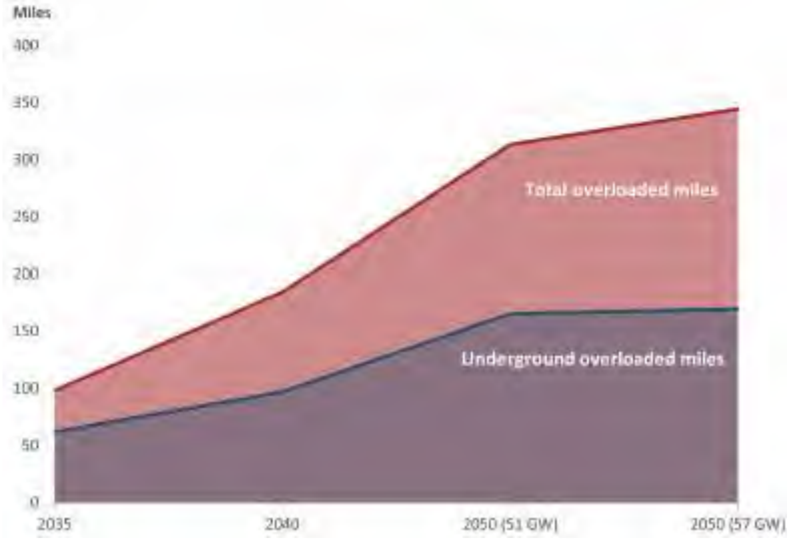


Figure source: 2023 Regional System Plan, Figure 4-9
Data Source: 2023 CELT Report

The Region's Transmission System Will Need Significant Investment

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

Line Mileage Overloaded in Boston with Generator Interconnection Locations Optimized



Source: 2050 Transmission Study, Figure 2-1

Constraints on the distribution system may also present bottlenecks

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

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

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

2025 AND 2026 PRELIMINARY BUDGET OVERVIEW

2025 Preliminary Budget Overview

- Key drivers supporting the proposed increase are (see further details on the following pages):
  - Continuing to enhance capabilities to address the modeling, analysis, processing, and communication needs directly resulting from the clean energy transition
  - Addressing the effects of inflation on products/licenses, labor, and professional fees as well as the year-over-year costs of continued operation

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

Clean Energy Transition Driving 2025 ISO-NE Budget

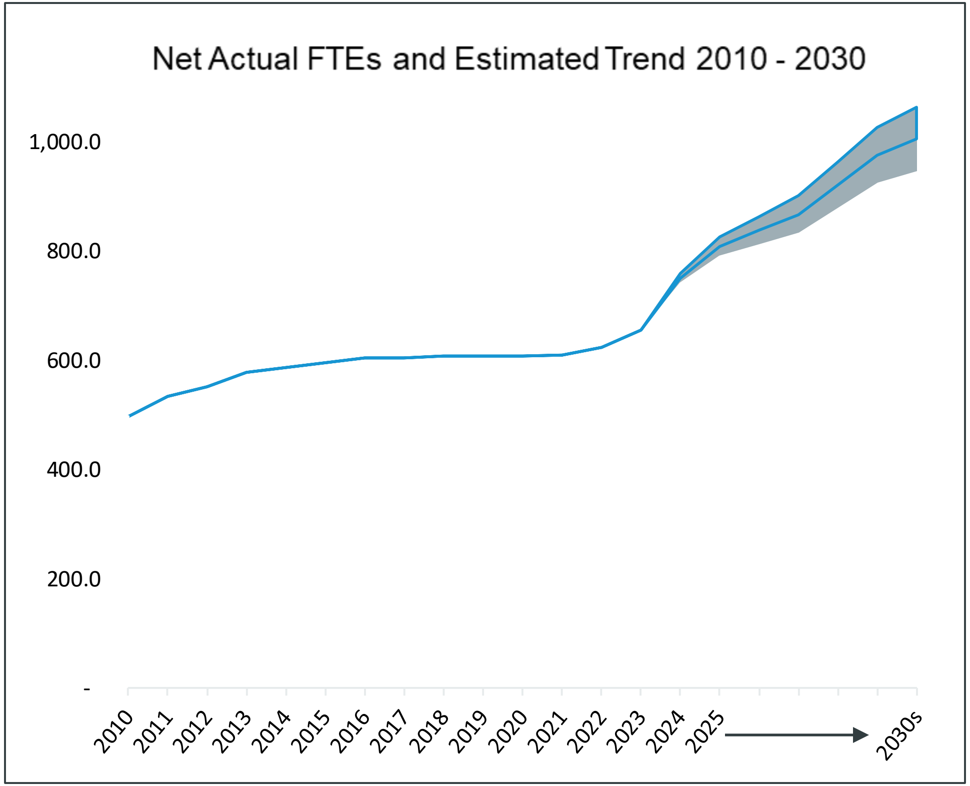
Driver: The main driver of the 2025 budget is the need to add personnel to the organization to address the modeling, analysis, processing, operational and communication needs directly resulting from the clean energy transition, and includes:

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

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

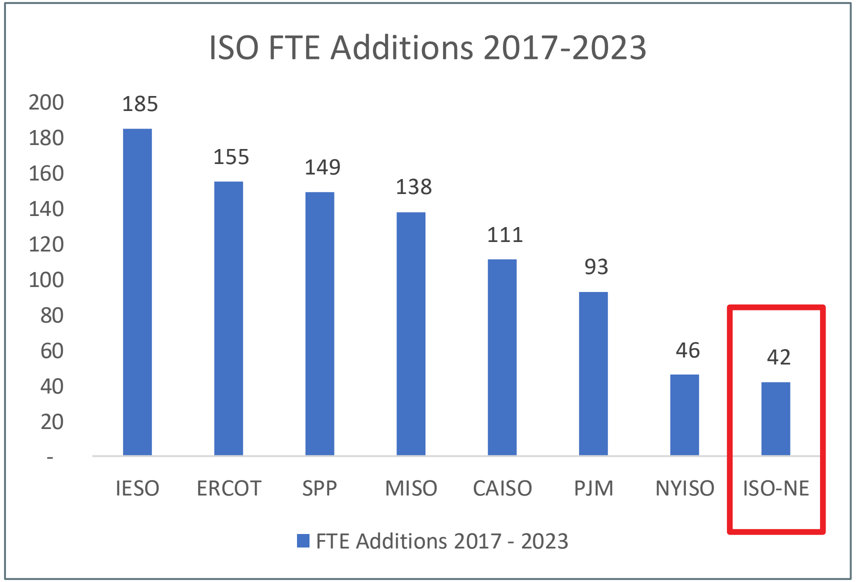
Clean energy transition driving FTE needs:

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

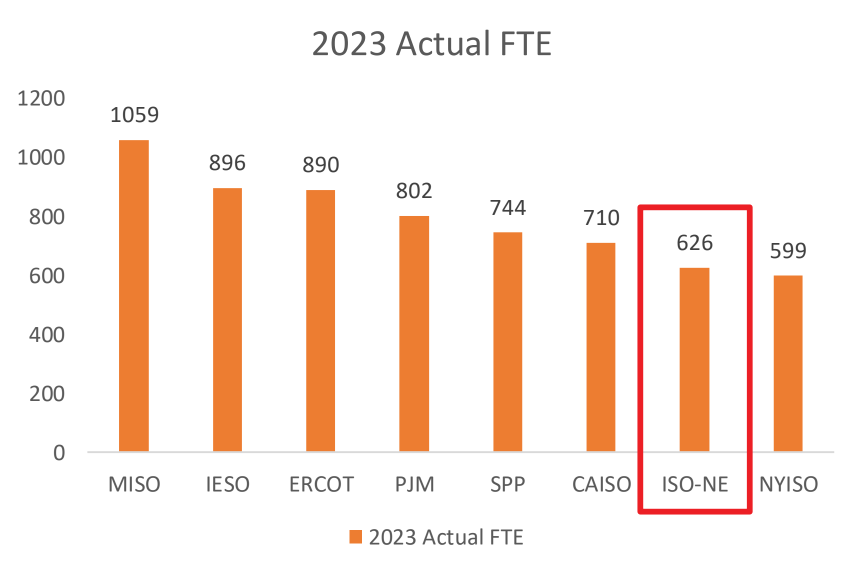


ISO-NE's Plan to Increase Its Headcount is Similar to Other ISO/RTOs' Practices Over Last Several Years

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



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



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

Other Factors Driving Increases to the 2025 Budget

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

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

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

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

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

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

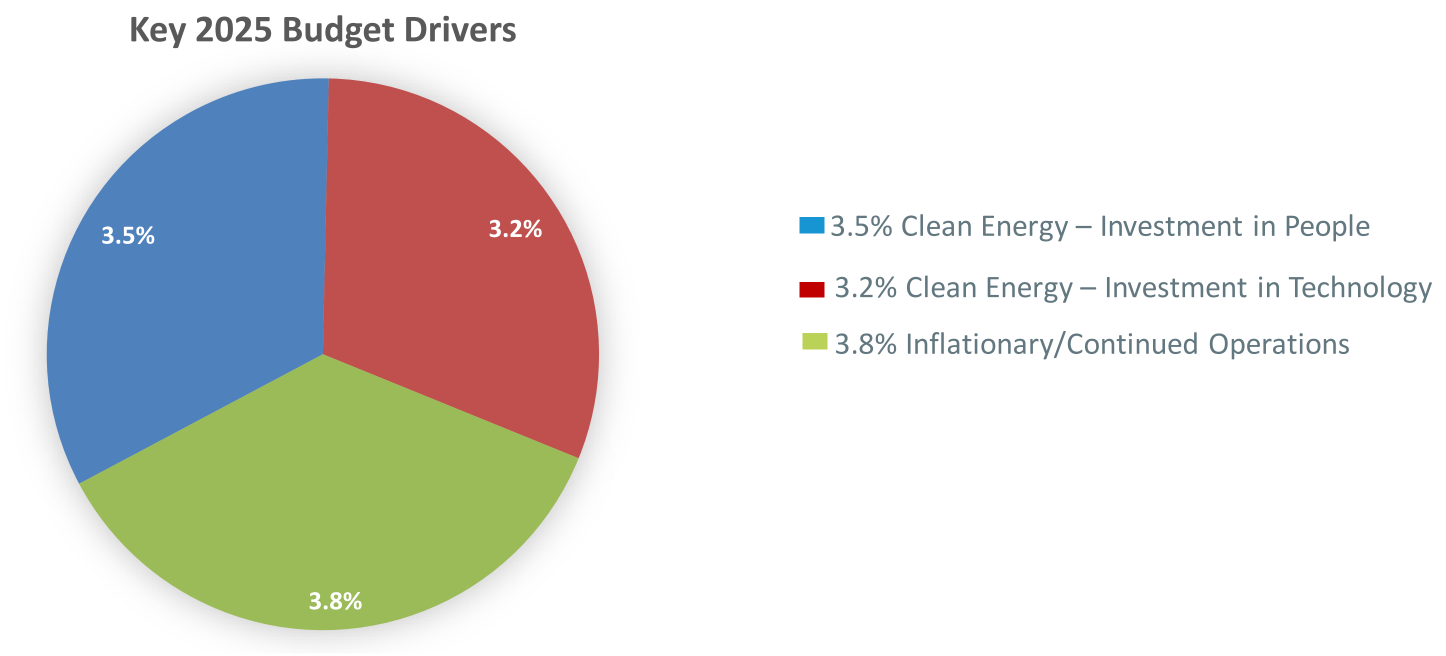
The main factors for the increases to the 2025 ISO budget are:

1. Adding full-time employees (FTEs) and other resources to address work directly related to the transition to clean energy and indirect support
   - Including additional investment in information technology (IT) to address, cybersecurity, and the transition to cloud-based infrastructure
2. Inflationary and continued operations drivers:
   - Standard salary increases to keep pace with labor market in order to retain and attract employees
   - Inflationary and renewal costs for IT infrastructure and licensing

Factor	% Increase	$ Amount	$KWh Rate	Average Monthly Consumer Cost Impact *
Clean Energy Transition	6.7 %	$18,476,600	$0.00013	$0.10
Inflationary/ Continued Operations	3.8 %	$10,700,600	$0.00008	$0.06
Total:	**10.5 %**	**$29,177,200**	**$0.00021**	**$0.16**

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

Key Factors to the 2025 ISO-NE Budget



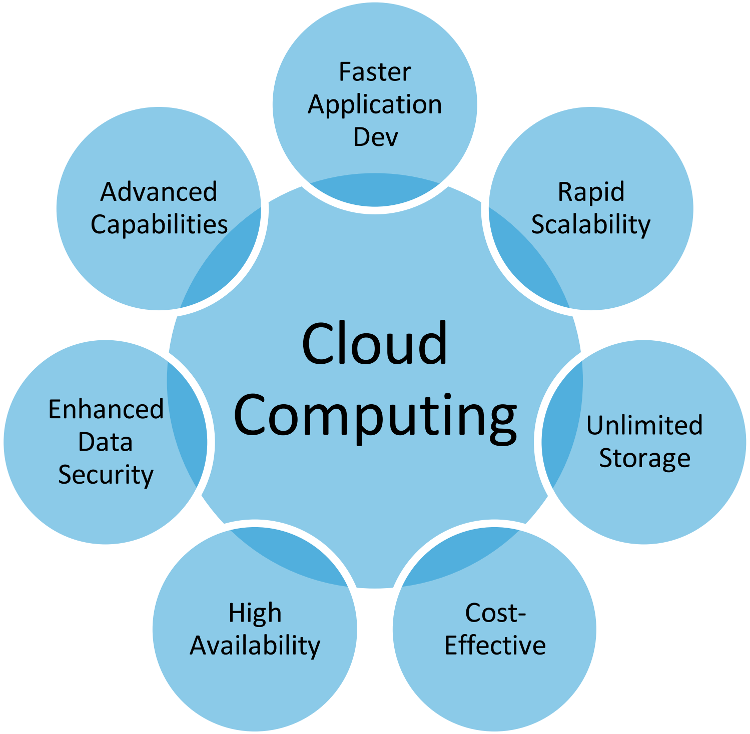
Budget Driver: The Need to Enhance Computer Services and Technology Stack

Computer services driving budget costs in 2025:

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

Training existing staff to support new platforms and tools will drive operating costs as well.

Benefits of moving to the cloud

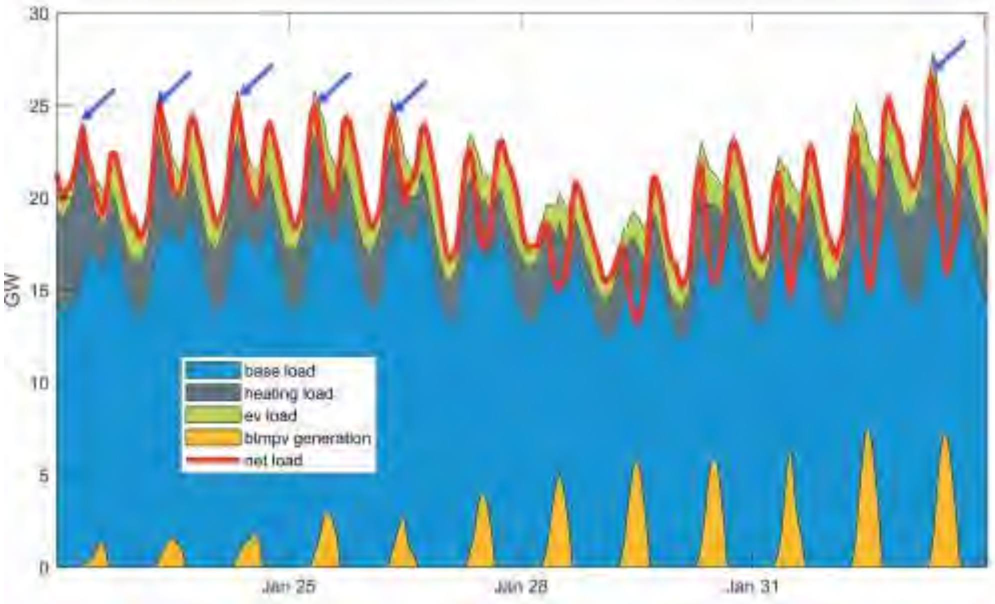


Budget Driver: Forecasting for Demand; Planning Studies Becoming More Complex

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

Need Explicit Accounting of Load Shape

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



Source: Data from 2023 CELT Report

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

- Hiring to support the development and maintenance of new market mechanisms for the changing resource mix:
  - Resource Capacity Accreditation
  - Move to a prompt/seasonal market
  - Ramping and flexible response products
  - Day-Ahead Ancillary Services Initiative
- Hiring to support the effects of evolving resource mix on supporting market analyses
  - New and more frequent energy analyses
  - Growing number of transmission and interconnection studies
  - Need to support transmission RFPs with economic analyses

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

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

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

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

2025 Preliminary Capital Budget Overview

The 2025 Capital Budget is also presented in summary form

- The 2025 Capital Budget has increased from $35M in 2024 to $40M in 2025 and beyond
  - The increased capital budget need is being driven by four primary drivers as explained in further detail Appendix 3
  - The increased capital spending will result in higher interest expense costs and depreciation expense in future years as capital projects go into service and are included in operating budgets and rates
- The 2025 proposed capital budget of $40M is provided with a list of projects by strategic goal that are currently chartered and on-going or in planning/conceptual design (See Appendix 4)
- Detailed project descriptions will be presented in August once the final resource requirements are determined

2026 Preliminary Budget Overview

- 2026 Budget Assumptions include:
  - The addition of 30 FTEs, primarily to address the Clean Energy Transition, in the areas of System Operations & Market Administration, Information and Cyber Security Services, Participant Relations and Services, System Planning, Advanced Technology Solutions, and External Affairs
  - Merit and promotional/equity annual increases consistent with 2025 percentage increases noted on slide 49
  - Estimated increases based on market or historical trends related to: employee benefits (primarily for health insurance); Computer Services; Insurance Expense; and NPCC/NERC Dues
  - Inflationary increases in other lines based on consumer price index indicator
  - An increase of Interest Expense to fund increases in the Capital Budget program (See Appendix 5)

2025 and 2026 Operating Budget Risks

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

APPENDIX 1: 2025 Detailed Budget Changes by Strategic Goal

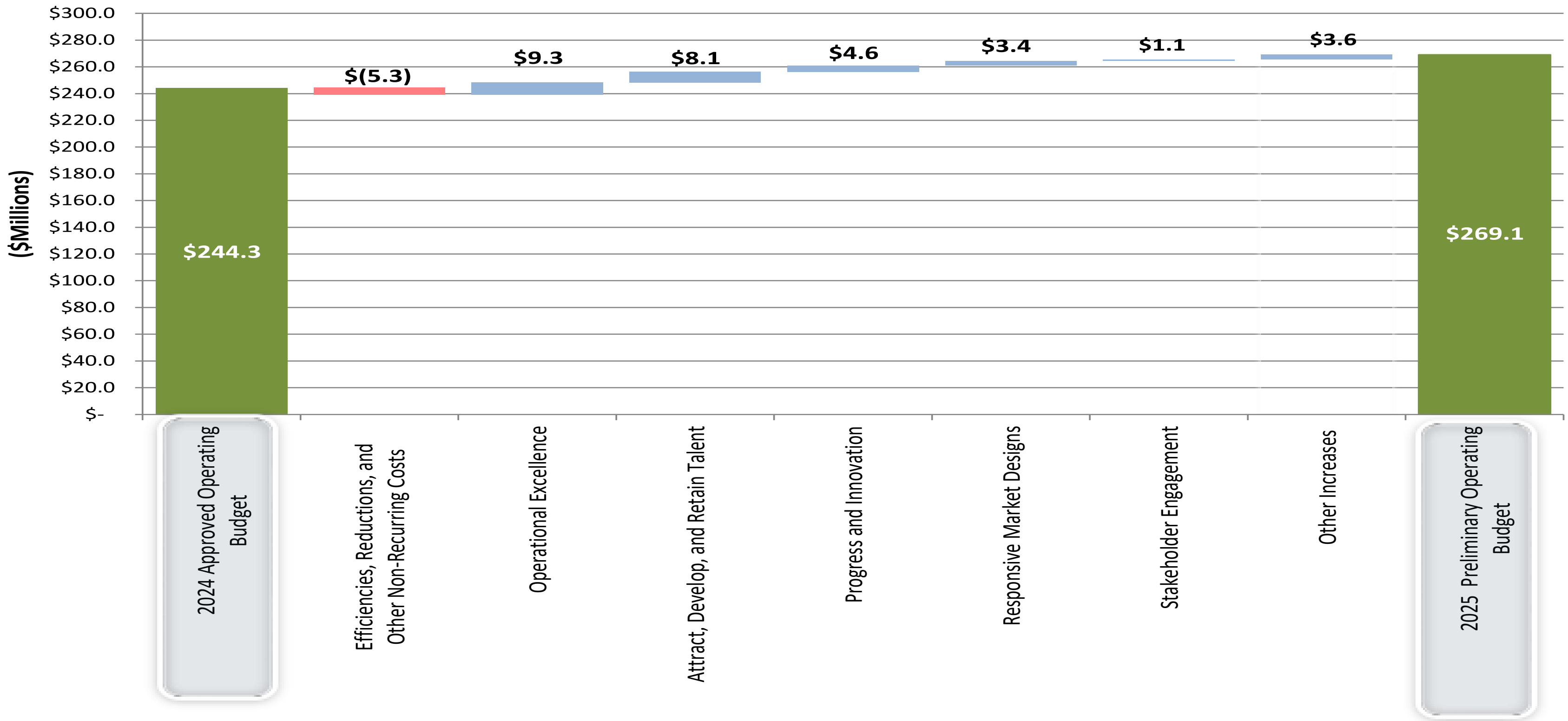
2025 ISO-NE Strategic Goals

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

Responsive Market Designs:	Advance the competitive wholesale markets to support the investment and new services required for a reliable clean energy transition
Progress and Innovation:	Expand capabilities to support increasing grid complexity as the region transitions to clean energy, including improved power system and market modeling, and system assessments. Support investment in transmission infrastructure to enable renewable energy. Facilitate the integration of distributed energy resources
Operational Excellence:	Continuously improve operations and processes, with a focus on prioritizing project scope and implementation, business results, and continuity of reliable operations
Stakeholder Engagement:	Collaboratively understand and anticipate needs, demonstrate thought leadership through high-quality analysis and communication, and nurture productive relationships with regulators and stakeholders in supporting the four pillars of the clean energy transition
Attract, Develop, and Retain Talent:	Continue to promote our Culture, Mission, Vision, and Goals; develop and position the workforce to support the evolving needs of the organization; recognize and reward employees’ success and innovation; tailor programs to retain and attract critical, in-demand skills; and honor diversity and promote inclusion

2025 Preliminary Budget

Changes in budget by Strategic Goal



2025 Preliminary Budget Details

Efficiencies, Reductions, and Other Non-Recurring Costs

Reductions include: ($5.3M)

- Reductions for consulting professional fees for 2024 studies or other non-recurring work including:
  - Utilization of external support for New England States' requests to be offset by ISO-NE internal staff
  - Funding for FCA 21 Cost of New Entry (CONE) parameter updates
  - Reduction in funding for the assessment of a conceptual framework for a Prompt Seasonal Capacity Market
  - Reduction in funding for a regional study with PJM and NYISO for 1,200MW single source contingency limit appropriateness and determine upgrades required to support 2,000MW single source limit
  - Removal of funding in Market Administration & Auctions and Market Monitoring related to the delay in FCA 19
  - For Distributed Energy Resource and minimum load studies for assistance in determining requirements on how to ensure reliability on the system under conditions where it is powered solely by inverter-based resources
  - For Energy Resource Opportunity cost support in Market Monitoring
- Increase in Interest Income due to raising of interest rates for 2025 to 2.75% compared to 1.00% in 2024 budget

2025 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 3: Operational Excellence: $9.3M

- Computer service and leasing increases for: cyber security (security logging, firewall updates, network collaboration tool, network traffic segmentation, encryption software and risk management); leasing of servers as part of data center refresh; photovoltaic and demand response forecast products; licensing for System Planning and Operations applications; performance monitoring software; Enterprise Resource Planning software; compliance software; and inflationary and vendor increases across our portfolio of computer service products ($6.0M)
- Funding for 10.0 FTEs* related to this goal across Information and Cyber Security for Cloud Computing transition including architecture, security and infrastructure support and FinOps management, for IT modeling and software development, and support for enterprise and settlement applications; for Participant Training Support; and for Finance and Market Credit Risk to support the growth in these areas to support the organization ($2.3M)
- Network Operations increases for transition of communication lines to new technologies, for data redundancy, and for inflationary and communication line increases ($0.6M)

* FTE totals and related funding on slides 47-54 reflect partial funding for 2025 positions (26.5 FTEs), as well as a partial carryover for 2024 positions (20 FTEs).

2025 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

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

- Information and Cyber Security Services staff augmentation inflationary rate increases ($0.2M)
- Travel and training due to full renewal of in-person meetings, higher travel costs, and training of staff to support new platforms and tools ($0.2M)

2025 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 5: Attract, Develop, and Retain Talent: $8.1M

- Merit and Promotion increases: for annual merit (4.0%) and for standard and targeted equity/promotions (2.0%), less timing of 2024 equity/promotion adjustments and allocation of amounts between operating and capital/reimbursable work ($4.6M)
- Increases in employee benefit costs, primarily for medical trend, increased number of employees in Defined Contribution Benefit Plan and higher 401K match due to overall employee salaries ($1.5M)
- Increase for employee incentive target amounts including adjustments based on compensation study review ($1.4M)
- Funding for 6.0 FTEs* related to this goal across Human Resources (for Talent and Project Management, Early Career Associates, and Learning Coordinator), for Corporate Counsel to support employee related matters, and Communications Specialist for dissemination of information to employees ($1.0M)
- Higher recruiting and benefits administration related expenses including relocation, recruiter fees, and employee experience consulting ($0.5M)

* FTE totals and related funding on slides 47-54 reflect partial funding for 2025 positions (26.5 FTEs), as well as a partial carryover for 2024 positions (20 FTEs).

2025 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

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

- Leasing of land adjacent to Holyoke facility in conjunction with Workspace Utilization project ($0.3M)
- Human Resources support for instructional design and executive coaching ($0.2M)
- A reduction for the increase of employee vacancy from 5% to 6% (reduction of $1.4M)

2025 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 2: Progress and Innovation: $4.6M

- Funding for 15.0 FTEs* including Information Technology and Advanced Technology for bringing ISO-NE developed advanced technologies into the operating environment to increase our situational awareness capabilities; System Operations and System Planning positions for forecasting and energy analysis across different timespans as the system's resource mix continues to evolve, for modeling and electromagnetic transient analyses for market and reliability operating limits of Inverter Based Resources, and in Transmission Planning and Services for RFP processing and long-term studies ($3.1M)
- Funding for a transmission planning system assessment under NERC Transmission Planning Standard TPL-001 ($0.5M)
- Increased utilization of cloud computing with more products moving to the cloud including the Customer and Asset Management System (CAMS) and Forward Capacity Tracking System (FCTS) ($0.4M)
- Funding to support transmission planning and analysis studies to establish facility out transfer capability for Northern New England and NECEC ($0.3M)
- Funding for Planning Services benchmarking and validation of generator outage data ($0.1M)

* FTE totals and related funding on slides 47-54 reflect partial funding for 2025 positions (26.5 FTEs), as well as a partial carryover for 2024 positions (20 FTEs).

2025 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

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

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

2025 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 1: Responsive Market Designs: $3.4M

- Funding for 10.0 FTEs* related to this goal including for: Market Development in design of market overhauls including prompt seasonal capacity market, resource capacity accreditation, and flexible response services; Operations training and integration to design and support training needs of Operations and Market Administration and Auctions staff for new market features; Information Technology and Advanced Technology staffing to support and integrate new market features into applications and tools; and Planning and Transmission Services that will continue to be heavily involved with new market designs, identifying enhancements to existing reliability modeling and researching and developing modeling techniques for emerging technologies ($2.2M)
- nGEM vendor support with the Day-Ahead Market Clearing Engine production application that is being supported at the same time as the legacy Real-Time application (forecasted to go live in 2026) ($0.6M)
- Support in Advanced Technology Solutions and Market Development for Integrated Market Simulator and other market system enhancements ($0.5M)
- Support for Market & Credit Risk Modeling ($0.1M)

* FTE totals and related funding on slides 47-54 reflect partial funding for 2025 positions (26.5 FTEs), as well as a partial carryover for 2024 positions (20 FTEs).

2025 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Goal 4: Stakeholder Engagement: $1.1M

- Funding for 3.0 FTEs* in Participant Relations and Services for project services (gathering, managing, and supporting the assessment of participant requests), for data analytics on key trends and for technical readiness on participants inquiries and proposals, and for technical writing and instructional design work for broader and deeper training for new market features and initiatives scheduled for 2025 and 2026 ($0.6M)

- Funding for 1.5 FTEs* in System Planning for Economic Study and Environment Outlook and Interconnection Study work; and 1.0 FTE* in External Affairs for increased support and substantive interactions with the states and facilitating engagement of ISO Subject Matter Experts on matters related to renewable and clean energy development, transmission and interregional planning, generator interconnections, and integration of demand-side solutions and distributed resources ($0.5M)

* FTE totals and related funding on slides 47-54 reflect partial funding for 2025 positions (26.5 FTEs), as well as a partial carryover for 2024 positions (20 FTEs).

2025 Preliminary Budget Details *(cont.)*

Detailed allocation by Strategic Goal/2025 Initiatives

Other Increases: $3.6M

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

APPENDIX 2: 5 YEAR BUDGET COMPARISON

2025 Preliminary Budget – 5 Year Comparison

(Budget Amounts are in Millions)	2025	% Change	2024	% Change	2023	% Change	2022	% Change	2021
Operating Budget Before Depreciation	$269.1	10.1%	$244.3	16.8%	$209.2	10.7%	$189.1	5.8%	$178.6
Capital Budget	40.0	14.3%	35.0	4.5%	33.5	4.7%	32.0	14.3%	28.0
Total Cash Budget	**$309.1**	**10.7%**	**$279.3**	**15.1%**	**$242.7**	**9.8%**	**$221.1**	**7.0%**	**$206.6**
Operating Budget Before Depreciation	$269.1	10.1%	$244.3	16.8%	$209.2	10.7%	$189.1	5.8%	$178.6
Depreciation **(1)**	37.0	13.6%	32.6	5.1%	31.0	19.1%	26.0	(1.2)%	26.3
Revenue Requirement Before True-up	306.1	10.5%	276.9	15.3%	240.2	11.7%	215.1	4.9%	205.0
True up	4.8		(3.0)		(14.6)		1.1		0.2
Revenue Requirement	**$310.9**	**13.5%**	**$273.9**	**21.4%**	**$225.6**	**4.4%**	**$216.1**	**5.4%**	**$205.1**
Forecast – TWhs (2)	**136.5**	**(3.0)%**	**140.7**	**(1.6)%**	**143.0**	**(1.0)%**	**144.4**	**(2.0)%**	**147.4**
$/KWh Rate	**$0.00228**	**17.1%**	**$0.00195**	**23.4%**	**$0.00158**	**5.4%**	**$0.00150**	**7.5%**	**$0.00139**
Average Monthly Consumer Cost (3)	**$1.71**		**$1.46**		**$1.18**		**$1.12**		**$1.04**

(1) The 2025 *preliminary* depreciation budget is a placeholder. The 2025 *proposed* budget will result in a detailed review of project budgets and estimated go-live dates for the impact on depreciation expenses.

(2) 2025 Forecast based on May 2024 CELT Report (Schedule 1.5.2 - Net Annual Energy - Gross (without reductions)). All other years based on CELT Report for the applicable year, which can be found on www.iso-ne.com.

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

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

APPENDIX 3: Forward Looking Capital Budget Spending

Forward Looking Capital Budget Spending

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

Forward Looking Capital Budget Spending *(cont.)*

nGEM Platform Replacement (*)

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

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

Forward Looking Capital Budget Spending *(cont.)*

Major Market and Reliability Related Efforts

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

Forward Looking Capital Budget Spending *(cont.)*

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

- Significant Capacity Market Reforms: The ISO is currently recommending the move from a forward capacity auction construct to a prompt and seasonal capacity auction construct; this is a substantial scope of work that will better position the ISO to mitigate energy adequacy risks as the power system evolves
- Resource Capacity Accreditation (RCA): This is a major project that accredits resources on their marginal reliability contributions during reliability hours; the project maybe impacted by the recent FERC Order to delay FCA 19 until 2028. ISO-NE will evaluate and reflect any impact in the proposed 2025 budget materials later in 2024.
- Transmission Line Ratings Enhancements: This project is in response to recent FERC orders and will require substantial IT and database work to collect and appropriately use data in planning and operations
- Market Simulator, 21 Day Energy Simulator, Inverter-Based Resource Modeling: There are various research and development efforts at the ISO that are expected to result in significant improvements to ISO modeling capabilities and situational awareness
- Stakeholder Priorities: The ISO has embarked on an improved prioritization process with stakeholders; each year, the ISO expects stakeholders to highlight three key priorities; some of these priorities will require the development of new software and associated applications
- Other Market Design Projects Identified in the ISO's Multi-Year Work Plan: The ISO plans to continue to make improvements to existing ancillary services, and design new ancillary services products; new ancillary products may include replacement reserves and ramping products

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

Forward Looking Capital Budget Spending *(cont.)*

Cyber Security & IT Asset and Infrastructure Replacement

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

APPENDIX 4: 2025 Preliminary Capital Budget

Capital Budget

2025 Expenditures

Goal: Responsive Market Designs

Project	2025 Budget	Total Project Cost	Estimated Completion Date	Project Stage
Day-Ahead Ancillary Services Improvements	$1.7M	$9.1M	03/25	In Development
FERC Order 2222	$1.0M	$6.5M	11/26	Planning/Conceptual Design
FERC Order 841	$1.5M	$1.7M	10/25	Planning/Conceptual Design
Resource Capacity Accreditation (see Note 1)	$0.5M	$1.6M	12/25	Planning/Conceptual Design
Solar Do Not Exceed Dispatch Phase III	$0.3M	$0.3M	11/25	Planning/Conceptual Design
Storage as Transmission Only Asset	$0.2M	$0.2M	12/25	Planning/Conceptual Design
Total:	**$5.2M**			

Goal: Progress and Innovation

Project	2025 Budget	Total Project Cost	Estimated Completion Date	Project Stage
nGEM Real-Time Market Clearing Engine Implem. (see Note 2)	$4.2M	$14.8M	05/26	In Development
nGEM Software Development Part III (see Note 2)	$2.4M	$4.5M	03/25	In Development
nGEM Software Development Phase IV	$1.0M	$2.0M	06/26	Planning/Conceptual Design
Integrated Market Simulator Enhancement	$1.5M	$1.5M	12/25	Planning/Conceptual Design
Total:	**$9.1M**			

Note 1: Resource Capacity Accreditation work may be impacted by the recent FERC Order to delay FCA 19 until 2028. ISO-NE will evaluate and reflect any impact in the proposed 2025 budget materials later in 2024 and as necessary in Capital Funding Tariff quarterly filings.

Note 2: nGEM related projects will advance multiple goals including Responsive Market Designs, Progress and Innovation, and Operational Excellence. For purposes of this presentation, nGEM projects have been grouped under the Progress and Innovation strategic goal.

Capital Budget
2025 Expenditures *(cont.)*

Goal: Operational Excellence

Project	2025 Budget	Total Project Cost	Estimated Completion Date	Project Stage
Managing Transmission Line Ratings	$3.0M	$7.7M	06/25	In Development
CIP Electronic Security Perimeter Redesign Phase II	$0.1M	$5.2M	05/25	In Development
EMP 3.5 Upgrade	$0.8M	$4.8M	12/26	Planning/Conceptual Design
Enterprise Resource Planning System Replacement	$1.9M	$4.1M	12/25	Planning/Conceptual Design
Microsoft 365 Service Adoption	$2.0M	$3.0M	12/25	Planning/Conceptual Design
Enterprise Core Network Refresh	$2.0M	$2.0M	12/25	Planning/Conceptual Design
Windows Server Replacement Phase II	$1.5M	$1.7M	12/25	Planning/Conceptual Design
Automatic Ring Down Circuit Continuity Modernization and Reliability Enhancements	$1.0M	$1.6M	12/25	Planning/Conceptual Design
2025 Issue Resolution Project	$0.8M	$1.5M	09/25	Planning/Conceptual Design
CAMS Application Software Technology Upgrade	$1.5M	$1.7M	12/25	Planning/Conceptual Design
Network Modeling Tool Enhancements	$0.4M	$1.3M	06/25	In Development
MW Dependent Fuel Price Adjustment	$1.0M	$1.1M	11/25	Planning/Conceptual Design
Adoption of NERC CIP Compliance of Synchrophasor Systems	$0.3M	$1.0M	10/26	Planning/Conceptual Design
Circuit Inventory Management Platform	$0.4M	$0.6M	10/25	Planning/Conceptual Design
Control Room Tie Line Telemetry and PCEC Upgrades Phase II	$0.5M	$0.5M	09/25	Planning/Conceptual Design
Replace Employee & Pager Application	$0.4M	$0.5M	10/25	Planning/Conceptual Design
New England Clean Energy Connect	$0.1M	$0.2M	10/25	Planning/Conceptual Design
Non-Project Capital Expenditures	$4.5M			
Total:	**$22.2M**			

Capital Budget
2025 Expenditures Summary

- 2025 Capital Budget Expenditure Summary

Allocation Category		2025 Budget
Goal: Responsive Market Designs		$ 5.2M
Goal: Progress and Innovation		$ 9.1M
Goal: Operational Excellence		$22.2M
Other Emerging Work		$ 2.5M
Capital Interest		$ 1.0M
	Total:	**$40.0M**

APPENDIX 5: CAPITAL STRUCTURE

Capital Structure

- The ISO increased its working capital line from $20M to $40M in March of 2024; the working capital line, which will expire on March 1, 2028, covers the ISO’s operational needs and cash flow risks, including lower than projected load driving decreased Tariff collections, a continued increase in budgetary needs over the next 3 - 4 years, and more recently the issuance of FERC Order 2023 which may increase withdrawals of system impact studies
- Capital project costs are largely funded by $50M in Private Placement Notes set to expire in November 2024
- For the three months ended March 31, 2024, the ISO’s total weighted average cost of capital was 3.82%, excluding fees charged on the various debt financing; fees ranged from .075% to .38%

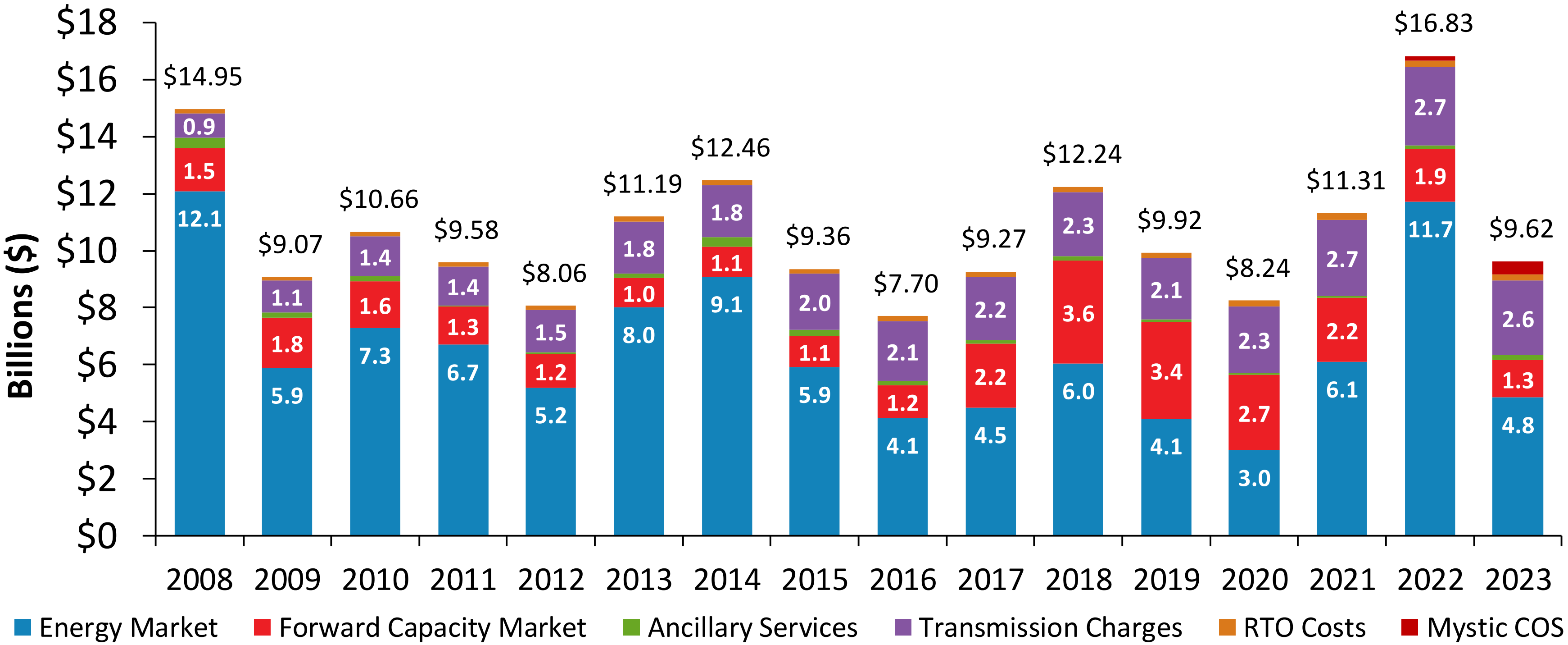
Capital Structure *(cont.)*

- The ISO is increasing the current capital program from $35M in 2024 to $40M in 2025 and beyond in order to support markets and reliability efforts
  - As noted last year and in Appendix 3 regarding Capital Budget Spending, the areas driving the increase in spending are dependent on various factors such as regulatory approvals, use of professional services versus internal staff, estimated range of spending, and longer lead times to complete
  - Longer lead time to complete results in a greater period of time from when the ISO spends capital funds to tariff recovery through depreciation expense of these projects
- In order to support the future capital program, the ISO anticipates going out to market in 2024 for $75M in Private Placement Notes

APPENDIX 6: HISTORICAL NEW ENGLAND WHOLESALE AND RETAIL ENERGY COSTS

New England Wholesale Electricity Costs*

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



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

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

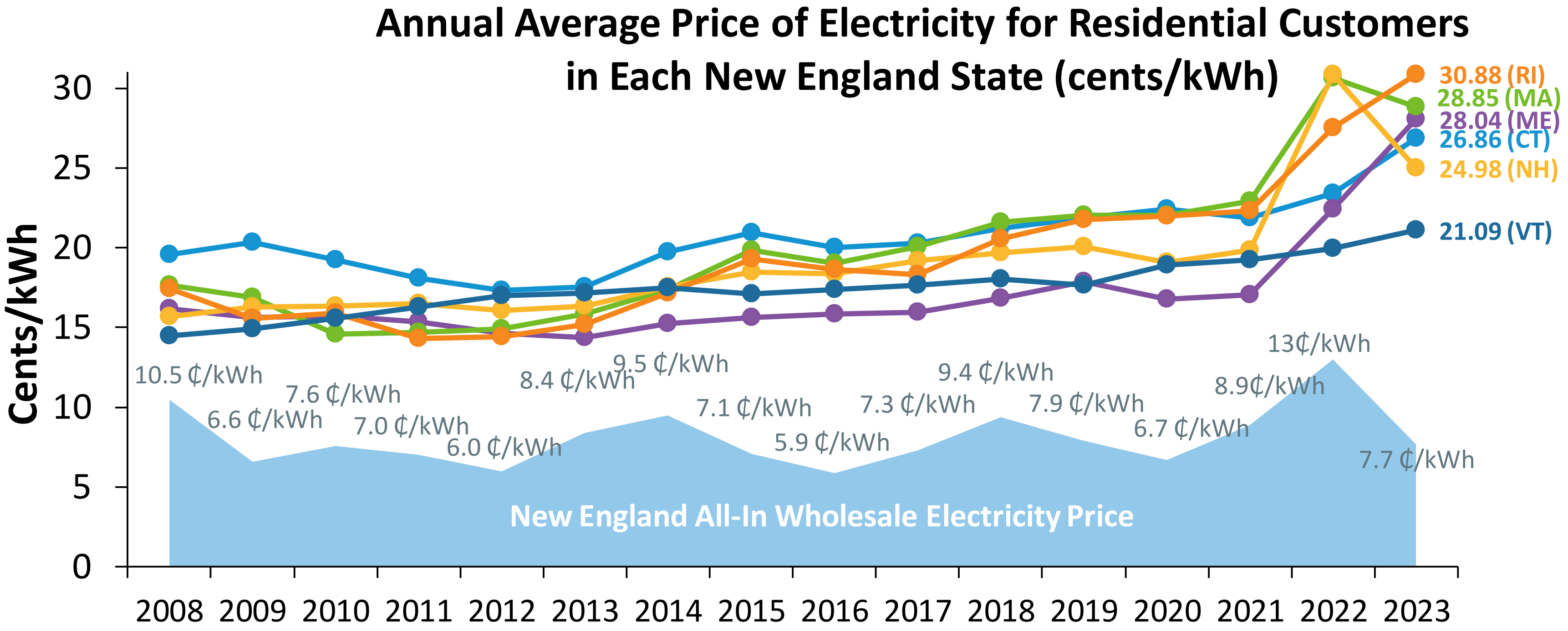
Note: Forward Capacity Market values shown are based on auctions held roughly three years prior to each calendar year.

New England Wholesale Electricity Costs[a]

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

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

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



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

APPENDIX 7: RETHINKING WORKSPACE AT THE ISO

Overview

- The ISO's Holyoke Campus was designed and built in 2003 - 2007; it was designed to support a headcount of 560
- ISO's current authorized headcount is 698.5 and possibly growing to over 900 in the next several years with the paradigm shift of planning and operating the system of the clean energy future
- ISO believes that the integrated nature of the work promotes the need for one campus
- As such there is a need to redesign the Holyoke facilities to accommodate the larger workforce needed to meet the region's needs
- Short-term activities:
  - Opportunity to lease an adjacent parcel and building with an option to purchase (Annual costs +/- $275,000) to alleviate future parking needs when fully staffed in Holyoke
  - Relocate 75 - 100 employees to the Backup Control Center (BCC) in Windsor and reprogram the Holyoke Campus to solve for the immediate needs; these changes are expected to satisfy the short-term constraints for the next couple of years

Overview *(cont.)*

- As part of the move to the BCC we would make modest changes to BCC amenities and repair some deferred maintenance items (estimated capital costs $2M)
- Longer-term activities:
  - Revisit the program at Holyoke to develop a plan, schedule and budget to accommodate the workforce of the future
  - We conducted a preliminary study that accounted for 900 employees (leaving the parking constraint unsolved) that would take approximately 3 ½ years, using a phased approach, at a cost estimate of $50M; by deferring this effort for a couple of years, we would expect the cost estimate to increase

Project Financing

- The ISO has engaged in discussions with TD Bank to explore financing options best suited for the phased approach to address the short term BCC work and longer term MCC work
- We intend to review the selected financing options with the NEPOOL Budget & Finance Subcommittee at the August 9th meeting
- ISO will seek Board approval for the new debt following that meeting
- The ISO anticipates making a Section 204 filing with FERC in the September timeframe for separate financing (outside of the annual capital budget) for the renovations

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of June 24, 2024

The following activity, as more fully described in the attached Litigation Report, has occurred since the report dated May 1, 2024 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

FERC Administrative Developments

		Matter	Date	Activity
		FERC Commissioner Nominee Congressional Hearings	Jun 12-13	Senate confirms as FERC Commissioners: ***David Rosner***, for a term expiring Jun 30, 2027; ***Lindsay S. See***, for a term expiring Jun 30, 2028; and ***Judy W. Chang***, for a term expiring Jun 30, 2029
			Jun 17	Commissioner Rosner sworn in

I. Complaints/Section 206 Proceedings

		Matter	Date	Activity
*	1	206 Proceeding: *TO Initial Funding Show Cause Order* (EL24-83)	Jun 13	FERC institutes Section 206 proceeding; ISO-NE response due on or before ***Sep 11, 2024***; interventions due on or before ***Jul 5, 2024***
			Jun 14-24	Calpine, National Grid, NRDC, MA DPU, ACPA, EPSA, SEIA, WIRES, PJM IMM intervene

II. Rate, ICR, FCA, Cost Recovery Filings

		Matter	Date	Activity
*	5	CSC CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER24-2159)	May 31	Cross-Sound Cable requests recovery of $478,182 in incremental medium impact CIP-IROL Costs incurred between Jan 1, 2023 and Dec 31, 2023
	5	FCA18 Results Filing (ER24-1290)	May 7	ISO-NE files answer to individual comments
			May 16	NCNG answers ISO-NE May 7 answer
			Jun 18	FERC accepts FCA18 Results, eff. *Jun 20, 2024*
	6	Versant MPD OATT 2023 Annual Update Settlement Agreement (ER20-1977-006)	Jun 7	FERC approves uncontested Versant MPD OATT 2022 Annual Update Settlement Agreement
	6	Versant MPD OATT 2022 Annual Update Settlement Agreement (ER20-1977-005)	Jun 7	FERC approves uncontested Versant MPD OATT 2022 Annual Update Settlement Agreement
	7	**Mystic 8/9 COSA (ER18-1639)**		
	9	(-027) Second CapEx Info Filing Settlement Proceedings	May 17	4th settlement conference held
			Jun 10	Judge French submits 3rd status report recommending continuation of settlement proceedings
			Jun 14	5th settlement conference held
			Jun 18	6th settlement conference held
	9	(-028) Second CapEx Info Filing - Request for Rehearing	May 23	FERC issues *Second CapEx Info Filing Order Allegheny Order* (i) modifying the discussion in the *Second CapEx Info Filing Order*; (ii) granting in part and denying in part, the clarifications requested by Mystic (iii) setting aside the *Order* in part; and (iv) dismissing Mystic's alternative request for reh'g
*	11	ISO Securities: Authorization for Future Drawdowns (ES24-41)	Jun 17	ISO-NE requests authorization for the issuance of up to ***$75 million*** in senior unsecured notes; comment deadline ***Jul 8, 2024***

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

*	12	eTariff § I.2 Corrections (ER24-2270)	Jun 13	ISO-NE files conforming changes to eTariff § I.2.2 to ensure that the currently effective eTariff Viewer does not include changes to the defined terms that were included earlier with the DASI and SATOA filings, but that are not yet effective and will become effective at a later date
	11	FCA19 2-Year Delay (ER24-1710)	May 20	FERC approves FCA19 delay until ***Feb 2028***
	12	Waiver Request: Withdrawal from IEP and Return of IEP Net Revenues Received (Canal Marketing/ Canal 3) (ER24-1407)	May 24	Canal requests FERC action on waiver request
			Jun 7	Canal answers IMM's Mar 25 comments
	13	New England's *Order 2222* Compliance Filings (ER22-983)	May 23	FERC modifies and sets aside, in part, the Nov 2, 2023 *Order 2222 60-Day Compliance Filing Order*; further compliance filing deadline ***Jul 22, 2024***
			Jun 10	ISO-NE files Metering Data Submission Revisions (-008) in response to requirements of the Apr 11, 2024 *Further Order 2222 Compliance Filing Order*; comment deadline ***Jul 1, 2024***

IV. OATT Amendments / TOAs / Coordination Agreements

*	15	*Order 2023* Compliance Changes (ER24-2009)	May 14	ISO-NE, NEPOOL and PTO AC file Tariff changes in compliance with Orders *2023* and *2023-A*
			May 23-Jun 4	MA DPU, Calpine, RIE, Constellation, NESCOE, Shell Energy/Savion, National Grid, Clearway Energy, and Cordelio Services intervene
			May 31	ISO-NE and NEPOOL file errata to transmittal letter
			Jun 4	BlueWave, Glenvale, New Leaf, RENEW, Clean Energy Associations, Longroad Energy Holdings file comments
			Jun 20	ISO-NE answers Jun 4 comments
*	15	*Order 2023* Related Changes (ER24-2007)	May 14	ISO-NE, NEPOOL and PTO AC file Tariff changes related to the *Order 2023* Compliance Changes
			May 23-Jun 5	MA DPU, Calpine, Clearway, BlueWave, National Grid, NESCOE, RIE, Shell Energy/Savion, and Cordelio Services intervene
			Jun 4	Glenvale, Longroad Energy Holdings, New Leaf Energy, RENEW and the Clean Energy Associations file comments
			Jun 20	ISO-NE answers Jun 4 comments
*	16	LTTP Phase 2 Tariff Changes (ER24-1978)	May 9	ISO-NE, NEPOOL and PTO AC submit proposed revisions to OATT Attachment K to establish mechanisms that enable the New England states to develop policy-based transmission facilities in connection with Longer-Term Transmission Studies, and associated cost allocation mechanism
			May 10-30	Brookfield, Calpine, EDF, MA AG, National Grid, NRG, MA DPU, ME PUC, ACPA, and Public Citizen intervene
			May 30	AEU, NESCOE, Public Interest Organizations, Public Systems, RENEW and NHT/LSPower file comments
			Jun 14	ISO-NE answers NHT/LSPower, AEU and RENEW comments
			Jun 20	ISO-NE supplements May 9 filing, identifying changes to definitions in Section I.2.2 that were included in error in the May 9 filing and proposing a process to back out those incorrectly included changes

V. Financial Assurance/Billing Policy Amendments

No Activities to Report

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

	16	Schedule 20A-NEP (ER24-1805); Schedule 21-NEP (ER24-1808)	May 22 Jun 18	NEP files amends Schedule 21-NEP to address minor omission FERC accepts revisions to both Schedules, eff. *May 1, 2024*

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activities to Report

VIII. Regional Reports

*	19	Capital Projects Report – 2024/Q1 (ER24-1991)	May 10 May 14 May 20 Jun 24	ISO-NE files Q1 2024 Capital Projects Report NEPOOL files comments supporting ISO-NE 2024 Q1 Report National Grid intervenes FERC accepts 2024/Q1 Report, eff. *Apr 1, 2024*
*	19	Interconnection Study Metrics Processing Time Exceedance Report 2024/Q1 (ER19-1951)	May 15	ISO-NE files required quarterly report
	20	Reserve Market Compliance (36th) Semi-Annual Report (ER06-613)	May 9	National Grid intervenes
*	20	IMM 2023 Annual Markets Report (ZZ24-4)	May 24	IMM files annual report covering calendar year 2023; to be discussed at the July 9-10 Markets Committee Summer Meeting
*	21	IMM Quarterly Markets Reports (ZZ24-4)	May 31	IMM files Winter 2023/24 Report
*	21	ISO-NE FERC Form 3Q (2024/Q1) (not docketed)	May 22	ISO-NE submits its 2024 Q1 FERC Form 3Q
*	22	ISO-NE FERC Form 714 (2023) (not docketed)	May 31	ISO-NE submits its 2023 FERC Form 714

IX. Membership Filings

*	22	June 2024 Membership Filing (ER24-2169)	May 31	***New Members:*** ATNV Energy; Delorean Power d/b/a Lightshift Energy; Fanfare Energy; ProGrid Ventures; and ZGE Massachusetts; ***Termination of Participant status:*** Agile Energy Trading; Energy Harbor; Hydroland; and the CT Materials Innovations and Recycling Authority; and ***Name Change:*** Reworld REC, LLC
	22	May 2024 Membership Filing (ER24-1895)	Jun 5	FERC accepts: (i) membership of Comity Inc., Earthjustice, Gunvor USA, MFT Energy US POWER, and Viridon New England; and (ii) the termination of the Participant status of Paper Birch Energy
	22	April 2024 Membership Filing (ER24-1650)	May 16	FERC accepts: (i) membership of Eagle Creek Madison Hydro and Vineyard Offshore; and (ii) the termination of the Participant status of Power Supply Services and Green Choice Energy

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

	23	Revised Reliability Standard: CIP-012-2 (RD24-3)	May 23	FERC approves new Reliability Standard CIP-012-2, eff. *Jul 1, 2026*
	24	NERC Cold Weather Data Collection Plan (RD23-1-002)	May 23	FERC approves NERC's proposed cold weather data collection plan
	24	CIP Standards Development: Info Filings on Virtualization and Cloud Computing Srvs. Projects (RD20-2)	Jun 13	NERC files final quarterly report; revised Reliability Standards to be filed by end of June, 2024

*	24	Report of Comparisons of Budgeted to Actual Costs for 2023 for NERC and the Regional Entities (RR24-3)	May 30	FERC files Report

XI. Misc. - of Regional Interest

*	25	203 Application: Trailstone/ Engelhart (EC24-87)	Jun 11	Trailstone Marketing, Trailstone Renewables and Engelhart US request authorization for Engelhart's acquisition of 100% of the interests in the Trailstone companies from Riverstone V Trailstone Holdings; comment deadline ***Jul 2, 2024***
			Jun 24	Public Citizen intervenes
	25	203 Application: Eversource/ GIP IV (EC24-59)	Jun 7	FERC authorizes GIP IV Whale Fund Holdings or one of its affiliates' acquisition of Eversource's interest North East Offshore, Revolution Wind, and South Fork Wind
	25	203 Application: GIP/BlackRock (EC24-58)	May 10	Applicants supplement Mar 12 application
			May 13	Public Citizen and Private Equity Stakeholder Project file joint protest
			May 20	Public Citizen and Private Equity Stakeholder Project file second protest; Sierra Club files protest
			Jun 5	Applicants answer protests; FERC issues deficiency letter
			Jun 18	Applicants file response to deficiency letter
	26	PURPA Enforcement Petition – Allco Finance Ltd (EL24-95)	May 23	FERC issues notice of its intent not to initiate an enforcement action against CT DEEP
*	26	D&E Agreement: CL&P/BPUS (ER24-2233)	Jun 11	CL&P files Agreement in connection with the interconnection of BPUS' 50 MW solar facility; comment deadline ***Jul 2, 2024***
*	26	TSA Amendment: NSTAR/Park City Wind (ER24-2104)	May 28	NSTAR files Transmission Support Agreement governing the construction of transmission facilities required to interconnect Park City Wind LLC's 800 MW facility
*	26	CSA: NextEra Seabrook/NECEC (ER24-2097)	May 24	Seabrook files Agreement with NECEC related to the Seabrook Station 24.5 kV generator circuit breaker and ancillary equipment, including pre-Fall 2024 Planned Outage work
			May 29 -Jun 5	Avangrid/NECEC, National Grid, Eversource intervene
*	27	SGIA: PSNH White Pine Hydro (ER24-2092)	May 23	PSNH files a non-conforming SGIA to provide for continued interconnection of Brookfield Hydro's 3.2 MW facility
*	27	RFA Termination: PSNH/NECEC (ER24-2087)	May 23	PSNH files to terminate the RFA between Eversource Energy, on behalf of PSNH, and NECEC
*	27	*Order 2023* Compliance Filing: Versant MPD OATT (ER24-2035)	May 16	Versant Power submits *Order 2023* compliance filing
*	27	IA 2nd Amendment: CMP/White Pine Hydro (ER24-1966)	May 8	CMP files 2nd amended IA
	28	SGIA – NEP/Ampersand Gillman (ER24-1851)	Jun 24	FERC accepts SGIA, eff. Jun
	28	LGIA: ISO-NE/NEP/SouthCoast Wind (ER24-1840)	Jun 4	FERC accepts LGIA, eff. *Mar 26, 2024*
	28	EPC Cancelation: CMP/FPL Wyman (ER24-1510)	May 14	FERC accepts termination of the EPC, eff. *Mar 15, 2024*
	28	LGIA: ISO-NE/CMP/Andro Hydro (ER24-1477)	May 8	ISO-NE/CMP amend Mar 17 filing

28	LGIA: ISO-NE/NSTAR/MMWEC (ER24-1238)	Jun 3	FERC accepts LGIA, eff. *Apr 13, 2024*
29	CMP ESF Service Rate (ER24-1177)	May 8 May 31 Jun 4	Judge Hessler schedules 2nd settlement conference for ***Jul 17, 2024*** CMP requests protective treatment of proprietary and commercially sensitive information Deputy Chief Administrative Law Judge grants CMP's motion and adopts a Protective Order to govern this proceeding

XII. Misc. - Administrative & Rulemaking Proceedings

33	*Order 1977*: Transmission Siting Changes (RM22-7)	May 13	FERC issues *Order 1977* eff. ***Jul 29, 2024***
33	NOPR: Compensation for Reactive Power Within the Standard Power Factor Range (RM22-2)	May 2, 7 May 10 May 24 May 24-28	PJM IMM file comments support of comment deadline extension, COMPP opposes FERC declines to extend comment deadlines Over 30 sets of comments filed, including by: ISO-NE, Calpine, CT OCC, EDP Renewables, Glenvale, National Grid, New England Consumer Advocates, ACPA/SEI, ACORE, EPSA, National Hydropower Assoc., NEI, and Reactive Service Providers Reply comments due ***Jun 26, 2024***
34	*Order 1920*: Transmission Planning Reforms (RM21-17)	May 13 Jun 11-12	FERC issues *Order 1920* eff. *Aug 12, 2024* Over 50 parties file requests for rehearing, including requests by: AEU, Dominion, Invenergy, NESCOE (with VT PUC supporting), Versant, APPA, EEI, Large Public Power Council, NARUC, NRECA, TAPS, WIRES, Consumer Advocates, Harvard Electricity Institute

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

* 36	Engie Stipulation and Consent Agreement (IN24-6)	May 20	FERC approves Stipulation and Consent Agreement resolves OE's investigation into Engie's failure to properly evaluate whether necessary all conditions were met prior to the submission of an attestation to the ISO-NE IMM for energy market mitigation under the FCM; Engie must pay a ***civil penalty of $48,000*** and submit one annual compliance report

XIV. Natural Gas Proceedings

No Activity to Report

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

40	Mystic Second CapEx Info Filing - Request for Rehearing (24-1077)	May 1	ISO-NE, NESCOE intervene
		May 3-6	Mystic files underlying decision, statement re: Appendix deferral, statement of issues
		May 6	FERC requests case be held in abeyance
		Jun 6	Court orders case be held in abeyance; directs parties to file motions to govern further proceedings in this case by ***Jul 16, 2024***
40	*Orders 2023 and 2023-A* (23-1282 et al.) (consolidated)	Jun 6	Court orders cases remain in abeyance and parties to submit motions to govern future proceedings by ***Jun 25, 2024***
40	*Order 2222* Compliance Orders (23-1167, 23-1168, 23-1169, 23-1170, 23-1335)(consolidated)	Jun 6	FERC files a status report reporting that, on May 23, 2024, the FERC issued its order on reh'g of its Nov 2023 order and that, under the Court's Feb 6 order, motions to govern future proceedings in these consolidated appeals are due ***Aug 5, 2024***

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity and Teresa Chen, NEPOOL Counsel

DATE: June 24, 2024

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

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"),[1] state regulatory commissions, and the Federal Courts and legislatures through June 24, 2024. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

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

On June 13, 2024, the FERC instituted a Section 206 proceeding finding that the ISO-NE Tariff appears to be unjust, unreasonable, and unduly discriminatory or preferential because it includes provisions for transmission owners to unilaterally elect transmission owner ("TO") Initial Funding (the funding of network upgrade capital costs that the TO incurs to provide interconnection service to an interconnection customer, with the network upgrade capital costs subsequently recovered from the interconnection customer through charges that provide a return on and of those network upgrade capital costs).[2] TO Initial Funding, the FERC found, may increase the costs of interconnection service without corresponding improvements to that service, may unjustifiably increase costs such that it results in barriers to interconnection, and may result in undue discrimination among interconnection customers.[3] The FERC also found that there may be no risks associated with owning, operating, and maintaining network upgrades for which transmission owners are not already otherwise compensated.[4] Accordingly, ISO-NE was directed, on or before ***September 11, 2024***, to either: (1) show cause as to why the Tariff remains just and reasonable and not unduly discriminatory or preferential; or (2) explain what changes to the Tariff it believes would remedy the identified concerns if the FERC were to determine that the Tariff has in fact become unjust and unreasonable or unduly discriminatory.[5] The refund effective date for this proceeding will be June 24, 2024.[6] A more detailed summary of the *TO Initial Funding Show Cause Order* was circulated to, and will be reviewed with, the Transmission Committee. Interventions are due on or before ***July 5, 2024***. Thus far, interventions have been filed by: Calpine, National Grid, NRDC, Massachusetts Department of Public Utilities ("MA DPU"), American Clean Power Association ("ACPA"), Electric Power Supply Association ("EPSA"), Solar Energy Industries Association ("SEIA"), WIRES, and the PJM IMM. 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).

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

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

[3] *Id.* at P 1.

[4] *Id.*

[5] *Id.* at P 2.

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

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

This Section 206 proceeding is being held in abeyance. As previously reported, this proceeding was instituted by the FERC on May 5, 2023, pursuant to its finding that the existing ISO-NE Tariff provisions related to the mechanics of its market power mitigation and the consideration of any proposed fuel price adjustment, may be unjust and unreasonable.[7] Changes in response to some of the requirements of the *Dynegy Mitigation Order* ("Upward Mitigation Revisions") were supported by the Participants Committee, jointly filed with ISO-NE, accepted by the FERC,[8] and became effective as of *December 12, 2023*. On January 29, 2024, ISO-NE requested that this proceeding continue to be held in abeyance,[9] through ***August 30, 2024***, "pending completion of the stakeholder process through which further revisions to [the Tariff] are being proposed and vetted.[10] The FERC granted ISO-NE's motion on February 7, 2024, stating that it would not take any action on this 206 proceeding before ***August 30, 2024***. Further changes to address issues raised by the FERC in the *Dynegy Mitigation Order* are to be considered by the Participants Committee at the Summer Meeting (Consent Agenda Item No. 5). If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

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

Responses, comments and protests were filed in late January 2023 by ISO-NE (which alternatively moved to dismiss itself as a party ("ISO-NE Jan 19 Motion")), the PTO AC, NEPOOL, AEU/Clean Energy Council, CPV Towantic, Glenvale, MA AG, NECOS, NEPGA, and NESCOE. Doc-less interventions only were filed by Calpine, CMEEC, EMI, Eversource, Narragansett ("RI Energy"), National Grid, New Leaf Energy, NextEra, NRG, Versant, CT DEEP, MA DPU, the American Clean Power Association ("ACPA"), Solar Energy Industries Association ("SEIA"), and Public Citizen. In additional rounds of briefing, RENEW answered ISO-NE's Jan 19 Motion; RENEW, the PTO AC, and National Grid filed answers to the January 23 protests/comments; ISO-NE answered RENEW's February 7 answer; and CPV Towantic, Glenvale, and the MA AG filed answers to the February 7 answers. There was again no activity since the last Report. As noted, this matter remains pending before the FERC. If you have questions on

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[7] *Dynegy Marketing and Trade, LLC and ISO New England, Inc.*, 183 FERC ¶ 61,091 (May 5, 2023) ("*Dynegy Mitigation Order*"). In the Dynegy Mitigation Order, ISO-NE was directed to either: (1) show cause as to why the Tariff remains just and reasonable and not unduly discriminatory or preferential; or (2) explain what changes to the Tariff it believes would remedy the identified concerns if the FERC were to determine that the Tariff has in fact become unjust and unreasonable or unduly discriminatory. The refund effective date for this proceeding is May 12, 2023.

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

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

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

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

this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

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

There are four proceedings pending before the FERC in which consumer representatives seek to reduce the TOs' return on equity ("Base ROE") for regional transmission service.

- ***Base ROE Complaint I (EL11-66)***. In the first Base ROE Complaint proceeding, the FERC concluded that the TOs' ROE had become unjust and unreasonable,[12] 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*).[13] However, the FERC's orders were challenged, and in *Emera Maine,*[14] 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)[15] and third (EL14-86)[16] 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.[17] 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[18] also went to hearing before an Administrative Law Judge ("ALJ"), Judge Glazer, who issued his initial decision on March

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[12] 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*")).

[13] *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*").

[14] *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).

[15] 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%.

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

[17] *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*").

[18] 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,

27, 2017.[19] 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.[20] 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.[21] 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*[22] (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.[23]

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

2017. The September 26, 2016 order was challenged on rehearing, but rehearing of that order was denied on January 16, 2018. *Belmont Mun. Light Dept. v. Central Me. Power Co.*, 156 FERC ¶ 61,198 (Sep. 20, 2016) ("*Base ROE Complaint IV Order*"), *reh'g denied*, 162 FERC ¶ 61,035 (Jan. 18, 2018) (together, the "*Base ROE Complaint IV Orders"*). *The Base ROE Complaint IV Orders*, as described in Section XVI below, have been appealed to, and are pending before, the DC Circuit.

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

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

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

[22] *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 mode l 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*.

[23] *Id.* at P 19.

unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[24] 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[25] 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*[26] and requested that the FERC re-open the record to permit that additional testimony on the impacts of the *MISO ROE Order*'s changes. On January 21, 2020, EMCOS and CAPs opposed the TOs' request and brief.

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

II. Rate, ICR, FCA, Cost Recovery Filings

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

On May 31, 2024, Cross-Sound Cable ("CSC") requested FERC acceptance of its revised rate schedule to allow recovery eligible medium-impact Interconnection Reliability Operating Limits ("IROL") critical infrastructure protection ("CIP") costs ("IROL-CIP Costs") under Schedule 17 of the ISO-NE Tariff, effective July 31, 2024. CSC seeks to recover $478,182 of incremental medium impact CIP-IROL Costs incurred between January 1, 2023 and December 31, 2023. Comments on CSC's request were due on June 21, 2024; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FCA18 Results Filing (ER24-1290)**

On June 18, 2024, the FERC accepted the results of the eighteenth Forward Capacity Auction ("FCA18") for the June 1, 2027 - May 31, 2028 Capacity Commitment Period ("CCP").[27] In accepting the FCA18 results, the FERC

[24] *Id.* at P 59.

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

[26] *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).

[27] *ISO New England Inc.*, 187 FERC ¶ 61,175 (June 18, 2024) ("*FCA18 Results Order*").

found that ISO-NE conducted FCA18 in accordance with its Tariff. The FERC found the protests of No Coal No Gas, 198 Methods, other organizations and *pro se* commenters "largely challenge the FCM design and raise various challenges related to climate change, fossil fuels, the minimum offer price rule and the Merrimack Generating Station, which are issues that are beyond the scope of the instant proceeding."[28] The FERC accepted the FCA18 Results effective *June 20, 2024,* as requested. Unless the *FCA18 Results Order* is challenged on or before ***July 19, 2024***, this proceeding will be concluded. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Transmission Rate Annual (2023-24) Update/Informational Filing (ER20-2054-003)**

Formal Challenge by MOPA. As previously reported, the Maine Office of the Public Advocate ("MOPA") filed a formal challenge ("MOPA Formal Challenge") to the 2023-24 Annual Update on January 31, 2024.[29] MOPA asserted that, with respect to the cost of asset condition projects placed into service in 2022, the NETOs have refused to answer questions regarding investment policies and practices related to prudence of these investments and asserts that the NETOs' decision not to respond to these questions violates their obligation under the OATT's Protocols. Comments on the MOPA Formal Challenge were due on or before February 21, 2024 and were filed by Consumer Advocates[30] (who supported MOPA's attempt to discover the information requested in its September 15, 2023 requests and agreed that policies, processes, and procedures related to ACP costs are discoverable pursuant to the Protocols) and Identified TOs[31] (who urged the FERC to reject the MOPA Formal Challenge as baseless and misguided). On March 4, 2024, MOPA answered Identified TOs' comments. Identified TOs answered MOPA's March 4 answer on March 15 (as corrected on March 18, 2024). This matter remains pending before the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Versant MPD OATT 2023 Annual Update Settlement Agreement (ER20-1977-006)**

On June 7, 2024, the FERC accepted the uncontested Joint Offer of Settlement ("Versant MPD OATT 2023 Annual Update Settlement Agreement") between Versant and the Eastern Maine Electric Cooperative, Inc. ("EMEC") and the Maine Public Utilities Commission ("MPUC") resolving all issues regarding to Versant's 2023 annual update to the transmission charges under the MPD OATT.[32] Unless the June 7 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Versant MPD OATT 2022 Annual Update Settlement Agreement (ER20-1977-005)**

Also on June 7, 2024, the FERC accepted the uncontested Joint Offer of Settlement ("Versant MPD OATT 2022 Annual Update Settlement Agreement") between Versant and the Maine Wholesale Customer Group, the Aroostook Energy Association, MOPA, and the MPUC resolving all issues regarding Versant's 2022

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[28] *Id.* at P 15.

[29] 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.

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

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

[32] *Versant Power*, 187 FERC ¶ 61,148 (June 7, 2024).

annual update to the transmission charges under the MPD OATT.[33] Unless the June 7 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

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

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

(-018) Second CapEx Info Filing. On December 5, 2023, the FERC issued an order[35] on the formal challenges to Mystic's September 15, 2022 "Second CapEx Info Filing".[36] As previously reported, formal challenges to the Second CapEx Info Filing were submitted by NESCOE and ENECOS[37] (with ENECOS challenges supported separately by MMWEC/NHEC). Several rounds of answers, described in previous reports, followed. In February 2023, Mystic asked that the Formal Challenges to the Second CapEx Info Filing be held in abeyance pending submission of a settlement agreement to resolve challenges to the First CapEx Info Filing. ENECOS protested that request, identifying issues in their challenges to the Second CapEx Info Filing that would not be resolved by a First CapEx Settlement Agreement. The First CapEx Settlement Agreement was filed and approved, leaving for resolution certain of ENECOS' challenges.

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

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[33] *Versant Power*, 187 FERC ¶ 61,147 (June 7, 2024).

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

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

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

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

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

Recall that, as previously reported with respect to this aspect of the Mystic proceeding, Mystic requested rehearing and/or clarification of the March 28, 2023 *Mystic I Order on Remand (*-024*)*. Mystic asserted that (a) the FERC should have considered and rejected NESCOE's arguments about "truing up" and challenging the Revenue Credit; (b) the Tank Congestion Charge and the calculation of the Forward Sales Margin credited to Mystic and its ratepayers should not be included in the true-up process; and (c) if the FERC does not grant rehearing on (a) or (b), in the alternative, it should clarify that the scope of review during the true-up for Revenue Credits and the Forward Sale Margin Shared with Mystic is not a prudence review and does not require disclosure of granular, unmasked transaction data. On May 30, 2023, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[42] The FERC then issued the *Mystic I Order on Remand Modification Order* which modified the discussion in the *Mystic I Order on Remand* and set aside that *Order* in part.[43] In addition, the *Order* also denied Public Systems[44] May 19, 2023 request that the FERC direct ISO-NE to release

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

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

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

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

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

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

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

additional information concerning ISO-NE's audit of performance under Mystic COSA ("Audit Information Request").[45]

(-027) Second CapEx Info Filing Settlement Proceedings. While the FERC set several aspects of ENECOS Formal Challenges for a trial-type evidentiary hearing, the FERC encouraged the parties to make every effort to settle their disputes before hearing procedures are commenced, and to that end, is holding the hearing in abeyance pending the completion of settlement judge procedures. As directed, the Chief ALJ appointed a settlement judge, Judge Patricia M. French, to assist participants in settling the issues in this proceeding, and deemed the settlement proceedings continued without further action. Judge French has since convened six settlement conferences.[46] Judge French submitted her 3rd status report on June 10, 2024, recommending that the settlement process continue.

(-028) Second CapEx Info Filing Order - Mystic's Request for Rehearing Deemed Denied by Operation of Law. On January 4, 2024, Mystic requested clarification, and in the alternative rehearing, of the *Second CapEx Info Filing Order*.[47] Specifically, Mystic requested clarification and/or rehearing of (i) the FERC's ruling on ENECOS's Formal Challenge No. 7 related to Everett's projected 2023 capital expenditures, (ii) that the FERC denied the accounting argument that ENECOS included in their Formal Challenge No. 1; and (iii) the FERC's rulings related to capital costs incurred prior to the start of the term of the COS Agreement (its grant in part of ENECOS's Formal Challenge No. 1 on the basis that Mystic did not adequately "support" Mystic 8&9 capital costs between July 2004 and December 31, 2017 ("Pre-2018 Rate Base"), and its grant of ENECOS's Formal Challenges Nos. 2 and 6). On January 19, 2024, ENECOS answered Mystic's request. On February 5, 2024, the FERC issued an "Allegheny Notice",[48] noting that ENECOS request for rehearing may be deemed to have been denied by operation of law, but noting that ENECOS' request will be addressed in a future order.[49] On April 3, 2024, Mystic appealed to the DC Circuit the *Second CapEx Info Filing Order Allegheny Notice* (Case No. 24-1077) (*See* Section XVI below).

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

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

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

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

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

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

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

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

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

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

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

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

RENEW Formal Challenge. RENEW's January 31, 2023 formal challenge ("Challenge") to the 2022/23 Update/Informational Filing[53] remains pending before the FERC. In the Challenge, RENEW asserted that (i) the TOs failed to provide adequate rate input information in the Annual Informational Filing and in the Information Exchange Period under the Interim Formula Rate Protocols regarding inclusion or exclusion of "O&M costs" on Network Upgrades that the TOs directly assign to Interconnection Customers (and thereby

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

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

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

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

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

On June 18, 2024, ISO-NE requested the necessary FERC authorization for the issuance of up to $75 million in senior unsecured notes ("Notes") to (i) refinance its existing financings[54] and (ii) raise an additional $25 million of indebtedness to support additional capital expenditures to support ISO-NE's market design objectives of "moving toward clean energy, balancing resources, energy adequacy and robust transmission". ISO-NE proposed to issue the Notes within the two-year period in which this authorization will be effective and stated that the Notes will be long-term debt expected to mature in a minimum of 10 years and a maximum of 12 years from the date of issuance. Comments on this filing are due on or before ***July 8, 2024***. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

- **FCA19 2-Year Delay (ER24-1710)**

On May 20, 2024, the FERC approved Tariff revisions jointly filed by ISO-NE and NEPOOL to delay New England's nineteenth Forward Capacity Auction ("FCA19") until ***Feb 2028*** in order to maximize the opportunity for ISO-NE and regional stakeholders to fully design and implement a prompt and seasonal capacity market framework, and to further refine the approach to capacity accreditation based on a resource's Marginal Reliability Impact ("FCA19 2-Year Delay Revisions").[55] Specifically, the FCA19 2-Year Delay Revisions (i) delay FCA19 and related market activities by two additional years beyond the revised timeline already accepted by the FERC;[56] (ii) extend the interim balancing (or reconfiguration) auction qualification process by two additional years; and (iii) augment the auction schedule for subsequent auctions beyond FCA19 to ensure an orderly return to a forward market in the unlikely case that future events necessitate such a return. The FCA19 2-Year Delay Revisions were accepted effective as of *May 21, 2024*. The *FCA19 2-Year Delay Order* was not challenged and is final and

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

[55] *ISO New England Inc.*, 187 FERC ¶ 61,083 (May 20, 2024) ("*FCA19 2-Year Delay Order*").

[56] *ISO New England Inc. and NEPOOL Participants Comm.*, 186 FERC ¶ 61,001 (Jan. 2, 2024, 2024) (accepting Initial FCA19 Delay Filing).

unappealable. Reporting on this proceeding is now concluded. Should you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

On June 13, 2024, ISO-NE filed corrections to its eTariff to remove from Section I.2.2 changes (from the DASI (ER24-275) and SATOA (ER23-739) filings) that were inadvertently included in the FRM Offer Cap eTariff changes that became effective on April 15, 2024. Other than to pull out the yet-to-effective changes from the effective eTariff text, no other changes were made to the definitions. Comments on this filing are due on or before ***July 5, 2024***. Thus far, Calpine has intervened doc-lessly. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

As previously reported, on March 4, 2024 (as amended and supplemented on March 8 and March 22, 2024), Canal Marketing LLC (f/k/a Stonepeak Kestrel Energy Marketing LLC) ("CM") requested a one-time waiver of the provisions of Appendix K to Market Rule 1 (Inventoried Energy Program (the "IEP")) so as to permit CM to (i) withdraw CM's participation in the IEP on behalf of Canal 3 Generating LLC ("Canal 3")[57] for Winter 2023-24 and (ii) to return to ISO-NE the net revenues, with applicable interest, that CM received on behalf of Canal 3 for Canal 3's participation in the IEP for Winter 2023-2024 because Canal 3's return from a forced outage was delayed beyond the end of the IEP's Winter 2023-24 period.[58] CM explained that, when it elected to participate in the IEP on behalf of Canal 3 on September 21, 2023, CM anticipated that the Canal 3 Facility would be back in service by December 18, 2023, and would be available for the remainder of the IEP's Winter 2023-24 period. However, the actual return-to-service date for the Canal 3 Facility was delayed beyond the end of the IEP's Winter 2023-24 period and Canal 3 was not able to perform during the Winter 2023-24 period. CM seeks the requested waiver because no provision in Appendix K nor any other provision of the Tariff was identified as providing a mechanism for a Participant to withdraw from the IEP or to return IEP revenues to ISO-NE. Comments on the CM Waiver Request were due on or before March 25, 2024. The IMM submitted comments supporting the CM Waiver Request insofar as CM requests the prompt repayment of the revenues received on behalf of Canal 3 under the IEP and, if determined to be warranted by the FERC, net of Program charges. NEPOOL (out-of-time) and National Grid intervened doc-lessly.

Since the Last Report, CM submitted 2 filings. The first, filed on May 24, 2024, requested that the FERC act on its waiver request and informed the FERC that ISO-NE supported CM's request to return to ISO-NE the net revenues, with applicable interest, that Canal Marketing has received on behalf of Canal 3 for Canal 3's participation in the IEP. In CM's second filing, submitted on June 7, 2024, CM answered the IMM's comments, highlighting that ISO-NE was apprised by mid-December 2023 of CM's intent to return all payments received on behalf of Canal 3 and to withdraw from the IEP, well before ISO-NE incurred any charges. This matter is pending before the FERC, with an order expected immanently. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

As previously reported, in response to the requirements of *Order 895*, ISO-NE and NEPOOL jointly filed, on October 18, 2023, changes to the Information Policy to (i) permit ISO-NE to share Market Participant, Transmission

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

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

Customer and Applicant (collectively, "Participants") credit-related information with other ISO/RTOs; (ii) permit ISO-NE to use credit-related information received from other ISO/RTOs to the same extent and for the same purposes as ISO-NE is permitted under the Tariff with respect to its Participants; and (iii) require ISO-NE to keep such received credit-related information confidential in accordance with the Tariff, in each case for the purpose of credit risk management and mitigation (the "Credit Info Sharing Changes"). The Credit Info Sharing Changes were supported by the Participants Committee by way of the October 5, 2023 Consent Agenda (Item # 6). Comments on the Credit Info Sharing Changes were due on or before November 8, 2023; none were filed. National Grid intervened doc-lessly. There were no developments in this proceeding since the last Report and this matter remains pending before the FERC. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

In a lengthy compliance Order[59] issued March 1, 2023, the FERC approved in part, and rejected in part, the *Order 2222* compliance filing[60] ("*Order 2222 Compliance Order*") filed jointly by ISO-NE, NEPOOL and the PTO AC ("Filing Parties").[61] In the *Order 2222 Compliance Order*, the FERC directed a number of revisions and additional compliance and informational filings to be filed within 30, 60 or 180 days of the *Order 2222 Compliance Order*. As previously reported, the FERC accepted the 30-, 60- and 180-day compliance filings.[62] In the order conditionally accepting the 60-day compliance filing,[63] the FERC directed ISO-NE to submit a further compliance filing, on or before January 31, 2024, to comply with the directives of the *First Compliance Order* regarding the submission of DERA meter data.[64] The FERC also granted in part ISO-NE's request for an extension of time to address directives

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

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

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

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

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

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

in the *First Order 2222 Compliance Order*.[65] On December 4, 2023, AEU requested rehearing of the *Order 2222 60-Day Compliance Filing Order*, which was deemed to have been denied by operation of law.[66]

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

Further Compliance Changes (-007). On April 11, 2024, the FERC conditionally accepted ISO-NE's January 31 Further Compliance Filing, subject to a further 60-day compliance filing.[71] In the *Further Order 2222 Compliance Filing Order*, the FERC found that ISO-NE complied with *Order 2222 60-Day Compliance Filing Order*'s directive to (i) designate the DER Aggregator as the entity responsible for providing any required metering information to ISO-NE; (ii) require that each DER Aggregator maintain and submit aggregate settlement data for DERAs; and (iii) establish protocols for sharing metering data. However, the FERC disagreed with ISO-NE's assertion that meter data submission responsibilities and deadlines at issue are technical and timing details to implement the Tariff's settlement requirements, and, therefore, properly included in ISO-NE's manuals rather than its Tariff. Rather, the FERC found that "the meter data submission deadline is a key component of metering practices for DER Aggregators that should be included in the basic description of metering practices in the Tariff".[72]

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

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

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

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

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

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

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

[72] *Id.* at P 13.

Accordingly, the FERC directed ISO-NE, on or before June 10, 2024, "to submit … Tariff revisions that include the meter data submission deadline in its Tariff."[73]

Metering Data Submission Revisions (-008). The Metering Data Submission Revisions required by the April 11, 2024 *Further Order 2222 Compliance Filing Order* were recommended for Participants Committee support by the Markets Committee at its May 7-8, 2024 meeting and, because of the compliance deadline, filed by ISO-NE on June 10, 2024. The changes will be considered by the Participants Committee at the June 25-27 Summer Meeting by way of the Consent Agenda (Item No. 6). Comments on ISO-NE's June 10 compliance filing are due on or before ***July 1, 2024***. NEPOOL will file comments by that deadline summarizing its actions, particularly those taken at the Summer Meeting.

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

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

IV. OATT Amendments / TOAs / Coordination Agreements

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

On May 14, 2024 (as corrected May 31, 2024), ISO-NE, NEPOOL and the PTO AC filed proposed Tariff revisions tin response to the requirements of *Orders 2023* and *2023-A* ("*Order 2023* Revisions"). The Order 2023 Revisions adopt most of the required *pro forma* OATT changes, with some regional variations to recognize certain existing features of the ISO-NE interconnection process, including an existing cluster process to address cases where cluster enabling transmission is required, integration of the interconnection process with FCM participation, and a unified treatment of all ISO interconnection requests, including those for small generators and Elective Transmission Upgrades ("ETU") (such revisions were filed in a separate concurrent filing (ER24-2007)). Concurrently, the Filing Parties proposed changes to aspects of the Tariff impacted by the *Order 2023* Revisions, but that may be considered to be beyond the scope of the compliance obligations (see ER24-2007 immediately below). The filing parties requested an effective date of August 12, 2024 for the *Order 2023* Revisions. Comments on this filing were due on or before June 4, 2024, and were filed by BlueWave, Glenvale, New Leaf, RENEW, Clean Energy Associations,[74] and Longroad Energy Holdings. Calpine, Clearway, Constellation, National Grid, NESCOE, RIE, Shell Energy/Savion, MA DPU, and Cordelio Services intervened doc-lessly. On June 20, 2024, ISO-NE answered the June 4 comments. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617- 345-4735; ekrunge@daypitney.com).

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

Also on May 14, 2024, ISO-NE, NEPOOL and the PTO AC filed proposed Tariff revisions to harmonize the SGIP, ETU Interconnection Procedures ("ETUIP"), and Regional Transmission Service rules with the contemporaneously-filed Order 2023 Revisions ("*Order 2023* Related Changes"). The *Order 2023* Related Changes, which propose changes to aspects of the Tariff impacted by the *Order 2023* Revisions, but that may be considered to be beyond the scope of the *Order 2023* compliance requirements, include: (i) revisions to the *pro forma* SGIP beyond those explicitly required in *Order 2023/2023-A* to align the Small Generator Interconnection Procedures ("SGIP") with the Large Generator Interconnection Procedures ("LGIP") and

[73] *Id.*

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

include Small Generating Facilities in the new Cluster Study Process; (ii) revisions to the ETUIP to ensure it remains aligned with the LGIP and include ETUs in the Cluster Study Process; and (iii) revisions to Study Procedures for Regional Network Service Requests and Through or Out Service Requests to require that System Impact Studies related to Regional Transmission Service requests take place in the Cluster Study incorporated as part of the Cluster Study Process. An effective date of August 12, 2024 was requested. Comments on the *Order 2023* Related Changes were due on or before June 4, 2024, and were filed by Glenvale, Longroad, New Leaf Energy, RENEW and Clean Energy Associations. BlueWave, Calpine, Clearway (out-of-time), National Grid, NESCOE, RIE, Shell Energy/Savion, Cordelio Services, and the MA DPU intervened doc-lessly. On June 20, 2024, ISO-NE answered the June 4 comments. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617- 345-4735; ekrunge@daypitney.com).

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

On May 9, 2024, ISO-NE, NEPOOL and PTO filed proposed revisions to Section 16 of Attachment K of the OATT to establish, as part of the optional, longer-term transmission planning process, the mechanisms that enable the New England states to develop policy-based transmission facilities in connection with Longer-Term Transmission Studies ("LTTS"), and the associated cost allocation methods for these upgrades (the "LTTP Phase 2 Changes"). The LTTP Phase 2 Changes incorporate the following processes: (i) comprehensive core process and (ii) add-on supplemental process. The core process allows the New England states to advance the development of transmission when at least one Longer-Term Proposal submitted in response to a request for proposal meets the identified needs and has financial benefits that exceed the project's costs as calculated over the first 20 years of the project's life has a benefit-to-cost ratio ("BCR") that is greater than one. The supplemental process is an addon to the core process that enables the New England states to agree to move forward with a transmission project where none of the proposals that meet the identified needs satisfy the greater-than-one BCR requirement. An effective date of July 9, 2024 was requested. Comments on this filing were due on or before May 30, 2024. Comments in support of the LTTP Phase 2 Changes were filed by: AEU, NESCOE, Public Interest Organizations[75], Public Systems, RENEW; adverse comments were filed jointly by NH Transmission ("NHT") and LS Power. Brookfield, Calpine, EDF, National Grid, NRG, ME PUC, MA AG, ACPA, and Public Citizen filed doc-less motions to intervene. ISO-NE answered the comments by NHT/LSPower, AEU and RENEW on June 14, 2024. On June 20, ISO-NE supplemented the May 9 filing with a summary of revisions related to defined terms that are not to be in effect as of, bu in effect later than, July 9, 2024 (the requested effective date for the LTTP Phase 2 Changes) but nevertheless included in error in the eTariff changes submitted as part of the May 9 Filing, and a proposal to correct those errors. The LTTP Phase 2 Changes are pending before the FERC. If you have any questions concerning this proceeding, please contact Eric Runge (617- 345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

No Activities to Report

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

- **Schedule 20A-NEP/Schedule 21-NEP: NEP Creditworthiness Policy Updates (ER24-1805, ER24-1808)**

On June 18, 2024, the FERC accepted revisions to both Schedule 20A (governing the resale by NEP of transmission service over the Phase I and II high-voltage direct current interconnection between New England and Quebec) (ER24-1805)[76] and Schedule 21 (governing Local Network Service and other services) (ER24-

[75] Acadia Center, Conservation Law Foundation ("CLF"), Earthjustice, NRDC, Sustainable FERC Project, Sierra Club, and Union of Concerned Scientists ("UCS").

[76] *ISO New England Inc.*, Docket No. ER24-1805-000 (Jun. 18, 2024) (unpublished letter order).

1808)[77] to reflect the current creditworthiness practices of New England Power d/b/a National Grid's ("NEP"). The revisions were accepted for filing effective as of May 1, 2024, as requested. Unless the June 18 orders are challenged, these proceedings will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

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

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

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

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

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

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[77] *ISO New England Inc.*, Docket No. ER24-1808-000 (Jun. 18, 2024) (unpublished letter order).

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

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

[80] 18 CFR § 35.11 (which permits, upon application and for good cause shown, the FERC to allow a rate schedule, tariff, service agreement, or a part thereof, to become effective as of a date prior to the date of filing or the date such change would otherwise become effective in accordance with the FERC's rules (e.g. 60 days after filing)). FERC policy is to deny waiver of the prior notice requirement when an agreement for new service is filed on or after the date that services commence, absent a showing of extraordinary circumstances.

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

Time Value Refunds Report. On February 21, 2024, National Grid filed a refund report ("Report") detailing the Time Value Refunds National Grid paid to GMP on January 22, 2024. Comments on the Report were due on or before March 13, 2024; none were filed. The Report is pending before the FERC.

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

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

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

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

On August 29, 2023, Versant submitted a Joint Offer of Settlement ("Versant 2022 Annual Update Settlement Agreement") between itself and the MPUC. Versant stated that, if approved, the 2022 Annual Update Settlement Agreement would resolve all issues raised by the MPUC with respect to the 2022 Annual Update. Comments on the Versant 2022 Annual Update Settlement Agreement were due on or before September 19, 2023; none were filed. MPUC intervened doc-lessly on September 15, 2023. This matter remains pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

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

On August 19, 2024, the 135th Agreement Amending New England Power Pool Agreement; and Amendment No. 13 to the PA (together, the "Unused Provisional Member Voting Share Allocation Changes" or "Changes") were approved unanimously by the Participants Committee pursuant to balloting under Section 6.10 of the NEPOOL Agreement and Section 17.2.3 of the Participants Agreement in which the Minimum Response Requirement was satisfied. As described at the April 4 Participants Committee meeting, the Changes modify the allocation of any unused Provisional Member Group Seat voting share to all six Sectors. The Changes will be filed with the FERC this month. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

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

VIII. Regional Reports[84]

- **Capital Projects Report – 2024/Q1 (ER24-1991)**

On June 24, 2024, the FERC accepted ISO-NE's May 10, 2024 Capital Projects Report and Unamortized Cost Schedule covering the first quarter ("Q1") of calendar year 2024 (the "Report"). As previously reported, Report highlights included the following new projects: (i) Network Modeling Tool Enhancements ($1.3 million); (ii) Day-Ahead Ancillary Services Benchmark Levels ($915,500); (iii) 2024 Issue Resolution ($486,000); (iv) IMS nGEM Compatibility Enhancement ($315,600); (v) Tie-Line Telemetry and PCEC Upgrade Phase I ($304,200); and (vi) On-Call Notification Systems ($141,100). One project was reported to have significant changes: IMM Data Analysis Phase IV (reduced by $285,700) and two projects were reported complete: FCM Order 2222 and Market Information Server Reporting by Sub Accounts. The Report was accepted effective *April 1, 2024*, as requested. Unless the June 24 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Interconnection Study Metrics Processing Time Exceedance Report 2024/Q1 (ER19-1951)**

On May 15, 2024, ISO-NE filed, as required,[85] public and confidential[86] versions of its Interconnection Study Metrics Processing Time Exceedance Report (the "Exceedance Report") for the First Quarter of 2024 ("2024 Q1"). ISO-NE reported that with respect to:

- **Interconnection Feasibility Study ("IFS") Reports**
  - Both of the 2024 Q1 IFS Reports delivered to Interconnection Customers were delivered later than the best efforts completion timeline of 90 days.
  - 32 IFSs that are not yet completed also exceeded the 90-day completion expectation.
  - The average time from ISO-NE's receipt of the executed IFS Agreement to delivery of the completed IFS Report to the Interconnection Customer was 173.5 days (which is approximately 20 days sooner than the previous quarter).

- System Impact Study ("SIS") Reports
  - 6 SIS Reports were delivered to Interconnection Customers in 2024 Q1. Those Reports were delivered later than the best efforts completion timeline of 270 days.
  - 31 SISs that are not yet completed have also exceeded the 270-day completion expectation.
  - The average time from ISO-NE's receipt of the executed SIS Agreement to delivery of the completed SIS report to the Interconnection Customer was 534.33 days (an increase of approximately 10 days from 2023 Q4).

- Facility Study Reports
  - 1 Facility Study Report was delivered to Interconnection Customers and was delivered later that the best efforts timeline of 90 days for 20% cost estimates or 180 days for 10% cost estimates.

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[84] Reporting on the *Opinion 531* Refund Reports (EL11-66) has been suspended and will be continued if and when there is new activity to report.

[85] Under section 3.5.4 of ISO-NE's LGIP, ISO-NE must submit an informational report to the FERC describing each study that exceeds its Interconnection Study deadline, the basis for the delay, and any steps taken to remedy the issue and prevent such delays in the future. The Exceedance Report must be filed within 45 days of the end of the calendar quarter, and ISO-NE must continue to report the information until it reports four consecutive quarters where the delayed amounts do not exceed 25 percent of all the studies conducted for any study type in two consecutive quarters.

[86] ISO-NE requested that the information contained in Section 3 of the un-redacted version of the Exceedance Report, which contains detailed information regarding ongoing Interconnection Studies and if released could harm or prejudice the competitive position of the Interconnection Customer, be treated as confidential under FERC regulations.

- No Facility Study in process has exceeded the 90-day completion expectations for a 20% level of cost estimate.
- The average time from executed Facilities Study Agreement receipt to delivery of completed Facilities Study report to the Interconnection Customer was 116 days (which is an improvement from previous quarter).

Section 4 of the Exceedance Report identified steps ISO-NE has identified to remedy issues and prevent future delays, including mitigating the impact of backlogs and initiating clustering, moving to earlier in the process certain Interconnection Customer data reviews, and enhanced information sharing and coordination efforts with Interconnecting TOs. The Exceedance Report was not noticed for public comment.

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

As directed by the original ASM II Order,[87] as modified,[88] ISO-NE submitted its 36th semi-annual reserve market compliance report on April 18, 2024. In the 36th report, ISO-NE described the October 31, 2023 Day-Ahead Ancillary Services ("DASI") filing. ISO-NE further stated that "DASI satisfies the underlying objectives of this reporting obligation. DASI procures sufficient DA TMSR from fast-ramping, "online" resources (i.e., those that also receive Day-Ahead Energy awards) to cover the expected TMSR requirements for each hour of the Operating Day. DASI provides the resources that clear for DA TMSR with market-based compensation that provides incentives to take cost-effective actions that increase their ability to deliver energy in Real-Time, when needed. Furthermore, as the FERC noted in the DASI Order, ISO-NE has also committed "to reviewing DASI's performance after implementation and proposing further adjustments to the design as necessary." Accordingly, ISO-NE asked that the FERC terminate the reporting obligation established in this proceeding, and that the 36th report "serve as the final update on the status of the region's efforts to implement a forward market for TMSR." In light of ISO-NE's request, the 36th status report was noticed for public comment. Comments were due on or before May 9, 2024; none were filed. National Grid intervened doc-lessly. ISO-NE's request that its reporting obligation be terminated is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **IMM 2023 Annual Markets Report (ZZ24-4)**

On May 24, 2024, the IMM filed its 2023 Annual Markets Report, which covers the 2023 calendar year period.[89] The report addresses the development, operation, and performance of the New England Markets and presents an assessment of each market based on market data, performance criteria, and independent studies, providing the information required under Section 17.2.4 of Appendix A to Market Rule 1. On the basis of its review of market outcomes and related information, the IMM concluded, as it has for many years in a row, that the New England Markets (with the exception of the Forward Reserve Market ("FRM")) operated competitively in 2023. The IMM reported that Day-Ahead and Real-Time Energy prices reflected changes in underlying primary fuel prices, electricity demand and the region's supply mix, and returned to typical levels after record highs in 2022 -- the annual average Day-Ahead price of $37/MWh was down by almost 60% from 20221. Energy prices continued to follow the market price of natural gas, which at about $3/MMBtu was nearly 70% lower than the average 2022 price. Lower natural gas prices reflected high national inventory levels, a lack of sustained cold weather in New England, and the settling of international energy markets following the Russian invasion of Ukraine.

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

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

[89] Please note that Annual Markets Reports filings are not noticed for public comment by the FERC.

In 2023, New England's average wholesale load was at its lowest level in at least 24 years. In addition, renewable energy sources like wind and solar, which have low marginal costs, alongside existing non-price-setting supply, can lead to instances of low or negative energy prices. Residential solar is reducing load levels and shifting peak load to later in the day.

Other highlights included:

- 2023 total wholesale costs ($9.5 billion) were 43% lower than 2022, driven by lower energy costs in turn driven by natural gas prices, which fell by 67% between 2022 ($9.28/MMBtu) and 2023 ($3.04/MMBtu). Also, with the exception of ancillary services costs (up by $0.01 billion), every other component of the wholesale cost of electricity decreased in 2023.
- 2023 Energy costs totaled $4.8 billion, a 59% decrease from 2022 (Day-Ahead LMPs averaged $36.82/MWh; Real-Time LMPs, $35.70/MW).
- Capacity costs ($1.32 billion) continued to decrease, down 30% from 2022. The costs were a function of lower combined clearing prices in FCAs 13 and 14).
- In 2023, net interchange (or net imports) averaged 1,724 MWs per hour, an 10% (or 190 MW) decrease compared to 2022, and the lowest level of net interchange since 2012. This reduction was influenced by lower reservoir levels in Québec, which resulted in decreased excess hydroelectric generation and lower availability of imports over the Phase II interface into New England.
- The trend of decreasing load driven by EE and BTM continued. Average and peak load levels were the lowest in years, down by 4% and 3%, respectively, from 2022 levels, consistent with mild summer and winter weather. Net Energy for Load ("NEL") averaged 13,096 MW per hour in 2023 and peak load 24,016 MW. On a weather-adjusted basis, load declined by 3%, which reflects the adoption of behind-the-meter (BTM) solar generation. BTM solar generation reduced weather-normalized hourly load by 489 MW (by 3%) which was a 7% increase (34 MW) compared to 2022; it is expected to continue this upward trend in future years. In 2023, energy efficiency (EE) reduced average hourly load by an estimated 2,269 MW (by 14%), which was an 11% decrease (268 MW) compared to 2022. This is in line with the ISO's expectation that EE will decline over time due to rising costs of eligible EE measures and the associated baselines used to calculate claimable savings.

In light of its review, the IMM, on pp. 21-27 of the Report, made a number of recommendations for Market Rule changes and identified areas for additional analysis in 2023. These recommendations will be discussed in more detail at the Markets Committee July 9-10 Summer Meeting.

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

On May 31, 2024, the IMM filed with the FERC its Winter 2024 report of "market data regularly collected by [the IMM] in the course of carrying out its functions under … Appendix A and analysis of such market data," as required pursuant to Section 12.2.2 of Appendix A to Market Rule 1. These filings are not noticed for public comment by the FERC. The Winter 2024 Report will be discussed with the Markets Committee at the Markets Committee's July 9-10 summer meeting.

- **ISO-NE FERC Form 3Q (2024/Q1) (not docketed)**

On May 22, 2024, ISO-NE submitted its 2024/Q1 FERC Form 3Q (quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is a quarterly regulatory requirement which supplements the annual FERC Form 1 financial reporting requirement. These filings are not noticed for public comment.

- **ISO-NE FERC Form 714 (2023) (not docketed)**

On May 31, 2024, ISO-NE submitted its Annual Electric Balancing Authority Area and Planning Area Report for calendar year 2023. Through its Form 714 filing, ISO-NE reports, among other things, generation in the New England Control Area, actual and scheduled inter-balancing authority area power transfers, and net energy for load, summer-winter generation peaks and system lambda. The FERC uses the data to obtain a broad picture of interconnected balancing authority area operations including comprehensive information of balancing authority area generation, actual and scheduled inter-balancing authority area power transfers, and load; and to prepare status reports on the electric utility industry including review of inter-balancing authority area bulk power trade information. Planning area data will be used to monitor forecasted demands by electric utility entities with fundamental demand responsibility, and to develop hourly demand characteristics. These filings are not noticed for public comment.

IX. Membership Filings

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

On May 31, 2024, NEPOOL requested that the FERC accept: (i) the following Applicants' membership in NEPOOL as of June 1, 2024: ATNV Energy LP (Supplier Sector); Delorean Power LLC d/b/a Lightshift Energy [Related Person to Howard Wind LLC, Hecate Energy Albany 2 LLC, RoxWind LLC, and Weaver Wind, LLC (Supplier Sector)]; Fanfare Energy, LLC [Related Person to Think Energy, LLC and to Brookfield Renewable Trading and Marketing LP (Supplier Sector)]; ProGrid Ventures, LLC (Supplier Sector); and ZGE Massachusetts LLC (Supplier Sector); (ii) the termination as of May 1, 2024 of the Participant status of: Agile Energy Trading LLC (Supplier Sector) and Energy Harbor LLC [Related Person to Dynegy Marketing and Trade, LLC (Supplier Sector)] and the termination as of June 1, 2024 of the Participant status of: Hydroland, Inc. (AR Sector) and Connecticut Materials Innovations and Recycling Authority (Publicly Owned Entity Sector); and (iii) the name change of the following Participant: Reworld REC, LLC (f/k/a Covanta Energy Marketing, LLC). Comments on this filing were due on or before June 21, 2024; none were filed. This matter is pending before the FERC.

- **May 2024 Membership Filing (ER24-1895)**

On June 5, 2024, the FERC accepted: (i) the following Applicants' membership in NEPOOL: Comity Inc. (Supplier Sector); Earthjustice (Governance Only End User); Gunvor USA LLC (Supplier Sector); MFT Energy US POWER LLC [Related Person to MFT Energy US 1 LLC (Supplier Sector)]; and Viridon New England LLC [Related Person to Champlain VT, LLC d/b/a TDI New England (Provisional Member Group Seat)]; and (ii) the termination of the Participant status of: Paper Birch Energy, LLC [Related Person to Berlin Station, LLC and CS Berlin Ops, Inc. (Generation Sector Group Seat)].[90] Unless the June 5 order is challenged, this proceeding will be concluded.

- **April 2024 Membership Filing (ER24-1650)**

On May 16, 2024, FERC accepted: (i) the following Applicants' membership in NEPOOL: Eagle Creek Madison Hydro LLC [Related Person to Ontario Power Generation Inc.; Ontario Power Generation Energy Trading, Inc.; Brown Bear II Hydro, Inc., and Eagle Creek Renewable Energy Holdings LLC (Supplier Sector)] and Vineyard Offshore LLC (Generation Sector) and (ii) the termination of the Participant status of: Power Supply Services, LLC (AR Sector) and RPA Energy Inc. d/b/a Green Choice Energy (Supplier Sector).[91] The May 16 order was not challenged and is final and unappealable.

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[90] *New England Power Pool Participants Comm.*, Docket No. ER24-1895-000 (June 5, 2024) (unpublished letter order).

[91] *New England Power Pool Participants Comm.*, Docket No. ER24-1650-000 (May 16, 2024) (unpublished letter order).

X. Misc. - ERO Rules, Filings; Reliability Standards[92]

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

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

On February 16, 2024, NERC filed proposed Reliability Standard EOP-012-2 (Extreme Cold Weather Preparedness and Operations) to provide a comprehensive framework of requirements addressing cold weather planning and operations ("Freeze Protection Standards"). NERC stated that EOP-012-2 would improve upon the approved, but not yet effective, EOP-012-1 by clarifying the applicability of standard's requirements for generator cold weather preparedness, further defining the circumstances under which a Generator Owner may declare that constraints preclude them from implementing one or more corrective actions to address freezing issues, and shorting the implementation timeline so cold weather reliability risks would be addressed more quickly. EOP-012-2 also reflects additional improvements that would address the recommendations of the FERC, NERC, and Regional Entity Staff Joint Inquiry into the causes of the February 2021 cold weather event affecting Texas and the south-central United States.

Comments on EOP-012-2 were due on or before March 21, 2024. The ISO/RTO Council ("IRC"), including ISO-NE, protested the proposed Standard citing various issues and concerns regarding the effectiveness of the Freeze Protection Standards as a winterization standard.[93] NEPGA submitted comments supporting the goals of the Freeze Protection Standards, and while it did not specifically protest or challenge the proposed Freeze Protection Standards, submitted comments requesting that the FERC encourage ISO-NE to work with affected Generator Owners to ensure that the Tariff allows for cost recovery of compliance costs (which, absent changes, it doubted could be achieved currently). On April 2, 2024, EPSA submitted comments supporting NEPGA's comments, urging the FERC to "survey the markets within its jurisdiction to determine whether there are sufficient vehicles for cost recovery should NERC's Freeze Protection Standards be approved. If there is a determination that any market does not have sufficient cost recovery pathways in place, the Commission should take action to remedy these issues ahead of the time generators would need to take action in order to meet the effective date of the proposed standard." Doc-less interventions were filed by Dominion (timely) and out-of-time by Avangrid Renewables, Calpine, PA PUC, and TAPS. Both NERC and TAPS answered the IRC's protest. NERC and TAPS answered IRC's April 4 answer on April 16 and April 22, respectively. This matter remains pending before the FERC.

- **Revised Reliability Standard: CIP-012-2 (RD24-3)**

On May 23, 2024, the FERC approved Reliability Standard CIP-012-2 (Cyber Security – Communications between Control Centers), which improves upon and expands the protections required by Reliability Standard CIP-012-1 by requiring Responsible Entities to mitigate the risk posed by loss of availability of communication links and Real-time Assessment and Real-time monitoring data transmitted between Control Centers.[94] Reliability Standard CIP-012-2 modified CIP-012-1 by adding two new Parts to Requirement R1 to address availability: Part 1.2, which

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[92] Reporting on the following ERO Reliability Standards or related rule-making proceedings has been suspended since the last Report and will be continued if and when there is new activity to report: NERC Report on Evaluation of Physical Reliability Standard (CIP-014) (RD23-2); *Order 901*: IBR Reliability Standards (RM22-12); and 2024 Reliability Standards Development Plan (RM05-17 *et al.*).

[93] The IRC urged the FERC to direct NERC to revise the standard to: exclude cost-based constraint criteria from the standard itself, recognizing that the issue needs to be addressed through other avenues in the regulatory process; use effective facility performance as a benchmark instead of relying on vague references to "general industry practice"; eliminate language that is vague, unauditable, and susceptible to multiple interpretations by different Generator Owners; narrow the proposed exemptions for existing generating units; shorten and clarify the periods allotted for implementation of freeze protection measures; eliminate grandfathering provisions so that the same enhanced winterization standard applies to all affected generating units regardless of commercial operation date; require annual reviews of declared Generator Cold Weather Constraints; and add timing specificity for required inspections and maintenance.

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

requires protections for the availability of data in transit; and Part 1.3, which requires protections to initiate recovery of lost (i.e., unavailable) communication links. Pursuant to the approved implementation plan, CIP-012-2 will become effective on *July 1, 2026*.

- **NERC Cold Weather Data Collection Plan (RD23-1-002)**

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

- **CIP Standards Development: Informational Filings on Virtualization and Cloud Computing Services Projects (RD20-2)**

As previously reported, NERC is required to file on an informational basis quarterly status updates regarding the development of new or modified Reliability Standards pertaining to virtualization and cloud computing services. NERC submitted its most recent informational filing regarding one active CIP standard development project (Project 2016-02 – Modifications to CIP Standards ("Project 2016-02"))[97] on June 13, 2024. Project 2016-02 focuses on modifications to the CIP Reliability Standards to incorporate applicable protections for virtualized environments. In the June 13 report, NERC reported that Project 2016-02 was successfully balloted in April, the Reliability Standards adopted by the NERC Board on May 9, 2024, and the Standards will be filed before the end of June. Because the Reliability Standards are to be filed before the end of June, NERC indicated that the June 13 report would be the last schedule update filed in this docket and asked that the FERC consider NERC to have satisfied the directive to file schedule updates.

- **Report of Comparisons of 2023 Budgeted to Actual Costs for NERC and the Regional Entities (RR24-3)**

On May 30, 2024, NERC filed its annual comparisons of actual to budgeted costs for 2023 for NERC and the six Regional Entities operating in 2023,[98] including NPCC. The Report includes comparisons of actual funding received and costs incurred, with explanations of significant actual cost-to-budget variances, audited financial statements, and tables showing metrics concerning NERC and Regional Entity administrative costs in their 2023 budgets and actual results. Comments on this filing were due on or before June 20, 2024; none were filed. This matter is pending before the FERC.

- **RTO Recommendations for Gas-Electric Coordination**

On February 21, 2024, ISO-NE, MISO, PJM, and SPP ("Joint RTOs") released "*Strategies for Enhanced Gas Electric Coordination: A Blueprint for National Progress*," a paper recommending potential initiatives that could help enhance the reliability of gas-electric coordination. Joint RTOs put forth a range of immediate- and near-term initiatives aimed at enhancements to the gas market, RTO operations, and coordination between state and federal regulators. The Joint RTOs identify specific recommendations along with suggested specific action steps to be undertaken respectively by the RTOs; gas producers, marketers, and pipelines; and/or federal and state regulators corresponding to each recommendation.

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

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

[97] The other project which had been addressed in prior updates, Project 2019-02, has concluded, and the FERC approved in RD21-6 the Reliability Standards revised as part of that project (CIP-004-7 and CIP-011-3) on Dec. 7, 2021.

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

XI. Misc. - of Regional Interest

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

On June 11, 2024, Trailstone Energy Marketing, LLC ("Trailstone Marketing"), Trailstone Renewables, LLC ("Trailstone Renewables", and together with Trailstone Marketing, the "Trailstone Companies") and Engelhart CTP (US) LLC ("Engelhart US") requested authorization for a transaction pursuant to which Engelhart US would acquire 100% of the interests in the Trailstone Companies from Riverstone V Trailstone Holdings (making the Trailstone Companies and Engelhart US Related Persons). Comments on this application are due on or before ***July 2, 2024***. Thus far, Public Citizen has filed a doc-less intervention. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Eversource/ GIP IV (EC24-59)**

On June 7, 2024, the FERC issued an order authorizing the proposed transaction pursuant to which GIP IV Whale Fund Holdings, L.P. ("GIP Whale") and/or one more of its affiliates will acquire Eversource Investment, LLC's interests in North East Offshore, LLC, Revolution Wind, LLC, South Fork Wind, LLC (together with North East Offshore, Revolution Wind and GIP Whale, the "Applicants").[99] Upon consummation, GIP Whale will hold: (i) Eversource Investment's 50 percent interest in North East Offshore and will thereby also indirectly hold a 50 percent interest in Revolution Wind; and (ii) Eversource Investment's 50 percent Class B interest in South Fork Class B and will thereby also indirectly hold an interest in South Fork Wind. The Applicants must file a notice within 10 days of consummation of the transaction, which as of the date of this Report has not happened. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On March 12, 2024, Global Infrastructure Management, LLC ("GIM") d/b/a Global Infrastructure Partners, on behalf of investment funds sponsored by GIM that own public utility subsidiaries, and BlackRock, Inc. requested authorization for a transaction pursuant to which BlackRock Funding Inc. will acquire 100% of the LLC interests in GIM and thereby an indirect controlling interest in the GIM public utility subsidiaries, including, among others, Clearway Power Marketing and GennConn Energy. Following an errata notice, comments on this 203 application were due on or before May 13, 2024. Public Citizen and Private Equity Stakeholder Project[100] filed two joint protests (the first related to upstream ownership/affiliate issues; the second, addressing Applicants' proposed purchase of Allete); Sierra Club also filed a protest. On June 5, 2024, Applicants answered the Protests.

Deficiency Letter. Also on June 5, the FERC issued a deficiency letter, requesting additional information before it acts on the Application. The deficiency letter response must address issues related to the data and methods used for the submitted Delivered Price Test ("DPT") and how Proposed Transaction is consistent with, or would have any impact on the terms of, the blanket authorization granted to BlackRock and certain of its investment management subsidiaries. GIM responded to the deficiency letter on June 18, 2024.

This matter is pending before the FERC. intervened. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On July 28, 2023, the FERC authorized[101] the disposition and consolidation of jurisdictional facilities and the lease of an existing generation facility that will result from the commencement of a master lease agreement ("Lease") between Three Corners Solar, LLC ("Lessor") and Three Corners Prime Tenant, LLC ("Lessee") pursuant to

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

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

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

which Lessee will lease, operate, and control an approximately 112 MWac solar photovoltaic ("PV") electric generation facility owned by Lessor in Kennebec County, Maine (the "Transaction"). Pursuant to the July 28 order, Lessor and Lessee 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).

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

On May 23, 2024, the FERC issued a Notice of Intent Not to Act on the petition by Allco Finance Limited ("Allco").[102] As previously reported, Allco asked the FERC to initiate an enforcement action against the Connecticut Department of Energy and Environmental Protection ("CT DEEP") to remedy what it asserted was CT DEEP's improper implementation of section 210 of PURPA. Allco asked the FERC to (i) invalidate and permanently enjoin the Shared Clean Energy Facility program's 50 MW volumetric cap, (ii) invalidate and permanently enjoin the CT DEEP from implementing Conn. Gen. Stat. §§ 16a-3f, 16a-3g, 16a-3j, and 16a-3m, which compel CL&P and UI to procure energy from zero carbon resources that have a 5 MW or greater nameplate capacity rating and participate in the New England Markets, (iii) invalidate and permanently enjoin the CT DEEP from implementing solicitations for off-shore wind facilities and/or nuclear facilities, and (iv) to permanently enjoin the CT DEEP from regulating wholesale sales except as permitted by PURPA. In light of the *Allco CT DEEP Notice,* Allco may now initiate an action against CT DEEP in an appropriate court. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On June 11, 2024, CL&P filed a Design & Engineering ("D&E") Agreement that sets forth the terms and conditions under which CL&P will perform necessary engineering, procurement and design services in connection with the interconnection of BPUS Generation Development LLC's 50 MW solar facility in Windham, Connecticut. Comments on this filing are due on or before ***July 2, 2024***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On May 28, 2024, NSTAR filed an Amended and Restated Settlement Transmission Support Agreement ("TSA") memorializing NSTAR's commitment to construct certain transmission facilities required to interconnect Park City Wind LLC's ("PCW") proposed 800 MW offshore wind farm to the NSTAR transmission system and sets forth the parties' respective responsibilities to finance and pay for those facilities. The initial Settlement TSA was approved on June 17, 2022. The amended TSA amends and restates the Settlement TSA with primary revisions to certain milestone dates associated with (i) PCW's provision of notices to NSTAR to proceed with work related to constructing transmission facilities required to interconnect PCW's offshore wind farm and (ii) NSTAR's completion of such facilities and costs of certain of the transmission facility upgrades that NSTAR will construct under the TSA. A July 28, 2024 effective date was requested. Comments on the filing were due on or before June 18, 2024; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On May 24, 2024, NextEra Energy Seabrook, LLC ("Seabrook") filed a Construction Services and Cost Reimbursement Agreement for Affected System Project ("Agreement") with NECEC Transmission LLC ("NECEC") to set forth the terms of Seabrook's performance related to the construction, implementation, and testing of the Seabrook Station 24.5 kV generator circuit breaker and ancillary equipment, including pre-Fall 2024 Planned Outage work that will commence following the effective date of the Agreement. A May 25, 2024 effective date was requested. Comments on the filing were due on or before June 14, 2024; none were filed. Avangrid/NECEC

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

National Grid and Eversource intervened. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On May 23, 2024, Public Service Company of New Hampshire ("PSNH") filed a non-conforming SGIA governing the continued interconnection to the PSNH system of Brookfield White Pine Hydro LLC's ("White Pine Hydro") 3.2 MW hydroelectric generation facility (located in Errol, New Hampshire). The facility receives interconnection service pursuant to a state-jurisdictional interconnection agreement dated April 7, 1986, which is set to expire on June 30, 2024. The SGIA restates and updates the terms under which White Pine Hydro will continue to receive interconnection service. The SGIA is non-conforming in that ISO-NE is not a party to the agreement. A May 24, 2024 effective date was requested. Comments on the filing were due on or before June 13, 2024; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On May 23, 2024, PSNH filed to terminate the Related Facilities Agreement ("RFA") between Eversource Energy, on behalf of PSNH, and NECEC Transmission LLC ("NECEC"). PSNH stated that it has completed all work pursuant to the RFA. An effective date of May 23, 2023 was requested. Comments on this filing were due on or before June 13, 2024; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- ***Order 2023* Compliance Filing: Versant MPD OATT (ER24-2035)**

On May 16, 2024, Versant Power proposed revisions to its *pro forma* LGIP, Large Generator Interconnection Agreement ("LGIA"), SGIP and Small Generator Interconnection Agreement ("SGIA") in the MPD OATT in compliance with *Orders 2023* and *2023-A*. The revised LGIP contains two deviations from *Order 2023-A*, Versant proposes (i) to eliminate the reference to when the transition process will commence and, instead, only reference when it plans to hold its first Cluster Study process on January 1, 2025 langauge that was previously approved by the FERC in Versant Power's Order No. 845 compliance filing and (ii) to limit the use of surety bonds to those where the surety bond is "issued by an insurer reasonably acceptable to the Transmission Provider" and that "specify a reasonable expiration date." An effective date of January 1, 2025 was requested. Comments were due on or before June 6, 2024; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA 2nd Amendment – CMP/Brookfield White Pine Hydro (ER24-1966)**

On May 8, 2024, CMP filed a second amendment to the Interconnection Agreement governing the interconnection of generation facilities owned by Brookfield Hydro to remove references to the "Bonny Eagle" and "West Buxton Hydro" generating facilities (now subject to a new *pro forma* LGIA between CMP, Brookfield and ISO-NE). The amended IA does not implement any new rates or charges. A July 8, 2024 effective date was requested. Comments on the filing were due on or before May 29, 2024; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **SGIA – NEP/Ampersand Gillman (ER24-1851)**

On June 24, 2024, the FERC accepted a non-conforming SGIA that governs the interconnection of Ampersand Gillman's four hydroelectric facilities (total capacity of 5.05MW) in Vermont and replaces the existing interconnection agreement between NEP and Ampersand Gilman's predecessor in interest, American Paper Mills of Vermont, Inc.[103] The SGIA is non-conforming in that ISO-NE is not a party to the agreement. The non-conforming SGIA was accepted effective as of *April 5, 2024*, as requested. Unless the June 24 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).

- **LGIA – ISO-NE/NEP/SouthCoast Wind (ER24-1840)**

On June 4, 2024, the FERC accepted, effective March 26, 2024 as requested, the non-conforming LGIA governing the interconnection of SouthCoast Wind Energy LLC's ("SouthCoast Wind") 14.7 MW offshore wind facility off the coast of Massachusetts.[104] Unless the June 4 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).

- **EPC Cancelation – CMP/FPL Wyman (ER24-1510)**

On May 14, 2024, the FERC accepted CMP's Notice of Termination of its Engineering and Procurement Agreement with FPL Energy Wyman, LLC ("FPL Wyman") after the completion of the services set forth in the Agreement.[105] The Notice was accepted effective *March 15, 2024* as requested. Unless the May 14 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).

- **LGIA – ISO-NE/CMP/Andro Hydro (ER24-1477)**

On March 13, 2024, ISO-NE and CMP filed a non-conforming LGIA to govern the interconnection of Andro Hydro, LLC's 27.57 MW hydro facility, which interconnects to the Jay Substation. The LGIA is non-conforming in that it contains limited deviations from the Schedule 22 *pro forma* LGIA that are necessary to reflect unique characteristics of Andro Hydro's proposed interconnection, including the interconnection of its facility through shared facilities co-owned, and used by, JGT2 Redevelopment LLC to serve its own load. A February 12, 2024 effective date was requested. Comments on the LGIA filing were due on or before April 3, 2024; none were filed. Andro Hydro intervened doc-lessly. On May 7, 2024, the Filing Parties filed a replacement LGIA to allow the FERC additional time to consider the filing, as well as a related filing made by Andro Hydro (ER24-1629), and further consultation among the Filing Parties. Comments on the May 7 filing were due on May 28, 2024; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA – ISO-NE/NSTAR/MMWEC (ER24-1238)**

On June 3, 2024, the FERC accepted, effective April 13, 2024, a non-conforming LGIA governing the interconnection of MMWEC's existing Large Generating Facility and the Surplus Interconnection of MMWEC's new 6.9 MW solar generating facility, both of which are located in Ludlow, MA.[106] Unless the June 3 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).

[103] *New England Power Co.*, Docket No. ER24-1851-000 (June 24, 2024) (unpublished letter order).

[104] *ISO New England Inc. and New England Power Co.*, Docket No. ER24-1840-000 (June 4, 2024) (unpublished letter order).

[105] *Central Maine Power Co*., Docket No. ER24-1510-000 (May 14, 2024) (unpublished letter order).

[106] *ISO New England Inc.*, Docket No. ER24-1238-000, 001 (June 3, 2024) (unpublished letter order).

- **CMP ESF Rate (ER24-1177)**

As previously reported, the FERC accepted, subject to refund and settlement judge procedures, CMP's rate schedule for distribution services for electric storage facilities ("ESFs") seeking to participate in the ISO-NE Market ("ESF Rate").[107] CMP filed the ESF Rate following re-consideration by the MPUC of the jurisdictional applicability of the ESF rate (which, while it recovers costs associated with the use of local the distribution network, the MPUC found upon re-consideration to include charges related to a FERC-jurisdictional wholesale transaction per *Order 841*). CMP sought in this proceeding to obtain FERC approval of a modified version of the MPUC Rate, with the primary difference between the MPUC Rate and the ESF Rate being the removal of state benefit charges. In the *CMP ESF Rate Order*, the FERC found that CMP's filing had not been shown to be just and reasonable, and raised issues of material fact that could not be resolved based on the record and would be more appropriately addressed in hearing and settlement judge procedures.[108] Accordingly, the FERC accepted the filing, subject to refund, and established hearing and settlement judge procedures. The FERC denied CMP's request for waiver of the FERC's 60-day prior notice requirement, and accepted the ESF Rate effective April 2, 2024, though, as noted, subject to refund and hearing and settlement judge procedures.[109] The FERC encouraged efforts to reach settlement before hearing procedures commence and will hold the hearing in abeyance pending the outcome of settlement judge procedures.

Settlement Judge Proceedings. As directed, the Chief ALJ appointed a settlement judge, Judge Jeremy Hessler, to assist participants in settling the issues in this proceeding, and deemed the settlement proceedings continued without further action.[110] The initial settlement conference was held on May 3, 2024 and a second settlement conference is scheduled for ***July 17, 2024.*** Judge Hessler submitted his first report on June 7, 2024 (and must submit a report every 60 days thereafter) addressing the parties' progress toward settlement. On May 31, 2024, CMP requested protective treatment of commercially sensitive or privileged information provided to FERC Trial Staff and other potential participants. On June 4, 2024, the Deputy Chief Administrative Law Judge granted CMP's motion and adopted a Protective Order to govern this proceeding. The Settlement Judge proceedings are on-going. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

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

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

[108] *Id.* at P 29.

[109] *Id*.

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

XII. Misc. - Administrative & Rulemaking Proceedings[111]

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

On March 21, 2024, the FERC issued an order establishing a Federal and State Current Issues Collaborative ("Collaborative").[112] The Collaborative will be the successor to the Joint Federal-State Task Force on Electric Transmission ("Transmission Task Force" or "JFSTF"),[113] which by design will expire on November 10, 2024 (3 years from its first public meeting). The FERC stated that the Collaborative will provide a venue for federal and state regulators to share perspectives, increase understanding, and, where appropriate, identify potential Jun 24, 2024 Report regarding 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 similarly be comprised of all FERC Commissioners as well as representatives from 10 state commissions, who will be nominated for and serve one-year terms from the date of appointment by the FERC. The FERC will issue notices announcing the time, place and agenda for each meeting of the Collaborative, after consulting with members of the Collaborative and considering suggestions from state commissions. Collaborative meetings will be on the record, and open to the public for listening and observing. The FERC expects that the first public meeting of the Collaborative will be held in the Fall of 2024. The Collaborative will expire 3 years after its first public meeting, but may be extended for an additional period of time prior to its expiration by agreement of both FERC and NARUC.

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

On October 19, 2023, the FERC issued a NOPR[114] proposing various changes to current Electric Quarterly Report ("EQR") filing requirements, including both the method of collection and the data being collected. The proposed changes are designed to update the data collection, improve data quality, increase market transparency, decrease costs, over time, of preparing the necessary data for submission, and streamline compliance with any future filing requirements. Among other things, the FERC proposes to implement a new collection method for EQR reporting based on the eXtensible Business Reporting Language ("XBRL")-Comma-Separated Values standard; amend its regulations to require ISO/RTOs to produce reports containing market participant transaction data; and modify or clarify EQR reporting requirements. Requests for additional time to comment on the *EQR NOPR* were filed by EEI/EPSA, the IRC and the Bonneville Power Administration ("BPA"). On December 7, 2023, the FERC extended the deadline for submitting comments to and including February 26, 2024. Comments on the NOPR were filed by ISO-NE, CAISO, MISO, NYISO, PJM, BPA, EEI, Energy Compliance Consulting, EPSA, Interstate Gas Supply, Macquarie, PG&E, Systrends, Tri-State, XBRL US. This matter remains pending before the FERC.

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

[112] *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*").

[113] *Joint Federal-State Task Force on Electric Transmission*, 175 FERC ¶ 61,224 (June 18, 2021). The Transmission Task Force is comprised of all FERC Commissioners as well as representatives from 10 state commissions (two from each NARUC region). State commission representatives will serve one-year terms from the date of appointment by FERC and in no event will serve on the Task Force for more than three consecutive terms. The Transmission Task Force will convene multiple formal meetings annually, with FERC issuing orders fixing the time and place and agenda for each meeting, and the meetings will be open to the public for listening and observing and on the record. The Transmission Task Force will focus on "topics related to efficiently and fairly planning and paying for transmission, including transmission to facilitate generator interconnection, that provides benefits from a federal and state perspective." New England is represented by Commissioners Riley Allen (VT PUC) and Marissa Gillett (Chair, CT PURA). *See* Order on Nominations, *Joint Federal-State Task Force on Elec. Trans.*, 180 FERC ¶ 61,030 (July 15, 2022).

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

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

Order 2023. On July 28, 2023, the FERC issued *Order 2023*,[115] its final rule on proposed reforms to the *pro forma* LGIP, *pro forma S*GIP, *pro forma* LGIA, and *pro forma* SGIA to address interconnection queue backlogs, improve certainty, and prevent undue discrimination for new technologies. *Order 2023* adopts reforms to: (i) implement a first-ready, first-served cluster study process;[116] (ii) increase the speed of interconnection queue processing;[117] and (iii) incorporate technological advancements into the interconnection process.[118] Many of the reforms adopted in *Order 2023* closely track the reforms set out in the FERC's Notice of Proposed Rulemaking.[119] However, the FERC did revise aspects of the reforms.[120] *Order 2023* became effective November 6, 2023[121] (60 days from its publication in the *Federal Register* ("Publication Date")).

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

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

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

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

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

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

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

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

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

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

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

Requests for Clarification and/or Rehearing Denied by Operation of Law. On September 28, 2023, the FERC issued a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration".[122] The *Order 2023 Allegheny Notice* confirmed that the 60-day period during which a petition for review of *Order 2023* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing and/or clarification of *Order 2023* within the required 30-day period. The Notice also indicated that the FERC would address, as is its right, the rehearing request in a future order, and may modify or set aside its order, in whole or in part, "in such manner as it shall deem proper." The FERC issued that order, *Order 2023-A*, on March 21, 2024 (*see* immediately below). Several parties submitted petitions in Federal Court challenging *Order 2023*. Developments in those federal court proceedings will be summarized in Section XVI below.

Order 2023-A. On March 21, 2024, the FERC issued *Order 2023-A*[123] addressing arguments raised on rehearing of *Order 2023*. *Order 2023-A* set aside, in part, and clarified *Order 2023*. Among other things, in *Order 2023-A* the FERC:

- upheld its prior determination that eliminating the Reasonable Efforts Standard with firm steady deadlines was "warranted as part of a package of comprehensive reforms to address interconnection queue delays and backlogs;"[124]
- denied several requests for rehearing or clarification regarding the transition process, including requests to revise the deposit amounts and withdrawal penalty amounts for the transitional process;[125]
- declined to revise the eligibility date for participation in a transitional cluster study or set a size threshold for the transitional cluster study;[126]
- declined to clarify whether transmission providers may use Energy Resource Interconnection Service ("ERIS") or Network Resource Interconnection Service ("NRIS") assumptions for public heatmaps, rather than just NRIS, but provided that a transmission provider may propose on

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

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

[124] *Id.* at P 280.

[125] *Id.* at P 257.

[126] *Id.*

compliance an option for heatmap users to view results using ERIS assumptions in addition to NRIS assumptions;[127]

- declined requests to revisit the requirement that transmission providers evaluate the list of alternative transmission technologies and noted that as long as a transmission provider has evaluated the list, it has complied with *Order 2023* and affirmed its prior decision not to include dynamic line ratings or storage-as-a-transmission-asset on the list of alternative transmission technologies.[128]

Due to breadth of the issues addressed in *Order 2023-A*, the FERC extended the *Order 2023* compliance filing deadline to May 16, 2024.[129] A more fulsome summary from NEPOOL Counsel of the Order was distributed to, and was reviewed with, the Transmission Committee at the March 27, 2024 meeting. ISO-NE's *Order 2023* and *Order 2023-A* Revisions were unanimously supported at the March 7 and May 2 Participants Committee meetings, respectively, and were filed on May 14, 2024 (see ER24-2007 and ER24-2009 above). Several parties submitted petitions in Federal Court challenging *Order-A 2023*. Developments in those federal court proceedings will be summarized in Section XVI below.

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

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

On May 16, 2024, the FERC issued *Order 1977*[130] updating the regulations governing applications for permits to site electric transmission facilities under section 216 of the FPA, as amended by the Infrastructure and Jobs Act, and particularly to reflect FERC's jurisdiction over projects located in National Interest Electric Transmission Corridors that have been denied state siting authority. There is no compliance filing requirement associated with *Order 1977*, but applicants seeking to develop transmission under federal authority in a National Interest Corridor must comply with the revised and new regulations effective ***July 29, 2024***.[131]

NEPOOL Counsel prepared a summary of *Order 1977* which was distributed to the Transmission Committee. If you have any questions concerning *Order 1977*, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

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

On March 21, 2024, the FERC issued a NOPR[132] proposing revisions to Schedule 2 of the *pro forma* OATT, § 9.6.3 of the *pro form* LGIA, and § 1.8.2 of the *pro forma* SGIA to prohibit separate compensation to generators for the provision of reactive power within the standard power factor range or "deadband."[133] The proposed change may affect revenues received by reactive power resources in New England.[134] The NOPR seeks comments on, among other issues, the following:

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[127] *Id*. at P 95.

[128] *Id*. at P 615.

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

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

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

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

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

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

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

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

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

(iv) If the FERC allows existing generation resources that have previously received compensation for reactive power supply to continue to receive compensation for a limited period while prohibiting new generation resources from receiving reactive power compensation, how should it determine eligibility for continued compensation in a manner that is just and reasonable and not unduly discriminatory or preferential.[135]

Initial comments on the *Reactive Power NOPR* were due May 28, 2024; reply comments are due ***June 26, 2024***.[136] NEPOOL Counsel prepared a summary of the NOPR which was distributed to, and was reviewed with, the Transmission Committee at the March 27, 2024 TC Meeting.

Comment Date Extension Request. On April 25, 2024, EPSA, the PJM Power Providers Group, NEPGA and Independent Power Producers of New York (collectively, the "Indicated Energy Trade Associations") filed a motion requesting that the FERC extend the NOPR comment deadline until 45 days after the D.C. Circuit issues its decision on challenges to the elimination of all charges for the provision of reactive power within the standard power factor range under the MISO Tariff. ACPA/SEIA, Vistra/Dynegy, Renewable Generation Companies[137] and Coalition of Midwest Power Producers ("COMPP")[138] supported the extension request; Joint Customers[139] and PJM IMM opposed the request. On May 10, 2024, the FERC denied the request.[140]

Comments. Following the denial of the Indicated Energy Trade Associations' request for extension of time to file comments, initial comments were filed on May 28, 2024 by over 30 parties, including by: ISO-NE, Calpine, CT OCC, EDP Renewables, Glenvale, National Grid, New England Consumer Advocates, ACPA/SEI, ACORE, EPSA, National Hydropower Assoc., NEI, and Reactive Service Providers. Reply comments are due by ***June 26, 2024***.

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

On May 13, 2023, the FERC issued *Order 1920*,[141] its final rule on proposed reforms to existing the transmission planning and cost allocation requirements. In *Order 1920*, the FERC explained that under existing

135 *Id.* at PP 47, 49, 56.

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

137 "Renewable Generation Companies" are: Capital Power Corporation; D. E. Shaw Renewable Investments, L.L.C.; Invenergy Renewables LLC, Lightsource Renewable Energy Operations, LLC; National Grid Renewables Development, LLC, NextEra Energy Resources, LLC, and RWE Renewables Americas, LLC.

138 COMPP is a non-profit trade association; member companies include Calpine, Vistra Energy, Rockland Capital and other entities that own and operate generation assets within MISO.

139 "Joint Customers" are: Northern Virginia Elec. Coop., Inc. ("NOVEC"), Old Dominion Elec. Coop. ("ODEC"); and Dominion Energy Services, Inc. on behalf of Virginia Electric and Power Company d/b/a Dominion Energy Virginia ("Dominion").

140 *Reactive Power NOPR*, Docket No. RM22-2-000 (May 10, 2024).

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

processes, transmission providers are not required to: (i) perform a sufficiently long-term assessment of transmission needs identifying Long-Term Transmission Needs; (ii) adequately account for known determinants of Long-Term Transmission Needs prospectively; and (iii) consider the broader benefits of regional transmission facilities planned to meet Long-Term Transmission Needs. The existing processes result in less efficient and cost-effective investment in transmission infrastructure and higher costs to customers and, therefore, unjust and unreasonable rates and need for reforms. *Order 1920* requires all transmission providers, *inter alia*, to

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

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

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

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

Order 1920 adopts a number of reforms from the *Transmission NOPR,*[142] but also declines to adopt several reforms, including the NOPR proposal to restrict the availability of the construction-work-in-progress ("CWIP") incentive for Long-Term Regional Transmission Facilities and to establish a federal rights of first refusal ("ROFR") for incumbent transmission providers, conditioned on the incumbent transmission provider establishing joint ownership of the transmission facilities. Although the FERC did not adopt a federal ROFR, it did adopt a limited ROFR applicable only to certain "right-sized" replacement transmission facilities. In addition, the FERC noted a willingness to consider the CWIP and ROFR issues in future proceedings.

Order 1920 takes effect on *August 12, 2024.*[143] Transmission providers must submit compliance filings by ***June 12, 2025*** with respect to most of the Order's requirements, while filings to comply with the interregional transmission coordination requirements are due by ***August 12, 2025***.

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

Requests for Clarification and/or Rehearing. Over 50 parties file requests for clarification and/or rehearing, including requests by: AEU, Dominion, Invenergy, NESCOE (with VT PUC supporting), Versant, APPA, EEI, Large Public Power Council, NARUC, NRECA, TAPS, WIRES, Consumer Advocates, and Harvard Electricity Institute. Those requests for rehearing are pending before the FERC.

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

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

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

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

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

On May 20, 2024, the FERC approved a Stipulation and Consent Agreement with ENGIE Energy Marketing NA, Inc. ("Engie") to resolve OE's investigation of Engie's involvement as Lead Market Participant and energy manager for unaffiliated generator assets (the "FRM Assets") that participated in the ISO-NE Forward Reserve Market ("FRM") between July 2021 and September 2022 (the "Relevant Period").[144] Enforcement determined that during the Relevant Period, Engie routinely submitted attestations to the ISO-NE IMM that one or more FRM Assets satisfy all six conditions necessary to seek exemption from energy market mitigation under the ISO-NE Tariff when certain conditions were not met. Enforcement determined that there were no instances during the Relevant Period in which the FRM Assets would have been subject to energy market mitigation but for an exemption request submitted by Engie. Enforcement found no intent to defraud; instead, Engie failed to properly evaluate whether necessary conditions were met prior to the submission of an attestation to the IMM; and, relatedly, failed to evaluate how changes Engie made to the internal model it used to generate offers might impact the accuracy of its attestations. Under the Stipulation and Consent Agreement, Engie agreed to pay a ***civil penalty of $48,000*** to the United States Treasury and file one annual compliance report with the requirement of a second annual filing at Enforcement's discretion. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

As previously reported, on February 21, 2024, the FERC directed Ketchup Caddy, LLC ("Ketchup Caddy") and Phillip Mango, Ketchup Caddy's CEO and co-owner (together, "Respondents"), to show cause why they should not be found to have violated FPA section 222, along with section 1c.2 of the FERC's regulations, Sections 69A.3.5 and 69A.7.1 of the MISO Tariff by offering uncontracted resources into the annual Planning Resource Auctions ("PRAs") that MISO uses to procure capacity necessary to maintain the reliability of the MISO grid.[145] The FERC directed Ketchup Caddy and Mango to show cause why they should not be assessed ***civil penalties of $25 million*** and ***$1.5 million***, respectively, and why ***Mango*** should not ***disgorge $506,502, plus interest***, in unjust profits. Enforcement alleges that "Ketchup Caddy operated as a fraudulent enterprise with no legitimate market activity, registering and clearing demand response resources without their knowledge or consent and collecting capacity payments in turn, without making payments to the registered resources. Mango … made no attempt to contract with—or even to contact—legitimate customers, and the purported customers Ketchup Caddy registered with MISO would not have responded if dispatched. Collectively, Mango and his co-owner received $1,013,004 in capacity payments paid to Ketchup Caddy by MISO during the Relevant Period. Staff's recommended penalties are predicated on its finding that Respondents caused $17,639,142.07 in losses to other suppliers because Ketchup Caddy's fraudulent offers lowered capacity prices in the 2019/20, 2020/21, and 2021/22 MISO PRAs."[146] Respondents had 30 days to file an answer or to make an election to have the procedures set forth in Section 31(d)(3) of the FPA apply to this proceeding;[147] they did neither. On April 10, 2024, OE Litigation Staff moved for summary disposition of these matters. That motion is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

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

[146] *Id.* at P 3.

[147] Under that provision, if the FERC finds a violation, the FERC will issue a penalty assessment and, if not paid within 60 days of the order assessing penalties, the FERC will institute an action in the appropriate United States district court.

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,[148] 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,[149] which (i) directed the Chief ALJ to reassign this proceeding to another ALJ not previously involved in the proceeding (i.e., designate a new presiding officer) once the *June 14 Order* takes effect; (ii) held that the *June 14 Order* will take effect once the Northern District clarifies or lifts its stay for the limited purpose of allowing the *June 14 Order* to take effect or the stay is lifted or dissolved such that hearing procedures may resume; and (iii) stated that this proceeding otherwise remains suspended until the Northern District's stay is lifted or dissolved such that hearing procedures may resume.

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

On December 16, 2021, the FERC issued a show cause order[150] 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,[151] 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;[152] (ii) failing to adequately monitor the right-of-way at the site of the Tuscarawas River HDD operation; and (iii) improperly disposing of inadvertently released drilling mud that was contaminated with diesel fuel and hydraulic oil. The FERC directed Respondents to show why they should not be assessed civil penalties in the amount of ***$40 million***.

On March 21, 2022, Respondents answered and denied the allegations in the *Rover/ETP CPCN Show Cause Order*. On April 20, 2022, OE Staff answered Respondents' March 21 answer. On May 13, Respondents submitted a surreply, reinforcing their position that "there is no factual or legal basis to hold either [Respondent] liable for 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.[153] This matter is pending before the FERC.

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[148] 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.

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

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

[151] *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*").

[152] 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.

[153] *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.

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

On April 28, 2016, the FERC issued a show cause order[154] in which it directed Total Gas & Power North America, Inc. ("TGPNA") and its West Desk traders and supervisors, Therese Tran f/k/a Nguyen ("Tran") and Aaron Hall (collectively, "Respondents") to show cause why Respondents should not be found to have violated NGA Section 4A and the FERC's Anti-Manipulation Rule through a scheme to manipulate the price of natural gas at four locations in the southwest United States between June 2009 and June 2012.[155]

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

Hearing Procedures. On July 15, 2021, the FERC issued and order establishing hearing procedures to determine whether Respondents violated the FERC's Anti-Manipulation Rule, and to ascertain certain facts relevant for any application of the FERC's Penalty Guidelines.[156] On July 27, 2021, Chief Judge Cintron designated Judge Suzanne Krolikowski as the Presiding ALJ and established an extended Track III Schedule for the proceeding.

Discovery in this case closed on December 2, 2022. On December 16, 2022, Respondents filed for a preliminary injunction in the US District Court for the Southern District of Texas ("Southern District"). In order to allow for briefing and a decision on that motion, the FERC placed this proceeding in abeyance.[157]

On June 14, 2023, the FERC issued an Order on Presiding Officer Reassignment,[158] which (i) directed the Chief ALJ to reassign this proceeding to another ALJ not previously involved in the proceeding (i.e., designate a new presiding officer) once the *TGPNA Presiding Officer Reassignment Order* takes effect; (ii) held that the *TGPNA Presiding Officer Reassignment Order* will take effect once the Southern District clarifies or lifts its stay for the limited purpose of allowing the *TGPNA Presiding Officer Reassignment Order* to take effect or the stay is lifted or dissolved such that hearing procedures may resume; (iii) stated that this proceeding otherwise remains suspended until the Southern District's stay is lifted or dissolved such that hearing procedures may resume; and (iv) provided procedural guidance to the new presiding officer. On July 18, Judge Patricia M. French was substituted as Presiding Judge (relieving Judge Krolikowski of all of her duties with respect to this proceeding).

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

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

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

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

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

XIV. Natural Gas Proceedings

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

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

- **Iroquois ExC Project (CP20-48)**
  - 125,000 Dth/d of incremental firm transportation service to ConEd and KeySpan by building and operating new natural gas compression and cooling facilities at the sites of four existing Iroquois compressor stations in Connecticut (Brookfield and Milford) and New York (Athens and Dover).
  - Three-year construction project; service request by November 1, 2023.
  - On March 25, 2022, after procedural developments summarized in previous Reports, the FERC issued to Iroquois a certificate of public convenience and necessity, authorizing it to construct and operate the proposed facilities.[159] The certificate was conditioned on: (i) Iroquois' completion of construction of the proposed facilities and making them available for service within ***three years*** of the date of the; (ii) Iroquois' compliance with all applicable FERC regulations under the NGA; (iii) Iroquois' compliance with the environmental conditions listed in the appendix to the order; and (iv) Iroquois' filing written statements affirming that it has executed firm service agreements for volumes and service terms equivalent to those in its precedent agreements, prior to commencing construction. The March 25, 2022 order also approved, as modified, Iroquois' proposed incremental recourse rate and incremental fuel retention percentages as the initial rates for transportation on the Enhancement by Compression Project.
  - On April 18, 2022, Iroquois accepted the certificate issued in the *Iroquois Certificate Order*.
  - On June 17, 2022, in accordance with the *Iroquois Certificate Order,* Iroquois submitted its Implementation Plan, documenting how it will comply with the FERC's Certificate conditions.
    - In its March 8, 2024 monthly status report, Iroquois indicated that it is still awaiting issuance of air permits from the New York State Department of Environmental Conservation ("NYDEC") and the CT DEEP. Iroquois noted that the public comment period on the NY DPS reliability and needs determination, noticed by NYDEC was open until March 29, 2024. Iroquois has still not yet requested or received authorization to commence construction; accordingly, no construction activities were undertaken in February 2024 and no construction was planned for March 2024.

XV. State Proceedings & Federal Legislative Proceedings

No activities to report.

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

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

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).

- **Mystic Second CapEx Info Filing - Request for Rehearing (24-1077)**
  Underlying FERC Proceeding: ER18-1639-028[160]
  Petitioner: Mystic
  Status: Being Held In Abeyance; Motions to Govern Future Proceedings Due Jul 16, 2024

On April 3, 2024, Constellation Mystic Power, LLC petitioned the DC Circuit Court of Appeals for review of the FERC's orders. Mystic filed, on May 6, 2024, a Certificate as to Parties, Rulings, and Related Cases, a Docketing Statement, a Statement of Intent to Utilize Deferred Joint Appendix, a Statement of Issues, and the Underlying Decision from which the appeal arose. Appearances and other procedural motions, if any, were also due on or before May 6. Interventions were filed by ISO-NE, NESCOE, and a collective of Massachusetts municipal utilities.[161]

In response to a motion by the FERC, the Court order that this case be held in abeyance pending further order of the court. The Court directed the parties to file motions to govern further proceedings in this case by ***July 16, 2024***.

- **Orders 2023 and 2023-A (23-1282 et al.) (consolidated)**
  Underlying FERC Proceeding: RM22-14[162]
  Petitioners: AEU et al.
  Status: Being Held In Abeyance; Motions to Govern Future Proceedings Due Jun 25, 2024

Several Petitioners have challenged *Orders 2023 and 2023-A*. Those challenges have now been consolidated, with the AEU docket (23-1282) as the lead docket. Since the last Report, the Court ordered that these consolidated cases remain in abeyance pending further order of the court. The Court directed the parties to file motions to govern further proceedings in these consolidated cases by ***June 25, 2024***.

- ***Order 2222*** **Compliance Orders (23-1167, 23-1168, 23-1169, 23-1170, 23-1335)(consolidated)**
  Underlying FERC Proceeding: ER22-983[163]
  Petitioners: Eversource, ISO-NE, National Grid, and CMP/UI
  Status: Being Held In Abeyance; Motions to Govern Future Proceedings Due Aug 5, 2024

On June 30, 2023, ISO-NE (23-1168), CMP/UI (23-1170), Eversource (23-1167), and National Grid (23-1169) petitioned the DC Circuit Court of Appeals for review of the FERC's orders related to the FERC's *Order 2222 Compliance Orders*.[164] On July 3, 2023, the Court consolidated the cases, with Case No. 23-1667 as the lead case.

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[160] *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*").

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

[162] *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).

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

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

On July 24, 2023, the FERC moved to have the consolidated cases held in abeyance pending the issuance of the Commission's further order on rehearing. The Court granted that motion on July 27, 2023, with the case to be held in abeyance pending further order of the Court. Since the last Report, on June 6, 2024, the FERC filed a status report reporting that, on May 23, 2024, the Commission issued its order on rehearing of its November 2023 order in the ER22-983 docket and that, under the Court's February 6 order, the parties therefore have until ***August 5, 2024***, to file motions to govern future proceedings in these consolidated appeals.

- **Seabrook Dispute Order (23-1094, 23-1215) (consolidated)**
  Underlying FERC Proceeding: EL21-6, EL 23-3[165]
  Petitioner: NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC
  Status: Oral Argument Held Feb 6, 2024; Case Pending Before the Court

On April 4, 2023, NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC (collectively, "NextEra") petitioned the DC Circuit Court of Appeals for review of the FERC's orders related to the Seabrook Dispute.[166] NextEra subsequently petitioned the Court for review of the June 15, 2023 *Seabrook Dispute Allegheny Order*, which was consolidated with Case No. 23-1094. Briefing is completed. Oral argument was heard on February 6, 2024 by Judges Millett, Katsas and Rao. This matter is pending before the Court.

coordination with distribution utilities and relevant electric retail regulatory authorities ("RERRAs") for DERA/DER registration, operations, and dispute resolution purposes.

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

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

- **Mystic II (ROE & *True*-Up)**
  (21-1198; 21-1222, 21-1223, 21-1224, 22-1001, 22-1008, 22-1026) (consolidated)
  Underlying FERC Proceeding: ER18-1639-010, -011,[167] -013[168] -017[169]
  Petitioners: Mystic, CT Parties,[170] MA AG, ENECOS
  Status: Being Held in Abeyance; Motions to Govern Future Proceedings Due Jul 23, 2024

This case was initiated when, on October 8, 2021, Mystic petitioned the DC Circuit Court of Appeals for review of the FERC's orders setting the base ROE for the Mystic COS Agreement at 9.33%. The *Mystic ROE Order* and subsequent FERC orders addressing the Mystic ROE issues have all also been appealed by various parties and consolidated under 21-1198. Docketing Statements and Statements of Issues to be Raised, and the Underlying Decision from which the various appeals arise have been filed as new dockets have been opened and then consolidated with 21-1198. As previously reported, the Certified Index to the Record was due, and filed by the FERC, on February 22, 2022. On March 10, 2022, MMWEC and NHEC filed a notice of intent to participate in support of FERC in Case Nos. 21-1198, 22-1008, and 22-1026 and in support of Petitioners in the remaining consolidated cases, and filed a statement of issues. On March 17, 2022, CT Parties moved to intervene, and those interventions were granted on May 4, 2022.

As previously reported, on July 8, 2022, Connecticut Parties and ENECOS jointly moved to hold these proceedings in abeyance until 30 days after the DC Circuit issued an opinion in *MISO Transmission Owners v. FERC*, 16-1325 ("*MISO TOs"*). They requested abeyance on the basis that the consolidated petitions in this proceeding and *MISO TOs* both involve challenges to the FERC's ROE methodology (the FERC set the ROE used in calculating Constellation's rates using the methodology challenged in *MISO TOs*). Although Constellation opposed the abeyance request, the Court granted the abeyance request on July 27, 2022, directing the Parties to file motions to govern future proceedings within 30 days of the court's disposition of *MISO TOs*. The Court has since decided *MISO TOs*. However, the parties continue to agree that this case should remain in abeyance pending further proceedings related to MISO TOs, now on remand at the FERC. Most recently, on January 24, 2024, Constellation reported that all parties agree and asked the Court that this case should remain in abeyance for an additional 90 days pending FERC action on remand in the *MISO TOs* case. On April 24, 2024, the Court issued an order that these cases remain in abeyance and that the parties file motions to govern future proceedings by ***July 23, 2024***.

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  Underlying FERC Proceeding: ER18-619[171]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF
  Status: Being Held in Abeyance; Motions to Govern Future Proceedings Due Mar 2, 2026

As previously reported, the Sierra Club, NRDC, RENEW Northeast, and CLF petitioned the DC Circuit Court of Appeals on August 31, 2020 for review of the FERC's order accepting ISO-NE's CASPR revisions and the FERC's subsequent *CASPR Allegheny Order*. Appearances, docketing statements, a statement of issues to be raised, and a statement of intent to utilize deferred joint appendix were filed. A motion by the FERC to dismiss the case was

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

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

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

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

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

dismissed as moot by the Court, referred to the merits panel (Judges Pillard, Katsas and Walker), and is to be addressed by the parties in their briefs.

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

- ***Opinion 531-A*** **Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[172]
  Petitioners: TOs (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[173] 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*[174] decision. On September 22, 2020, the FERC submitted an unopposed motion to hold this proceeding in abeyance for four months to allow for the Commission to "a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the Commission." On October 2, 2020, the Court granted the FERC's motion, and directed the parties to file motions to govern future proceedings in this case by February 2, 2021. On January 25, 2021, the FERC requested that the Court continue to hold this petition for review in abeyance for an additional three months, with parties to file motions to govern future proceedings at the end of that period. The FERC requested continued abeyance because of its intention to issue a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the FERC. Petitioners consented to the requested abeyance. On February 11, 2021, the Court issued an order that that this case remain in abeyance pending further order of the court. On April 21, 2021, the FERC filed an unopposed motion for continued abeyance of this case *because* the Commission intends to issue a future order on Petitioners' request for rehearing of the challenged *Order Rejecting Compliance Filing*, and because the remand proceeding in which the challenged order was issued remains ongoing.

On May 4, 2021, the Court ordered that this case remain in abeyance pending further order of the Court, directing the FERC to file a status report by September 1, 2021 and at 120-day intervals thereafter. The parties were directed to file motions to govern future proceedings in this case within 30 days of the completion of agency proceedings. The FERC's last status report, indicating that the proceedings before the FERC remain ongoing and that this appeal should continue to remain in abeyance, was filed on March 26, 2024.

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

[173] 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.

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

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NEPOOL Participants Committee Summer Meeting

Federal Energy Regulatory Commission | Washington D.C.

Mary Wierzbicki

Division of Energy Market Assessments

Office of Energy Policy and Innovation

Federal Energy Regulatory Commission

June 25, 2024

This presentation represents the own opinions and views of the speaker and may not represent the opinions or views of the Federal Energy Regulatory Commission or of individual Commissioners.

Outline of Presentation

- Office of Energy Policy and Innovation, Division of Energy Market Assessments
- Market Assessment Reports
- Regular calls with market monitors
- New England Winter Gas-Electric Forums
- Major FERC rulemakings – transmission, interconnection

Office of Energy Policy and Innovation

Jignasa Gadani, Office Director
Michael McLaughlin, Deputy Office Director
Total Staff: 90
OEPI formed in 2009

The OEPI Mission
The Office of Energy Policy and Innovation (OEPI) provides leadership in the development and formulation of policies and regulations to address emerging issues affecting wholesale and interstate energy markets. The Office undertakes significant outreach to other regulators and industry, conducts studies and prepares reports, and recommends policy reforms to the Commission for consideration. The Office works in close coordination with other offices within the Commission to develop proposals and effectuate change.

Division of Energy Market Assessments

Mary Wierzbicki, Division Director
David Hunger, Deputy Division Director
Total Staff: 28
Division joined OEPI in 2019 from OE

The DEMA Mission

The Division of Energy Market Assessments (DEMA) examines, analyzes, and reports on the structure and operation of the electric and natural gas markets and provides information to the Commission and the public on significant market events and trends. DEMA observes market operations and performance to develop market intelligence to inform the development of policies that promote the competitiveness and efficiency of the wholesale energy markets.

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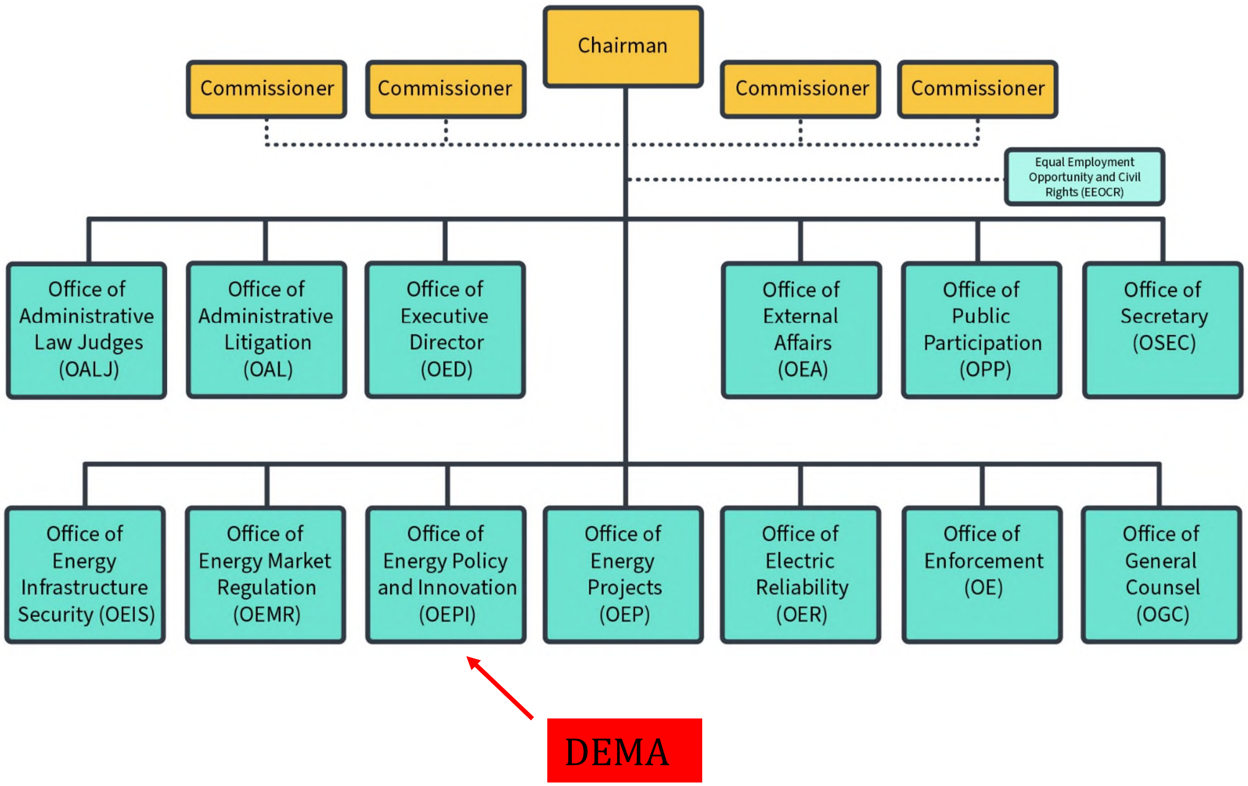
OEPI and DEMA within FERC

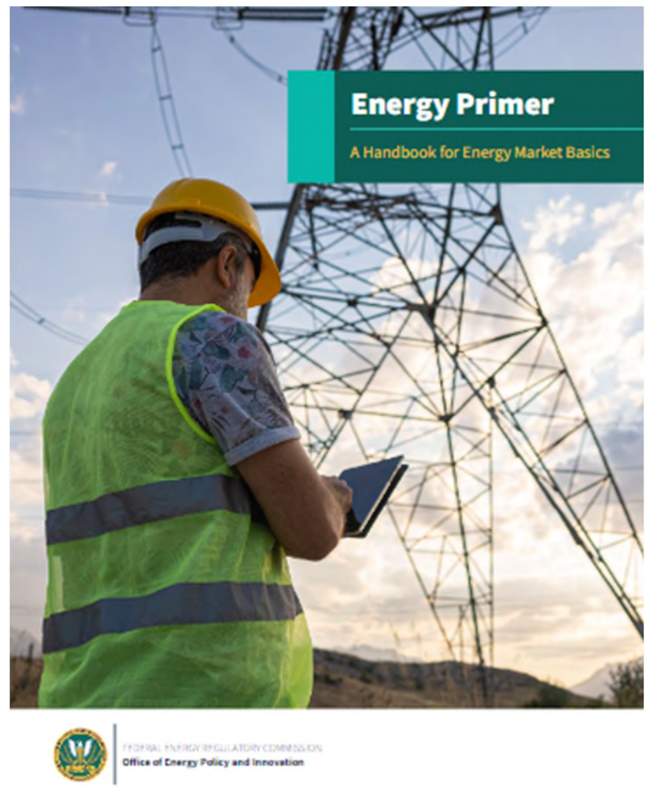


OEPI's Market Assessments

- DEMA publishes three market assessments each year.
  - Presented at Commission meetings and to state officials.
    - ***Winter and Summer Market and Reliability Assessments***
      - Forward-looking assessment of reliability and market conditions for the upcoming winter and summer seasons, using projections from EIA, NOAA, NERC and others.
      - Typically published in May and October/November.
    - ***State of the Markets***
      - Assessment of the previous year to update the Commission, industry, and the public on recent market conditions, emerging issues and significant trends.
      - Typically published in March.
      - https://www.ferc.gov/market-assessments

FERC's *Energy Primer*

- DEMA also periodically updates an *Energy Primer: A Handbook on Energy Market Basics:*
  - Overview of the industries and markets that FERC regulates, including how the markets have evolved and how FERC's authorities over them have evolved.



https://www.ferc.gov/sites/default/files/2024-01/24_Energy-Markets-Primer_0117_DIGITAL_0.pdf

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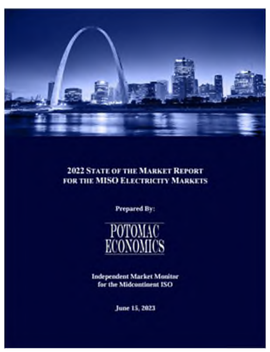
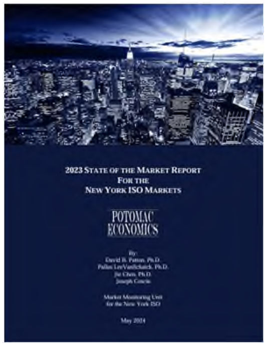
Calls with Market Monitors

- DEMA staff hold regular calls with the market monitors of each of the FERC-jurisdictional RTOs/ISOs
- Discuss market performance
- Discuss recommendations from market monitor reports





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New England Winter Gas-Electric Forum 2022 & 2023

- FERC convened two Commissioner-led meetings in New England
  - 2022 – Burlington, VT
  - 2023 – Portland, ME
- To discuss concerns about winter energy adequacy and potential solutions
- Staff continues to analyze comments, follow progress on addressing issues in the region
  - Market rules
  - Infrastructure
  - Modeling/studies

Order No. 1920 Transmission

Deficiencies in Existing Transmission Planning and Cost Allocation Processes

- Failure to conduct a sufficiently long-term assessment of transmission needs
- Failure to adequately account for known determinants of long-term transmission needs
- Failure to consider the broader set of benefits provided by regional transmission facilities that are planned to meet those long-term transmission needs
  - These failures have resulted in piecemeal transmission expansion that addresses relatively near-term transmission needs and relatively inefficient investment in transmission. Customers also end up paying more than is necessary to meet their transmission needs, or forgoing benefits

Order No. 1920 Rulemaking Process

July 2021
Regional Transmission Planning and Cost Allocation and Generator Interconnection ANOPR

April 2022
Regional Transmission Planning and Cost Allocation Notice of Proposed Rulemaking (NOPR)

August - September 2022
(and after)
Commission receives 32,155 pages of initial, reply, and supplemental comments and appendices

May 13, 2024
Commission issues Order No. 1920

Joint Federal-State Task Force on Electric Transmission
Eight meetings held from November 2021 – February 2024
Topics Include: State perspectives on transmission planning, categories and types of transmission benefits, interregional transmission planning, regulatory gaps and oversight in transmission development, grid enhancing technologies, and transmission siting

Major Reforms Established by Order No. 1920

- Long-Term Regional Transmission Planning (at a minimum every 5 years, using a 20 year horizon, at least three long-term scenarios and sensitivities that incorporate specific categories of factors and best available data inputs)
- Benefits (measure and use seven specific benefits to determine whether any identified long-term regional transmission facilities more efficiently or cost-effectively address long-term transmission needs)
- Evaluation Process and Selection Criteria (identify and evaluate long-term regional transmission facilities for selection)
- Consideration of Interconnection-related Transmission Needs and Alternative Transmission Technologies-(consider transmission facilities that address interconnection-related needs, and consider the use of alternative transmission technologies in transmission planning)

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Major Reforms Established by Order No. 1920 (cont’d)

- Enhanced Transparency (for local transmission planning information, and hold at least three stakeholder meetings)
- Right-Sizing Replacement Transmission Facilities (identify potential opportunities to right-size replacement transmission facilities)
- Long-Term Regional Cost Allocation (one or more ex ante long-term regional transmission cost allocation methods, optional state agreement process)
- Interregional Transmission Coordination (reflect the applicable reforms in the final rule, and comply with additional information sharing and transparency requirements)

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Effective Date, Compliance, and Implementation

- Order No. 1920:
  - Becomes effective ***August 2024.***
  - Compliance filings for all requirements except those related to interregional transmission coordination: ***June 2025***
  - Compliance filings for all requirements related to interregional transmission coordination by ***August 2025***
  - Implementation: Transmission providers must commence the first Long-Term Regional Transmission Planning cycle no later than ***one year following due date of compliance filing***

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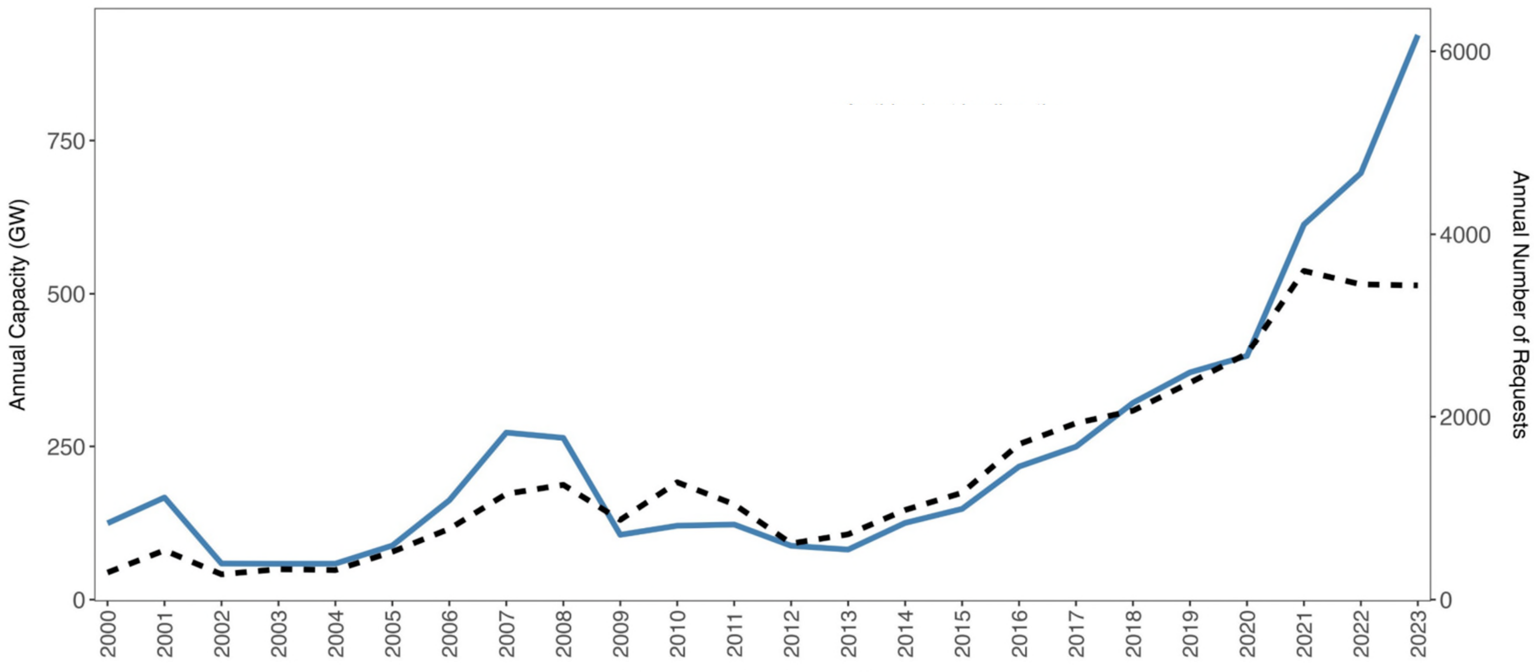
Order No. 2023 Interconnection



An Order Designed to Address Soaring Generator Interconnection Requests

Need for Reform

- The Commission found that existing interconnection procedures and agreements were insufficient to ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner
- Persistent generator interconnection queue backlogs
  - Nearly 12,000 active requests (2,600 GW) in queues at the end of 2023
  - Typical time spent in queues before COD increasing from 2.1 years (for generating facilities built in 2000-2010), to 3.7 years (2010-2021), to ~5 years (2023)
  - The majority (>70%) of interconnection requests are withdrawn. Only 19% of requests (14% of capacity) submitted from 2000-2018 had been built as of the end of 2023
- Interconnection customers have a high degree of uncertainty regarding the cost of interconnection
- Commenters overwhelmingly agreed that there was a need to reform the Commission's *pro forma* interconnection procedures and agreements

Selected Order No. 2023 Reforms

- Reforms to Implement a First-Ready, First-Served Cluster Study Process
  - Public Interconnection Information
  - Cluster Study Process
  - Allocation of Network Upgrade Costs for Interconnection Customers in Clusters
  - Financial Commitments and Readiness Requirements
  - Transition Process
- Reforms to Increase the Speed of Queue Processing
  - Affected System Study Process
  - Study Delay Penalties
- Reforms to Incorporate Technological Advancements
  - Increasing Flexibility in the Generator Interconnection Process
  - Evaluating Alternative Transmission Technologies in the Generator Interconnection Process
  - Modeling and Performance Requirements for Non-Synchronous Generating Facilities

Improvements to Generator Interconnection Procedures and Agreements (Order 2023)

- Cluster Study Process
  - Streamlines process by requiring transmission providers (utilities, RTOs) to conduct larger studies consisting of numerous generating facilities and to prioritize projects that are commercially and operationally ready to proceed. This replaces a first-come, first served process in which studies were conduced one-by-one, which was often subject to delays.

- Speed Up Interconnection Queue Processing
  - Requires firm deadlines and establishes penalties if transmission providers do not complete interconnection studies on time

- Incorporate Technological Advancements into the Interconnection Process
  - Permits flexibility for generators by allowing more than one generating facility to co-locate on a shared site behind a single interconnection point. Also requires realistic operating assumptions for storage resources
  - Requires consideration of alternative transmission technologies

Thank you!
Questions?

Highlights of the 2023 Assessment of the ISO New England Markets

Presented By:

David B. Patton, Ph.D.

Potomac Economics
External Market Monitor

June 25, 2024

POTOMAC ECONOMICS

Introduction

- Potomac Economics serves as the External Market Monitor ("EMM") for the ISO-NE. In this role, we:
  - ✓ Evaluate the competitive performance and operation of the markets;
  - ✓ Identify and recommend necessary changes to existing and proposed market rules, tariff, and market design elements; and
  - ✓ Evaluate the mitigation by the Internal Market Monitor ("IMM").
- Our annual assessment of the ISO-NE markets complements the IMM's report, and focuses on key market areas summarized in this presentation:
  - ✓ Cross-market comparison of key market outcomes and metrics;
  - ✓ Navigating the clean energy transition;
  - ✓ Competitive assessment of the energy market;
  - ✓ Out-of-market commitment and reserve pricing;
  - ✓ Assessment of the Pay-For-Performance event on July 5; and
  - ✓ Winter risk in the reliability planning models and capacity market.

Summary of Findings

- We find that the markets performed competitively but identify key improvements that will be increasingly important in the coming years.
- High priority recommendations to improve the performance of the markets today and facilitate large-scale entry of intermittent resources include:
  - ✓ **2012-8:** Introducing co-optimized day-ahead operating reserves to reflect forecasted system needs – DASI expected March 2025
  - ✓ **2018-7:** Modify the pay-for-performance rate to a reasonable level that would vary with the size of the operating reserve shortage.
  - ✓ **2020-2:** Accrediting capacity resources based on marginal reliability value.
  - ✓ **2021-1**: Replace the FCM with a prompt seasonal capacity market – FCA 19 Further Delay facilitates transition
- These improvements are important for reliably integrating the large quantities of renewable resources the New England states are requiring.
- We recommend ten other improvements to lower costs and improve market performance, which are lower in priority to those above.

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Cross-Market Comparison and Competitive Assessment

POTOMAC ECONOMICS

See Section I.A-C

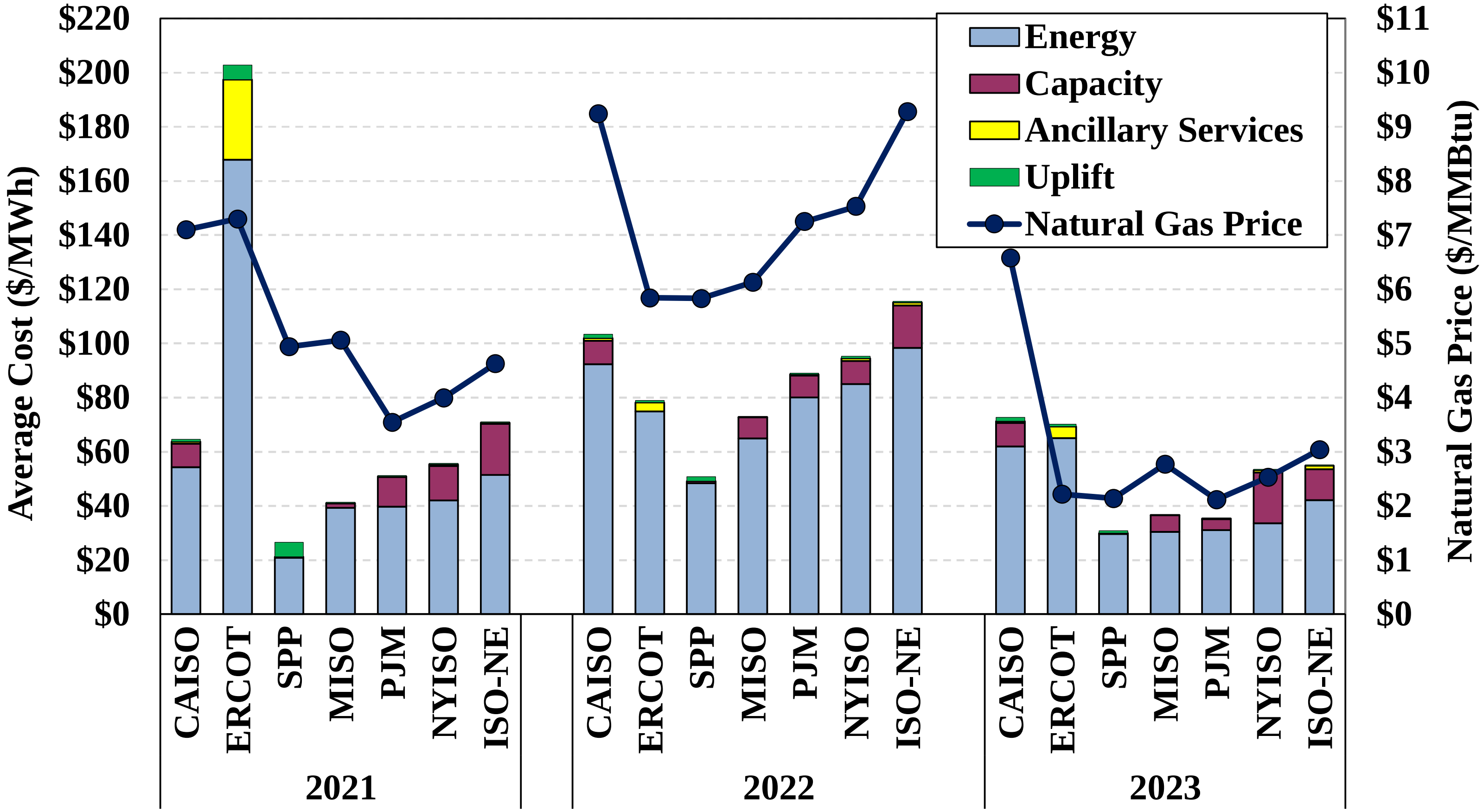
Cross-Market Comparison of Key Outcomes and Metrics

Compared to most other RTO markets, ISO-NE has:

- The highest capacity charges because of over-forecasted demand ahead of the FCAs, which are slow to correct in the FCM.
  - ✓ Larger surpluses in other areas and poor market design in MISO contributed to lower prices in these areas.
  - ✓ Prices in NYISO rose in 2023 after air permits caused GTs to retire.
- The highest energy prices in the East due to higher gas prices in NE.
- Far less congestion (10-20% of other RTOs per MWh of load) because of transmission investments over the past decade.
  - ✓ Tx. rates are more than double the average rates in other RTO markets.
- Less liquidity in the day-ahead market and poorer performance – caused by the inefficient allocation of costs to virtual transactions.
- Higher market-wide uplifts costs because the lack of DA reserve markets causes ISO-NE to commit resources out-of-market.

See Section I.A

All-in Prices in RTO Markets



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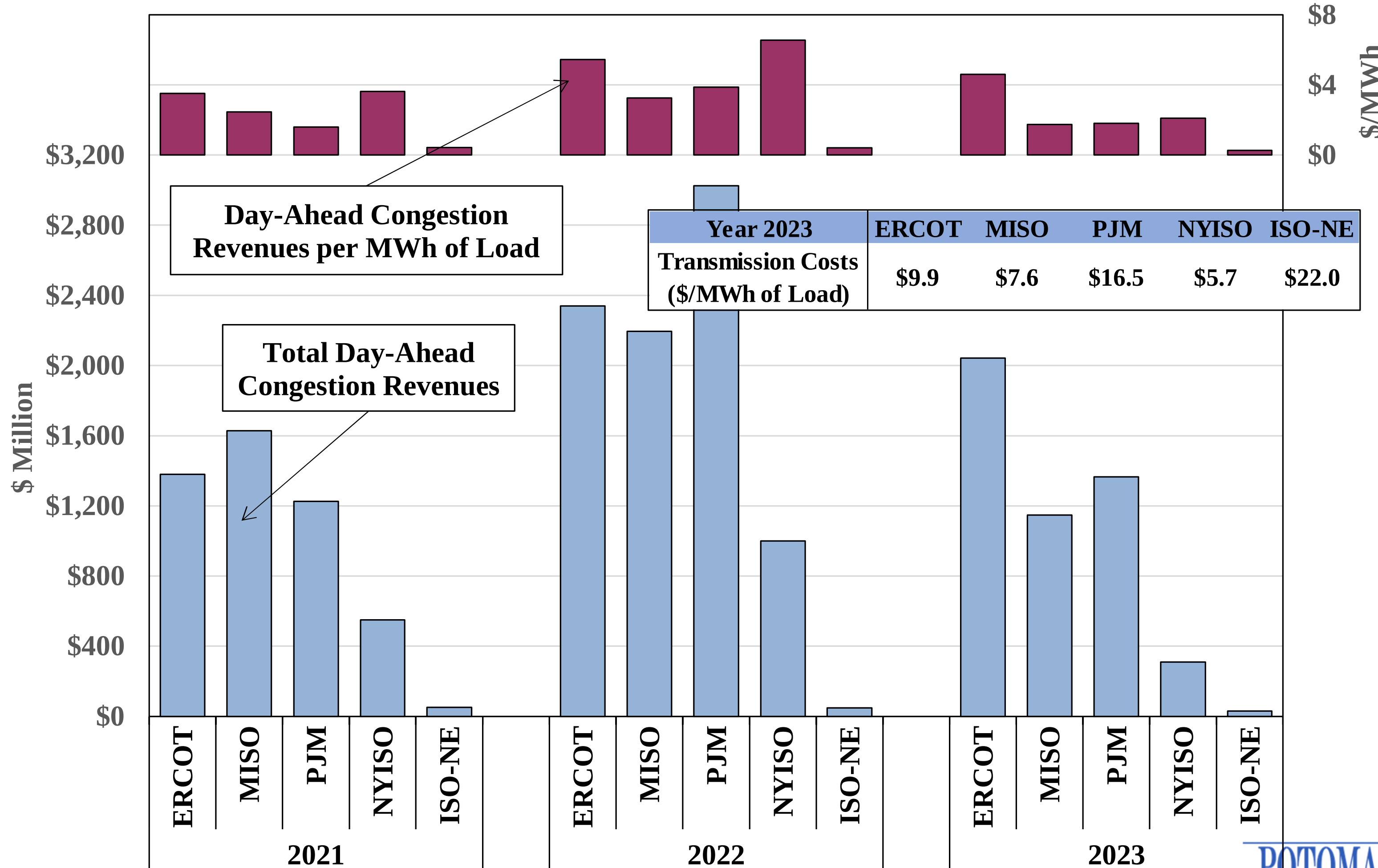
See Section I.B

Transmission Congestion Costs



Year 2023	ERCOT	MISO	PJM	NYISO	ISO-NE
Transmission Costs ($/MWh of Load)	$9.9	$7.6	$16.5	$5.7	$22.0

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See Section I.C

Virtual Transactions

Market	Year	Virtual Load		Virtual Supply		Uplift Charge Rate
		MW as a % of Load	Avg Profit	MW as a % of Load	Avg Profit	
ISO-NE	2020	2.8%	$0.36	4.6%	$0.72	$0.46
	2021	2.8%	-$1.29	4.5%	$2.07	$0.53
	2022	3.1%	-$1.75	4.8%	$3.23	$1.02
	2023	4.2%	-$2.09	6.3%	$1.28	$0.83
NYISO	2023	7.2%	-$0.76	8.6%	$0.64	< $0.1
MISO	2023	16.1%	$0.40	15.9%	$1.11	$0.16

Navigating the Clean Energy Transition

- Rapid influx of intermittent generation in other markets highlights challenges:
  - ✓ Higher uncertainty regarding energy output and transmission flows; and
  - ✓ Output fluctuations lead to greater demand for flexible ramp up and down.
- ISO-NE's market is fundamentally robust and structured to handle this. Flexible resources are supported by two essential design elements:
  - ✓ *Efficient shortage pricing* – ISO-NE's ORDCs and PFP address this element;
  - ✓ *Marginal capacity accreditation* – ISO-NE is pursuing changes in this area.
- Even if renewables set negative prices in many hours, flexible resources will set prices in most hours, and reserves shortages will be more frequent.
- ISO-NE's real-time dispatch optimizes over a single period, but this will not lead to efficient *schedules* and *prices* when:
  - ✓ Slower resources begin ramping in advance of a sharp net load increase; or
  - ✓ Energy storage must be held in reserve for subsequent intervals.
- We recommend (#2023-1) ISO-NE evaluate a look-ahead dispatch model to optimize multiple hours into the future.

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See Section II

Competitive Assessment of the Energy Market

- In our competitive assessment of the energy market, we find:
  - ✓ Little evidence of structural market power;
  - ✓ No market power abuse or manipulation affecting clearing prices; and
  - ✓ Mitigation has helped prevent the exercise of market power.
- We recommend revisions to the energy mitigation process (Rec #2022-2) following the mitigation instances on December 24, 2022:
  - ✓ ***(a) Implement hourly conduct and impact tests***: Resources should only be mitigated in hours when they violate both conduct and impact tests.
  - ✓ ***(b) Mitigate only offer segments that fail the conduct test***: No resource is mitigated to a *higher* offer price.
    - – Elimination of upward mitigation by ISO-NE Dec. 2023
  - ✓ ***(c) Allow multiple FPAs for calculating reference levels***: Multiple FPAs for different output ranges will avoid inappropriate mitigation.
    - – MW-dependent fuel price adjustment proposed for Nov. 2026

OOM Commitments and Operating Reserve Prices

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See Section III.A

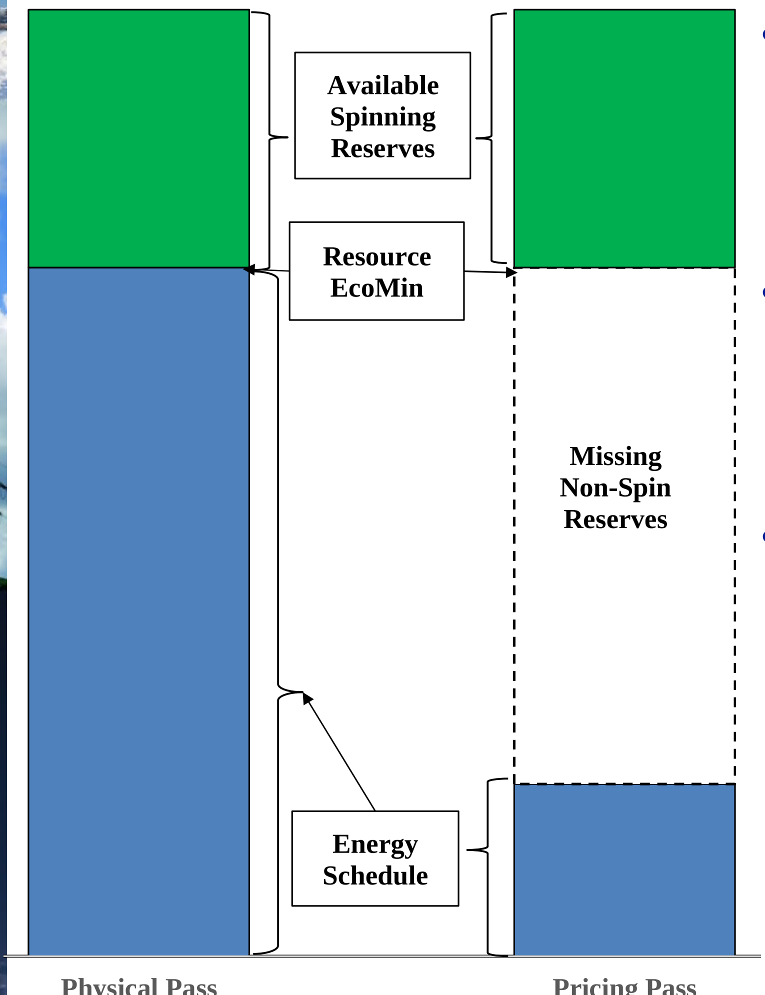
Day-Ahead Commitments for 10-Minute Spinning Reserve

- OOM commitments, on average, occurred in **25-40%** hours per year for the system's 10-minute spinning reserve requirement.
  - ✓ These commitments produced **35-63%** of day-ahead NCPC.
  - ✓ These commitments lower prices and depress incentives for investment in flexible resources.
- Pricing 10-minute spinning reserves would raise revenue up to **$12** per kW-year for units providing energy and/or spinning reserves.
- This underscores the need for day-ahead operating reserve markets.

Year	# Hours	Average Capacity Committed per Hour (MW)	DA NCPC		Average Reserve Value ($/MWh)
			Million $	% of Total DA NCPC	
2021	3389	514	$5.4	35%	$1.94
2022	2450	496	$5.8	40%	$1.81
2023	2263	536	$2.9	63%	$0.46

See Section III.C

Pricing of Operating Reserves in the Fast-Start Pricing Logic



- *Pricing Logic* relaxes fast-start units' EcoMin to zero for pricing purposes.
  - ✓ However, it does not allow reserves to be held below EcoMin.
- The reduction in available non-spinning reserves often raises energy and reserve prices inefficiently under tight conditions.
- During intervals with binding reserve constraints, on average:
  - ✓ The physical dispatch had 360 MW more available 30-minute reserves than the pricing logic.
  - ✓ $86/MWh TMOR price in pricing logic vs. $10/MWh in physical dispatch.

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See Section III

OOM Commitments and Reserve Prices

Key Recommendations:

- Introduce co-optimized operating reserves in the day-ahead market reflecting all system needs. (Recommendation **#2012-8**)
  - ✓ *DASI* will address this.
- Modify the fast-start pricing logic to utilize the full capability of online resources for reserves (Recommendation **#2022-1**).
  - ✓ This will ensure that the reserve prices more accurately reflect the cost of maintaining operating reserves.

Assessment of PFP Event on July 5

See Section IV

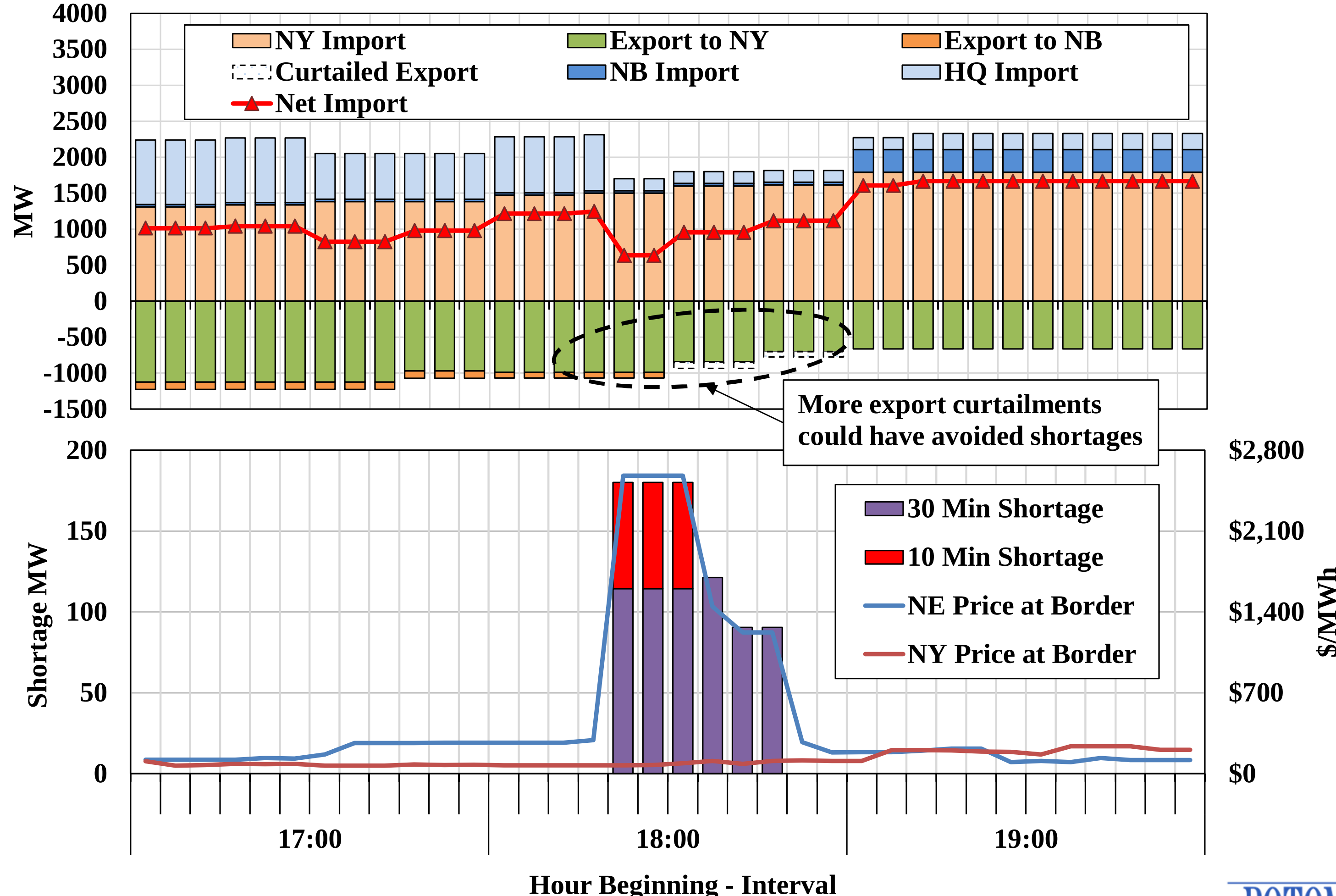
PFP Event on July 5

- The system was short of 10-minute and 30-minute reserves, with an average shortage < 200 MW.
  - ✓ Two key drivers were: (a) trip of the Phase II interface with Quebec; and (b) higher-than-expected load.
- ISO-NE curtailed ~10% of scheduled exports.
  - ✓ Shortage pricing + PFP settlements exceeded $6000 per MWh.
- Concern #1: Inefficient incentives to export. Imports are paid the PFP rate of $3,500/MWh but exports are not charged the PFP rate.
  - ✓ It can be simultaneously profitable to schedule in *both* directions - raises gaming concerns and disrupts import/export incentives.
- Concern #2: PFP rate not consistent with value of reserves – the rate is overstated and does not vary with the magnitude of shortage
  - ✓ Available units not committed day ahead received excessive penalties.
  - ✓ Problem will be *much* worse when rate rises to $9337 in 2025.

POTOMAC ECONOMICS

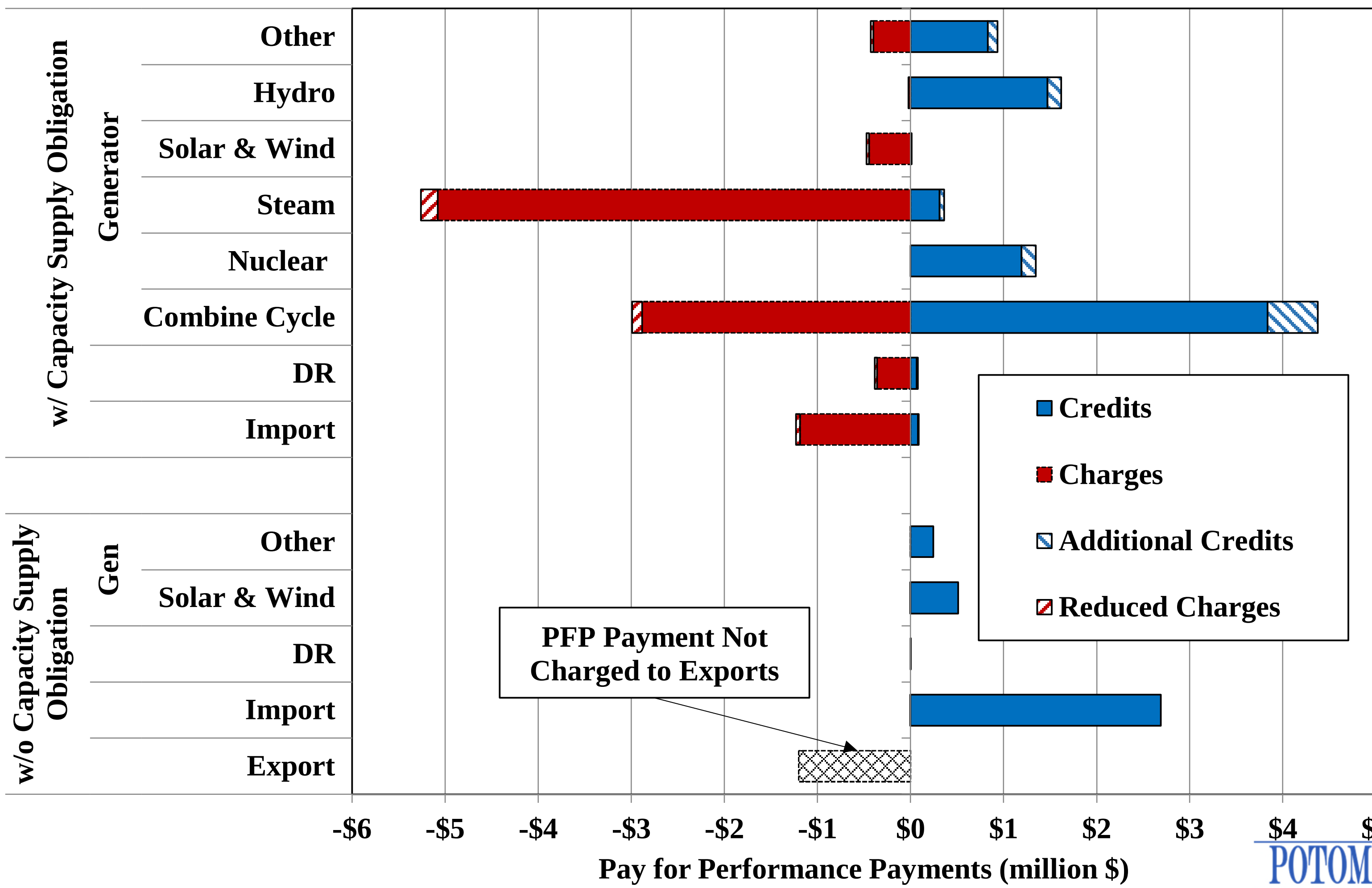
See Section IV.A

External Transactions During PFP Event



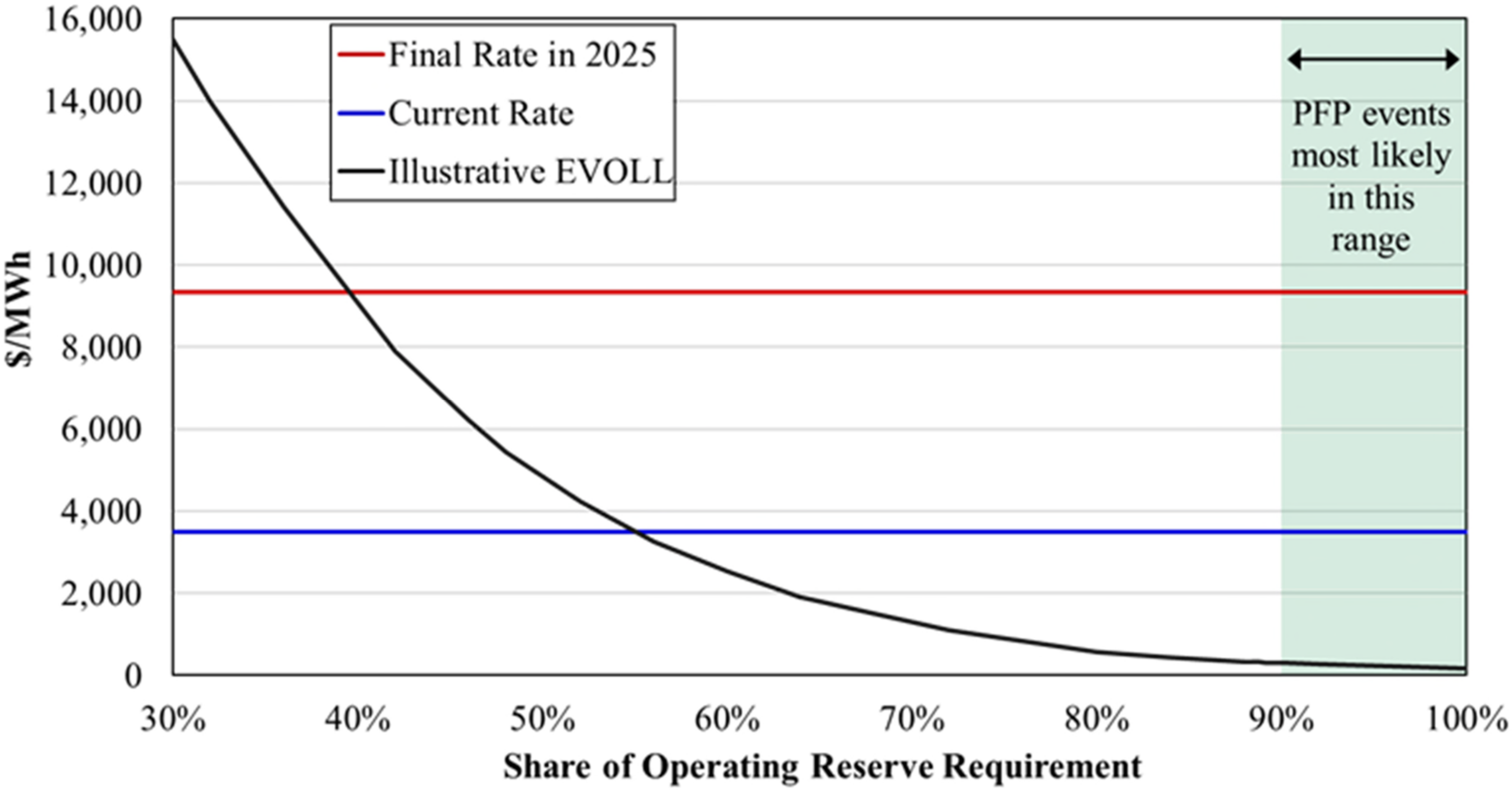
See Section IV.B

PFP Credits and Charges: Actual vs Recommended Treatment of Exports



See Section IV.B

PFP Rate and the Value of Lost Load



See Section IV

PFP Event on July 5

<u>Key Conclusions and Recommendations:</u>

- Applying the PFP rate to imports but not exports is a significant flaw.
  - ✓ This undermines the efficiency of scheduling incentives during reserve deficiencies, raises gaming concerns, and may undermine reliability.
- Fixed, escalating PFP rates and shortage pricing together set prices much higher than efficient levels during most shortages, incenting suppliers to:
  - ✓ Self-commit high-cost units inefficiently, and
  - ✓ Retire longer-lead time units inefficiently.
- To address these concerns, we make two key recommendations:
  - ✓ Revise its PFP rules to charge exporters at the PFP rate during Capacity Scarcity Conditions. (Recommendation **#2022-3**)
  - ✓ Modify the PFP rates to levels that are in line with a reasonable estimate of VOLL and that escalate as the reserve shortages grow deeper. (Recommendation **#2018-7**)

Assessment of Forward Capacity Market

POTOMAC ECONOMICS

See Section V

Winter Reliability in the FCA

- Winter reliability has become a critical concern due to:
  - ✓ Growing winter demand
  - ✓ Increased awareness of winter gas limitations
  - ✓ Retirement of fuel-secure resources
- *Resource Adequacy* and *Energy Adequacy* are the same goal – to be able to produce enough energy to keep the lights on when needed
- The capacity market can signal winter risk driven by energy adequacy and compensate suppliers appropriately
  - ✓ This supports reliability by incentivizing firm fuel procurement, attracting imports, retaining existing resources, and motivating investment when winter risk is high
  - ✓ It is necessary to realistically represent **all** drivers of winter reliability issues in the model used to set ICR and accreditation

See Section V.C

ISO-NE Projects Underway to Address Winter Reliability in Market

- Resource Capacity Accreditation (RCA)
  - ✓ Account for winter fuel limitations to set capacity mkt. parameters
  - ✓ Use generators' fuel arrangements when accrediting resources
- Prompt Seasonal Capacity Market
  - ✓ Reduction of lead time between auction and CCP should align better with firm fuel procurement timeframes
- Probabilistic Energy Adequacy Tool (PEAT) and Winter Energy Risk Threshold (REST) framework
  - ✓ Intended to anticipate and address winter reliability needs driven by fuel security at the planning level
- We evaluate how the above projects can be improved to manage it.
  - ✓ We simulate winter risk in the ISO-NE system using a resource adequacy model (PE-RAM), which is an hourly simulation modeling load and supply issues, including fuel limitations.

POTOMAC ECONOMICS

See Section V.Appendix

See additional assumption details in Appendix to this presentation

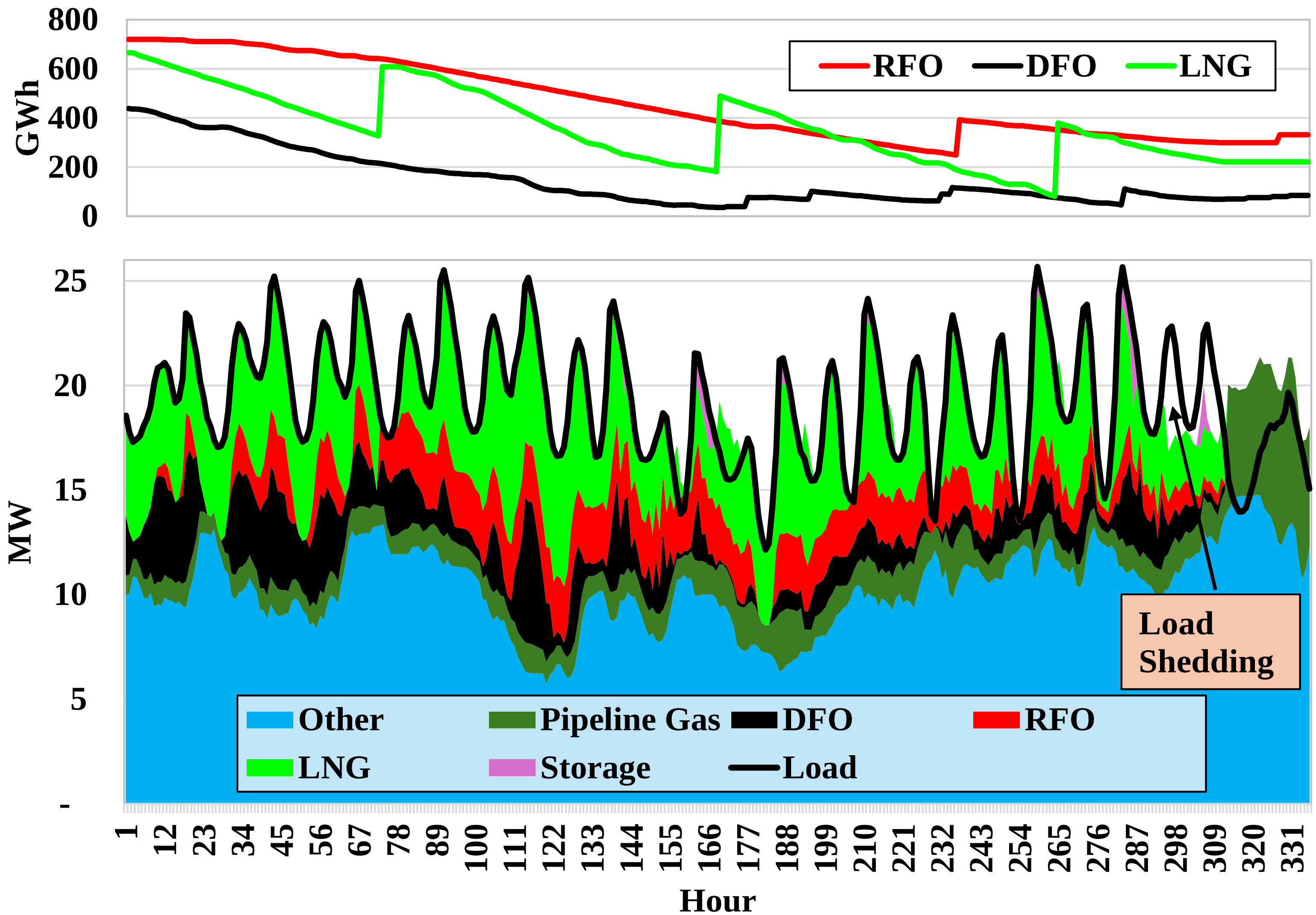
Impact of Market Participant Actions on Winter Reliability

- We developed cases for Winter 2031/32 using inputs from the PEAT study, FCA18 and 2024 CELT report:
  - ✓ **Base Case**: 2024 CELT electrification forecast, FCA18 cleared supply mix, renewables from PEAT study (incl. 4.8 GW offshore wind)
  - ✓ **Delayed OSW**: Only 3.2 GW offshore wind (OSW) included
  - ✓ **Delayed OSW + Low Retirements**: only 800 MW retirement of fuel-secure resources (vs. 1.7 GW in base case)
  - ✓ **Delayed OSW + Energy Storage (ESR)**: 3.5 GW of 2-hour battery (vs. 1.9 GW in base case)
- We calculate expected unserved energy (EUE) for each case based on 80 combinations of weather, imports and forced outages
  - ✓ We use Low/Mid/High assumptions for LNG and Oil inventory
  - ✓ Results are compared to an EUE requirement equivalent to 1-in-10 LOLE.
- The next figure shows how inventoried fuels are used in the model:
  - ✓ The economic dispatch includes conservation of limited inventories.
  - ✓ Individual oil unit replenishment and LNG deliveries are modeled.

See Section V.A

Example of Dispatch and Fuel Usage in PE-RAM

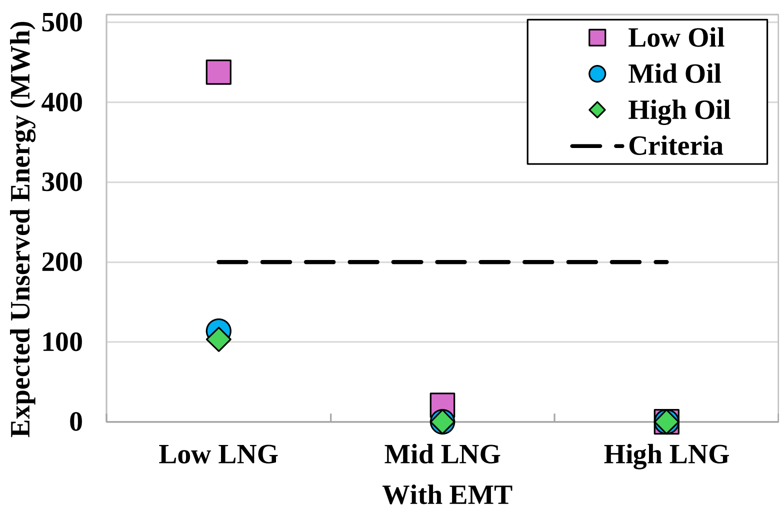
Mid LNG, Low Oil Inventory Scenario

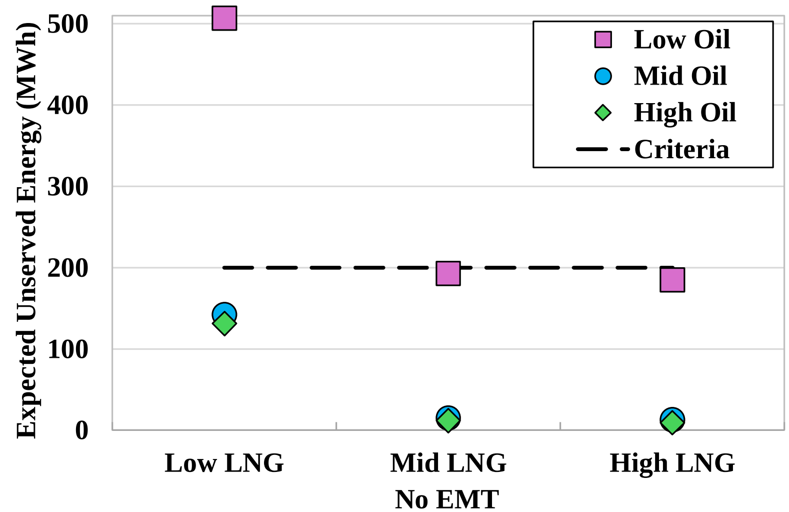


See Section V.A

Winter Reliability Risk, 2031-32

2024 CELT FCA18 Case



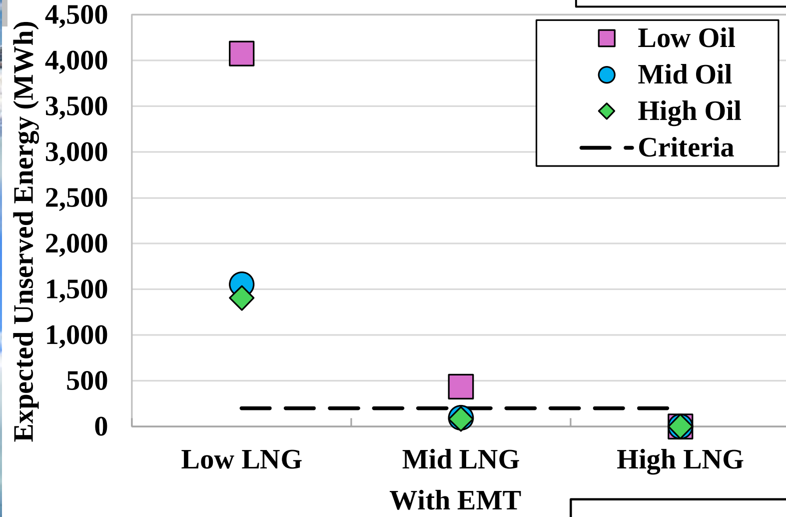


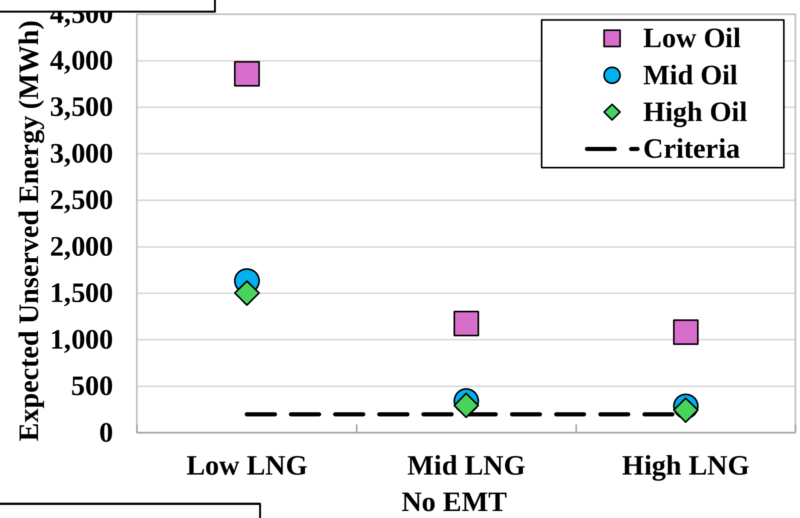
- Levels of LNG and oil inventories have a tremendous impact on the winter reliability risk in New England
  - ✓ Reliability criteria is substantially violated in the scenario with Low LNG and Low Oil, but generally satisfied in all other scenarios
  - ✓ The EUE falls to close to zero in cases with higher levels of LNG *and* oil
- Retirement of EMT causes higher winter risk in cases with low oil inventories
  - ✓ EMT allows more gas generation to operate simultaneously

See Section V.A

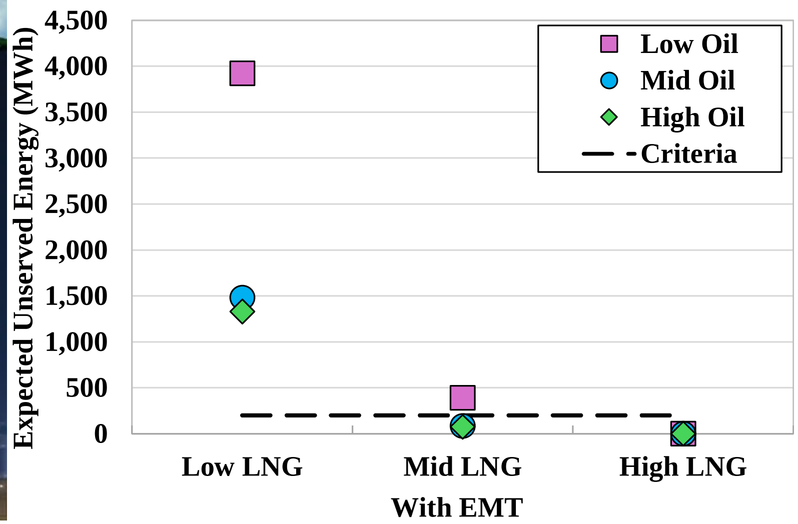
Alternative Winter Reliability Cases

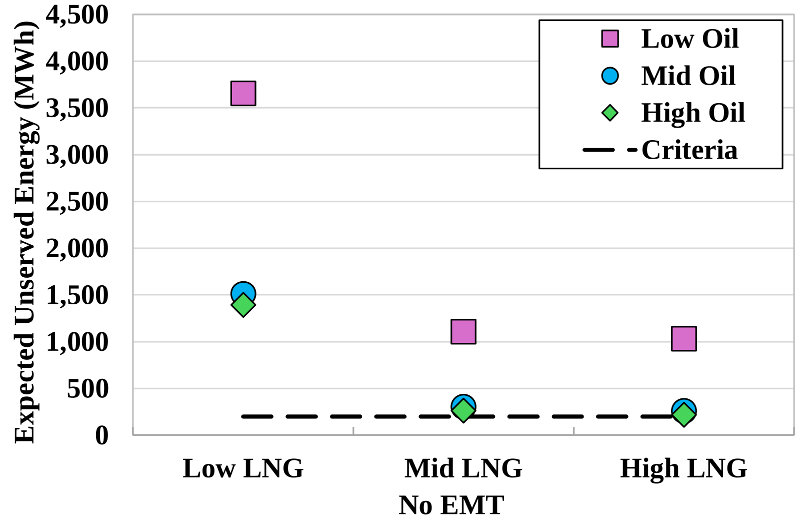
Delayed OSW Case





Delayed OSW + ESR

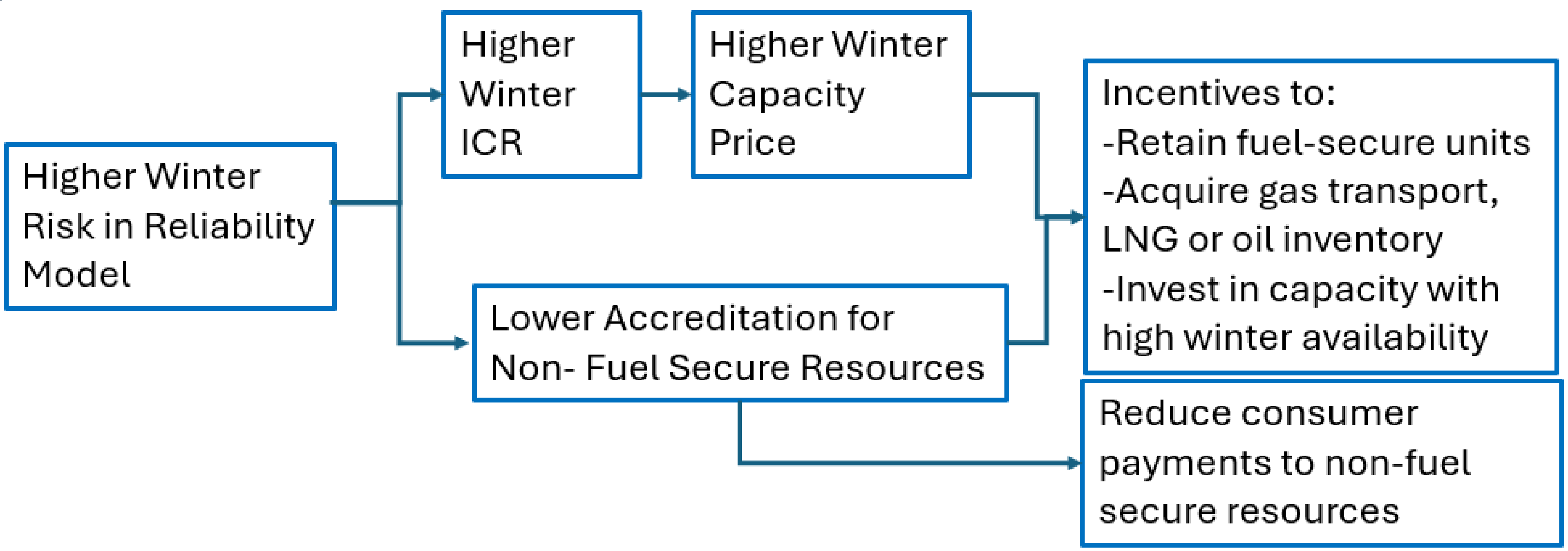




See Section V.A

Winter Reliability Risk, 2031-32
Conclusions

- Load shedding risk is driven by depletion of stored fuels (e.g. energy adequacy over cold period) – inventory levels are critical.
- Premature retirements of fuel-secure units will exacerbate winter risk
- EMT is not essential if other fuel procurement and investment occurs.
- The *type* of new entry is important – battery storage does little to mitigate winter risk while offshore wind has large impacts.
- Hence, efficient winter reliability modeling is very important.



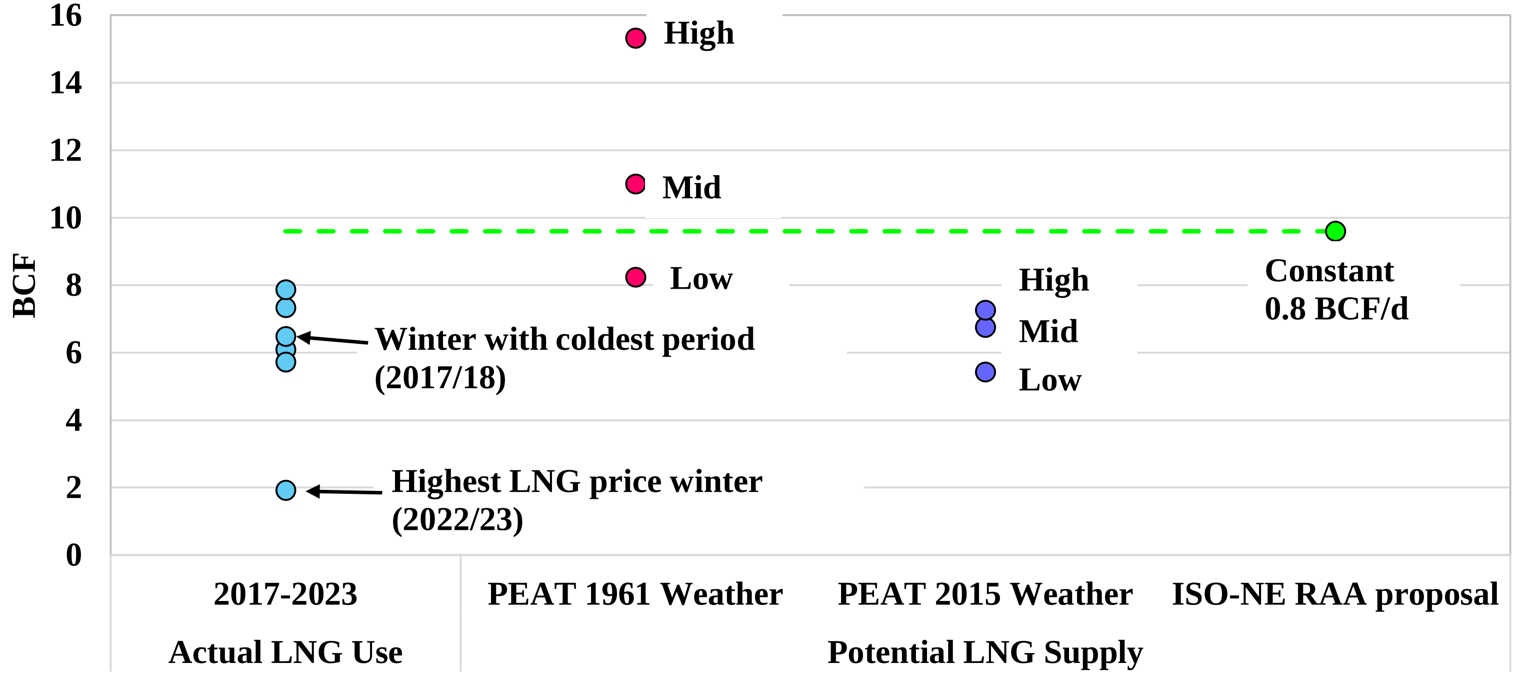
See Section V.B.1

LNG Available to Generators in Extreme Conditions

- The region relies on LNG from St John and Everett terminals in very cold weather when there is insufficient pipeline transport capacity
- Most generators don’t contract for LNG directly, but some amount that is contracted by other entities is typically made available in winter
- The amount of “secondary LNG” assumed to be available in risk models is a major determinant of winter reliability risk
  - ✓ Assuming a large amount of LNG will be made available to generators will result in low modeled winter risk and eliminate incentives for generators to contract for LNG or hold larger oil inventories
  - ✓ Hence, reliability models should reflect the underlying variability and uncertainty of secondary LNG available in extreme conditions
- The following slides compare LNG assumptions in ISO-NE’s recent RCA and PEAT processes to historic data

See Section V.B.1

Comparison of 12-Day LNG in Reliability Models and Historic Data



- Historic "Actual LNG use" shows injections onto interstate pipelines from St John, Everett and NE Gateway terminals (excludes deliveries to Mystic 8 & 9)
- "Potential LNG Supply" reflects assumption of maximum quantity available to generators in reliability studies
- Historic quantities were generally lower than model assumptions

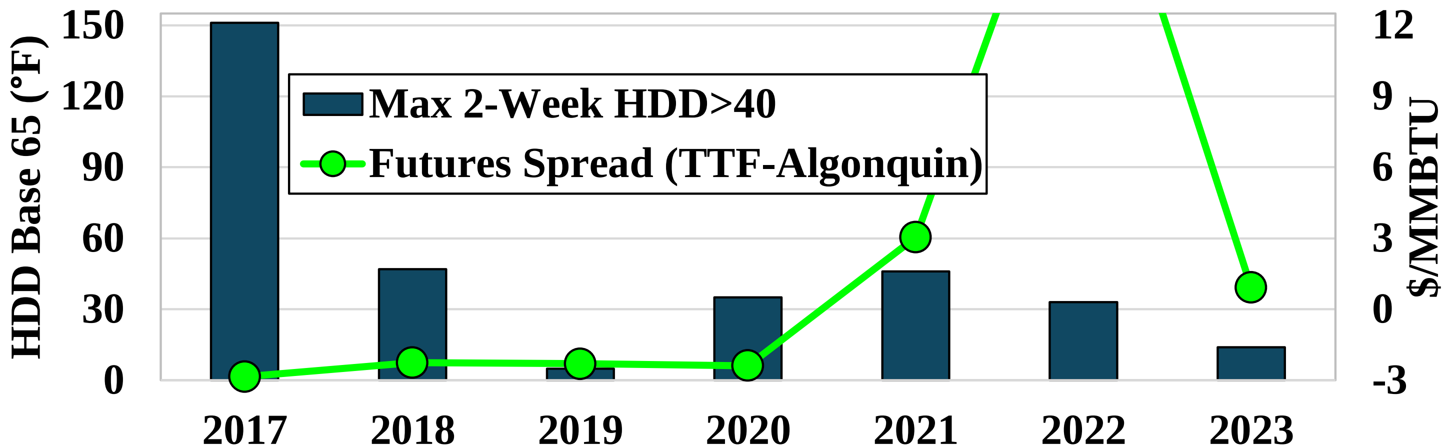
See Section V.B.1

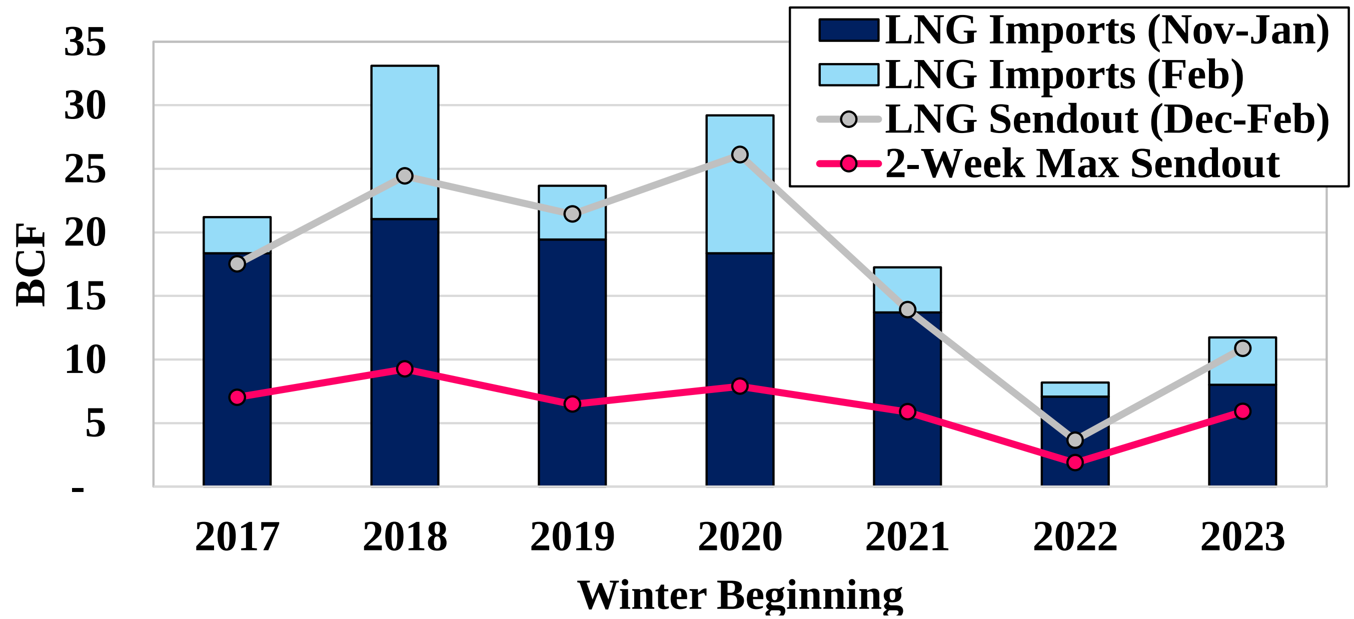
Historic LNG Deliveries, Sendout, Prices and Cold Weather

- The next figure shows historic LNG imports and sendout to pipelines in recent winters, along with weather and pricing conditions in each winter.
  - ✓ *Top panel*: severity of each winter (measured by maximum total HDD above 40 in any two week period) and LNG pricing (spread between Dutch TTF and Algonquin futures for Dec-Feb in the prior summer/fall)
  - ✓ *Bottom Panel*: total LNG imports to St John, EMT and Canaport terminals (less usage by Mystic 8 and 9) in each winter, total and max 2-week LNG sendout from terminals to pipelines
- Takeaways:
  - ✓ LNG imports vary significantly year-to-year based on global LNG prices
  - ✓ More extreme cold events (e.g. 2017/18 winter) do not lead to full utilization of LNG sendout capacity to pipelines
    - – LNG shipment quantities are typically arranged months before winter
  - ✓ Optimistic LNG assumptions will lower modeled winter reliability risk, greatly reducing incentives for generators to contract for firm fuel supplies
    - – We recommend conservative assumptions given historic variability

See Section V.B.1

Historic LNG Deliveries, Sendout, Prices and Cold Weather





See Section V.B.2

Dispatch Logic for Resources with Limited Inventories

- In winter risk models, the sequencing of inventory-limited units in the dispatch order can have a large impact on the results
- The risk model should use assumptions that reflect opportunity costs which provide incentives for generators to conserve fuel
  - ✓ While an unrealistically optimal use of fuel over a long period will understate reliability risk, an unrealistically short-sighted approach will overstate risk
- ISO-NE's PEAT model largely dispatches in ascending order of marginal cost, ignoring opportunity cost. A more realistic dispatch logic would account for:
  - ✓ Conservation of LNG by owners/terminals during prolonged cold events
  - ✓ Incentives for oil units to offer using opportunity costs when their fuel is low to avoid exposure to PFP penalties
- The figure on the following slide compares results from PE-RAM for a single scenario using alternative dispatch logic:
  - ✓ Short-Sighted Approach: Replicates sequencing in the PEAT study.
  - ✓ Conserve Inventories Approach: considers opportunity costs for oil and LNG resources.

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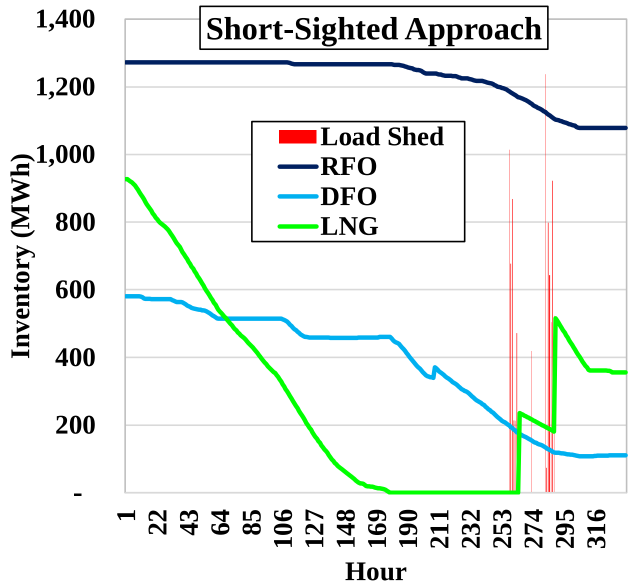
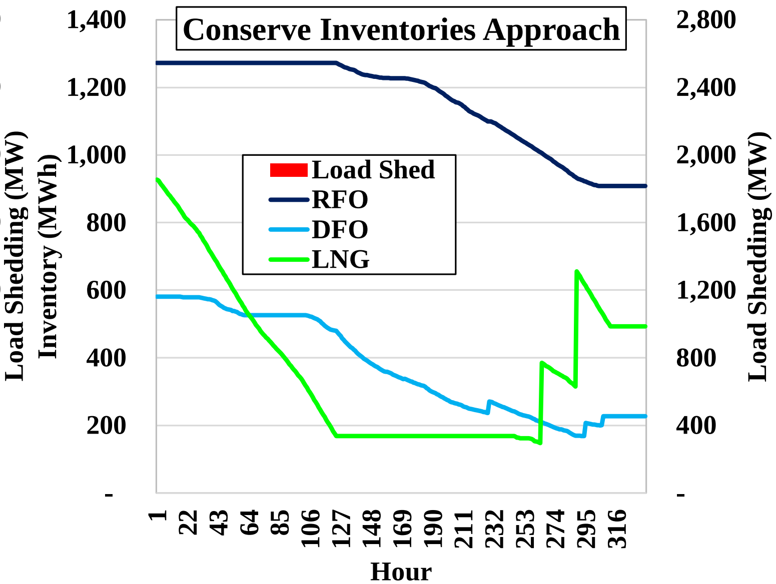
See Section V.B.2

Inventories and Load Shedding Under Alternative Dispatch Logic





- In Short-Sighted approach, LNG is always used before oil and is depleted prematurely, resulting in load shedding toward end of period
- In Conserve Inventories approach, resources at low inventory threshold are used after higher-inventory resources. This eliminates all load shedding.
- Realistic modeling of opportunity costs will more accurately quantify winter risk and value of alternative solutions.
  - ✓ PEAT study found that EMT worsens reliability due to quicker LNG depletion.

See Section V.B.3

Modeling Inventory Depletion When Determining Marginal Accreditation Values

- Marginal capacity credit values should reflect each resource's relative contribution towards the system's reliability needs
- Some resources have different value for:
  - ✓ Being available in the net peak load hour
  - ✓ Supporting energy adequacy over a prolonged period
  - ✓ A resource's capacity value depends on which of these situations drives the most critical reliability needs
- ISO-NE's RCA proposal calculates accreditation values using a model that does not explicitly represent depletion of inventories
  - ✓ Hence, calculated MRI values will largely reflect net peak availability
- The following figure shows winter MRI values calculated in our PE-RAM model for two cases with the same EUE but different modeling approaches
  - ✓ "Inventories Modeled" case models depletion of inventories directly
  - ✓ "Inventories Not Modeled" case adjusts load up to achieve same EUE

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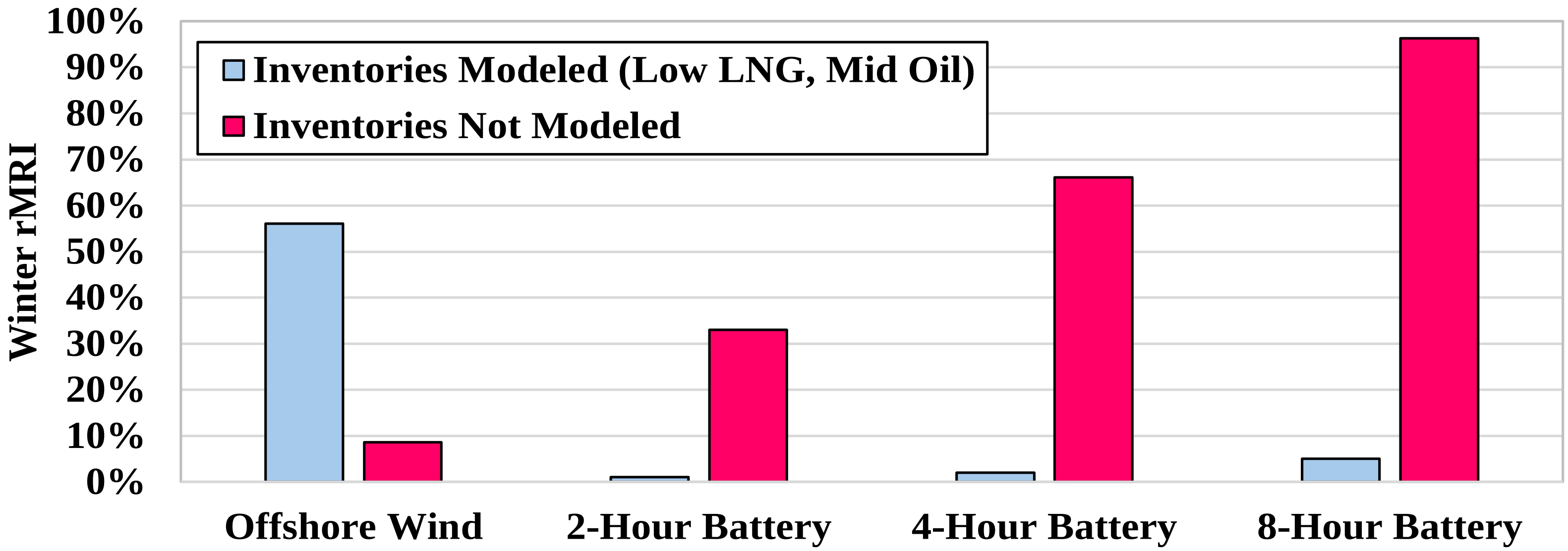
See Section V.B.3

Marginal Capacity Value Under Alternative Modeling Approaches



- Offshore Wind MRI is much higher in the Inventories Modeled case
  - ✓ Offshore wind has low net peak availability due to high penetration, but makes a large contribution per MW to energy adequacy (EA)
- Battery storage MRI is much lower in the Inventories Modeled case
  - ✓ Batteries are available at net peak but don't improve energy adequacy much
- Not modeling inventory depletion in accreditation model will result in inefficient incentives for these resource types
- Market incentives likely result in balance of net peak and EA risk in long term

See Section V.C

Conclusions on Winter Reliability in the Forward Capacity Market

- Participant actions will be key for addressing winter reliability risk so providing efficient incentives through the capacity market is essential.
- ISO-NE is changing its planning models and accreditation methods to reflect winter risk. We support the changes but improvements are needed.
- We recommend ISO-NE develop marginal accreditation for all resources and make needed RA modeling enhancements (#2020-2), which includes:
  - ✓ Developing a truly marginal accreditation method for gas-only units
  - ✓ Using reasonable assumptions for secondary available LNG
  - ✓ Including opportunity costs in the dispatch logic
  - ✓ Modeling inventory limitations in the accreditation models
- Other key capacity market recommendations:
  - ✓ Implement *a prompt capacity market* reflecting seasonal needs (#2021-1)
  - ✓ Replace descending clock auction format with sealed bid. (#2015-7)
  - ✓ Treat Energy Efficiency as a load reduction in the capacity market rather than a supply resource (#2020-3)

Full List of Recommendations

List of Recommendations

Recommendation Number and Description		High Benefit	Current/ Planned Efforts	Report Reference
Reliability Commitments and NCPC Allocation				
2020-1	Consider allowing firm energy imports from neighboring areas to satisfy forecasted local second contingency requirements.			III.B
2010-4	Modify allocation of "Economic" NCPC charges to make it consistent with a "cost causation" principle.			III of 2018 Report
2014-5	Utilize the lowest-cost configuration for multi-unit generators when committed for local reliability.			III.B
Energy and Operating Reserve Markets				
2023-1	Evaluate benefits and costs of a look-ahead dispatch model to optimally manage fluctuations in net load and the use of storage resources.	✓		Exec Summary
2022-1	Allow fast-start pricing model to utilize the full capability of online units for energy or reserves.			III.C
2019-3	Dynamically define a full set of local operating reserve requirements in the day-ahead and real-time markets.			III.B

Notes: High Benefit: Will likely produce considerable efficiency benefits.

List of Recommendations

Recommendation Number and Description		High Benefit[7]	Current/ Planned Efforts	Report Reference
Energy Market Mitigation				
2022-2a	Implement hourly conduct and impact tests in the automated energy mitigation procedure.			II.D
Capacity Market				
2022-3	Charge exporters the PFP rate during reserve shortages.			IV.B
2021-1	Replace the forward capacity market with a prompt seasonal capacity market.	✓	FCA19 Delay / Assessment of Prompt Seasonal	V.H
2020-2	Improve capacity accreditation by a) accrediting all resources consistent with their marginal reliability value, and b) modify the planning model to accurately estimate marginal reliability values.	✓	Resource Capacity Accreditation	V.G
2020-3	Account for energy efficiency as a reduction in load instead of as a supply resource in the FCM.			V of 2020 Report
2018-7	Modify the PPR to rise with the reserve shortage level, and do not implement the planned increase in the PPR.	✓		IV.B
2015-7	Replace the descending clock auction with a sealed-bid auction to improve competition in the FCA.			IV of 2017 Report

Appendix – Assumptions for Winter EUE Analysis using PE-RAM

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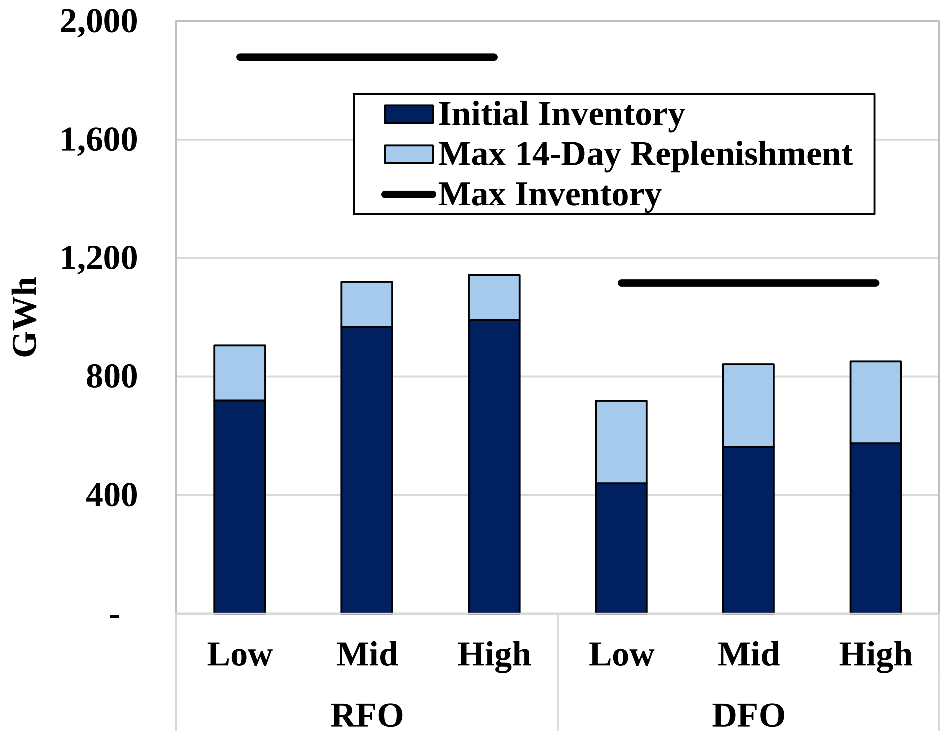
See Section V.Appendix

Summary of Cases and Assumptions in PE-RAM Analysis

2024 CELT Forecast FCA18 Case (2031/32 Winter)	
Load Shapes	PEAT Study 1961 and 2015
LNG and Oil Inputs	PEAT Study assumptions
Pipeline Gas Profile	PEAT Study assumptions
Electrification	2024 CELT
21-Day Peak / Average Load	25.7 GW / 18.1 GW (1961), 24.2 GW / 17.0 GW (2015)
Fuel Secure Retirements	Mystic 8 & 9 + 1.7 GW
Offshore Wind	4.8 GW
Utility Scale Solar	1.3 GW
Behind the Meter Solar	12 GW
Battery Storage	1.9 GW (2 hour)
NECEC Line	In Service
Sensitivity Cases	
Delayed OSW Case	3.2 GW OSW
Delayed OSW + Low Retirements	3.2 GW OSW, 0.8 GW Retirements (plus Mystic 8 & 9)
Delayed OSW + ESR	3.2 GW OSW, 3.5 GW Battery

See Section V.Appendix

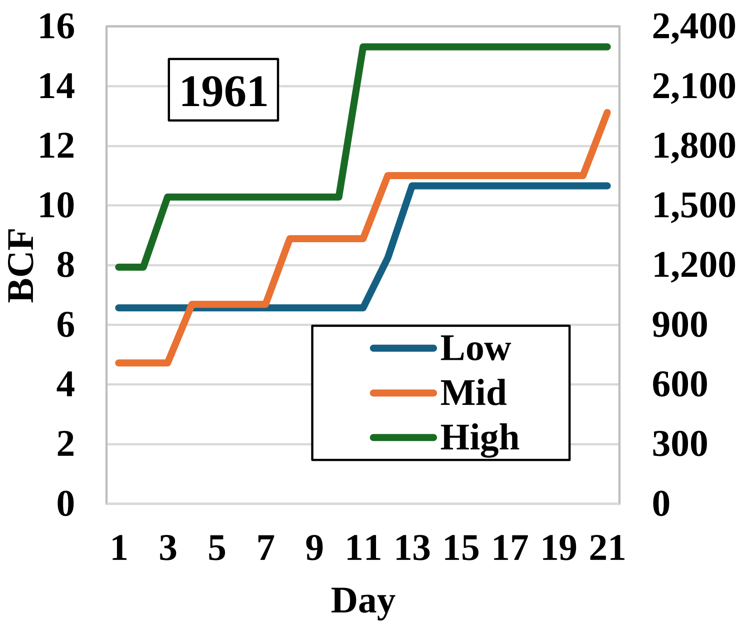
Summary of Oil Inventory Assumptions Used in PE-RAM Analysis

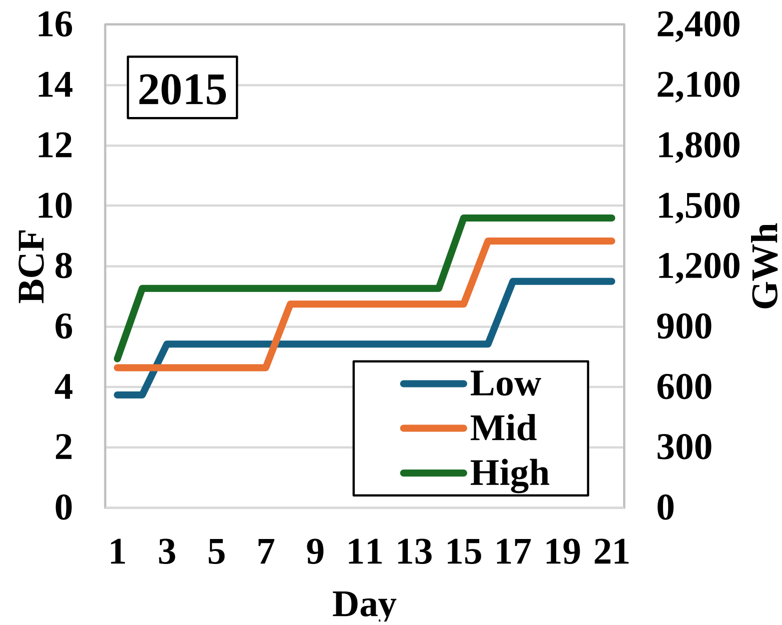


- Initial inventories and replenishment rates based on PEAT study assumptions
- ‘Max 14-day Replenishment’ includes deliveries to each generator within a single 14-day period when attempting to run continuously – actual replenishment in a given case varies based on generator utilization and outages

See Section V.Appendix

Summary of LNG Delivery Assumptions Used in PE-RAM Analysis





- Inventories allocated between St John and EMT terminals. In No EMT case, LNG is held constant and all deliveries are assumed to arrive at St John
- Right axis shows approximate equivalent GWh using 7,000 heat rate

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American Energy Transformation: Tracking Market & Policy Trends and Looking Forward

Lisa Jacobson
President
Business Council for Sustainable Energy (BCSE)

Lisa Jacobson is the President of the Business Council for Sustainable Energy, a 65-member trade association representing the energy efficiency, natural gas, and renewable energy industries. Lisa has over 20 years of experience advising federal and state policymakers on energy, tax, air quality, and climate change issues. She is a member of the United States Trade Representative's Trade and Environment Policy Advisory Committee, the Energy Efficiency Global Alliance Steering Committee, and the Gas Technology Institute's Public Interest Advisory Committee. Lisa has testified before Congress and has represented energy industries before the United Nations Framework Convention on Climate Change. Prior to her position with BCSE, Lisa was a legislative aide in the U.S. Congress. She has a master's degree in International Relations from the London School of Economics and Political Science and a bachelor's degree in Political Science from the University of Vermont.

Tara Narayanan
Lead Analyst, North America Regional Trends
Bloomberg New Energy Finance (BNEF)

Tara Narayanan Tara leads cross-sectoral analysis for North America, with a focus on long term decarbonization trends. Tara's research at BNEF has covered economic, policy and company trends in US solar and renewables, as well as power markets.

Prior to BNEF, Tara was a manufacturing engineer at an international carmaker. Her research experience includes analyzing consumer preferences for electrification in developing countries and life cycle impacts of agricultural systems.

Sustainable Energy in America 2024 Factbook

Tracking Market & Policy Trends

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The Business Council for Sustainable Energy®

Sustainable Energy in America 2024 Factbook

The Business Council for Sustainable Energy®

The Business Council for Sustainable Energy (BCSE) is a coalition of companies and trade associations from the energy efficiency, natural gas and renewable energy sectors.

BCSE advocates
for policies that promote clean, efficient, and sustainable energy products, technologies and services.

BCSE supports
business development, networking and knowledge exchange among its members and networks.

BCSE provides
a credible, broad-based business coalition on clean energy market trends and policy impacts.

Sustainable Energy in America 2024 Factbook

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NHA National Hydropower Association
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SEIA Solar Energy Industries Association®
TRANE TECHNOLOGIES
Washington Gas


Clean Energy Transition Thrives in 2023, Boosted by Federal Policies

Records keep rising

Sustainable Energy in America Factbook

Lisa Jacobson

President

Business Council for Sustainable Energy

June 26, 2024

BloombergNEF

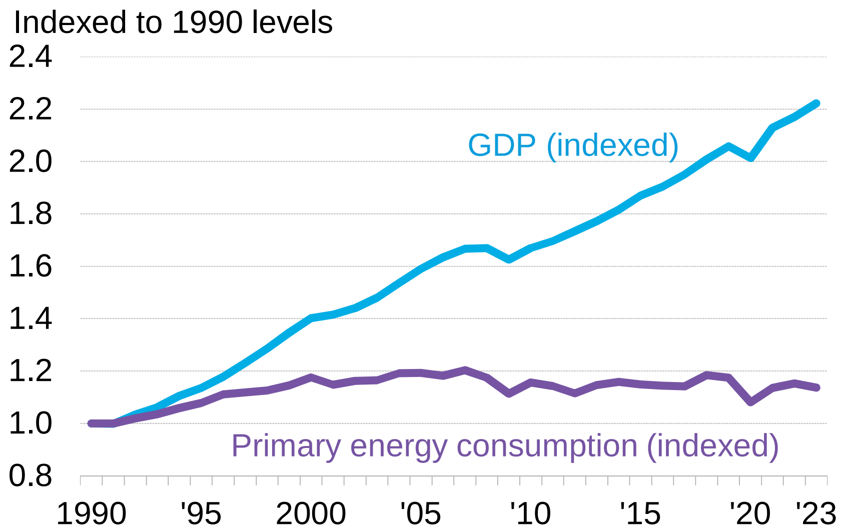
Disruptions in the rearview mirror

Prices ease

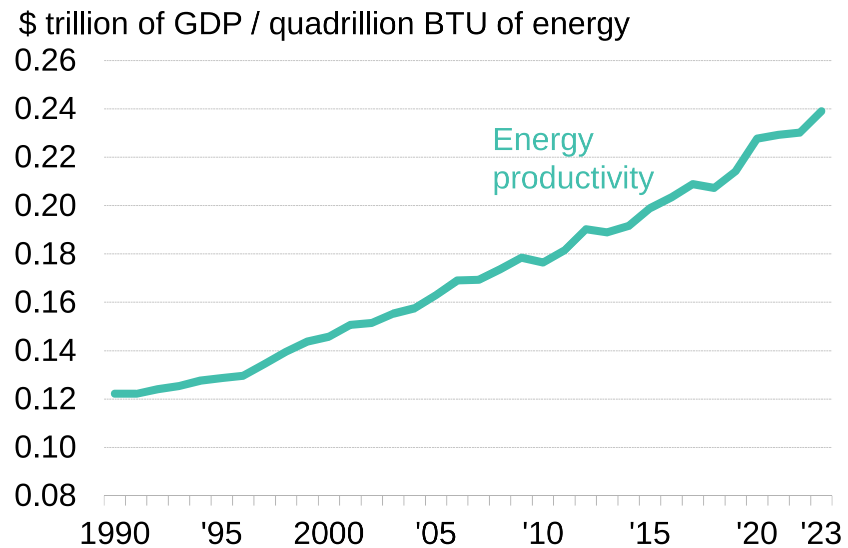
BloombergNEF

Energy Productivity

US GDP (real) and primary energy consumption



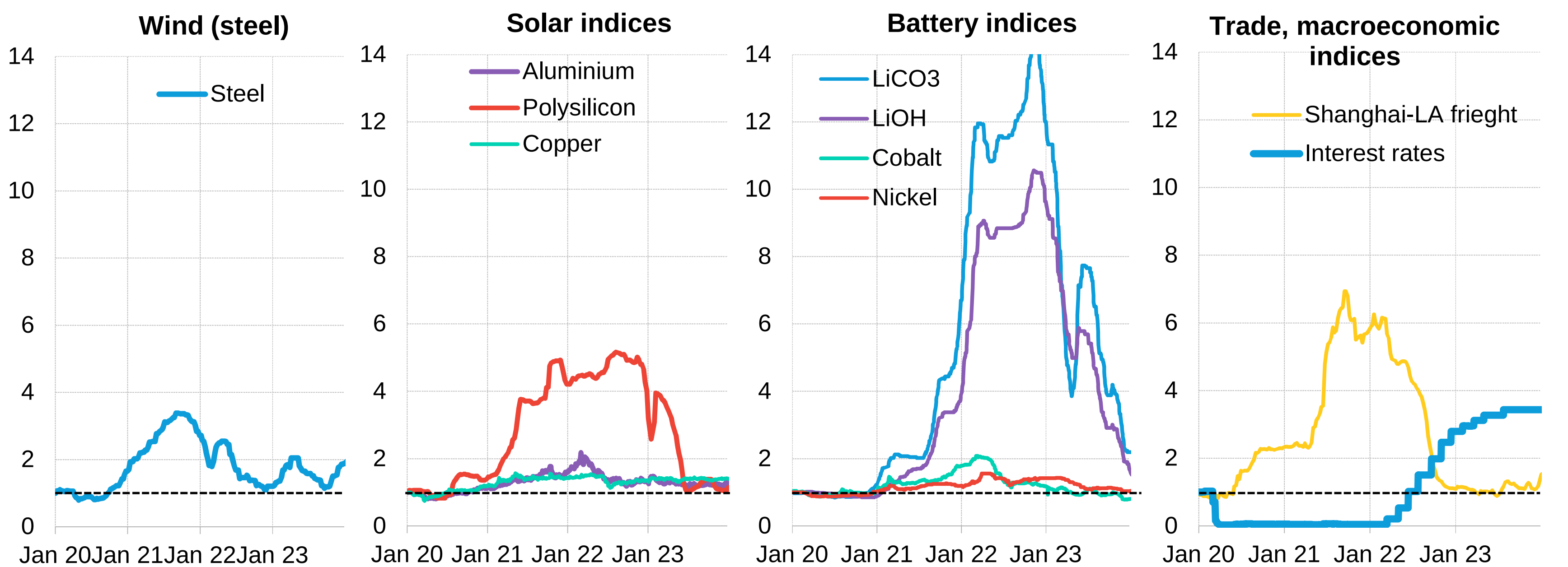
US energy productivity



Source: Bureau of Economic Analysis, EIA, BloombergNEF. Note: Values for 2023 are projected, accounting for seasonality, based on latest monthly values from EIA (data available through September 2023). The 2023 GDP estimate is a projection from economists compiled at ECFC <GO> on the Bloomberg Terminal.

BloombergNEF

Cost inputs for wind, solar, batteries and other equipment



Source: BloombergNEF, Bloomberg Terminal. Note: Data rebased to 1 on earliest available date in January 2020. Steel reflects North America costs, aluminum and copper are China prices. LiCO3 is lithium carbonate, LiOH is lithium hydroxide.

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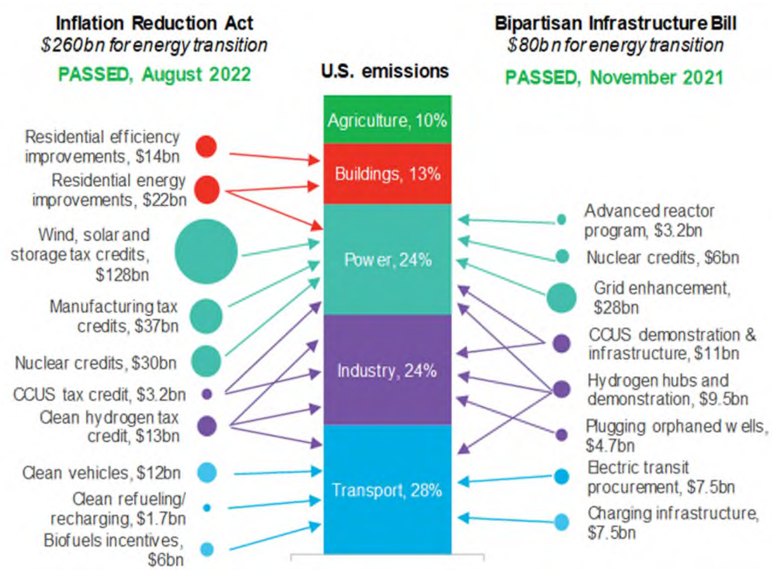
A post-IRA market

Excitement and activity

BloombergNEF

Policy: Inflation Reduction Act key details

Estimated 2022-2031 energy transition spend in Inflation Reduction Act, Bipartisan Infrastructure Law



Inflation Reduction Act key dates

2024

- **January 1:** Clean vehicle Foreign Entity of Concern battery exclusion, clean vehicle tax transfer provisions, and 45U clean nuclear tax credits take effect. Clean vehicle China/Russia battery component exclusion, clean vehicle tax transfer provisions, and 45U clean nuclear tax credits take effect.
- **August 16:** Lifecycle emissions methodology for alternative fuels to be released. Unspent state energy office home rebate funds to be distributed to states.
- **September 30:** EPA greenhouse gas reduction fund spend deadline. Defense Production Act spend deadline.
- **November 5:** US general election.
- **December 31:** Energy storage and microgrid controller construction initiation deadline. 45V hydrogen tax credit guidance to be finalized.
- **Unspecified:** 45Q tax credit's 75% capture requirement (against baseline CO_2 emissions) for electricity generation facilities goes into effect.

2025

- **January 1:** Clean fuel production credit and clean electricity investment and production credits to take effect. Ban on car batteries using critical minerals from sanctioned countries to take effect.
- **January 20:** Presidential inauguration.

2026

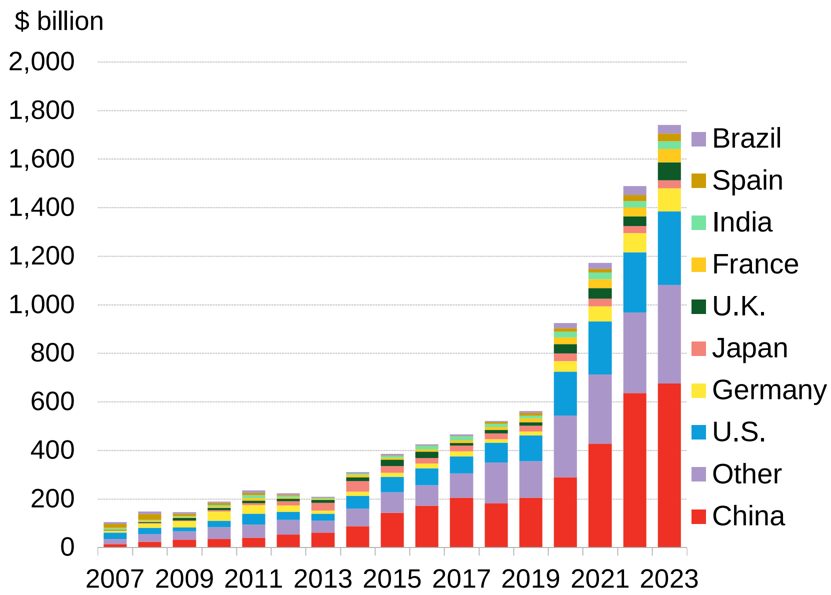
- **January 1:** 2017 Tax Cuts and Jobs Act expires; substantial negotiations on US business and energy taxes likely to take place beforehand.

*Note: Gray text indicates guidance was first expected in 2023.

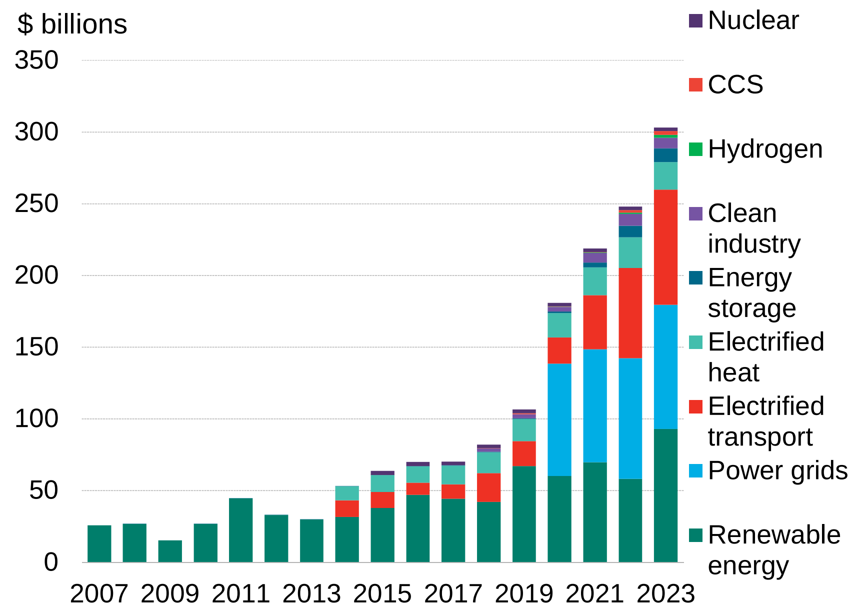
Source: EIA, EPA, Joint Committee on Taxation, Inflation Reduction Act, BloombergNEF. Note: Left-hand chart only captures tax credits and incentives, not grant programs or loans. CCUS is carbon capture, utilization and storage.

Energy transition investment

Energy transition investment, by market



US energy transition investment, by sector

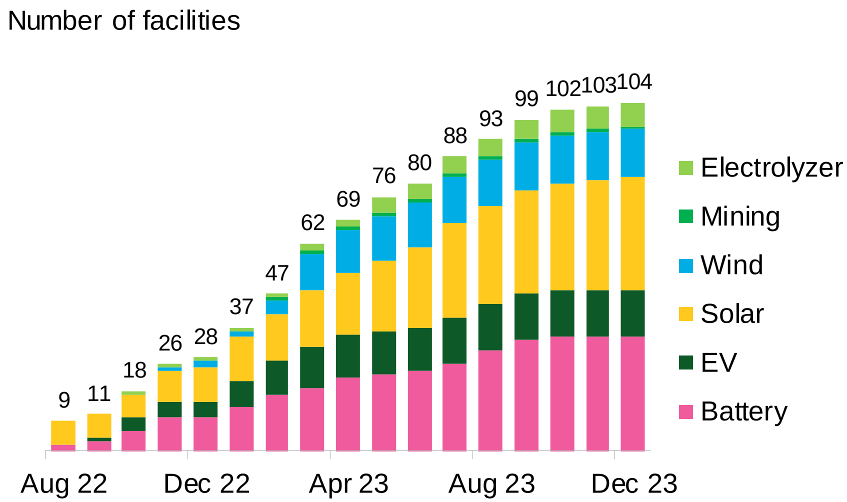


Source: BloombergNEF, Energy Transition Investment Trends database, World Bank. Note: Start years differ by sector, but all sectors are present from 2020 onwards. Most notably, nuclear figures start in 2015 and power grids in 2020. CCS refers to carbon capture and storage.

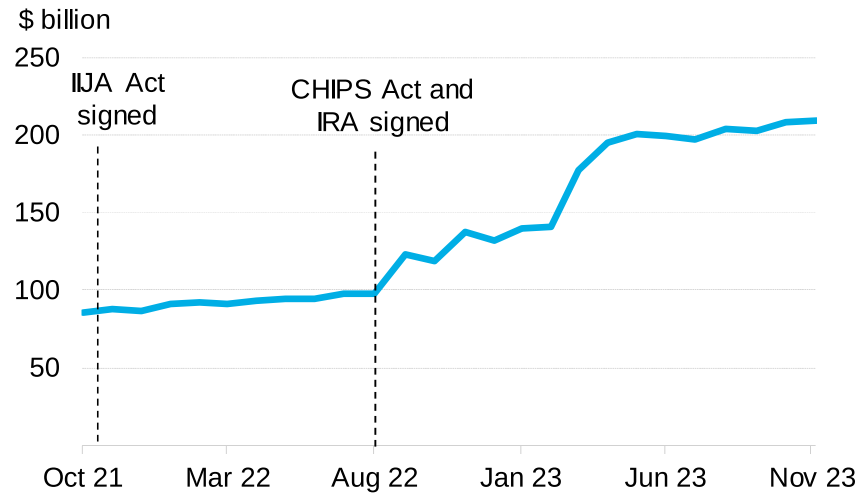
BloombergNEF

Clean-tech manufacturing investments

Clean-tech manufacturing investments announcement post-IRA



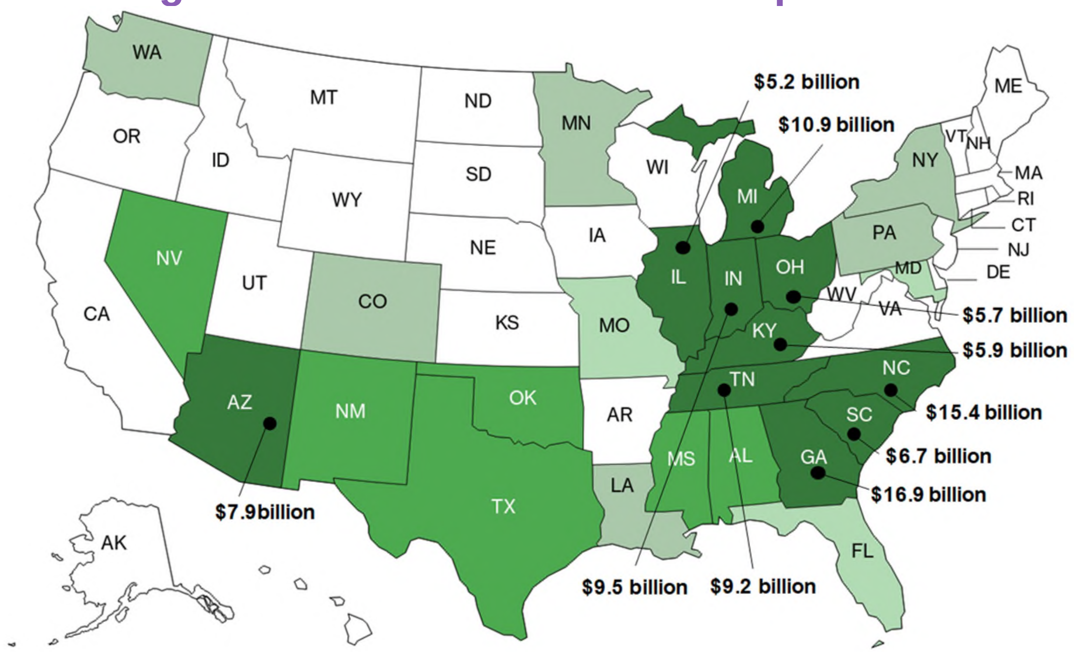
Total manufacturing construction spending in the US



Source: BloombergNEF. US Census Bureau. Note: IIJA is the Infrastructure Investment and Jobs Act; CHIPS stands for Creating Helpful Incentives to Produce Semiconductors; IRA is the Inflation Reduction Act.

Manufacturing projects announced since the passage of the IRA

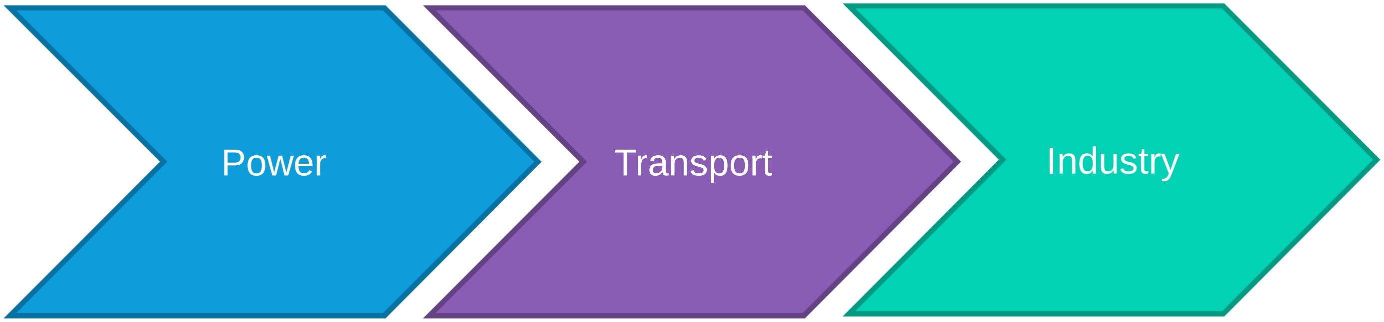
Clean-tech manufacturing investment announcements post-IRA



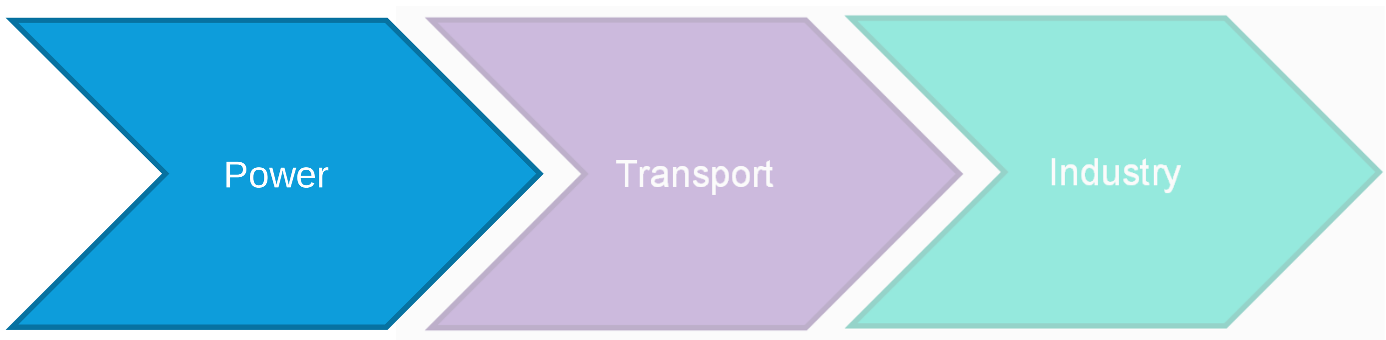
Source: BloombergNEF. Note: Data as of the end of December 2023. Only the top 10 investment figures are labeled.

BloombergNEF

A sector level view

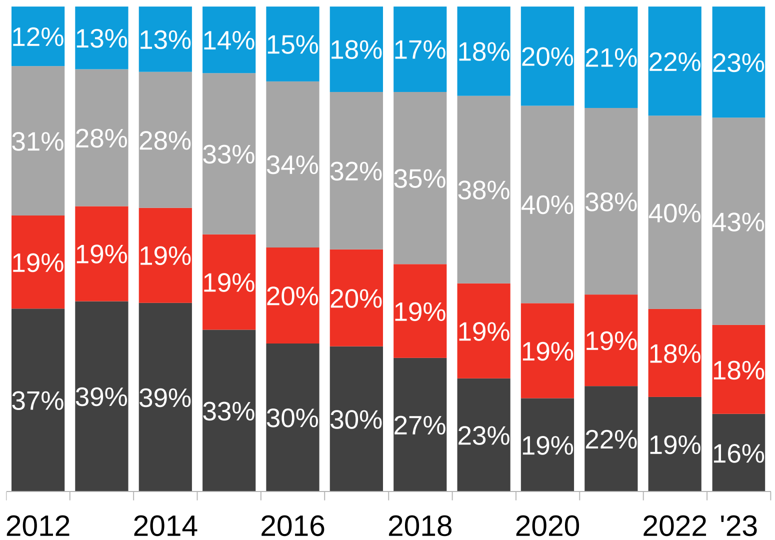


A sector level view

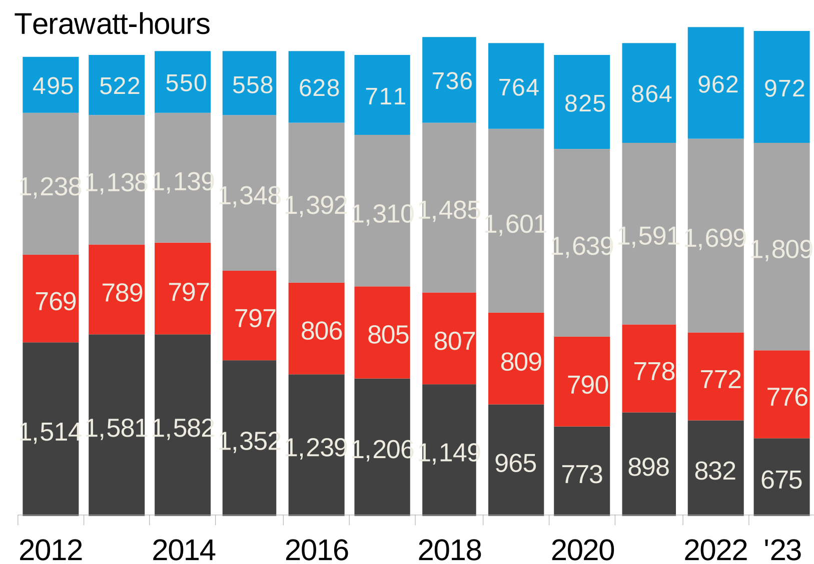


Electricity generation mix

Share of US electricity generation, by fuel type



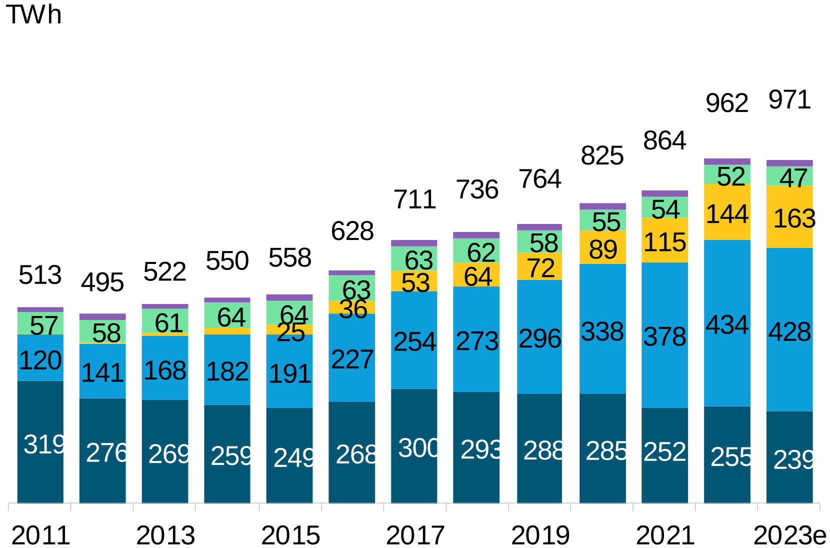
US electricity generation, by fuel type



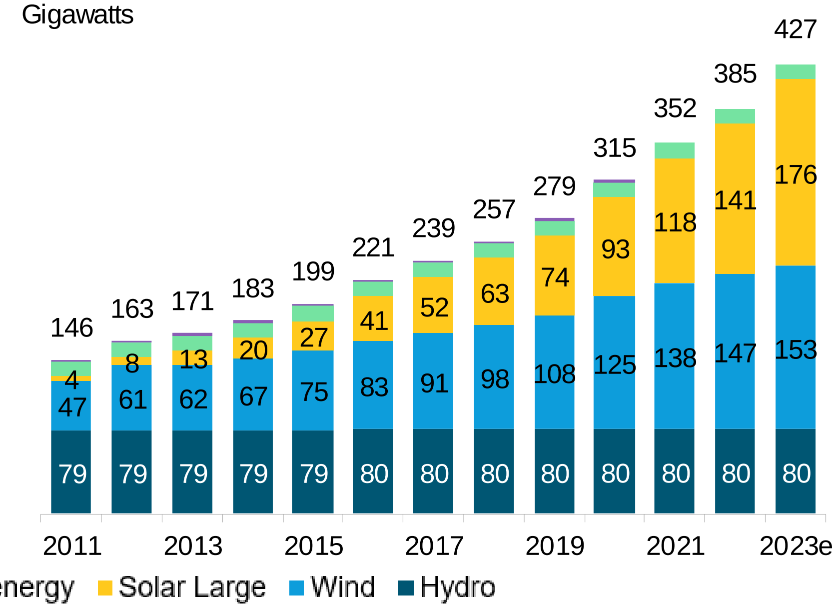
Source: EIA, BloombergNEF. Note: Values for 2023 are projected, accounting for seasonality, based on latest monthly values from EIA (data available through October 2023).

Cumulative renewable energy

US renewable generation, by technology



US cumulative renewable power capacity



Source: BloombergNEF, EIA. Note: All values are shown in alternating current (AC) except solar, which is in direct current (DC) capacity using a 1.34 conversion factor. Totals may not sum due to rounding. Values for 2023 are projected, accounting for seasonality, based on latest monthly values from EIA (data available through October 2023).

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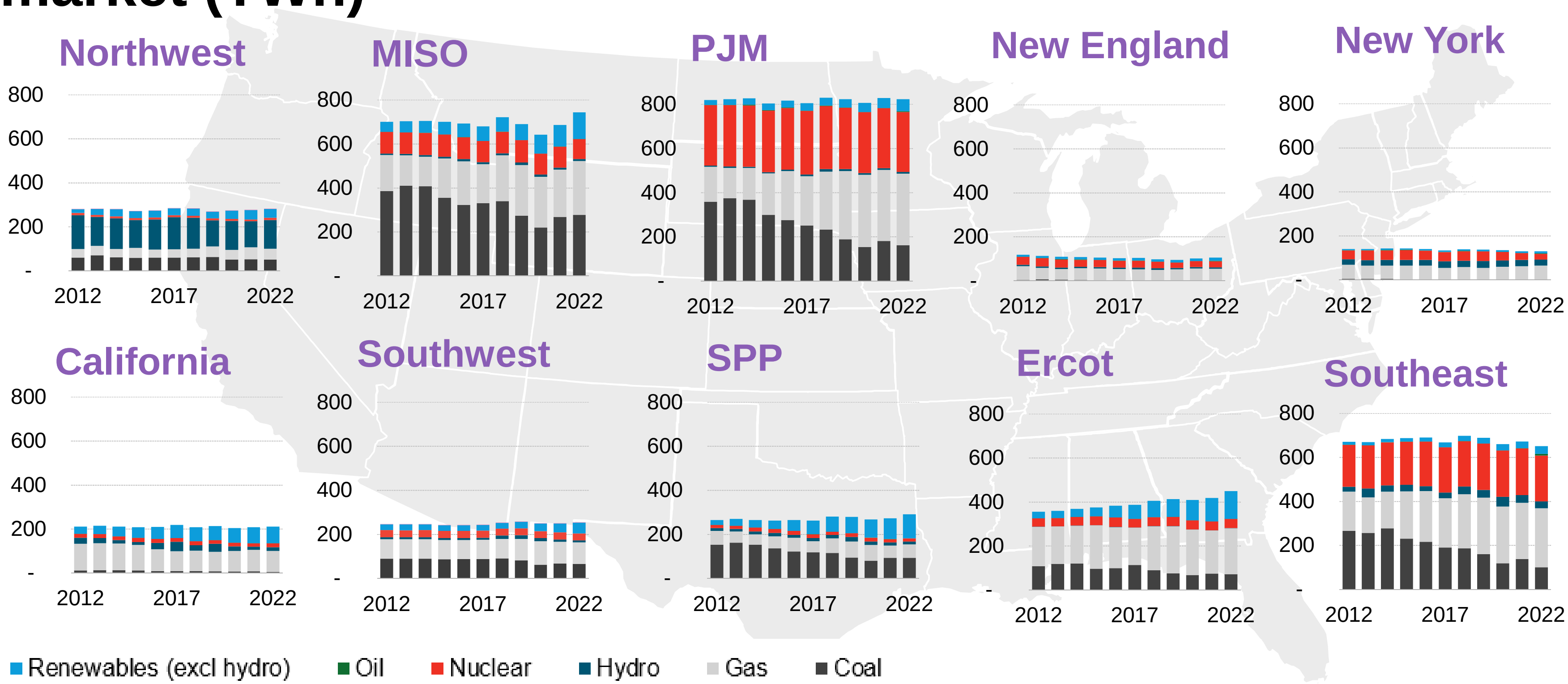
Electricity generation mix by power market (TWh)



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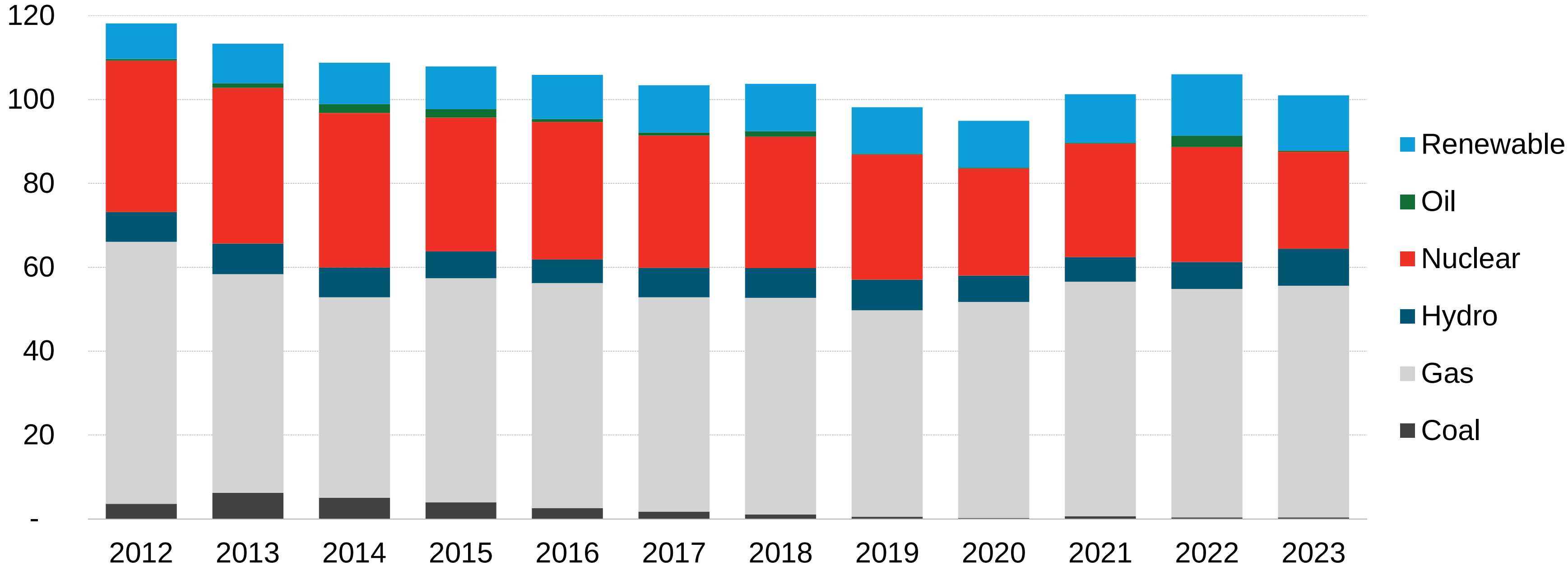
New England slides

New England’s six states rely largely on gas, followed by nuclear

Generation by fuel, TWh



Source: EIA, BloombergNEF. 2023 data is an estimate

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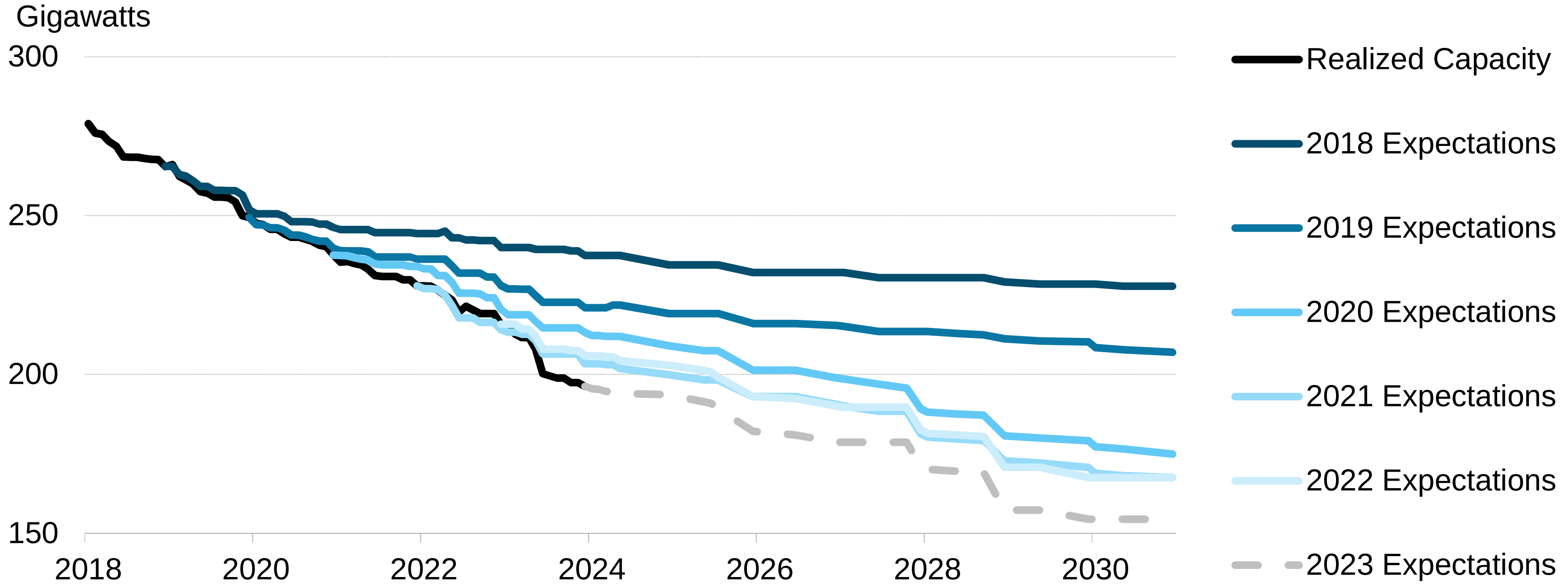
Trends in coal retirement expectations

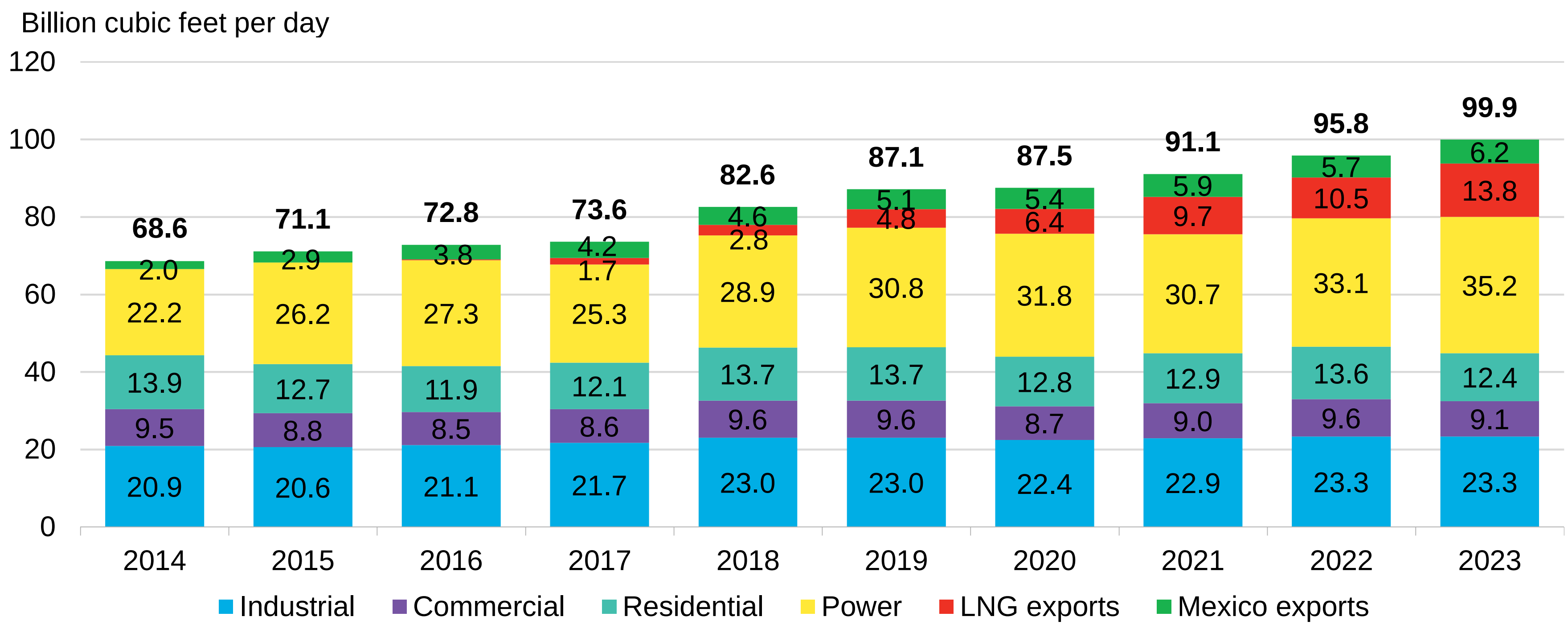
Actual and planned coal capacity



Source: EIA, BloombergNEF

BloombergNEF

US natural gas demand by end use

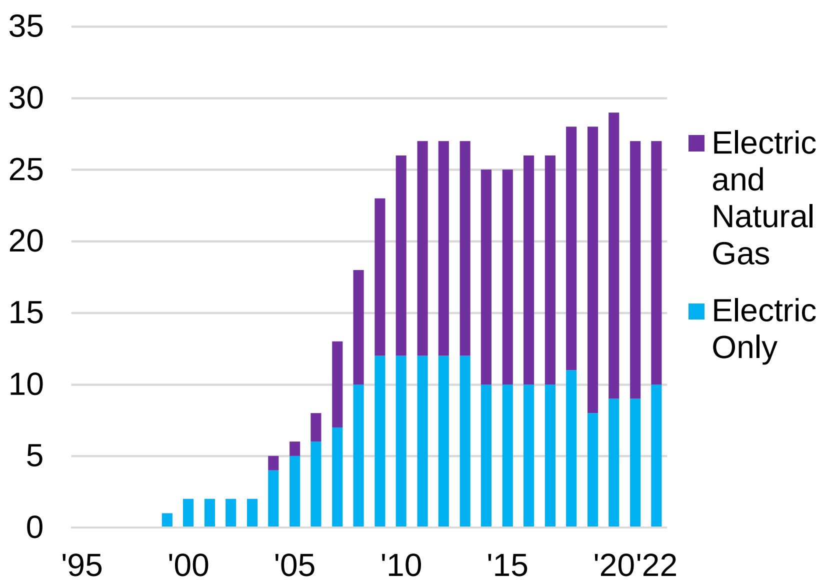


Source: BloombergNEF, EIA, US Department of Energy (DOE). Note: November and December 2023 values are forecasts. LNG is liquefied natural gas.

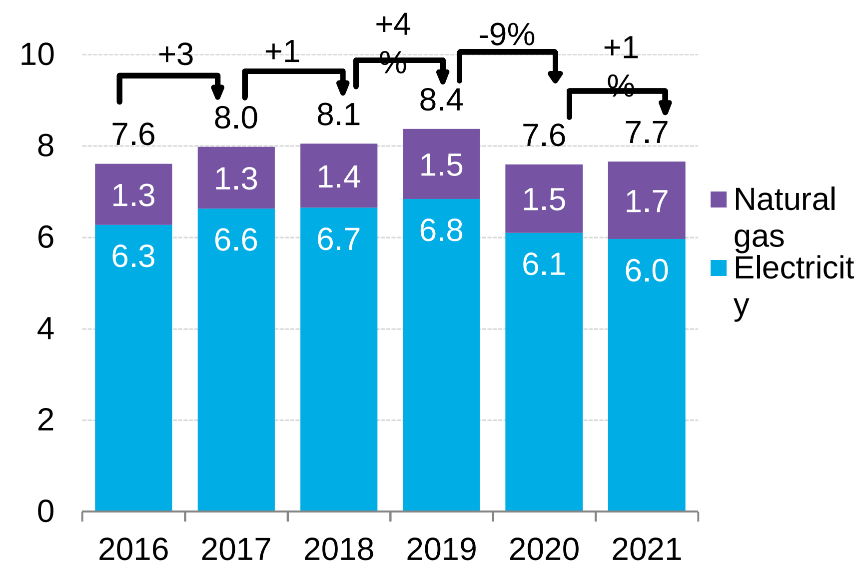
BloombergNEF

Energy efficiency

US states with Energy Efficiency Resource Standards (EERS)



Utility energy efficiency spending

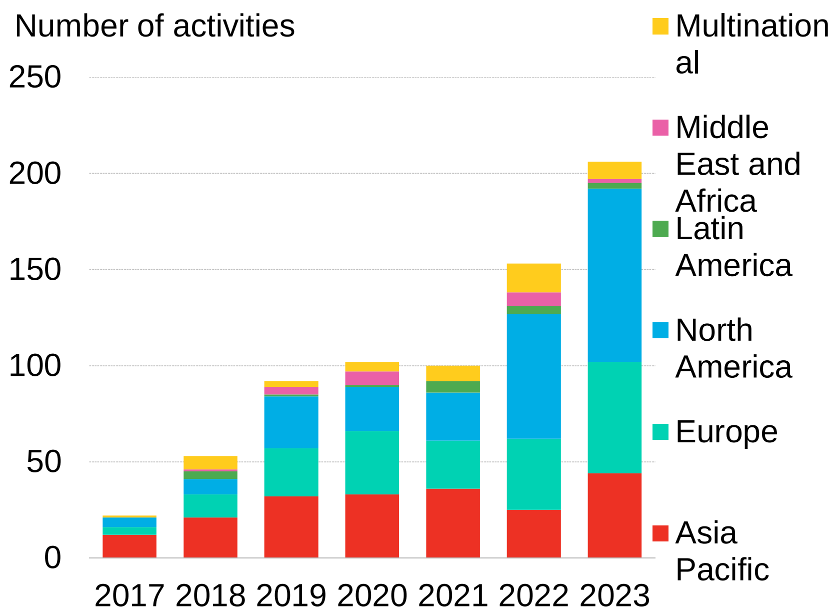


Source: EIA, BloombergNEF. Notes: "CAGR" in the right-hand chart is compound annual growth rate. Values for 2023 are projected, accounting for seasonality, based on the latest monthly values from EIA (data available through September 2023). BTU stands for British thermal units.

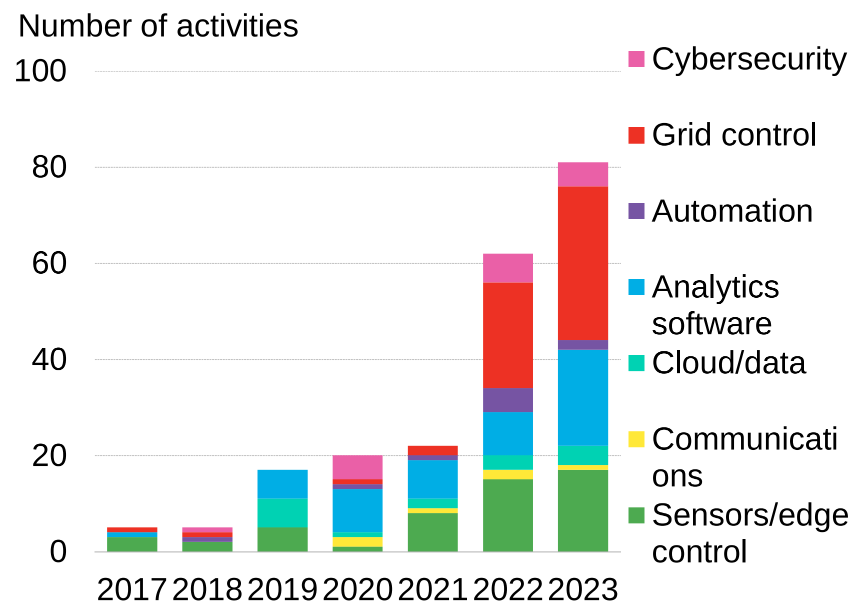
BloombergNEF

The US has emerged as a global leader in power digitalization

Number of digital projects and partnerships in the power sector, by region

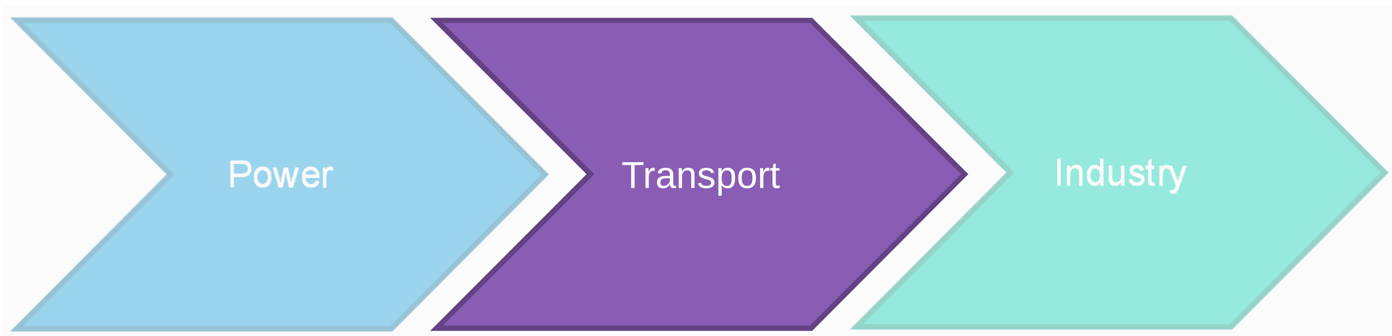


Number of US digital projects and partnerships in the power sector, by technology area

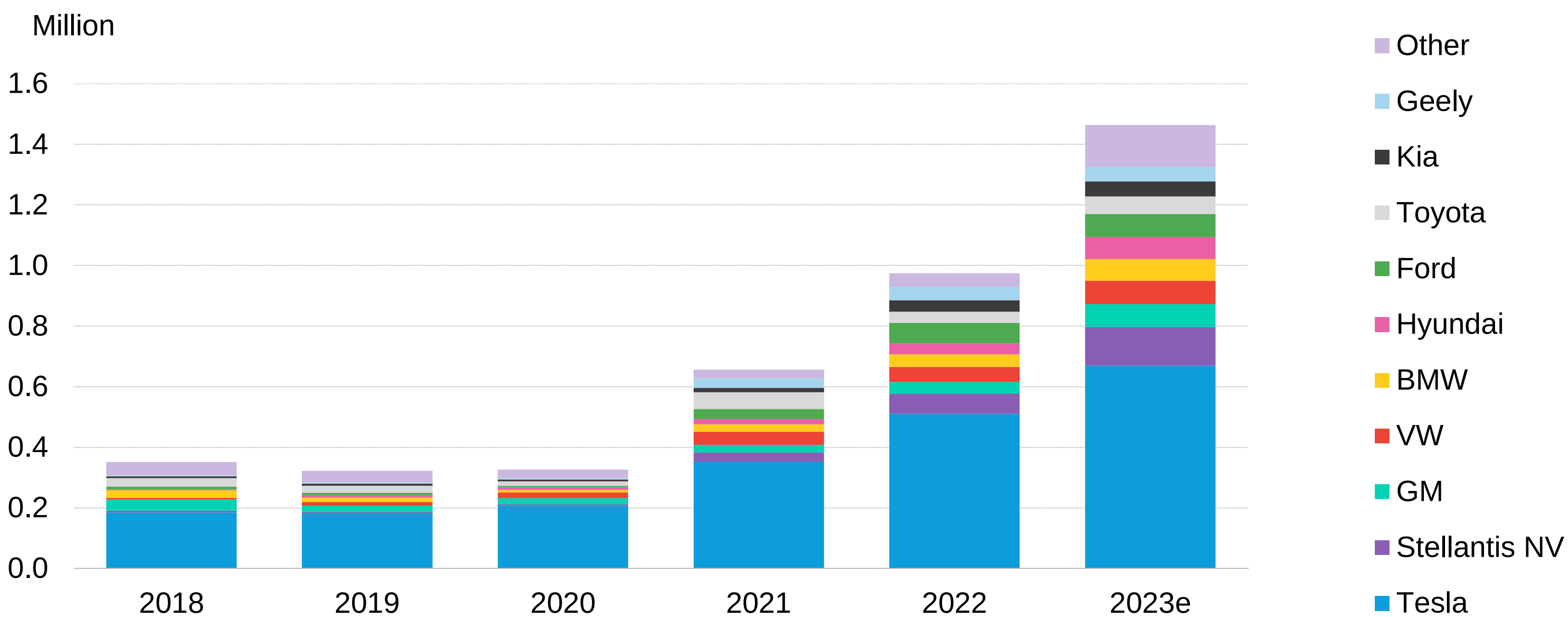


Source: BloombergNEF

A sector level view



US electric vehicle sales



Source: BloombergNEF, Marklines

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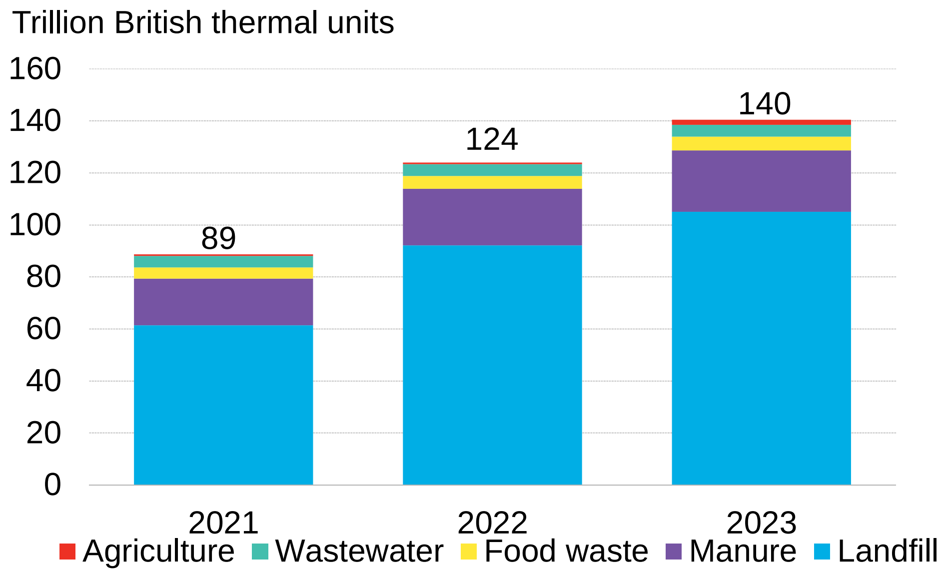
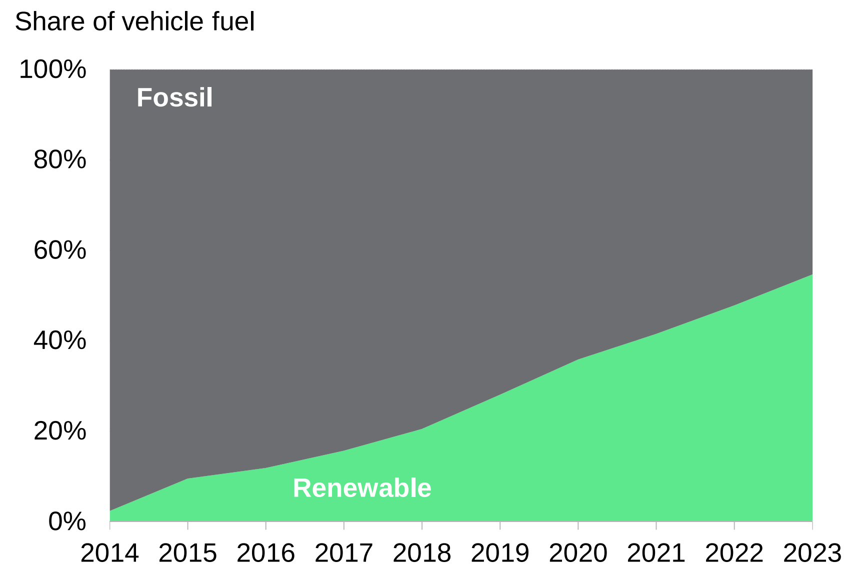
Renewable natural gas production and vehicle demand

RNG production capacity, by source

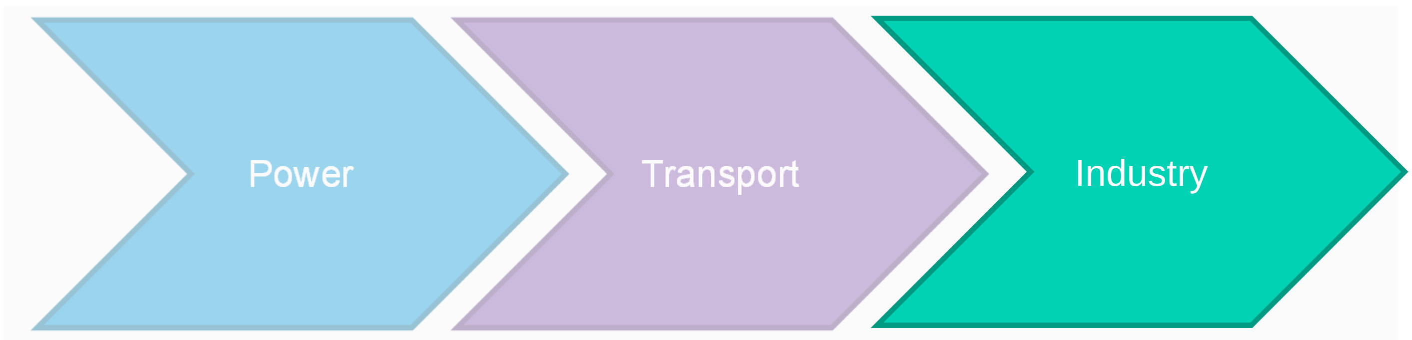


US natural gas vehicle demand, by source



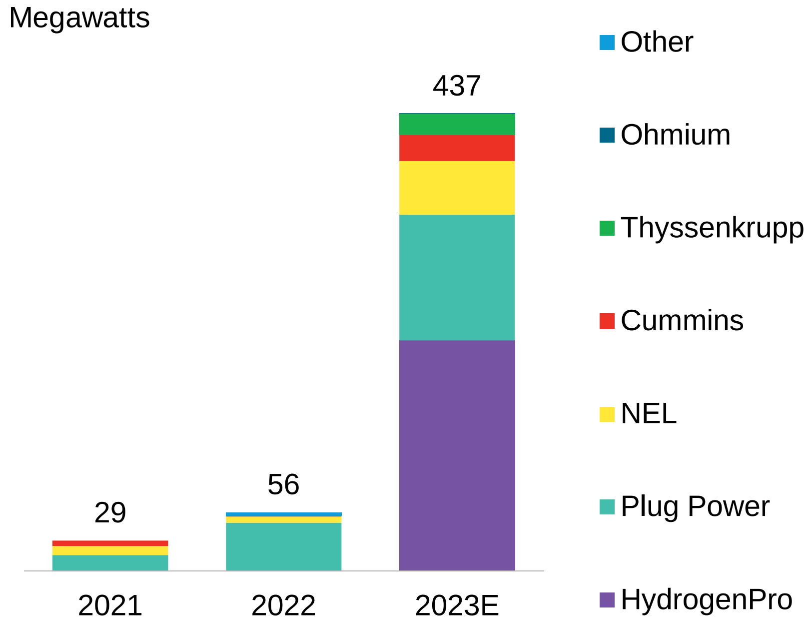
Source: BloombergNEF, Argonne National Labs, RNG Coalition, company announcements, California Air Resources Board, EPA. RNG is renewable natural gas.

A sector level view



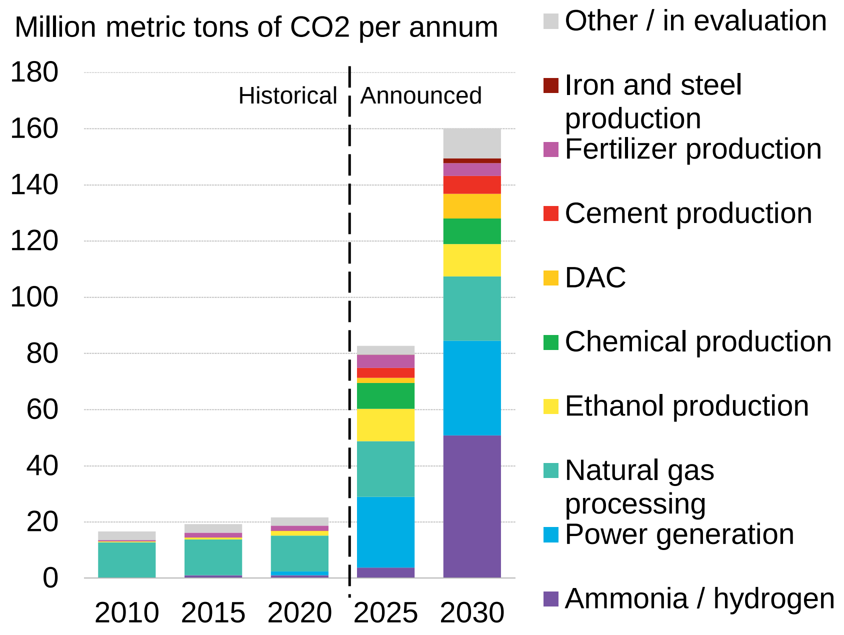
Maturing technologies are growing up fast

Electrolyzer shipments to the US



Source: BloombergNEF

CCS in the US, by source



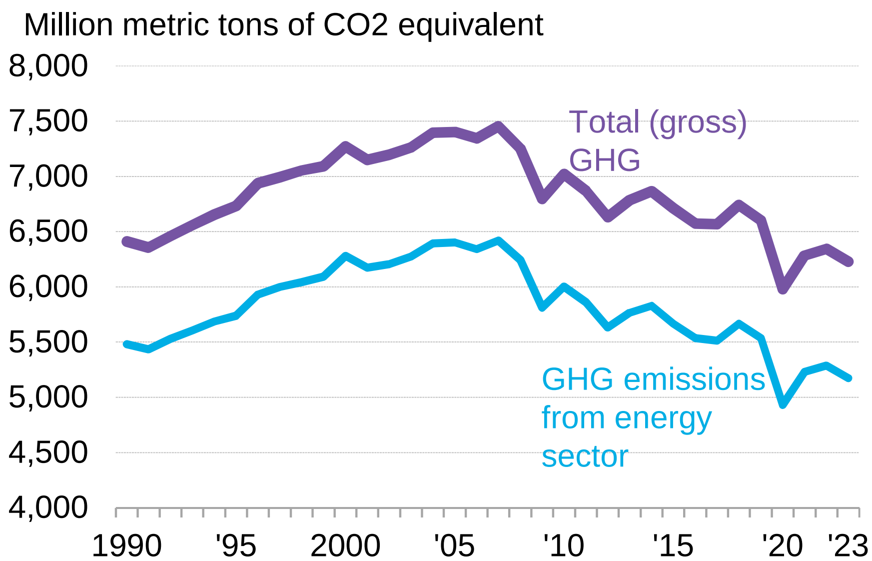
Source: BloombergNEF. Note: DAC is direct air capture.

Achieving Decarbonization Goals

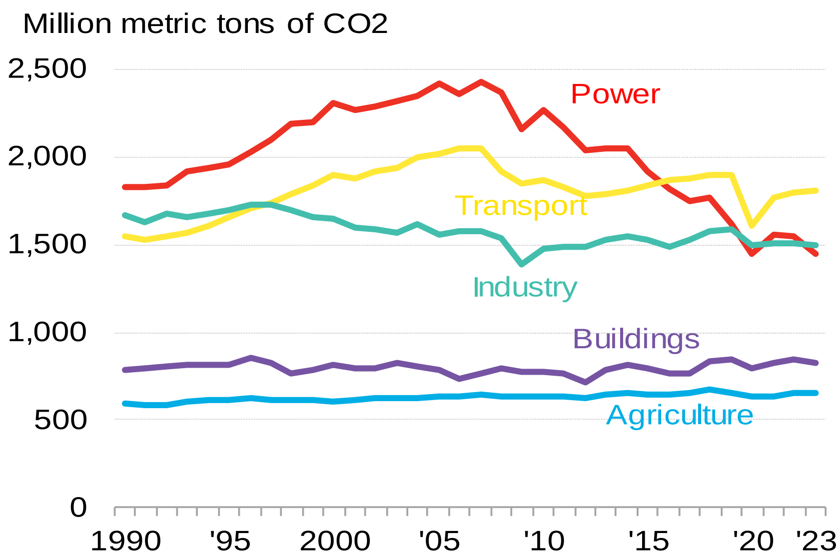
BloombergNEF

Greenhouse gas (GHG) emissions

Economy-wide and energy sector emissions



US emissions by sector

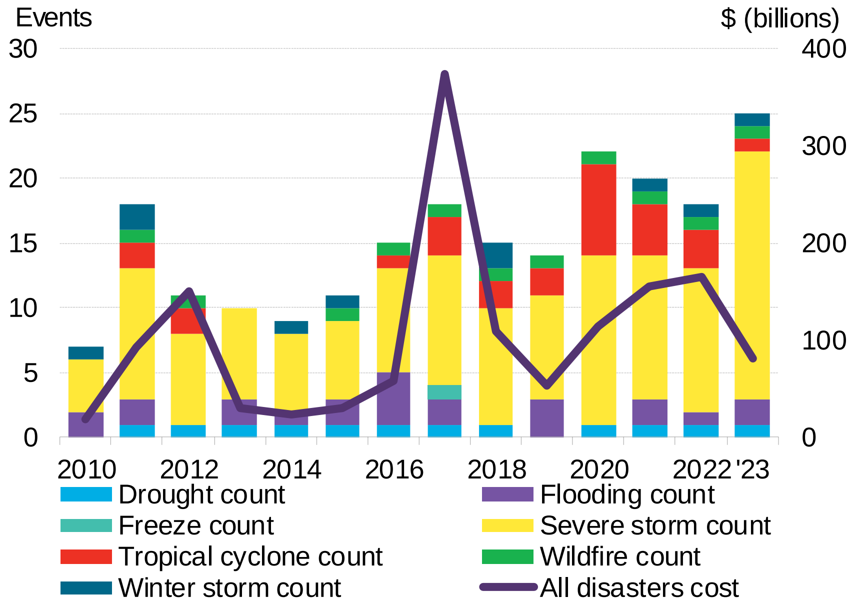


Source: BloombergNEF, EIA, EPA. Note: GHG stands for greenhouse gases.

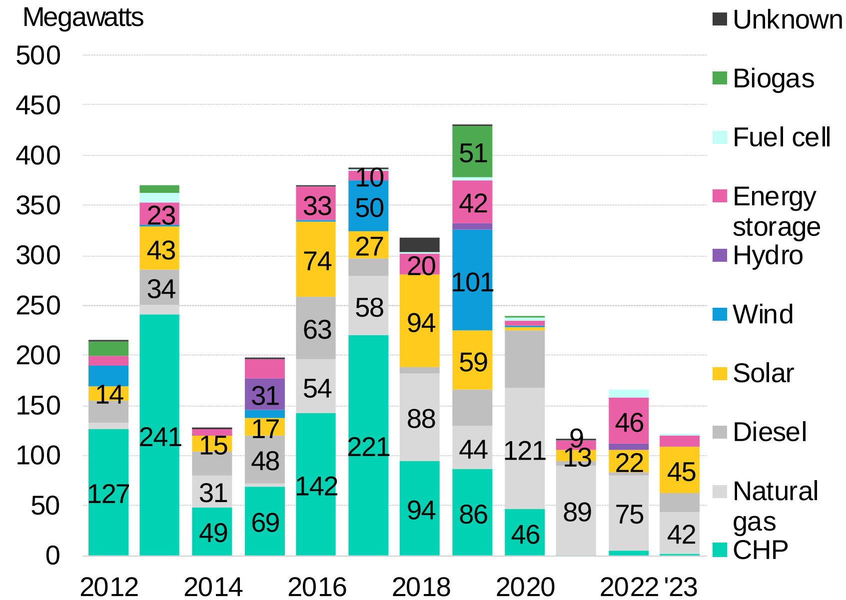
BloombergNEF

Infrastructure and resilience

US billion-dollar weather, climate disasters



US microgrid installed capacity, by technology



Source: National Oceanic and Atmospheric Administration, BloombergNEF, US Department of Energy, ICF. Note: Chart portrays annual counts of drought, flooding, freeze, severe storm, tropical cyclone, wildfire and winter storm events in the US with losses of more than $1 billion each. CHP stands for combined heat and power.

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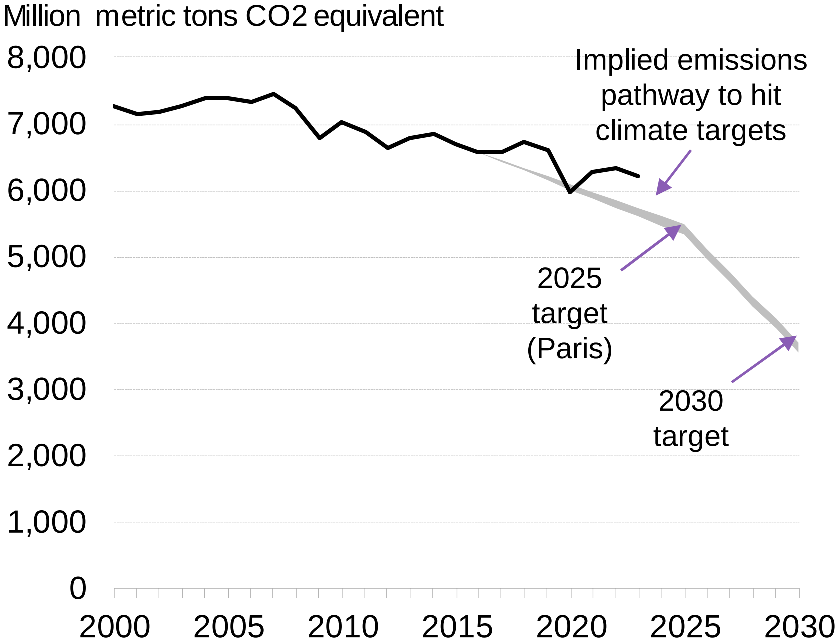
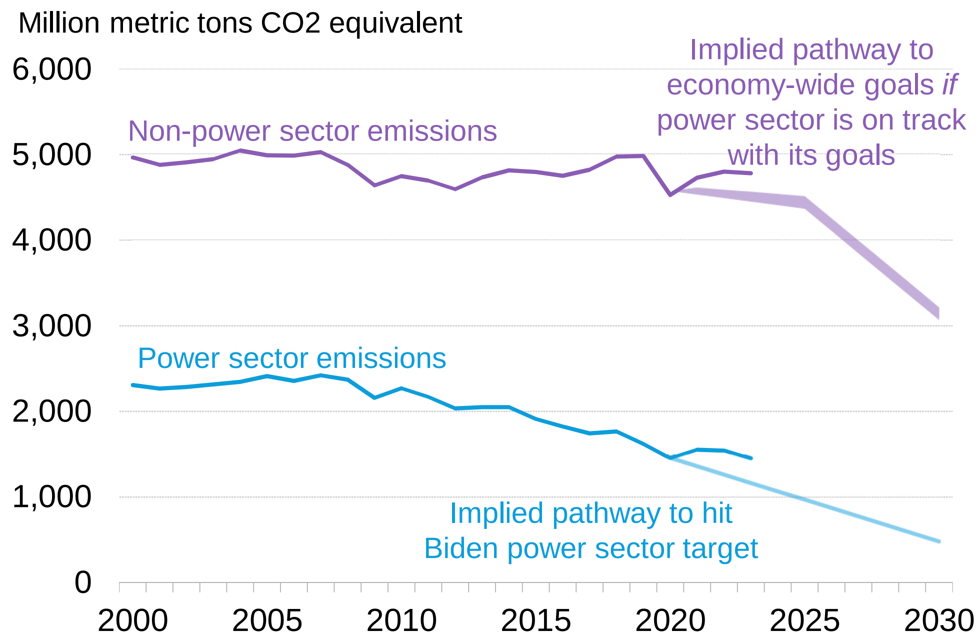
US progress toward emissions goals

US economy-wide emissions



US power emissions



Source: EIA, EPA, BloombergNEF.

BloombergNEF

Energy Sector Perspectives & Reflections "Beyond New England"

Sapna Gheewala Dowla
Associate Vice President, Policy & Research, Alliance to Save Energy (ASE)

Sapna Gheewala-Dowla is the Associate Vice President of Policy and Research for ASE. Sapna helps to lead the development, execution, and evaluation of the Alliance's policy work, including managing members of the policy team, conducting analysis and advocacy, and working closely with associate members, external stakeholders, and others to effectively achieve the organization's policy objectives. She forwards the organization's work by cultivating relationships with key congressional committees and staff. She also leads and manages issues related to the built environment, including managing the organization's Building Policy Committee and supporting the Responsible Energy Codes Alliance (RECA).

Before joining the Alliance, Sapna worked at the American Gas Association (AGA) where she provided analytical and policy support on energy efficiency and low-carbon resources to strengthen the role of natural gas in sustainable energy. Sapna also led the Gas Energy Efficiency Roundtable series, facilitating information exchange between program administrators and natural gas utilities.

Sapna holds an M.S. in Energy Policy and Climate from Johns Hopkins University and a B.S. in Environmental Science and Technology from the University of Maryland.

Rob Mosher
Vice President of Government Affairs, Interstate National Gas Association of America (INGAA)

Rob Mosher is the Vice President of Government Affairs for INGAA, and serves as the organization's lead federal public policy advocate on behalf of the domestic natural gas infrastructure sector.

Prior to joining the INGAA, Rob was the Director of Federal Government Relations for National Grid. He began his professional career with former Senator John Glenn, and then worked for several lawmakers, while handling energy, environmental and infrastructure matters, before concluding his time on Capitol Hill as Congresswoman Doris Matsui's Legislative Director.

Rob possesses a Bachelor of Arts in Political Science from Miami University (OH) and a Master of Public Policy & Administration from Baylor University.

Anthony Fratto
Senior Director, Research and Analytics American Clean Power Association (ACP)

Anthony Fratto is the Senior Director of Research and Analytics at ACP. Anthony oversees quantitative analysis that evaluates the impacts of policy and regulatory priorities for the clean energy industry. His primary interests are wholesale market design, hydrogen, transmission, and offshore wind.

Prior to joining ACP, Anthony was a Managing Consultant at E3. He primarily worked on asset valuation in which he quantified future revenue streams and helped clients make decisions about capital expenditures. In addition, he helped lead E3's electricity market forecasting for Texas and the Eastern Interconnect, and overseeing long-term resource planning projects under a decarbonized world.

Anthony received his Bachelor of Science in Chemical Engineering and Political Science from the University of Utah, and a Master's in Technology and Policy from MIT.