NEPOOL

NEW ENGLAND POWER POOL

Sebastian Lombardi
Secretary

September 28, 2023

VIA E-MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of October 5, 2023 Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the October 2023 meeting of the Participants Committee will be held **in person on Thursday, October 5, 2023, at the Providence Marriott Downtown, One Orms Street, Providence, RI 02904** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/.

For those who otherwise attend NEPOOL meetings but plan to participate in the October 5 meeting virtually, please use the following dial-in information: **866-803-2146; Passcode: 7169224.** To join WebEx, click this link and enter the event password **nepool**.

The NEPOOL reservations block at the Providence Marriott Downtown for the evening before the October 5 meeting is now closed. If you are still in need of a room, please contact Jaki Sloan (jsloan@daypitney.com) who may be able to assist getting you into the Marriott or an alternative venue if possible.

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

- **Thursday, November 2 Sector Meetings with ISO Board and State Official Panels** – The next Sector meetings with the ISO Board and State Officials are scheduled to be held in person on Thursday, November 2 at the Seaport Hotel, Boston, MA. The first session is scheduled to begin at 9:00 am; the last session is scheduled to conclude at 1:45 pm. The Participants Committee general session will begin at 2:00 pm and will conclude when all business has been conducted. The ISO and the States have each requested that proposed agendas and supporting materials for those Sector meetings be provided on or before ***Friday, October 13***. Materials for the meetings with the ISO Board can be sent directly to Maria Gulluni at mgulluni@iso-ne.com and Pat Gerity at pmgerity@daypitney.com; Materials for the meetings with State Officials can be sent directly to Pat Gerity at pmgerity@daypitney.com.

- **2024 NEPOOL Officers** – Each Sector needs to identify for us no later than ***Monday, October 23*** the voting member chosen by that Sector to serve as its 2024 Participants Committee officer. The Participants Committee will then select its 2024 Chair from among those Sector-selected officers, using the required voting process for that selection. We have included with this notice a memorandum that provides more information about the selection process.

Respectfully yours,

/s/

Sebastian Lombardi, Secretary

FINAL AGENDA

1. To approve the draft minutes of the September 7, 2023 Participants Committee meeting. A copy of the draft minutes for the September 7, 2023 meeting, marked to show changes since the draft minutes were circulated with the initial notice, has been included with this supplemental notice.

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

3. To receive an ISO Chief Executive Officer report. The October CEO report is included and posted with this supplemental notice.

4. To receive a report from the ISO Chief Operating Officer on the following:
   a. Operations Report Highlights (September data); and
   b. 2024 Annual Work Plan.

   The Annual Work Plan materials, which were circulated and posted separately, are also included with this supplemental notice. The October COO report will be circulated and posted in advance of the meeting.

5. To consider, and take action, as appropriate, on the following proposed budgets:
   a. 2024 ISO-NE Operating and Capital Budgets; and
   b. 2024 NESCOE Budget.

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

6. DEFFERED.
   [~~To receive an ISO Internal Market Monitor (IMM) report by David Naughton, Executive Director, Market Monitoring. The IMM's 2022 Annual Markets Report is available on-line at https://www.iso-ne.com/static-assets/documents/2023/06/2022-annual-markets-report.pdf. A presentation with report highlights is included and posted with this supplemental notice.~~]

[continued on next page]

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

COVID-19 Considerations. To safeguard the well-being of yourself and others, please refrain from attending a NEPOOL meeting in person if you have confirmed that you have COVID-19. If you suspect that you might have COVID-19, or if you have been exposed to COVID-19, please take the precautions recommended by the CDC. In any case, all are encouraged to be respectful of others' personal space, and to respect individual choices with respect to wearing or not wearing masks. Should you receive a COVID-19-positive test result within 10 days of attending a NEPOOL meeting in person, we'd kindly ask that you contact NEPOOL Counsel (pmgerity@daypitney.com) to report that result.

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

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

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

9. Administrative matters.

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

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M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity, NEPOOL Counsel

DATE: September 21, 2023

RE: 2024 Participants Committee Officer Elections

In order to ensure that the selection process requirements in the Participants Committee Bylaws for 2024's Participants Committee officers can be timely completed, we need each Sector to indicate, no later than **Monday, October 23, 2023,** who the Sector has selected to serve as the Sector's Participants Committee officer. A description of the qualifications, responsibilities, and expectations of the Sector officers selected has been included with this memorandum. We urge each of you to work within your Sectors to select your Sector's 2024 Participants Committee officer.

By way of reminder, the Bylaws require that one voting member from each Sector be selected by a majority of all the voting members in its Sector (i) to serve as a nominee for Chair of the Participants Committee and (ii) if not elected Chair, to serve as a Committee Vice-Chair. A secret written balloting process will then be conducted to elect the 2024 Chair from among the Participants Committee officers selected by each of the Sectors. To allow time for that balloting process ahead of the December 2 Annual Meeting, as required by the Bylaws, we need the officers to be identified by October 23, 2023.

If any Sector needs assistance in conducting the vote for its Sector officer, please let us know (preferably no later than October 13). We would be pleased to help however we can. Also, if you have any questions, please contact me at pmgerity@daypitney.com or (860) 275-0533.

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Participants Committee Sector Officer
Qualifications, Responsibilities and Expectations

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

Responsibilities and Expectations of Participants Committee Sector Vice-Chairs:

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

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

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

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

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

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

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

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

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

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

9/21/2023

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held via teleconference on Thursday, September 7, 2023, at 10:00 a.m. 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.

Mr. David Cavanaugh, Chair, presided, and Mr. Sebastian Lombardi, Secretary, recorded. Mr. Cavanaugh welcomed the members, alternates and guests who were in attendance.

APPROVAL OF JUNE 27-29 AND AUGUST 3, 2023 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the June 27-29 and August 3, 2023 meetings, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of those meetings were unanimously approved as circulated, with an abstention by Mr. Jon Lamson recorded.

CONSENT AGENDA

Mr. Cavanaugh then referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved as circulated, with an abstention by Mr. Jon Lamson recorded.

ISO CEO REPORT

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

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by referring the Committee to his September Operations Report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the Report, including the Net Commitment Period Compensation (NCPC) data, was through August 30, 2023, unless otherwise noted. The Report highlighted: (i) Energy Market value for July 2023 was $301 million, down $279 million from the updated June 2023 value and down $1.1 billion from August 2022 (when natural gas prices were at record highs for the summer period); (ii) August 2023 average natural gas prices were 49% lower than July 2022 average prices, and at $1.41/MMBtu, were just above the record low for natural gas prices ($1.38/MMBtu). He explained that the low prices were related to the mild temperatures and related Real-Time Loads (which, for the month of August, averaged, respectively, 71° F and 13,600 MWh (the lowest average Real-Time Load since the implementation of Standard Market Design in 2003)); (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for July ($29.09/MWh) were 26% lower than July averages; (iv) average August 2023 natural gas prices and Real-Time Hub LMPs over the period were down 83% and 70%, respectively, from August 2022 average prices; (v) average Day-Ahead cleared physical energy during the peak hours as percent of forecasted load was 99.6% during August (down from 100.8% reported for July), with the minimum value for the month of 93.5% on Sunday, August 20; and (vi) Daily NCPC payments for August totaled $2.1 million, which was down $0.8 million from July 2023 and down $4.4 million from August 2022. August NCPC payments, which were 0.7% of total Energy Market value, were compromised of (a) $1.8 million in first contingency payments (up $0.7 million from July); (b) $77,000 in second contingency or voltage payments in July; and (c) $262,000 in distribution payments (down $219,000 from July).

Turning to information on the August 21 Master/Local Control Center Procedure No. 2 (M/LCC 2) declaration for hours ending (HE) 18:00 to 22:00, Dr. Chadalavada stated that temperatures were warmer (85-86° F, rather than 80-82° F) and the dew point much higher (68-70° F, rather than 60-62° F) than expected. He explained that, as a result, demand was higher than forecast. For the peak hour (HE 19:00), peak load was only about 200 MW higher than that forecasted. But the load continued to persist, so that, by HE 22:00, load was roughly 1,000 MW higher than that forecasted (17,500 MW rather than the 16,500 MW forecasted). The M/LCC 2 declaration was to protect against potential capacity deficiencies. There were also some generation unit trips that day, but they did not require actions beyond the M/LCC 2 declaration.

Dr. Chadalavada noted two upcoming regional transmission outages: (1) Hydro Quebec's scheduled fall maintenance outage for Phase II, which would take place from September 11 to September 18, and would reduce the total transfer capability of Phase II in both directions to 1,200 MW; and (2) an auto-transformer outage at the Holbrook substation, which for replacement would be out from September 10 to December 1, 2023, and could present, under certain circumstances, the potential for second contingency uplift for the Southeastern Massachusetts/Rhode Island and Boston interfaces. He said that maintenance outages, both generation and transmission outages, were the primary and not unusual reason why capacity margins were projected to be lower during the late September to mid-November timeframe.

Dr. Chadalavada then noted that the draft 2023-24 Regional System Plan (RSP) had been shared with stakeholders on August 16, with comments received by August 30. He said that discussions on the second phase of the Extended-Term/Longer-Term Transmission Planning would begin at the Transmission Committee meeting in October. Referring to questions received ahead of the meeting regarding the Resource Capacity Accreditation (RCA) project, he briefly described information that was to be posted by the end of the day for discussion at the September 12-13 Markets Committee meeting, and said he looked forward to feedback after those discussions had taken place.

In response to questions regarding the annual peak load for 2023, Dr. Chadalavada confirmed that the telemetered load (load that the Control Room sees) was higher by approximately 100 MW on September 6 than on July 6 (the previous peak for 2023), but the final Revenue Quality Metered (RQM) Load number (telemetered load plus Settlement Only Resources) would not be available and the final peak load determination unable to be made until the following day. However, because the peak load for September 7 was forecast at 23,500 MW, Dr. Chadalavada expected that September 7 would set the peak load for 2023. He added that, if so, 2023 would be the first year in which the annual peak would be set after Labor Day. At a member's request, he committed, once the full data was available the following week, to update the Participants Committee with the 2023 peak load information.

2023 ISO AND NESCOE BUDGETS

Mr. Tom Kaslow, Budget & Finance Subcommittee (B&F) Chair, referred the Committee to the materials circulated and posted in advance of the meeting related to the proposed 2024 ISO and NESCOE Budgets. He reported that the 2024 Budgets had been reviewed and considered at the Subcommittee's August 11 meeting. He noted that the 2024 NESCOE Budget was consistent with that proposed in the 5-year *pro forma* budget approved the year before. He reported that no objections or concerns had been raised with respect to either the ISO's or NESCOE's 2024 Budgets.

Addressing the status of the 2024 ISO Budgets process, Mr. Bob Ludlow, ISO Chief Financial and Compliance Officer, referred members to the summary in the meeting materials, and added that the ISO had received comments from a few of the States, which, with all of the information and feedback received, would be reviewed with and discussed by the ISO Board the following week. Responses to the comments received would be sent thereafter, with those responses posted and available in advance of the Committee's planned October 5 vote on the Budgets. Presuming support, the ISO planned to submit the 2024 Budget filings to the FERC by mid-October and to request a January 1, 2024 effective date for those filings. In response to a question, Mr. Ludlow indicated that the ISO planned to make available during the last week in September details on the rate and tariff changes associated with the 2024 ISO Budgets. A member from Vermont thanked Mr. Ludlow and the ISO team for their efforts explaining the 2024 Budgets and associated rate impacts.

Turning to the 2024 NESCOE Budget, Ms. Heather Hunt, NESCOE Executive Director, reiterated that the 2024 NESOCE Budget was within the parameters identified in the NEPOOL-supported and FERC-approved five-year *pro forma* framework. She highlighted that the 2024 Budget was slightly less than the 2023 Budget. She noted that the estimated Schedule 5 billing rate (the mechanism for funding NESCOE's operations) would be updated, if and as appropriate based on ISO data, before being finalized and submitted to the FERC. She encouraged anyone with questions or concerns on the 2024 NESCOE Budget to so indicate or to reach out to her in advance of the Participants Committee's October vote. There were no questions or comments on the NESCOE Budget.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the September 6, 2023 Litigation Report that had been circulated and posted before the meeting. He highlighted the following developments:

(i) *Second New England Winter Gas-Electric Forum (AD22-9).* Many comments related to the FERC's June 20 Forum had been filed by the late August comment date established by the FERC.

(ii) *FCA18 De-List Bids Filing (ER23-2379).* The FERC had accepted the ISO's Permanent and Retirement De-List Bids filing, effective September 11, 2023.

(iii) *Order 2023 (Interconnection Reforms) (RM22-14).* Mr. Lombardi reported that more than 35 parties had requested clarification and/or rehearing of *Order 2023.* In addition, three of the RTOs (MISO, PJM and SPP) had jointly requested an extension of time for compliance with *Order 2023* to at least 90 days after the FERC issues a substantive order on the issues raised by the requests for clarification and/or rehearing. A more detailed summary of those requests had been separately attached as a supplement to the end of the September 6 Litigation Report. He highlighted that, with the publication of *Order 2023* in the *Federal Register* on September 6, absent further action by the FERC, the deadline for the submission of compliance filings would be on or before December 5, 2023. In response to a question, Ms. Gulluni confirmed that the ISO would not itself seek an extension of the compliance deadline.

COMMITTEE REPORTS

Markets Committee (MC). Mr. Bill Fowler, MC Vice-Chair, reported that the MC would next meet the following week in Westborough for a one and one half day meeting. He indicated that key topics would include, in addition to discussion on FCA19, consideration and a vote on an update to Net Cost of New Entry (CONE), as well as a discussion related to upward mitigation issues that had been experienced the prior winter and was the topic of a FERC Show Cause order (EL23-62) that was being held in abeyance through at least February 1, 2024. He previewed that the ISO planned to present a new proposal to the MC to respond to the Show Cause order and, with sufficient support, may pursue condensed Participant Processes to potentially permit implementation of that proposal for ~~w~~Winter 2023/24.

Reliability Committee. Mr. Robert Stein, the RC Vice-Chair, reported that the RC would next meet on September 19, 2023. He highlighted planned action on: the FCA18 Hydro-Québec Interconnection Capability Credits (HQICCs), Installed Capability Requirement (ICR) and related values (including net ICR, Maine Maximum Capacity Limit (MCL), Northern New England MCL, and Capacity Demand Curves for the System and Capacity Zones based on the Marginal Reliability Impact (MRI) methodology); additional information to be received related to the probabilities in the 2032 extreme weather study; and preliminary discussion regarding the 2024 load forecast cycle.

Transmission Committee. Mr. David Burnham, TC Vice-Chair, reported that the TC would next meet on September 27, 2023. The primary matter to be addressed would be *Order 2023* compliance. He noted that, because of *Order 2023*'s December 5, 2023 compliance deadline, plans had been made for an additional TC meeting on November 9, at which the *Order 2023* compliance changes could be voted, followed by Participants Committee action at a special teleconference meeting, likely to be held on November 16.

Budget & Finance Subcommittee. Mr. Kaslow reported that, in addition to the posted October 10 meeting, there would also be an earlier meeting, during the afternoon of September 26, to address ISO proposed changes to the Financial Assurance Policy's Pay-for-Performance provisions. He encouraged all those interested to watch for a memo and further information from the ISO on that topic.

Membership Subcommittee. Ms. Sarah Bresolin, Membership Subcommittee Chair, reported that the next Membership Subcommittee meeting was scheduled for September 11, 2023.

ADMINISTRATIVE MATTERS

Mr. Lombardi noted that the next Participants Committee meeting was scheduled to be held in person on October 5, 2023 at the Marriott Downtown in Providence, RI. Looking further ahead, he said that the November 2 meeting would be held in person at the Seaport Hotel in Boston and would include the second of the semi-annual opportunities for modified Sector meetings with the ISO Board and State Officials. The November 2 meeting would be held the day after the ISO Board's planned open meeting, also to be held at the Seaport Hotel. He noted, as mentioned earlier, the possibility of an additional Participants Committee meeting in November to address *Order 2023* compliance and other matters, which, if held, was likely to be a teleconference meeting on November 16. The 2023 Annual Meeting of the Participants Committee was scheduled for December 7 at the Colonnade Hotel in Boston.

There being no other business, the meeting adjourned at 10:43 a.m.

Respectfully submitted,

Sebastian Lombardi, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN SEPTEMBER 7, 2023 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Advanced Energy United (AEU)	Associate Non-Voting	Caitlin Marquis		
Ashburnham Municipal Light Plant	Publicly Owned Entity			Dan Murphy
Associated Industries of Massachusetts (AIM)	End User			Mary Smith
AVANGRID: CMP/UI Avangrid Renewables	Transmission	Alan Trotta Kevin Kilgallen	Jason Rauch	Zach Teti
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		
Boylston Municipal Light Department	Publicly Owned Entity			Dan Murphy
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Brookfield Renewable Trading and Mktg.	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			Dan Murphy
ClearResult Consulting, Inc.	AR-DG	Tamera Oldfield		
Clearway Power Marketing LLC	Supplier			Pete Fuller
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw		
Connecticut Office of Consumer Counsel	End User		J.R. Viglione	
Conservation Law Foundation (CLF)	End User	Phelps Turner		
Constellation Energy Generation	Supplier		Bill Fowler	
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danske Commodities US LLC	Supplier			Norman Mah
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dominion Energy Generation Marketing, Inc.	Generation	Wes Walker		
DTE Energy Trading, Inc.	Supplier			José Rotger
Durgin and Crowell Lumber Co., Inc.	End User			Bill Short
Dynegy Marketing and Trade, Inc.	Supplier	Andy Weinstein		Bill Fowler
ECP Companies Calpine Energy Services, LP New Leaf Energy	Generation	Brett Kruse Liz Delaney	Andy Gillespie	Bill Fowler
EDF Trading North America, LLC	Supplier	Eric Osborn		
Elektrisola, Inc.	End User			Bill Short
Emera Energy Services Companies	Supplier			Bill Fowler
Enel X North America, Inc.	AR-LR	Alex Worsley		
Engie Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission	James Daly	Dave Burnham	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger	Jeff Iafrati	
Garland Manufacturing Company	End User			Bill Short
Generation Bridge Companies	Generation	Bill Fowler		
Generation Group Member	Generation		Abby Krich	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Granite Shore Companies	Generation			Bob Stein
Groton Electric Light Department	Publicly Owned Entity			Dan Murphy
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	AR-RG	Louis Guilbault	Bob Stein	
Hammond Lumber Company	End User			Bill Short

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN SEPTEMBER 7, 2023 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Hanover, NH (Town of)	End User			Bill Short
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity			Dan Murphy
Holyoke Gas & Electric Department	Publicly Owned Entity			Dan Murphy
Hull Municipal Lighting Plant	Publicly Owned Entity			Dan Murphy
Icetec Energy Services, Inc. (Icetec)	AR-LR	Doug Hurley		
Industrial Energy Consumer Group	End User	Dan Collins		
Ipswich Municipal Light Department	Publicly Owned Entity			Dan Murphy
Jericho Power LLC (Jericho Power)	AR-RG	Ben Griffiths	Nancy Chafetz	
Jupiter Power	AR-RG			Ron Carrier
Lamson, Jon	End User	Jon Lamson		
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned Entity		Craig Kieny	
Maine Power LLC	Supplier	Jeff Jones		
Maine Public Advocate’s Office	End User	Drew Landry		
Maine Skiing, Inc.	End User	Dan Collins		
Mansfield Municipal Electric Department	Publicly Owned Entity			Dan Murphy
Maple Energy LLC	AR-LR			Doug Hurley
Marblehead Municipal Light Department	Publicly Owned Entity			Dan Murphy
Mass. Attorney General’s Office (MA AG)	End User	Ashley Gagnon	Jaimie Donovan	Tina Belew
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Climate Action Network	End User	Elischia Fludd		
Mass. Dept. Capital Asset Management	End User		Paul Lopes	Nancy Chafetz
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity		Dan Murphy	
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Moore Company	End User			Bill Short
Narragansett Electric Co. (d/b/a RI Energy)	Transmission	Brian Thomson		
Nautilus Power	Generation		Bill Fowler	
New England Power (d/b/a National Grid)	Transmission		Tim Martin	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson	Dan Dolan	
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw
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	Generation	Dan Allegretti		
Paxton Municipal Light Department	Publicly Owned Entity			Dan Murphy
Peabody Municipal Light Department	Publicly Owned Entity			Dan Murphy
Princeton Municipal Light Department	Publicly Owned Entity			Dan Murphy
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
RI Division of Public Utilities Carriers	End User	Paul Roberti		
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN SEPTEMBER 7, 2023 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Russell Municipal Light Dept.	Publicly Owned Entity			Dan Murphy
Saint Anselm College	End User			Bill Short
Shipyard Brewing LLC	End User			Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity			Dan Murphy
South Hadley Electric Light Department	Publicly Owned Entity			Dan Murphy
Sterling Municipal Electric Light Department	Publicly Owned Entity			Dan Murphy
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Peter Fuller
Tangent Energy	AR-LR	Brad Swalwell		
Taunton Municipal Lighting Plant	Publicly Owned Entity	Devon Tremont	Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity			Dan Murphy
The Energy Consortium	End User		Mary Smith	
Vermont Electric Cooperative	Publicly Owned Entity			
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw
Versant Power	Transmission		David Norman	
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity			Dan Murphy
Walden Renewables Development LLC	Generation			Abby Krich
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity			Dan Murphy
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

Reliability Committee (RC)

From the previously-circulated notice of actions of the RC's September 19, 2023 meeting, dated September 19, 2023.[1]

1. FCA18 HQICC Values

Support the following Hydro-Québec Interconnection Capability Credit (HQICC) values for the eighteenth Forward Capacity Auction, which is associated with the 2027-2028 Capacity Commitment Period (FCA18), as recommended by the Reliability Committee at its September 19, 2023 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

2027-2028 Capacity Commitment Period (CCP) Month	HQICC Values (MW)
June	1,041
July	1,041
August	1,041
September	1,041
October	1,041
November	1,041
December	1,041
January	1,041
February	1,041
March	1,041
April	1,041
May	1,041

The motion to recommend Participants Committee support was approved, with one opposition in the Supplier Sector and 14 abstentions (4 Generation, 7 Supplier, 2 Alternative Resources, 1 End User) noted.

[continued on next page]

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

2. FCA18 ICR and Related Values

Support the following megawatt (MW) values that represent the New England Installed Capacity Requirement (ICR), Net Installed Capacity Requirement (Net ICR), Maine Maximum Capacity Limit (MCL), Northern New England MCL, and Capacity Demand Curves for the System and Capacity Zones based on the Marginal Reliability Impact (MRI) methodology for FCA18, as recommended by the RC at its September 19, 2023 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

	2027-2028 CCP ICR Values (MW)
Installed Capacity Requirement	31,591
Net Installed Capacity Requirement	30,550
Maine Maximum Capacity Limit	4,150
Northern New England (NNE) Maximum Capacity Limit	8,760

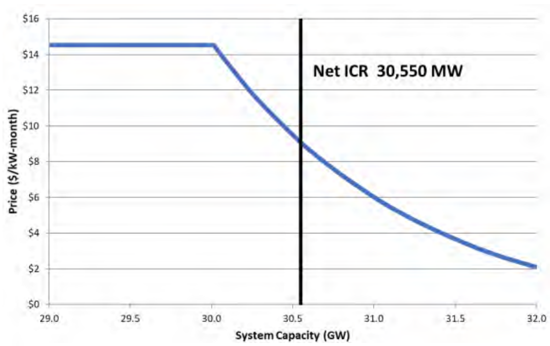

Figure 1: System Demand Curve
2027-2028 Capacity Commitment Period (CCP)

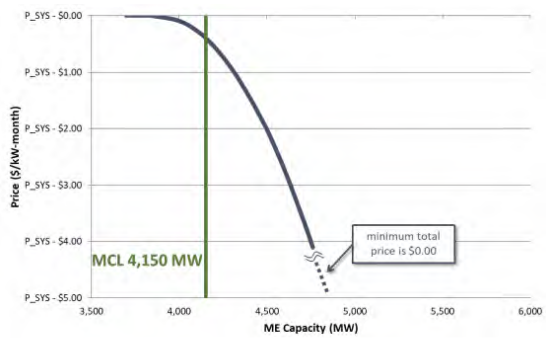

Figure 2: Maine Capacity Zone Demand Curve
2027-2028 CCP

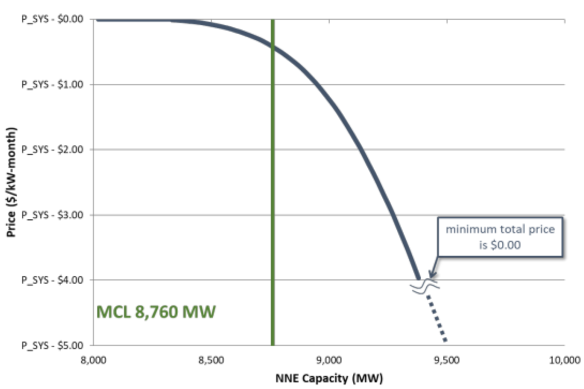

Figure 3: NNE Capacity Zone Demand Curve
2027-2028 CCP

The motion to recommend Participants Committee support was approved, with one opposition in the Supplier Sector and 14 abstentions (4 Generation, 7 Supplier, 2 Alternative Resources, 1 End User) noted.

[continued on next page]

3. Changes to OP-16, Including Appendices A-E and G-I (Periodic Review)

Support revisions to OP-16 (Transmission System Data), including Appendices A-E and G-I,[2] as recommended by the RC at its September 21, 2021 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

4. Changes to OP-21 (Conforming Changes to NERC Standards IRO-010 and TOP-003)

Support revisions to OP-21 (Operational Surveys, Energy Forecasting & Reporting, and Actions during an Energy Emergency),[3] as recommended by the RC at its September 21, 2021 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

Markets Committee (MC)

From the previously-circulated notice of actions of the MC's September 12-13, 2023 meeting (Revision One), dated September 13, 2023.[4]

5. Revisions to OP-9 (Periodic Review)

Support revisions to OP-9 (Scheduling and Dispatch of External Transactions) to improve the use of timestamps when scheduling External Transactions and to incorporate several clarifications and updates to the Procedure, as recommended by the MC at its September 12-13, 2023 meeting, together with such further non-material changes as the Chair and Vice-Chair of the MC may approve.

The motion to recommend Participants Committee support was approved unanimously.

6. Changes to Information Policy Sections 2.1 and 2.2 (*Order 895* Compliance)

Support revisions to Sections 2.1 and 2.2 of the Information Policy (Attachment D of the Tariff) to comply with FERC *Order 895* (Credit-Related Information Sharing in Organized Wholesale Electric Markets) (to permit the sharing of credit-related Market Participant information with other FERC-jurisdictional ISO/RTOs for the purpose of credit risk management and mitigation), as recommended by the MC at its September 12-13, 2023 meeting, together with such further non-material changes as the Chair and Vice-Chair of the MC may approve.

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

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[2] The recommended revisions to OP-16 and Appendices A-E and G-I to OP-16 include: operating mode label changes, the addition of a footnote defining "loadability"; an OP-16 NX-9 submission schedule change; clarifications for Smartvalve devices; the move of Dynamic Reactive Device reporting to NX-12D; and certification language adjustments.

[3] The recommended revisions to OP-21 align OP-21 with NERC Standards IRO-010 and TOP-003, each of which became effective on April 1, 2023, and clarify survey question 2 in Section V.B.2.

[4] 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.

Summary of ISO New England Board and Committee Meetings

October 5, 2023 Participants Committee Meeting

Since the last update, the Compensation and Human Resources Committee, the Markets Committee, the Nominating and Governance Committee, and the System Planning and Reliability Committee met on September 13. The Information Technology and Cyber Security Committee, and the Board of Directors, met on September 14. All of the meetings were held in Holyoke.

The Compensation and Human Resources Committee discussed the employee health and benefit plan renewals for 2024. The Committee received an update on the ongoing work of Mercer, the Company's compensation consultant, to benchmark various critical jobs to determine whether salaries remain competitive within the industry. Next, the Committee received an update on workforce demographics, Company culture, and talent market dynamics, and discussed workplace programs and development initiatives for employees. The Committee also discussed modifying its charter to reflect the Committee's responsibility for the Code of Conduct and oversight of Company culture, and recommended a revised charter for the Board's review in November. Regarding the 2024 compensation budget, the Committee reviewed national compensation surveys of projected 2024 merit and promotional increase budgets, including data specific to the utility industry, and data from other system operators. After considering the Mercer and survey data, and information about employee retention and hiring, the Committee approved as reasonable and competitive a 4.0% merit increase and a 4.0% promotional/equity increase for the 2024 operating budget.

The Markets Committee conducted its annual review of the External Market Monitor's business continuity and succession plans. The Committee then received a status report on the Resource Capacity Accreditation Project and Forward Capacity Auction #19. In addition, the Committee discussed an update on the Forward Reserve Market. Lastly, the Committee considered proposed clarifying revisions to its charter, and recommended further changes for the Committee's review.

The Nominating and Governance Committee discussed the Joint Nominating Committee process for 2024, and reviewed the Company's board succession process. The Committee also discussed board operations and governance. Next, the Committee received an update on the political environment, including state and federal topics, and discussed significant energy legislation and policies considered by federal and state policymakers this year. The Committee also discussed possible topics for its annual corporate governance review, and concluded that it would like to better understand the work of the Board and Company on environmental, social and governance issues. The Committee then undertook its biennial review of its charter to confirm compliance with the charter's terms, and agreed that the Committee is in compliance with the charter's terms and that no changes are necessary at this time. The Committee reflected on potential topics for discussion with the NEPOOL sectors in November, and also considered site visits for 2024.

The System Planning and Reliability Committee was provided with a status update on Regional System Plan projects. The Committee then discussed the draft 2023 Regional System Plan (RSP and stakeholder feedback on the draft report, and noted that the development of the overall RSP is on schedule. The Committee also discussed the status of the Economic Planning for the Clean Energy Transition pilot study, which is progressing as planned. Lastly, the Committee received its annual update on renewable resources development, and was provided with a summary of Order No. 2023: Final Rule on Interconnection Procedures/Agreements Reforms.

The Information Technology and Cyber Security Committee convened with the full Board for the Committee's annual "deep dive" on cyber security issues and received presentations from guest speakers. The first speaker provided a cyber threat intelligence briefing specific to the energy sectors. The second speaker presented an update on ransomware trends, an analysis of current tactics and techniques, procedures used to combat ransomware, and concluded with a ransomware event case study. Following the session with the full Board, the Committee conducted its regular business and received an update on cyber security projects and current activities. The Committee also discussed the progress of major IT projects and received updates on the Next Generation Electricity Market (nGEM) and Day-Ahead Ancillary Services projects.

The Board of Directors held its annual meeting and began with a report from the CEO, including an update on a proposed Northeast Power Coordinating Council (NPCC) Northeast Gas Study. The Board was provided with an update on the Resource Capacity Accreditation Project and Forward Capacity Auction #19, and concurred with the recommendation of management and the Board Markets Committee that the next auction should be delayed while the Resource Capacity Accreditation work is completed and the region considers the future format of its capacity market. Next, the Board discussed the proposed 2024 operating and capital budgets, including the states' comments on the budgets, and noted the remaining stakeholder process, following which the Board will vote on the budgets. In addition, the Board reviewed plans for the upcoming open board meeting, which is focused on system planning and operations and is being held in conjunction with the Regional System Plan public meeting. The Board then received reports from the standing committees. Regarding annual meeting matters, the Board re-elected Ms. LaFleur as Chair of the Board of Directors, and adopted the committee assignments recommended by the Nominating and Governance Committee, as follows:

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

- Mses. Flax and LaFleur and Messrs. Colangelo, Ivey, van Welie, Vannoy and Williams shall serve on the **Joint Nominating Committee**, with Mr. Colangelo to serve as Chair;

- Ms. Flax and Messrs. Curran, Corneli and Vannoy shall serve on the **Markets Committee**, with Mr. Curran to serve as Chair;

- Mses. Anders and LaFleur and Messrs. Colangelo and Vannoy shall serve on the **Nominating and Governance Committee**, with Mr. Colangelo to serve as Chair;

- Ms. Anders and Messrs. Colangelo, Ivey and Williams shall serve on the **System Planning and Reliability Committee**, with Ms. Anders to serve as Chair.

The Board also elected the Company's officers for the upcoming year, reviewed assignments of directors as liaisons to individual states, and thanked retiring director Roberto Denis for his service on the Board.

GORDON VAN WELIE, PRESIDENT & CEO, ISO NEW ENGLAND

BEFORE THE HOUSE ENERGY & COMMERCE COMMITTEE

SUBCOMMITTEE ON ENERGY, CLIMATE, & GRID SECURITY

THURSDAY, SEPTEMBER 28, 2023

Chairman Duncan, Ranking Member DeGette, Chairwoman Rogers, Ranking Member Pallone, and Members of the Committee, thank you for the opportunity to appear before you today.

My name is Gordon van Welie, and I am the President and Chief Executive Officer of ISO New England.

ISO New England is the independent, not-for-profit corporation responsible for keeping electricity flowing across the six New England states and ensuring that the region has reliable, competitively priced wholesale electricity today and into the future. We do this by executing our three core responsibilities – operating the grid, administering the competitive wholesale electricity market, and providing power system planning.

ISO New England is also committed to working with the New England states and our stakeholders to enable a reliable transition to an economy powered by clean energy. This is a monumental task and it requires four critical pillars to provide a robust foundation for the transition: New England will need to add significant amounts of clean energy to the grid; ensure we have sufficient flexible resources to balance the moment-to-moment variability of renewable energy; ensure that we have sufficient backup energy for those periods when renewables cannot perform; and we will need to further build out the region's transmission infrastructure to meet significantly higher demands on the electric grid.

We are transitioning to a power system that will have to meet a doubling of average demand and a tripling of winter peak demand by 2050. Moreover, this demand must be met with a resource mix where the majority of resources have variable production characteristics or are energy constrained under certain conditions. Our challenge is figuring out how much energy we will get from this evolving fleet of resources, how to ensure reliability through the wholesale market design and how to plan the transmission system to integrate the renewables and meet the forecast demand.

The outlook for reliability is manageable assuming certain assumptions hold up. These assumptions include a robust market design that assures resource and energy adequacy. Additionally, this assumes that the market will respond, (either to wholesale price signals or to state contracts), with new resources to meet increased electrification load and replace retiring resources; that there will be a reliable gas system and a responsive oil-supply chain; that transmission will be built to interconnect wind and to import incremental Canadian hydropower; that the region has readily available access to imported LNG; and that electricity production limitations due to emissions restrictions on generators will be manageable.

ISO New England has been working with the Electric Power Research Institute (EPRI) to conduct a probabilistic energy-security study for New England that provides a framework to assess risks associated with extreme weather events. The study tool provides an early warning system to inform the region on the magnitude of these risks and provides a basis for developing solutions. We have done analysis of two initial timeframes: 2027 and 2032.

We believe the risks in the 2027 timeframe are manageable, primarily due to the positive effect of significant regional investments in solar resources and energy efficiency, which have slowed demand growth, the fact that we have a committed resource mix for that timeframe through the forward capacity market, and the significant investments in the ISO market design and operator tools. We have developed enhanced tools to forecast a potential energy shortfall on a rolling, three-week basis. If we do forecast a shortfall, we can work with market participants to increase fuel inventories, and work with state officials to urge the public to conserve energy to mitigate the impact of a potential energy shortfall. These actions could be necessary due to the reality that the New England system is under stress during extended periods of cold weather when the region's fuel infrastructure is constrained.

The variables and risks in the 2032 timeframe are greater; however, these risks can be mitigated if the New England states, the ISO, and the FERC take proactive action.

The biggest long-term risk is that the region cannot maintain sufficient resource or energy adequacy to meet the demand for electricity. This could be caused by the rate of electrification outpacing the addition of new resources, or existing generators retiring prematurely, or the imposition of additional constraints on the utilization of the existing oil and gas generators.

The single biggest variable affecting resource adequacy is the efficacy of the FERC-regulated wholesale markets. The market structure is under increasing pressure to deliver outcomes that support both the states' decarbonization objectives and the region's reliability objectives. Ensuring an effective and durable market design that can address both objectives requires strong support for market improvements from both the state and federal regulatory community. In particular, our studies have shown that as more renewables are added to the power system, it will put downward pressure on energy market revenues, creating more reliance on increased capacity market revenues, or in the worst case, widespread reliance on contracts to retain selected resources needed for reliability. The latter outcome will result in an unwinding of the competitive wholesale market construct. I believe the most efficient, market-based solution to this problem is effective carbon pricing, which would drive innovation in the market by compensating new and existing clean energy resources for their carbon free energy, while also providing powerful incentives to existing carbon emitting resources to reduce their carbon emissions. In order to mitigate the wholesale price effects, the ISO has recommended implementing a form of carbon pricing called "net carbon pricing" that would automatically rebate the bulk of the collected carbon emission revenues back to consumers.

In addition, New England has particularly severe gas pipeline constraints during the winter that limit the delivery of gas into the region and therefore exacerbate energy adequacy risks. Natural gas generators supply about half of New England's electricity needs on an annual basis, yet the interstate pipelines are not designed to serve peak demand from both home heating and power generation. As a result, the generation mix switches to using significant amounts of oil and imported liquefied natural gas (LNG) in the winter. This creates price volatility during periods of cold weather and potential reliability risks if the supply chain for these fuels is compromised.

As has been demonstrated in recent events in other regions, the electric and gas systems are interdependent and a failure in one system impacts the other. ISOs have no jurisdiction over the natural gas system and do not have the expertise to determine whether it will remain reliable through the energy transition. Gas infrastructure and supplies will be needed well into the future until commercially available renewable fuels, or alternative technologies, are economic. In particular, while we expect that the average usage of gas will decline, our modeling shows that the peak demand for gas and oil will increase during periods when renewables are not able to perform. Our studies indicate that the most vulnerable scenarios occur during winter cold snaps. This raises difficult economic and regulatory questions that straddle multiple regulatory jurisdictions – namely, who will invest in the low capacity factor supply and demand response resources to support both the electric and gas systems during these periods of vulnerability, and how should the costs of these resources be recovered?

I believe that policymakers and regulators should be thinking of the reliability of the energy system as a whole. In that regard, I commend the recommendations in the report on Winter Storm Elliot issued jointly by the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC). I would like to highlight the recommendation that federal and state legislation is needed to provide more oversight to the reliability of the gas system. Congress established rigorous regulatory oversight and mandatory standards over the bulk electric system after the 2003 blackout, but has not established a comparable level of oversight and standards for the single biggest source of energy to that system. I urge this committee to support the report's recommendations and take the necessary action to assure the reliability of the energy system as a whole.

Thank you.

NEPOOL Participants Committee Report

October 2023

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Highlights

Data is through September 27th, unless otherwise noted.

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: August 2023 Energy Market value totaled $310M
  - September 2023 Energy market value was $324M, up $14M from August 2023 and down $368M from September 2022
  - September natural gas prices over the period were 18% higher than August average values
    - Average RT Hub Locational Marginal Prices ($33.69/MWh) over the period were 17% higher than August averages
      - DA Hub: $30.92/MWh
    - Average September 2023 natural gas prices and RT Hub LMPs over the period were down 76% and 45%, respectively, from September of last year
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 100.6% during September, up from 99.6% during August
      - The minimum value for the month was 94.9% on Tuesday, September 19th

*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

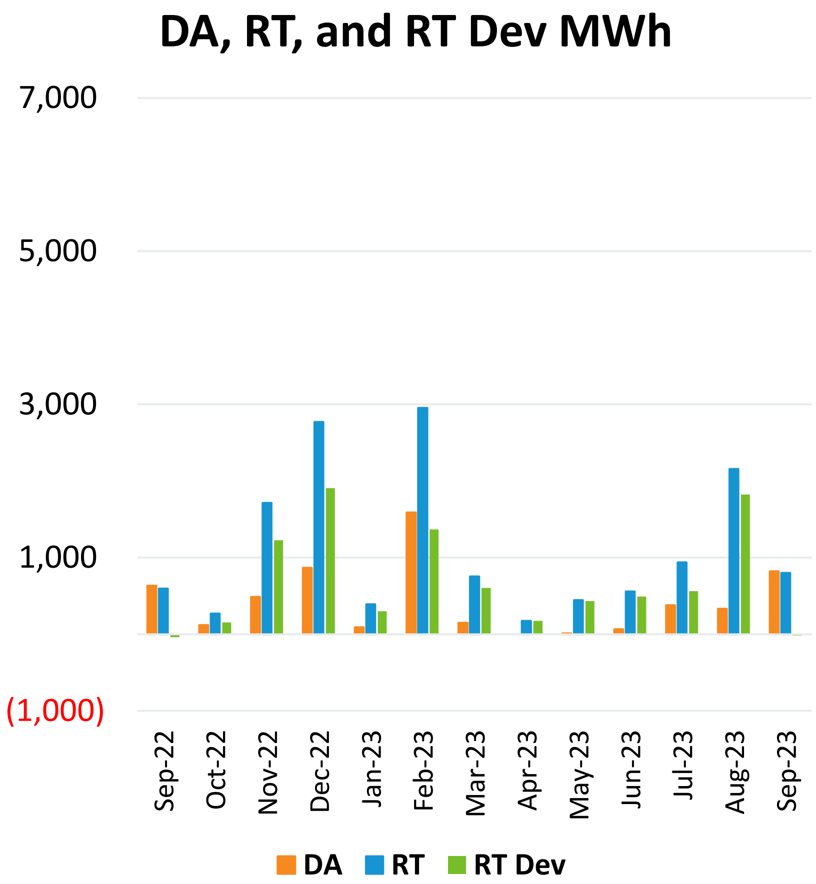
Underlying natural gas data furnished by: ICE Global markets in clear view

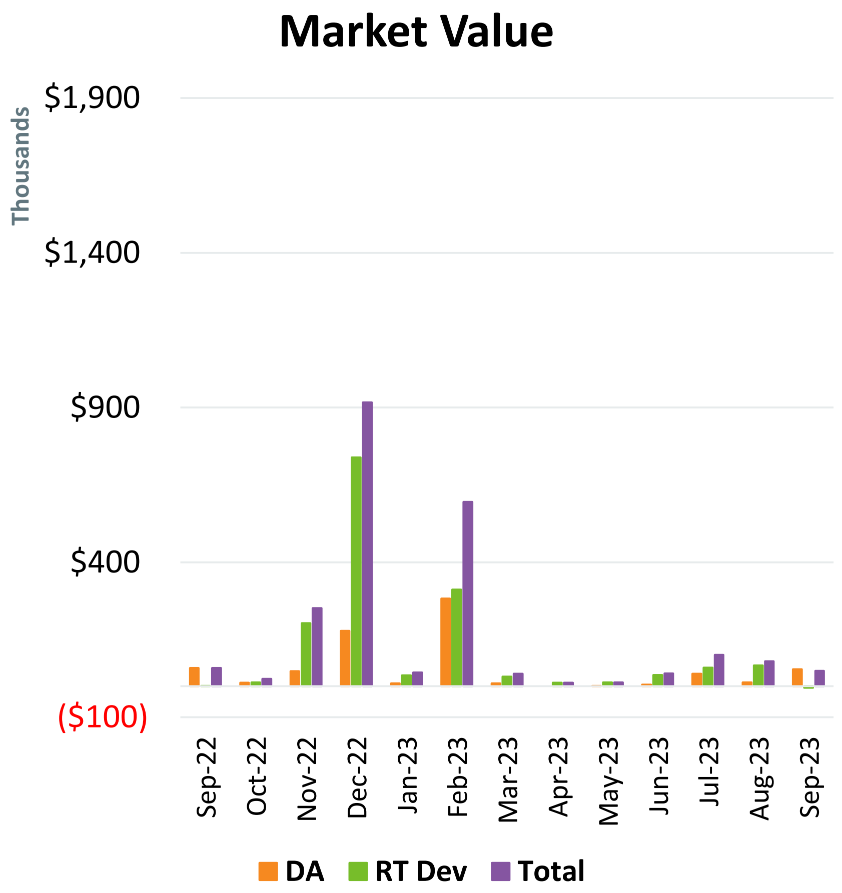
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - September 2023 NCPC payments totaled $3.4M over the period, up $1.2M from August 2023 and up $1.3M from September 2022
    - First Contingency payments totaled $3.3M, up $1.5M from August
      - $3.2M paid to internal resources, up $1.5M from August
        - » $160K charged to DALO, $2.3M to RT Deviations, $751K to RTLO*
      - $82K paid to resources at external locations, down $49K from August
        - » All charged to RT Deviations
    - Distribution payments totaled $67K, down $195K from August
      - Local protection for Martha's Vineyard early in the month
    - Second Contingency and Voltage payments were both zero
  - NCPC payments over the period as percent of Energy Market value were 1.0%
    - Elevated NCPC due to stressed conditions early in the month; Relatively low Energy Market Value (low natural gas and DA energy pricing)

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $300K; Rapid Response Pricing (RRP) Opportunity Cost - $451K; Posturing - $0K; Generator Performance Auditing (GPA) - $0K**

Price Responsive Demand (PRD) Energy Market Activity by Month





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

Forward Capacity Market (FCM) Highlights

- CCP 14 (2023-2024)
  - Third and final annual reconfiguration auction (ARA3) was held on March 1-3, and results were posted on March 30
- CCP 15 (2024-2025)
  - Second annual reconfiguration auction (ARA2) was held on August 1-3, and results were posted on August 24
  - At the September 21 PSPC meeting, ISO presented results for the CCP 15 ARA 3 tie benefits study
- CCP 16 (2025-2026)
  - First annual reconfiguration auction (ARA1) was held on June 1-5, and results were posted on July 3
- CCP 17 (2026-2027)
  - Auction results were filed with FERC on March 21 and, on July 18, FERC issued an order accepting the results effective July 19

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 18 (2027-2028)
  - FCA 18 will model the following zones:
    - Export-constrained zones: Northern New England and Maine nested inside Northern New England
    - Rest-of-Pool
  - New Capacity Qualification Package (NCQP) Submission Window closed on June 28, and review of the NCQPs is ongoing
  - ICR and related values were approved at the September 19 RC meeting

Highlights

- FCA 18 ICR and related values were approved by stakeholders at the September 19 RC meeting
- RSP Public Meeting will be held on November 1 and will be concurrent with the ISO Open Board Meeting
  - Presentation from Debra Lew, Associate Director, Energy Systems Integration Group
- Qualified Transmission Project Sponsor (QTPS)
  - 27 companies have achieved QTPS status
    - PPL Translink, Inc. was recently qualified
- The 2024 forecast cycle was initiated at the September 22 Load Forecast Committee (LFC) meeting
- The next LFC meeting will be held on November 13

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (1.8°F) Max: 93°F, Min: 49°F Precipitation: 3.75" – Above Normal Normal: 3.56"	Hartford	Temperature: Above Normal (2.1°F) Max: 95°F, Min: 43°F Precipitation: 12.18" - Above Normal Normal: 4.39"

Peak Load:	23,521 MW	September 7, 2023	18:00 (ending)

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

Procedure	Declared	Cancelled	Note
M/LCC 2	09/06/2023 17:29	09/06/2023 22:00	Projected Capacity Deficiency
M/LCC 2	09/15/2023 11:39	09/17/2023 11:48	Severe Weather

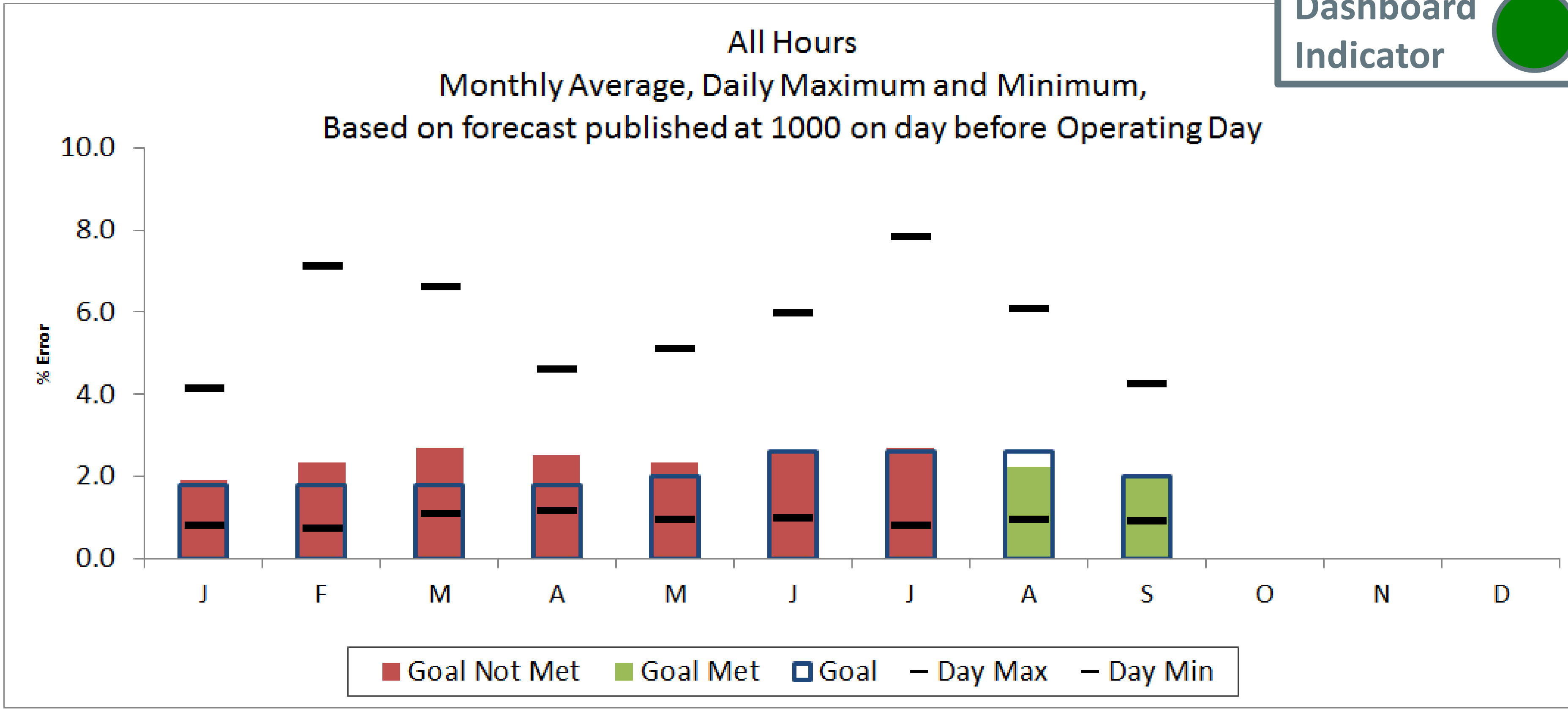
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
09/02/2023	NYISO	1258
09/06/2023	IESO	850
09/07/2023	IESO	900
09/09/2023	NYISO	563

2023 System Operations - Load Forecast Accuracy

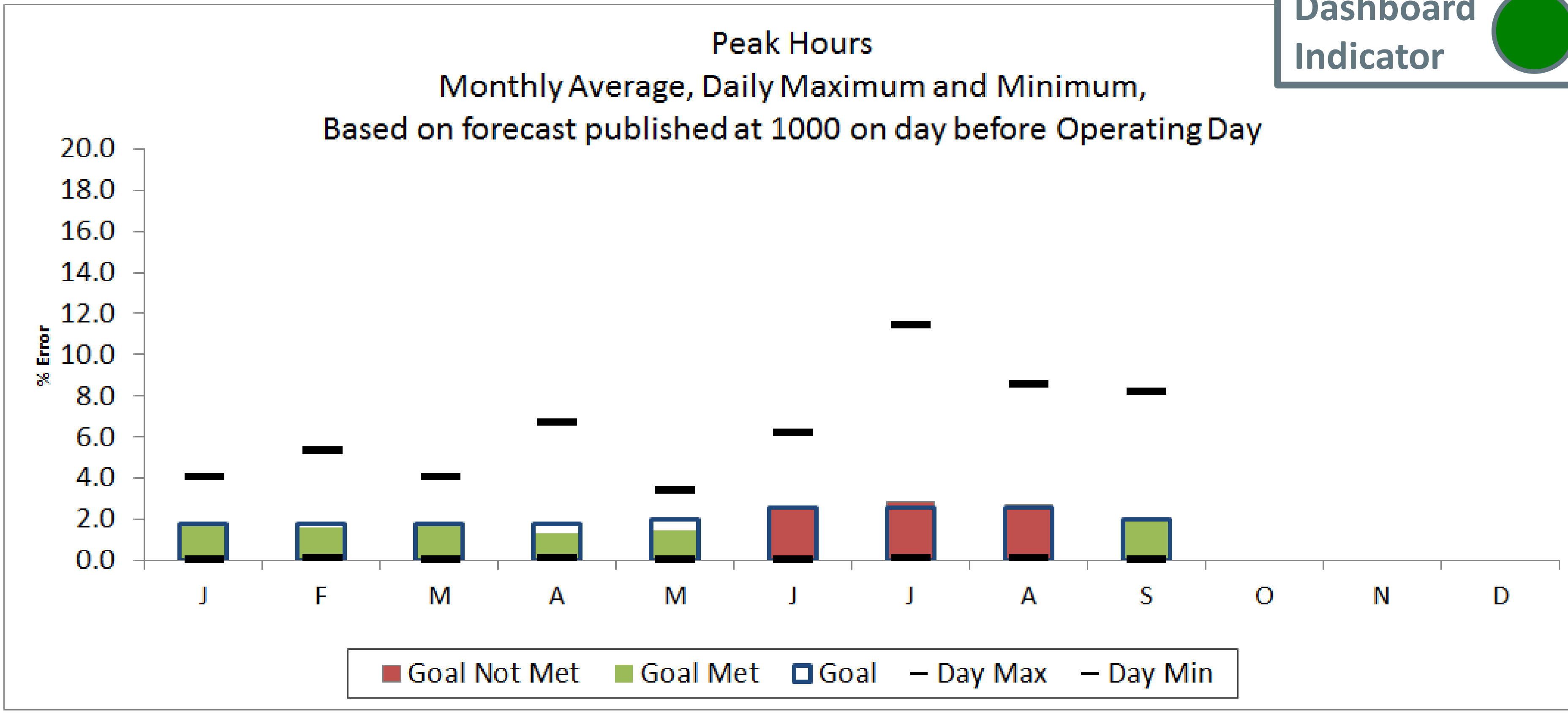
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.14	7.12	6.59	4.61	5.10	5.97	7.82	6.06	4.24				7.82
Day Min	0.80	0.74	1.08	1.17	0.96	0.97	0.79	0.95	0.91				0.74
MAPE	1.91	2.34	2.70	2.52	2.36	2.63	2.70	2.23	1.94				2.37
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00				

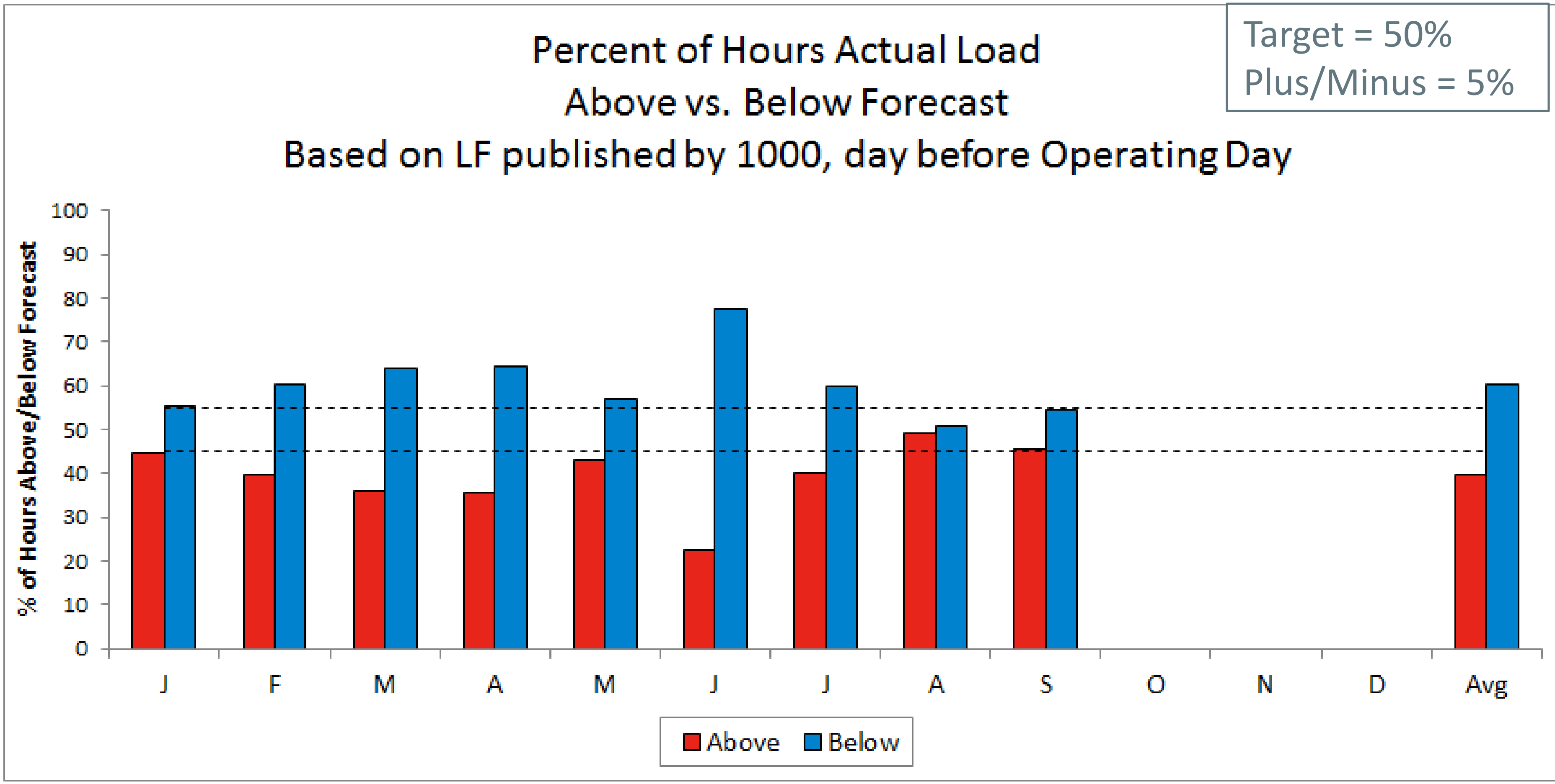
2023 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



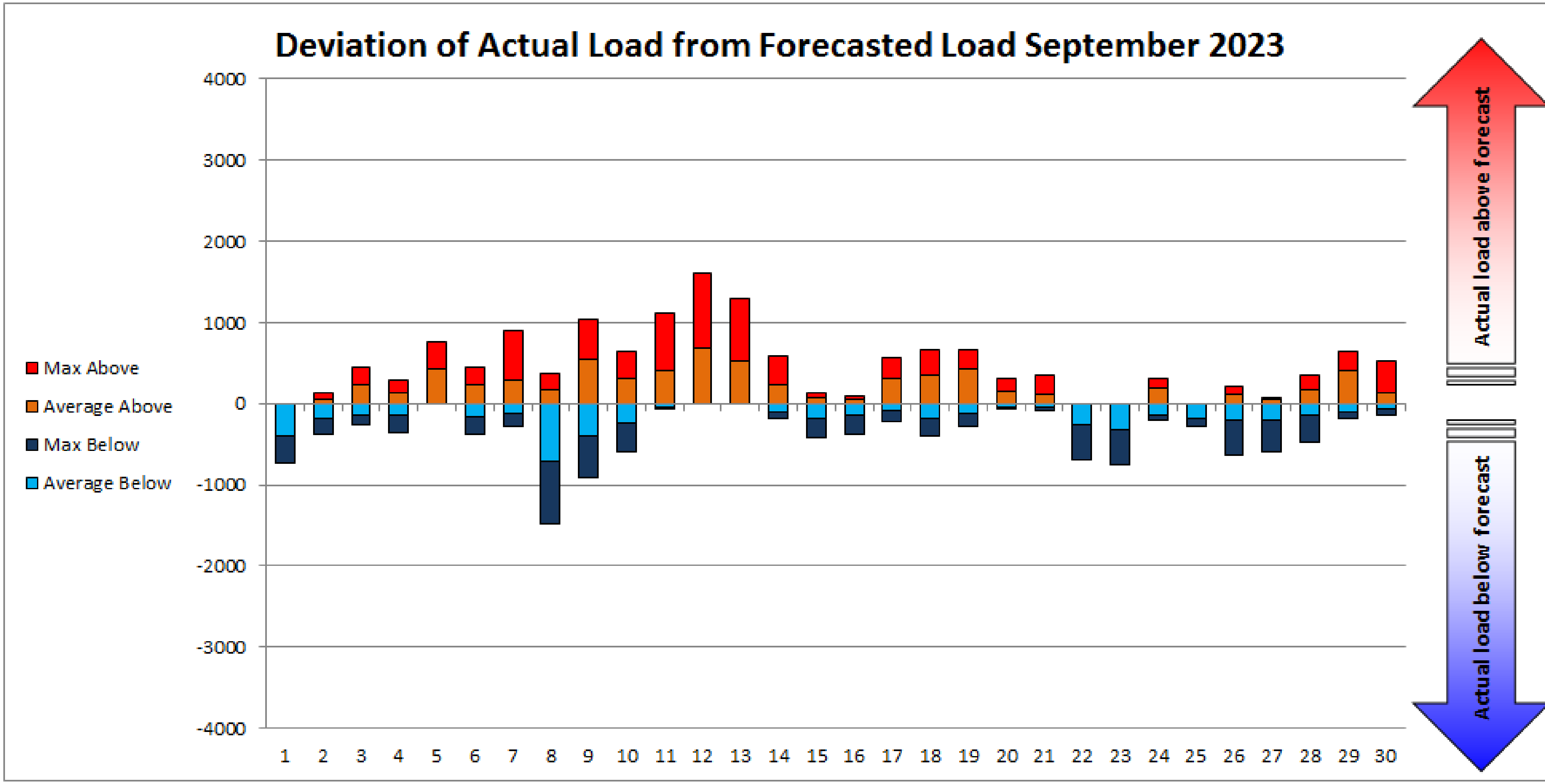
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.05	5.32	4.06	6.68	3.43	6.21	11.40	8.59	8.17				11.40
Day Min	0.01	0.08	0.06	0.11	0.03	0.04	0.08	0.14	0.01				0.01
MAPE	1.70	1.64	1.72	1.33	1.47	2.65	2.87	2.72	1.97				2.01
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00				

2023 System Operations - Load Forecast Accuracy cont.

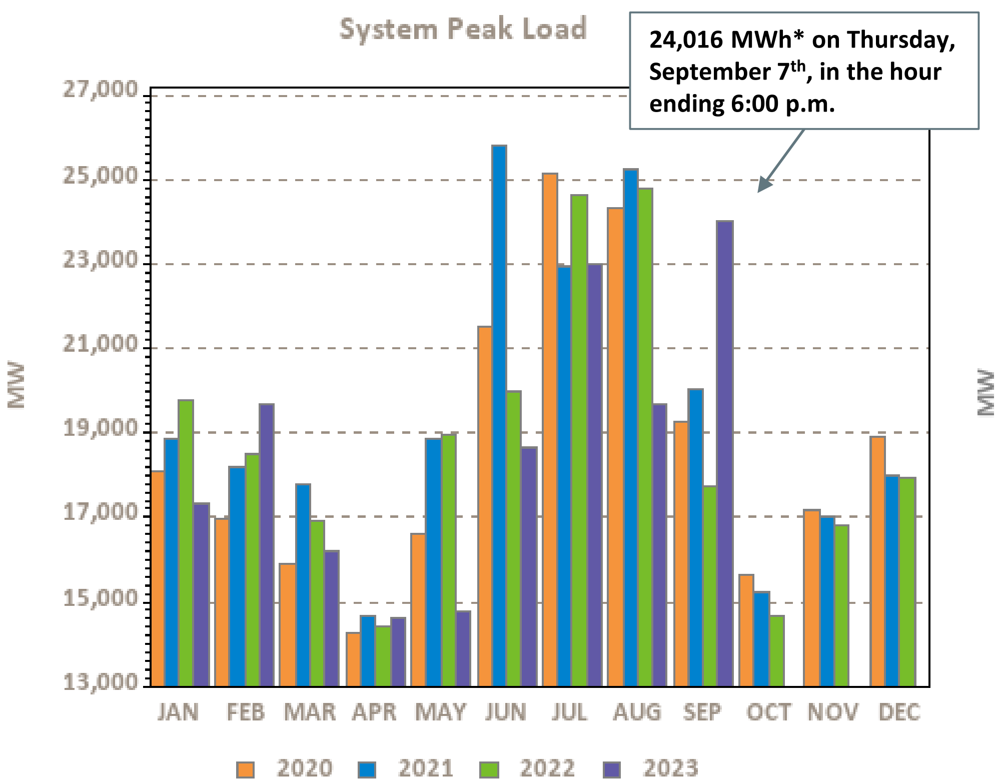


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	44.6	39.7	36.2	35.7	43	22.6	40.2	49.2	45.6				40
Below %	55.4	60.3	63.8	64.3	57	77.4	59.8	50.8	54.4				60
Avg Above	235.7	228	172.9	194.5	183.5	120	194.8	228.5	226				236
Avg Below	-197.3	-248.9	-328.3	-245.0	-200.1	-350.3	-388.6	-215.1	-169.7				-389
Avg All	-10	-28	-142	-74	-17	-236	-170	-6	20				-74

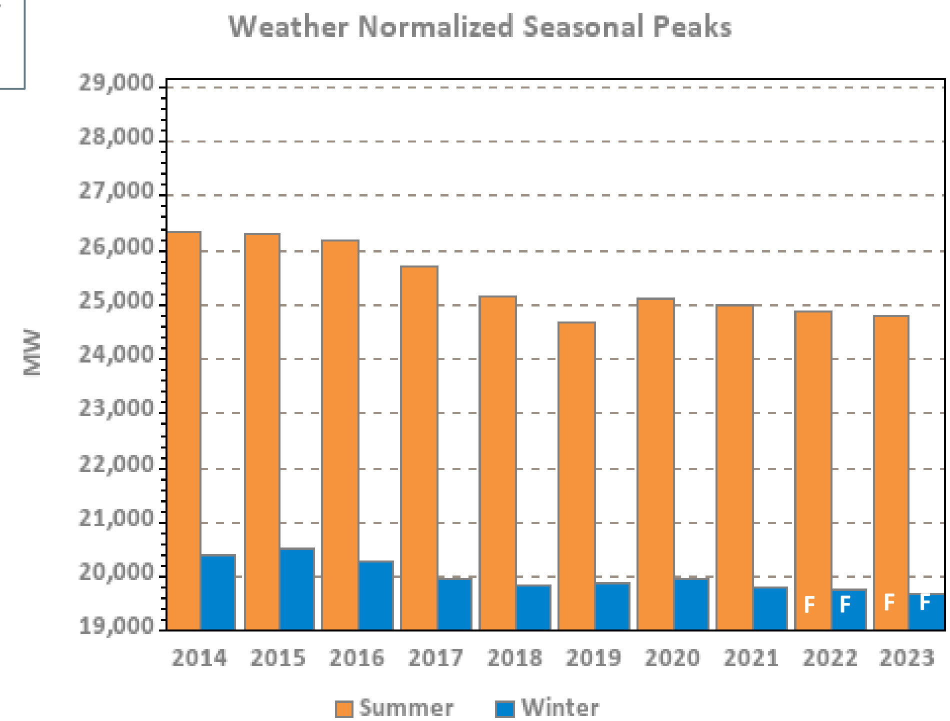
2023 System Operations - Load Forecast Accuracy cont.



Monthly Peak Loads and Weather Normalized Seasonal Peak History



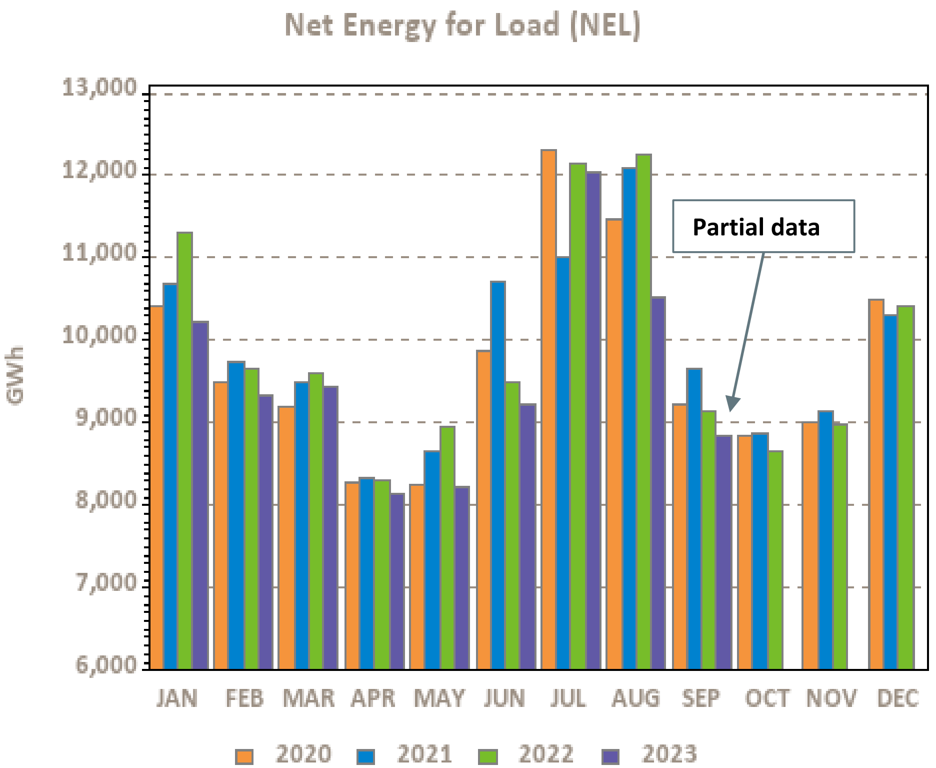
*Revenue quality metered value



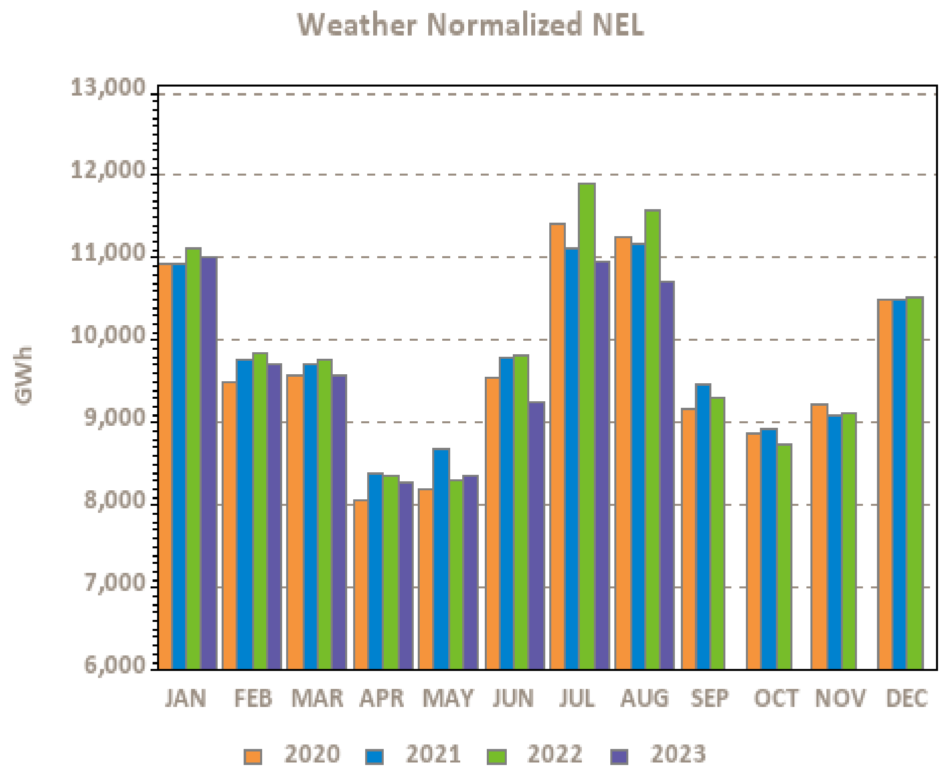
Winter beginning in year displayed

F – designates forecasted values, which are typically updated in April/May of the following year; represents "net forecast" (i.e., the gross forecast net of passive demand response and behind-the-meter solar demand)

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



Ann Tot (TWh): 116.9 118.8 118.9 86.0

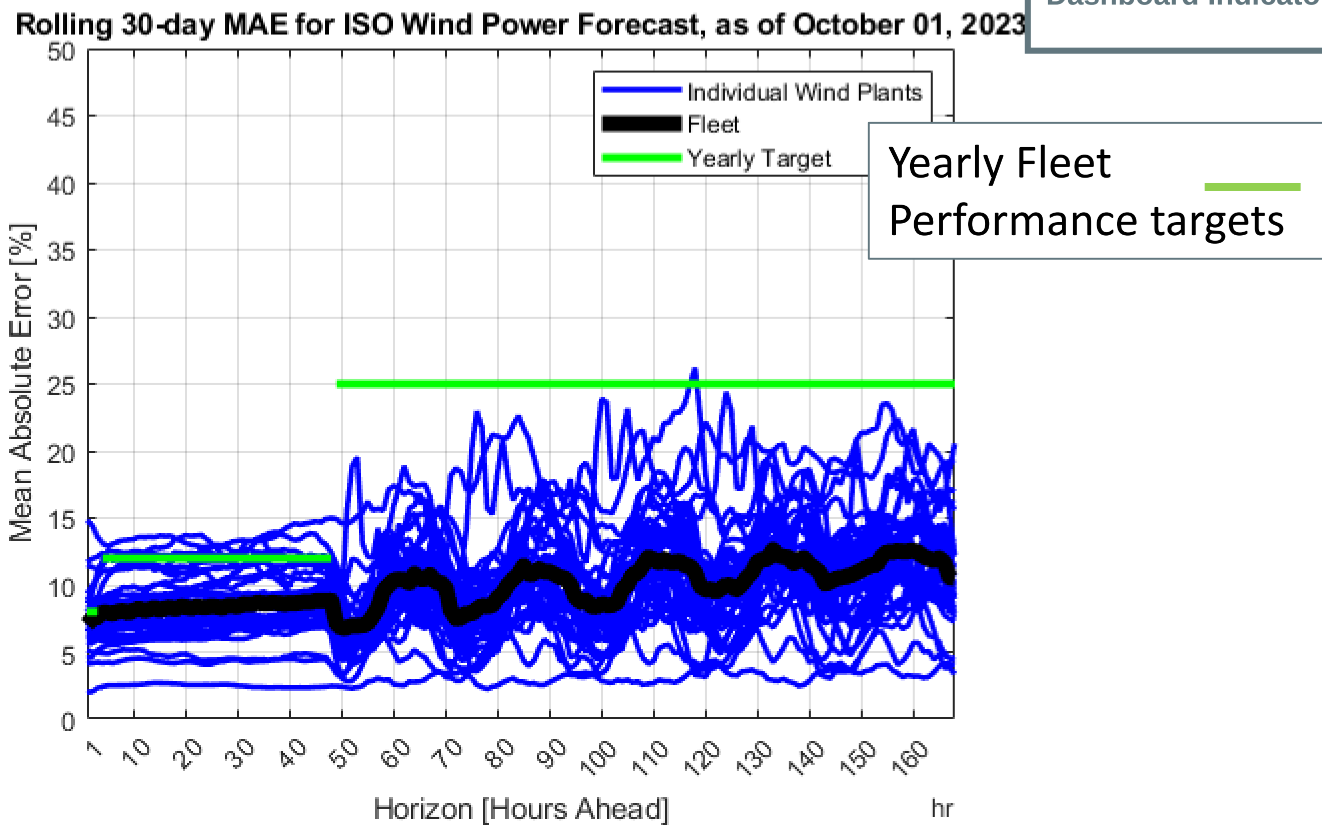


Ann Tot (TWh): 116.3 117.6 118.4 77.8

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 – 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.

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

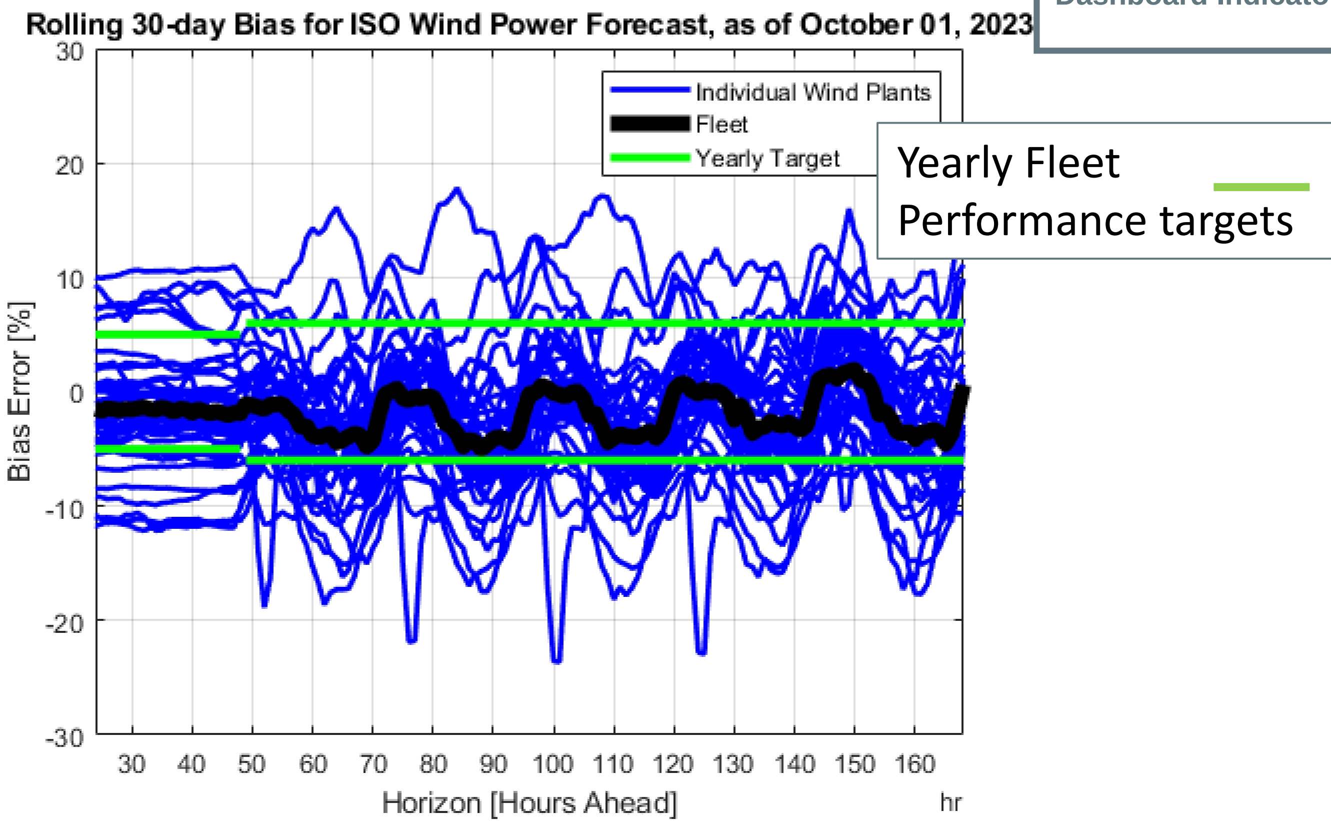
Dashboard Indicator



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 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

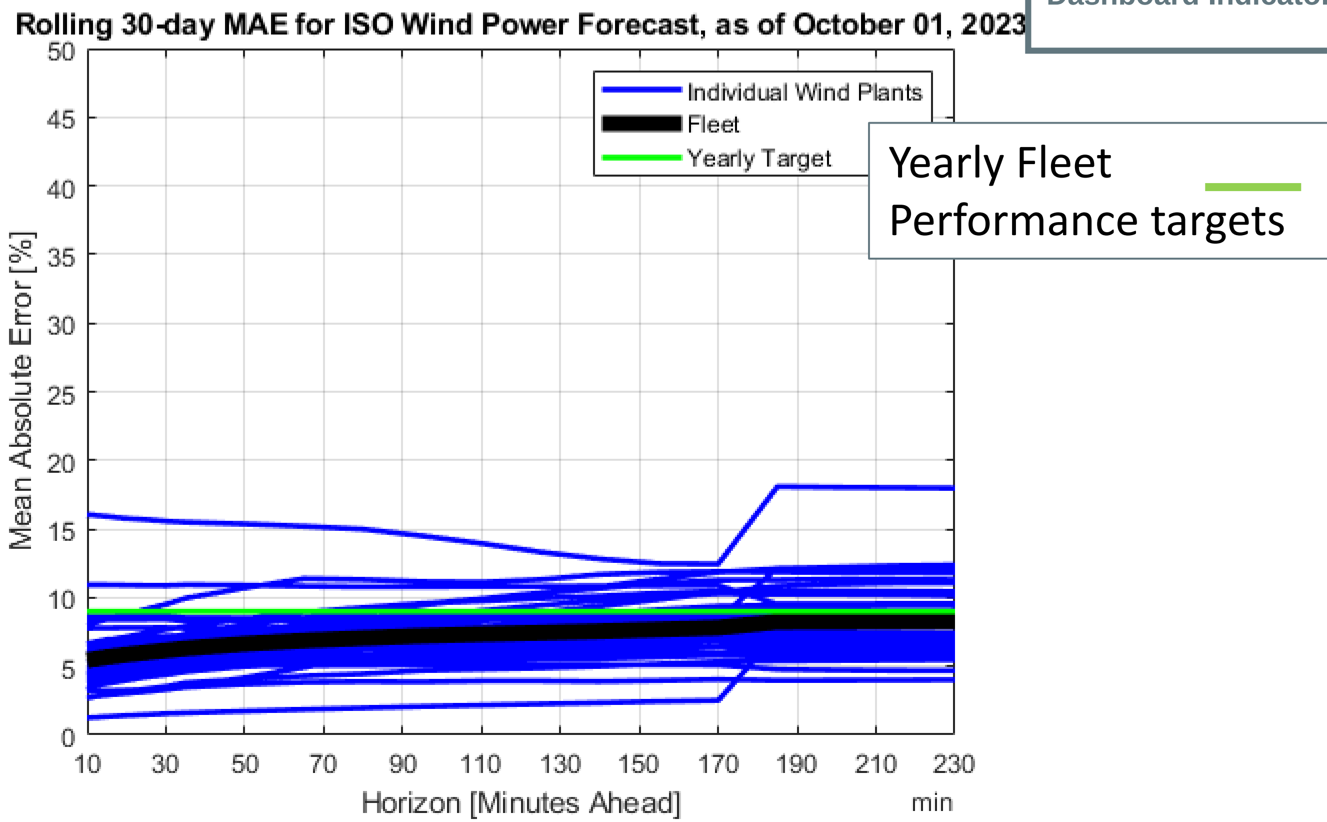
Dashboard Indicator



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



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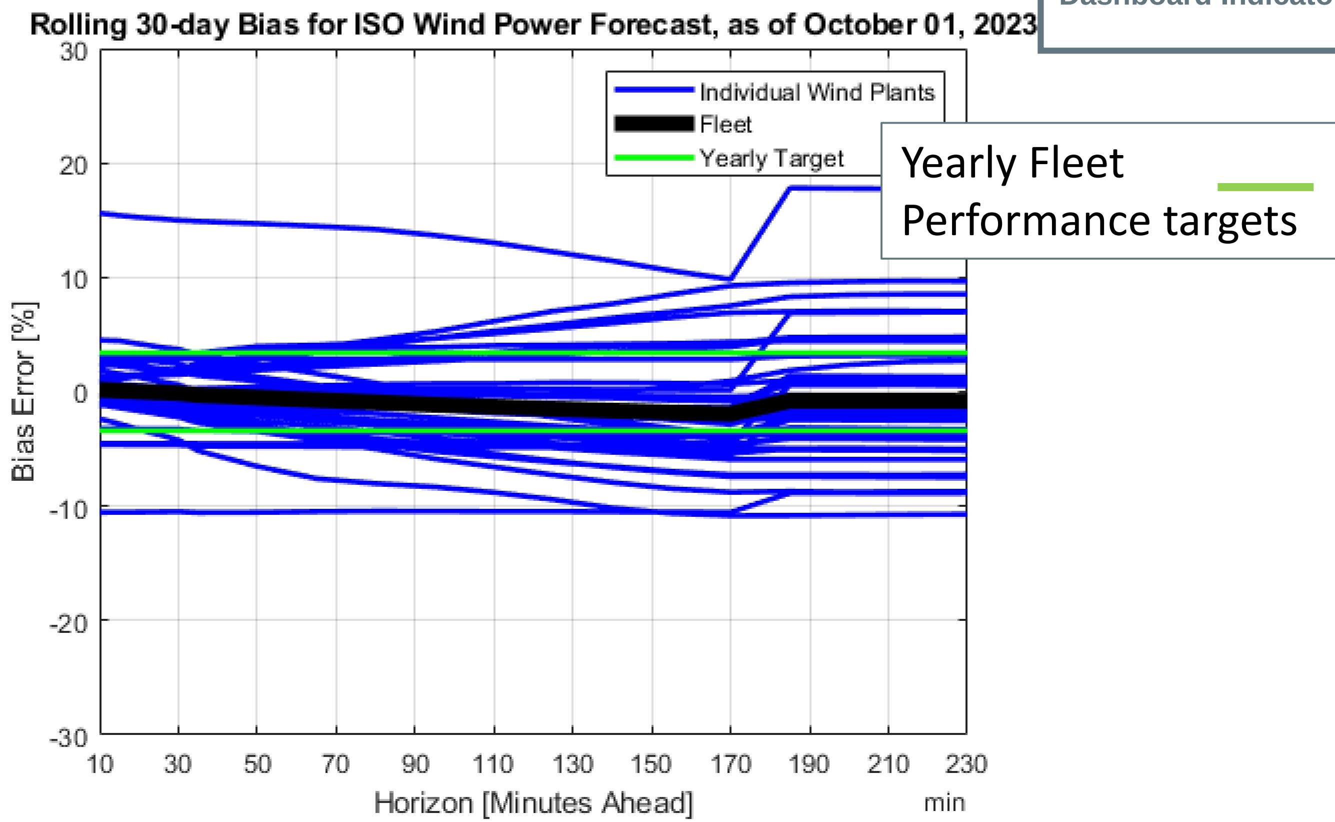
Wind Power Forecast Error Statistics: Short Term Forecast Bias

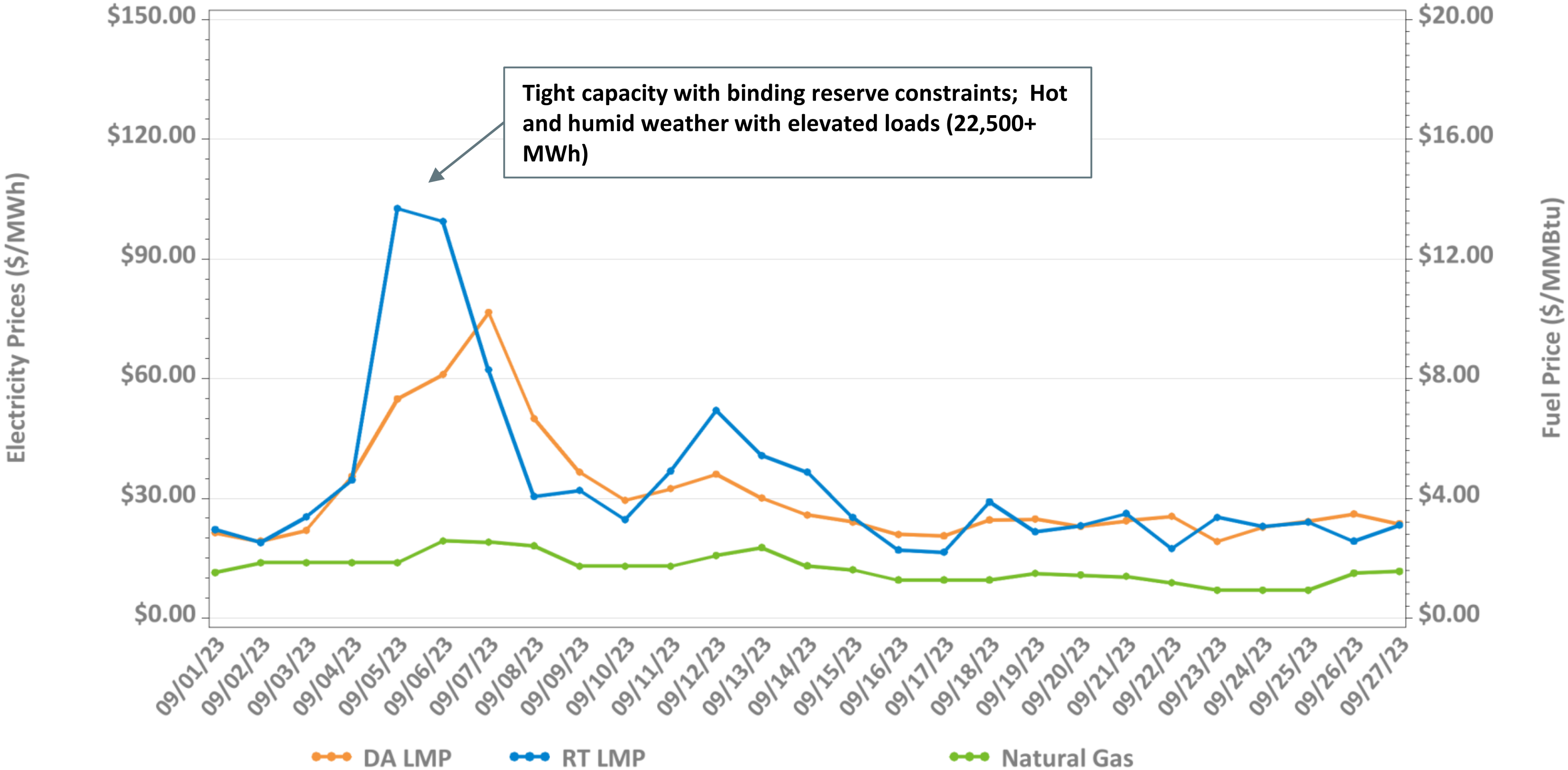
Dashboard Indicator



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.

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: September 1-27, 2023



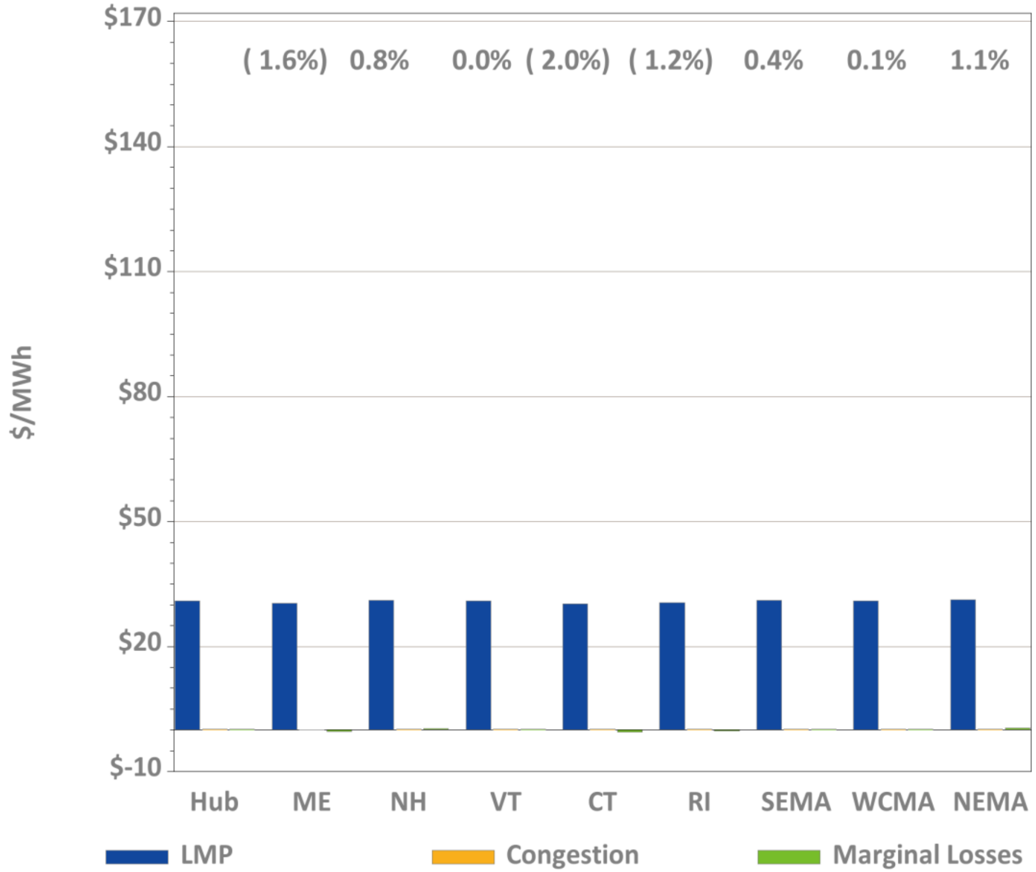
Underlying natural gas data furnished by:

ICE Global markets in clear view

*Revenue quality metered values

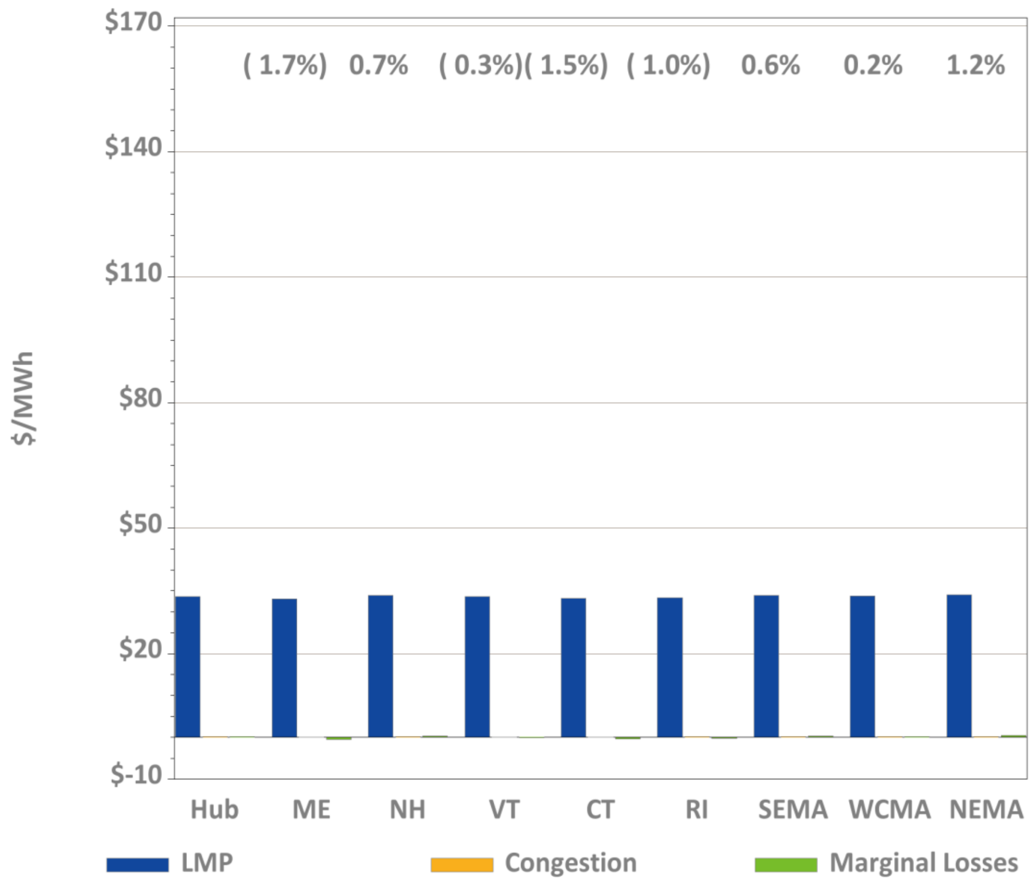
Average price difference over this period (DA-RT): $-2.77
Average price difference over this period ABS(DA-RT): $8.04
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 24%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, September 2023



ME - Maine
NH – New Hampshire
VT – Vermont
CT – Connecticut
RI – Rhode Island
SEMA – Southeastern Massachusetts
WCMA – Western/Central Massachusetts
NEMA – Northeastern Massachusetts

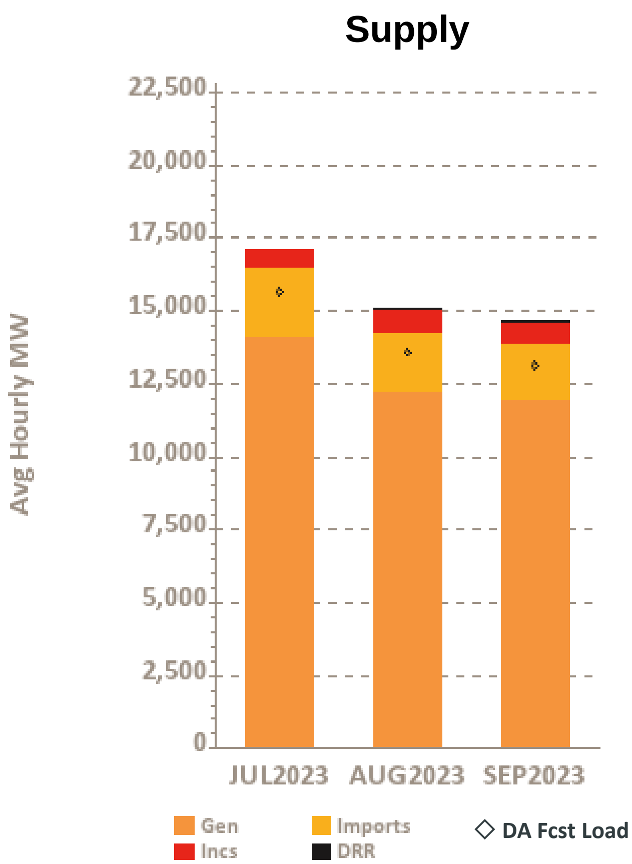
RT LMPs Average by Zone & Hub, September 2023

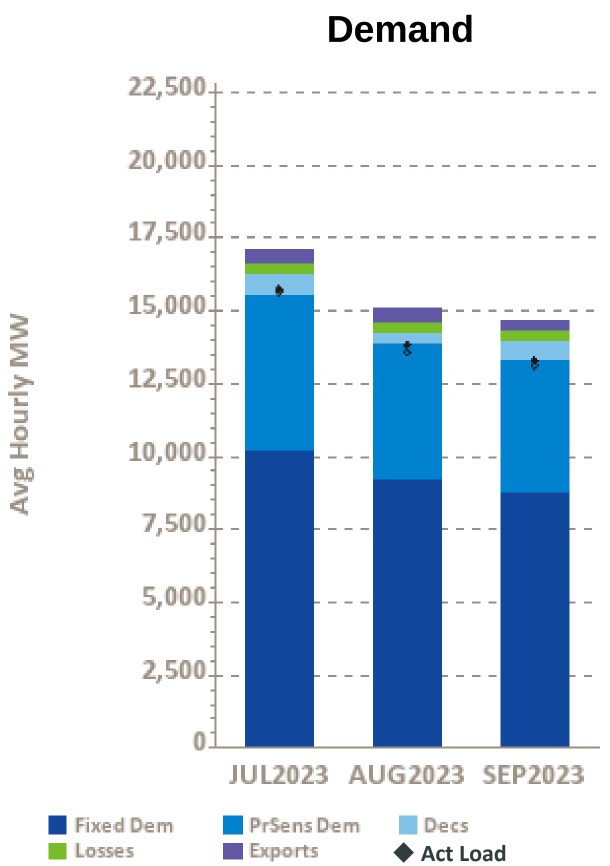


Definitions

Day-Ahead Concept	Definition
Day-Ahead Load Obligation **(DALO)**	The sum of day-ahead cleared load (including asset load, pump load, exports, and virtual purchases and excluding modeled transmission losses)
Day-Ahead Cleared Physical Energy	The sum of day-ahead cleared generation and cleared net imports

Components of Cleared DA Supply and Demand – Last Three Months

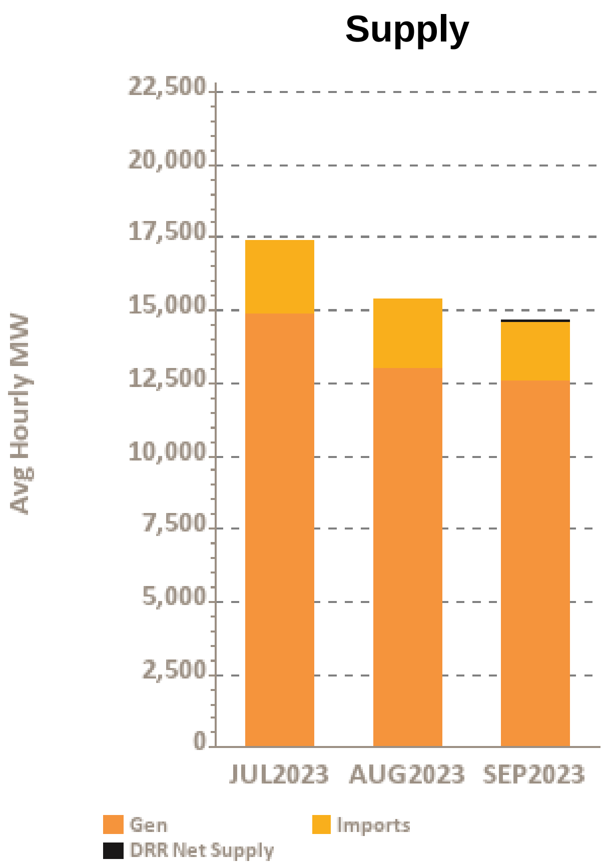


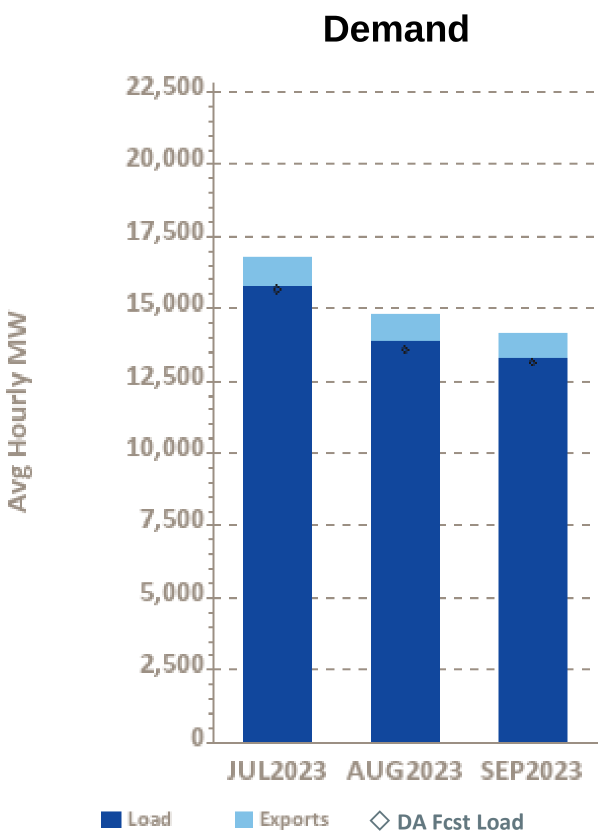


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

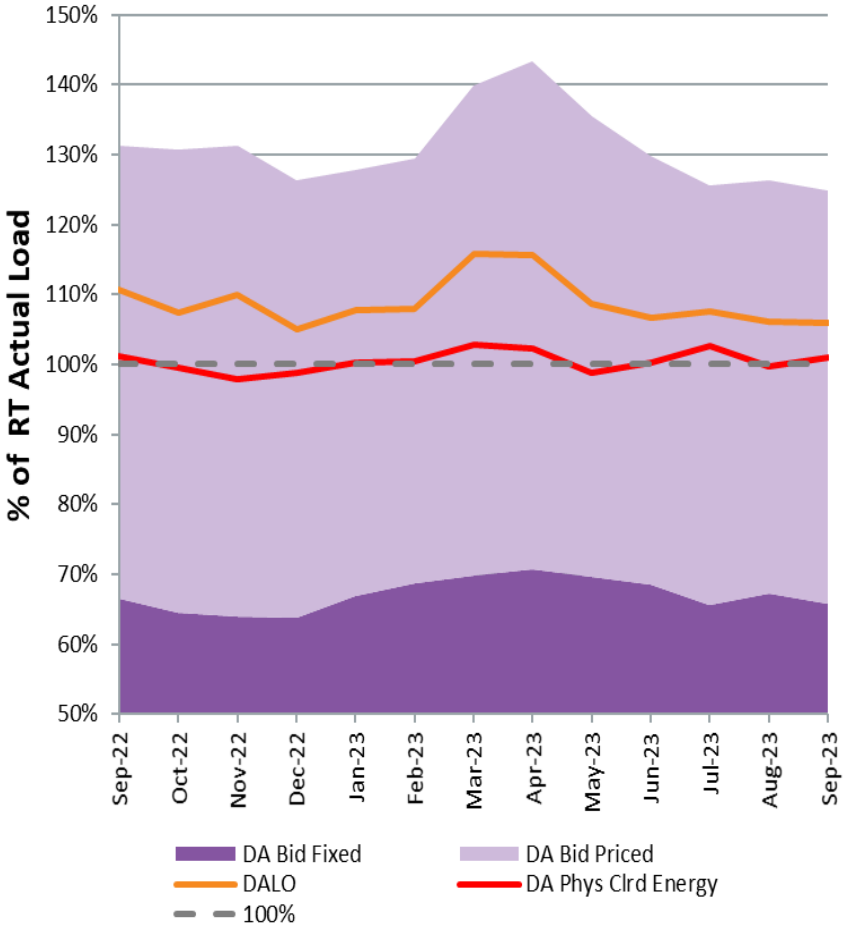
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

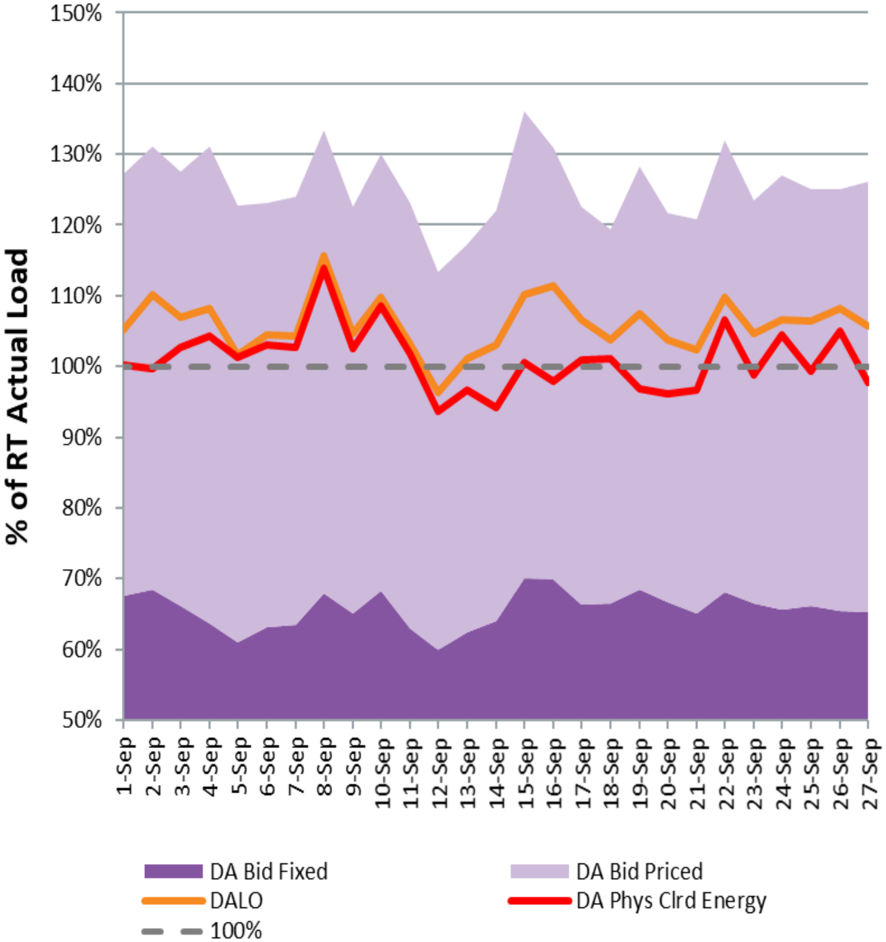
Components of RT Supply and Demand – Last Three Months





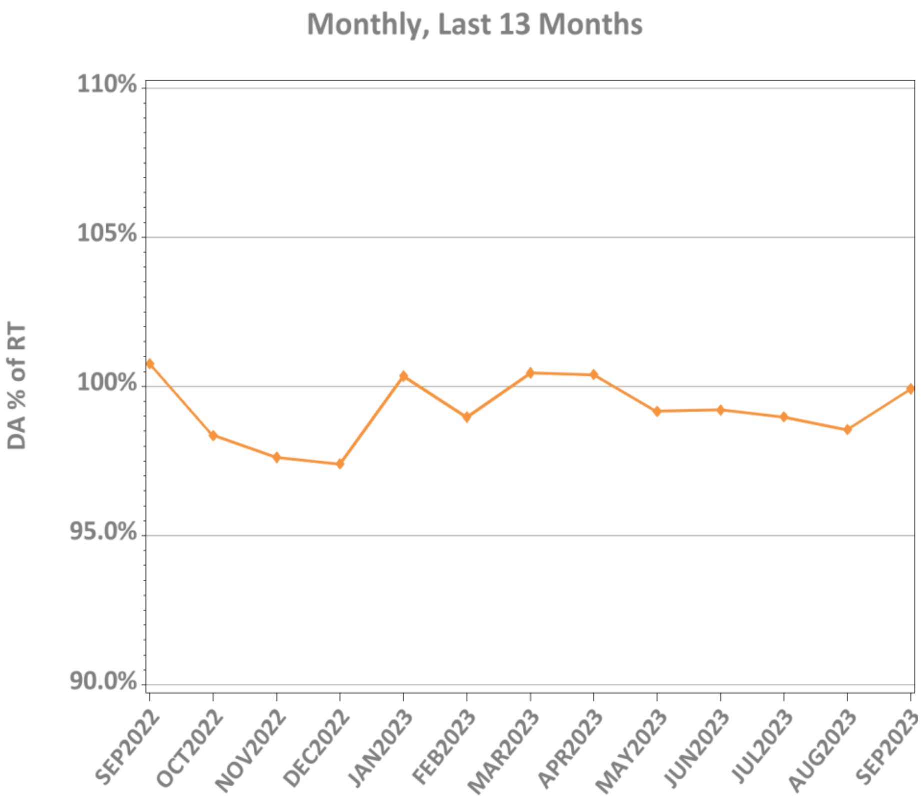
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

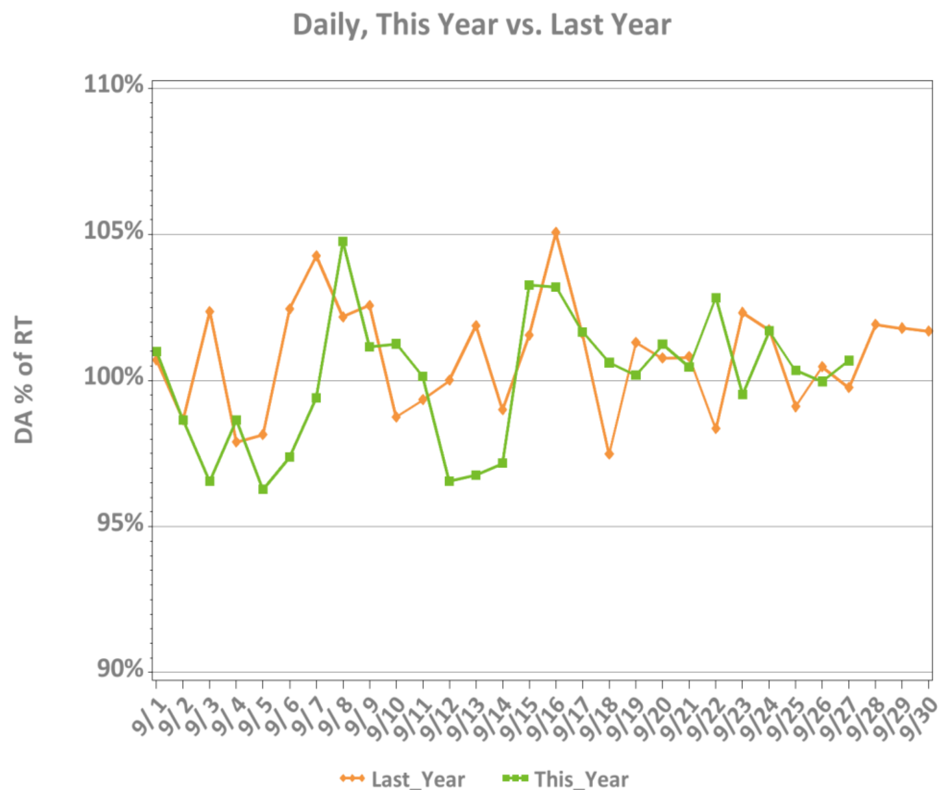




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

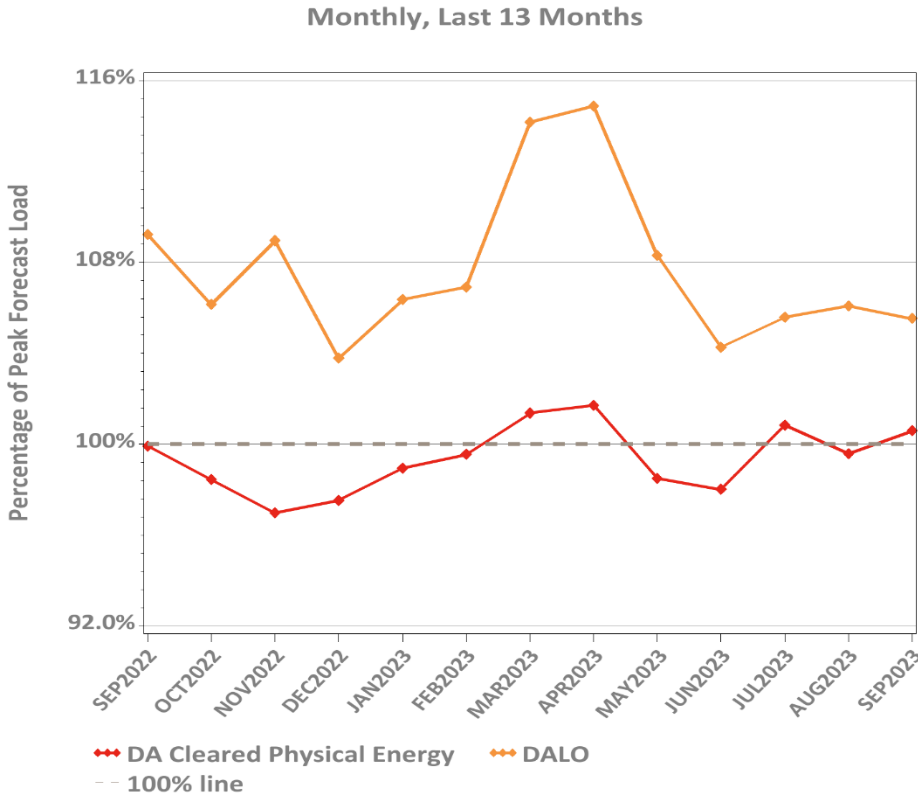
DA vs. RT Load Obligation: September, This Year vs. Last Year

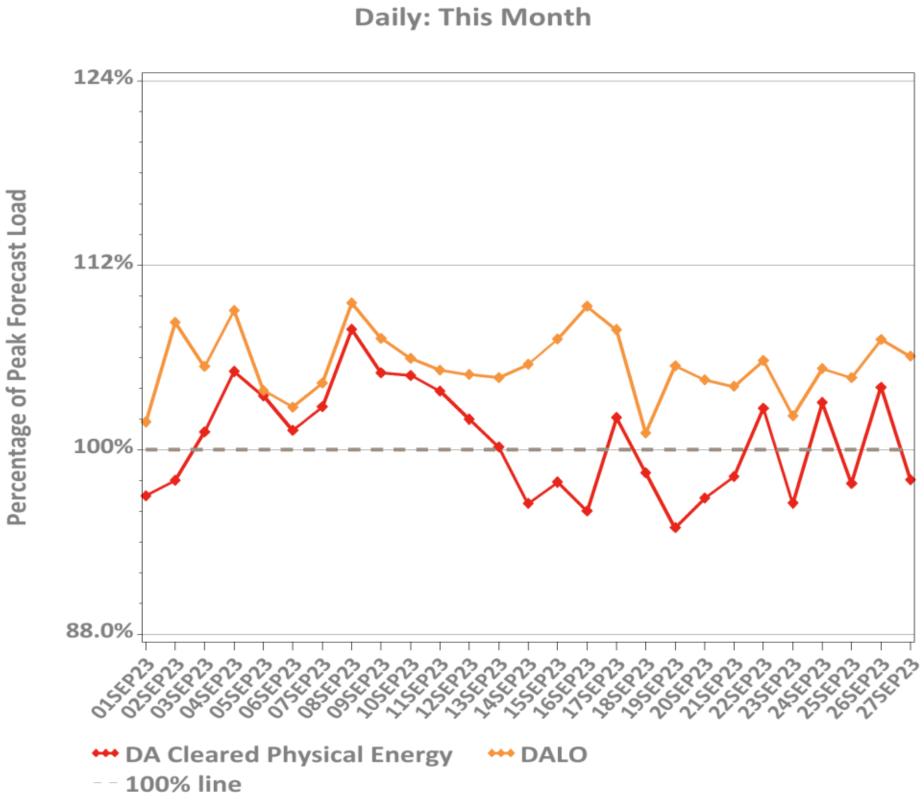




*Hourly average values

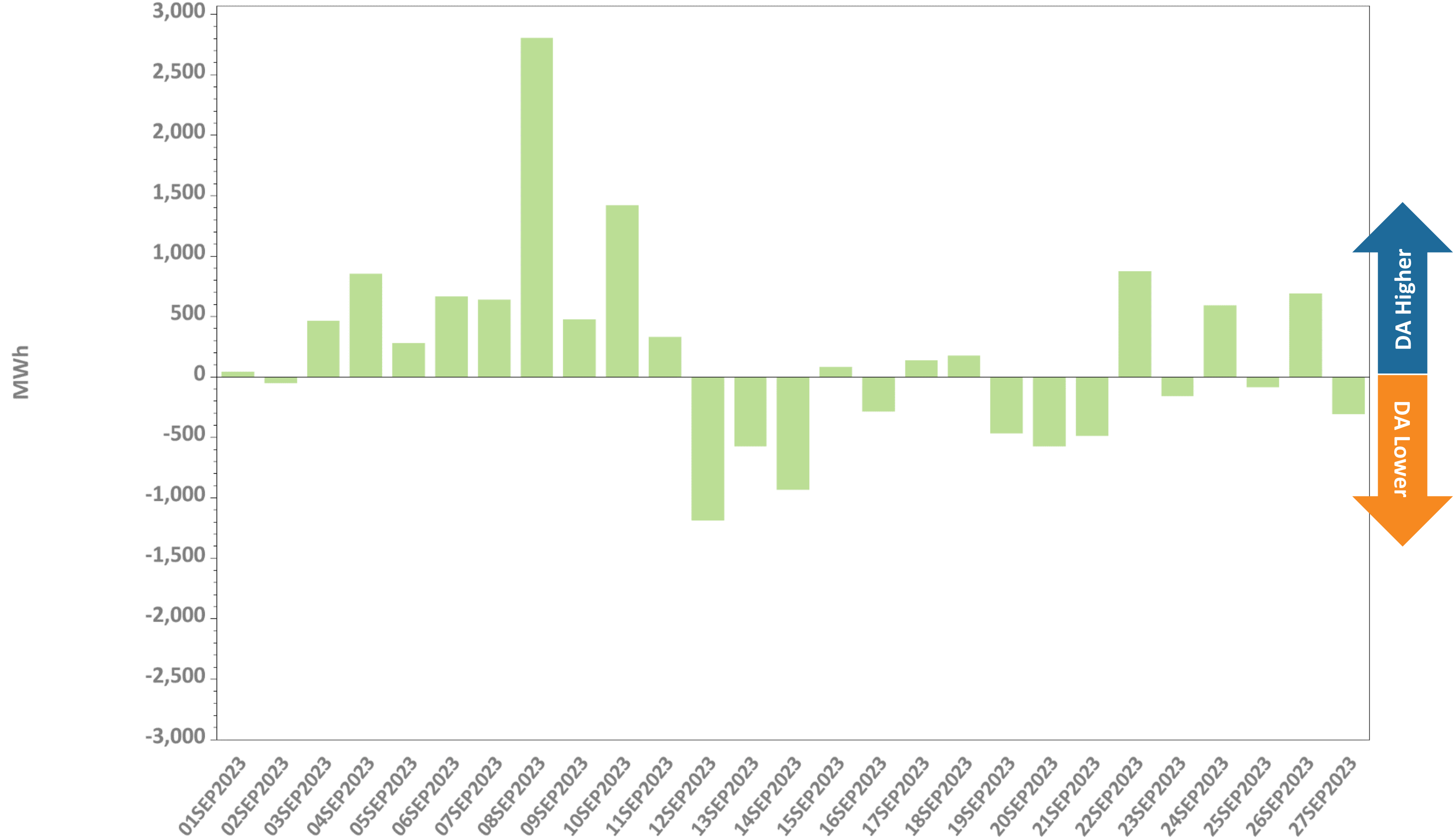
DA Volumes as % of Forecast in Peak Hour





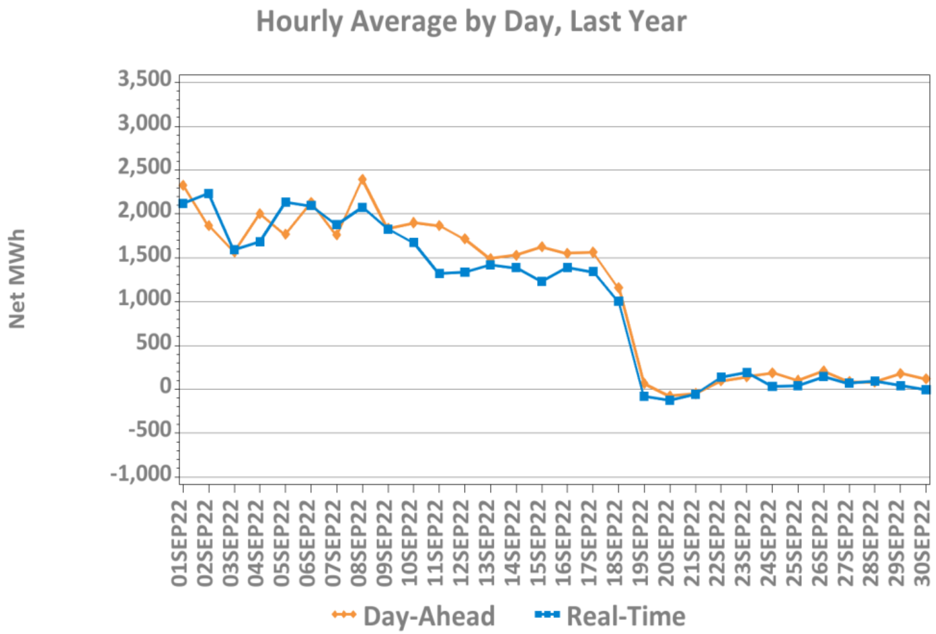
Note: The number of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month was: none

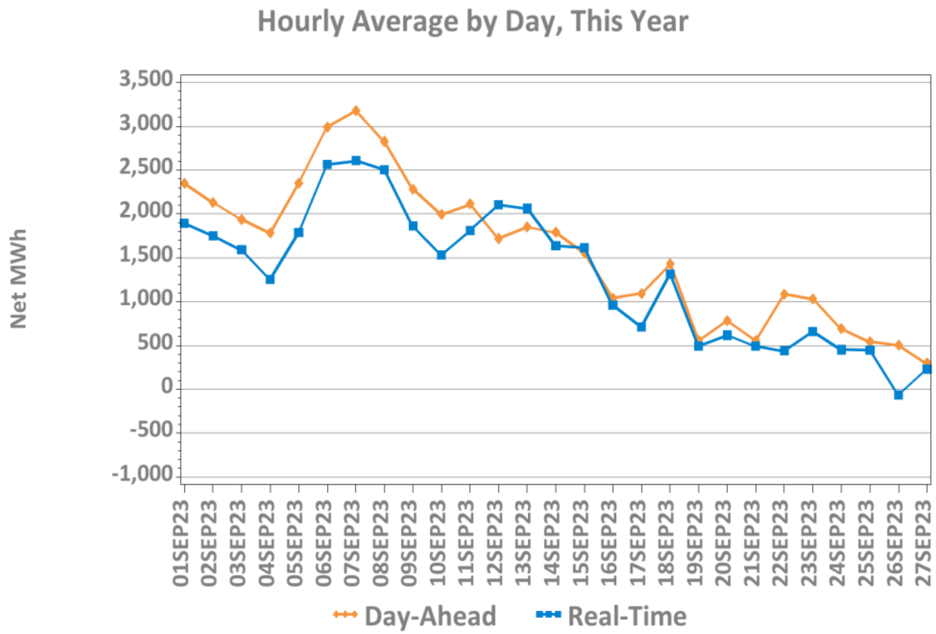
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



***Negative values indicate DA Cleared Physical Energy value below its RT counterpart. Forecast peak hour reflected.**

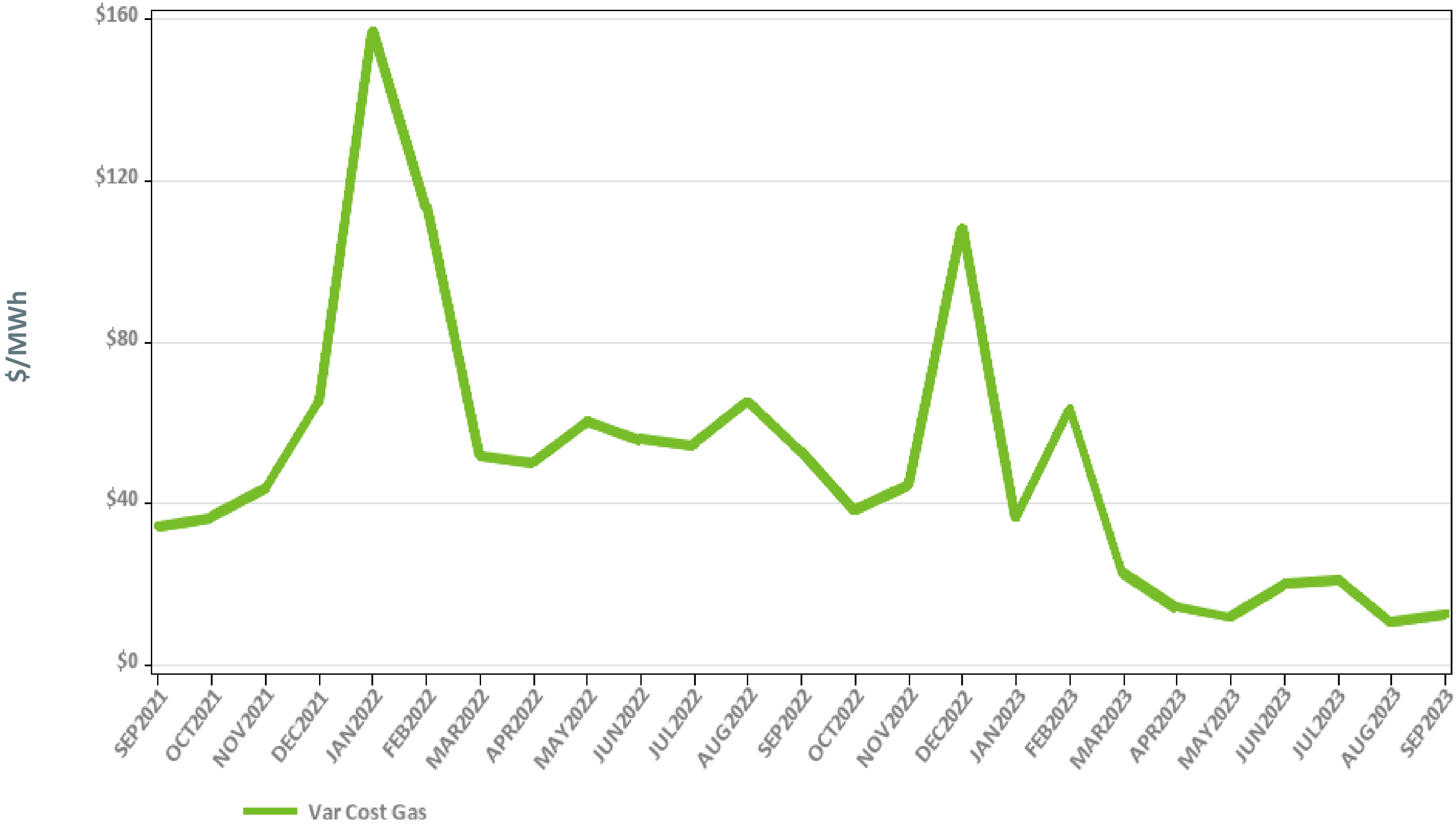
DA vs. RT Net Interchange September 2023 vs. September 2022





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

Variable Production Cost of Natural Gas: Monthly

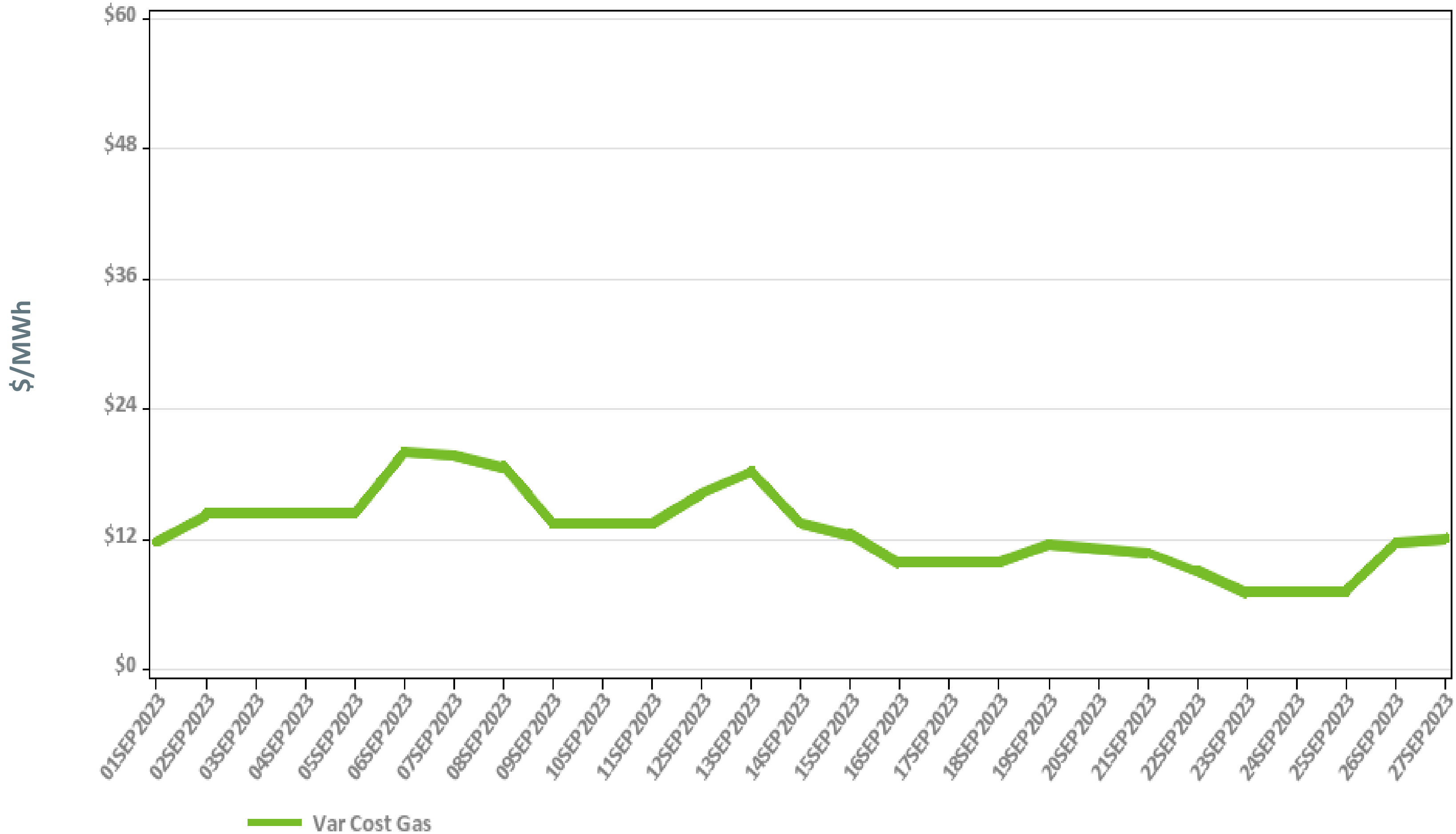


Underlying natural gas data furnished by:

ICE Global markets in clear view

Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Variable Production Cost of Natural Gas: Daily

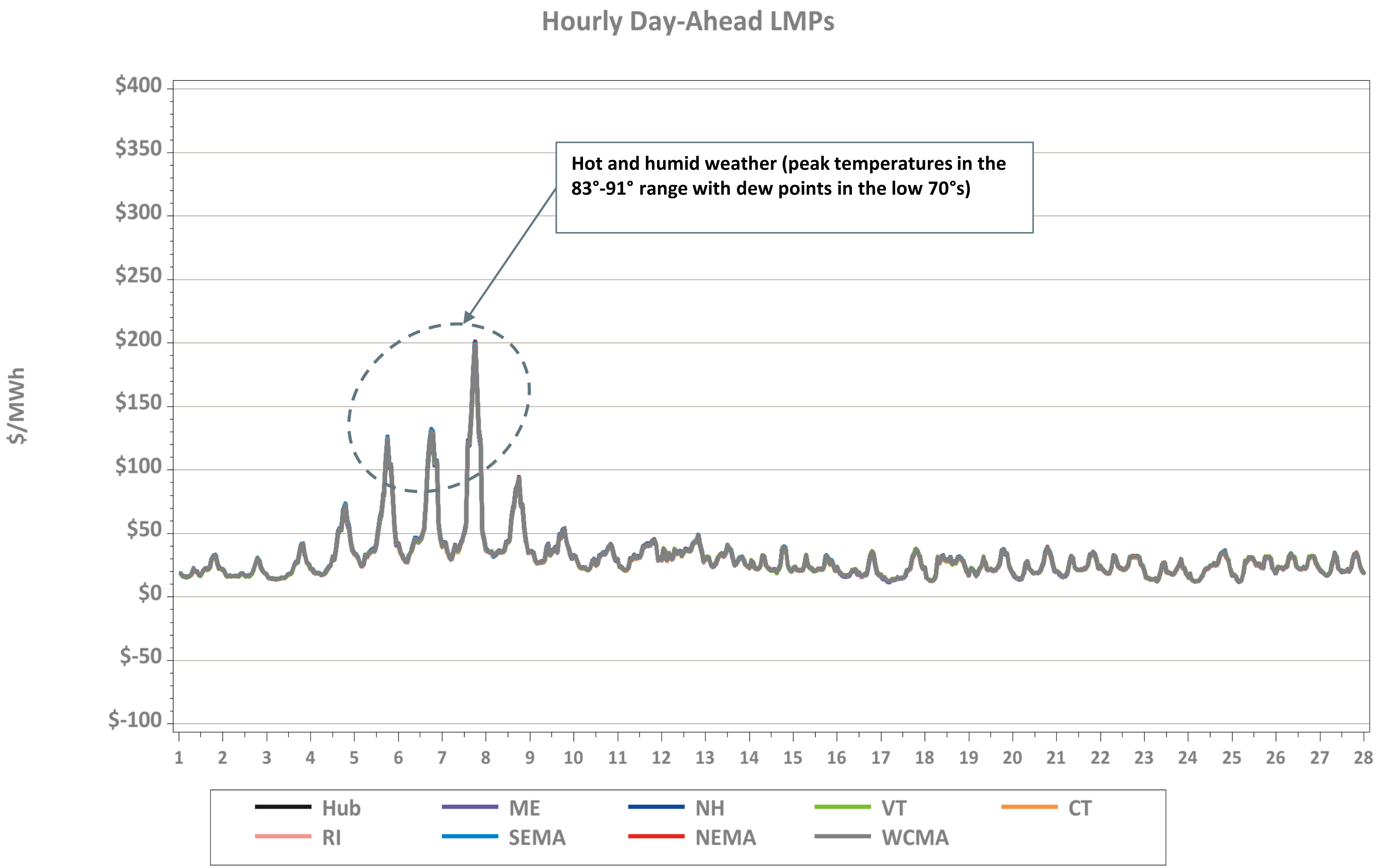


Underlying natural gas data furnished by:

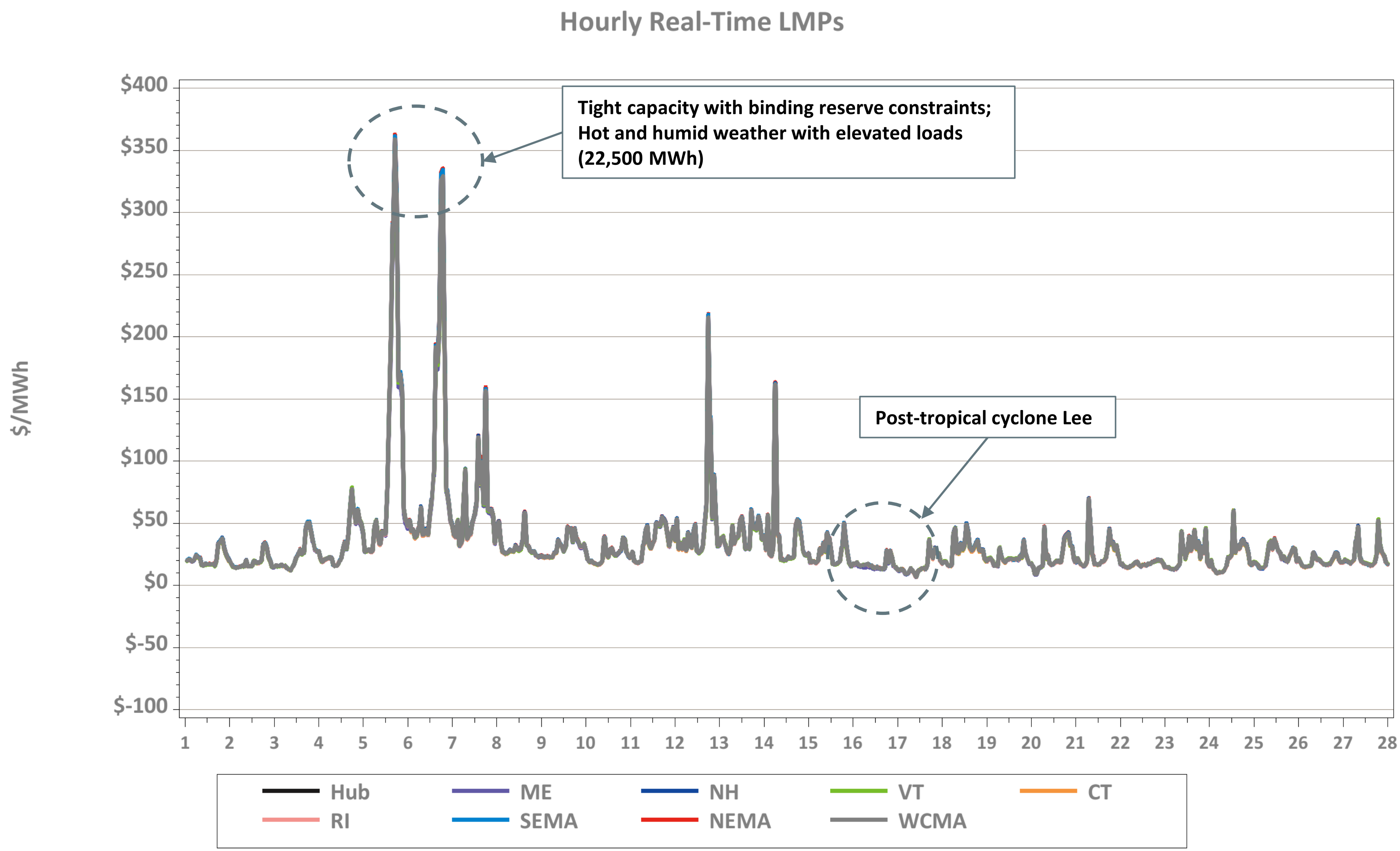
ICE Global markets in clear view

Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

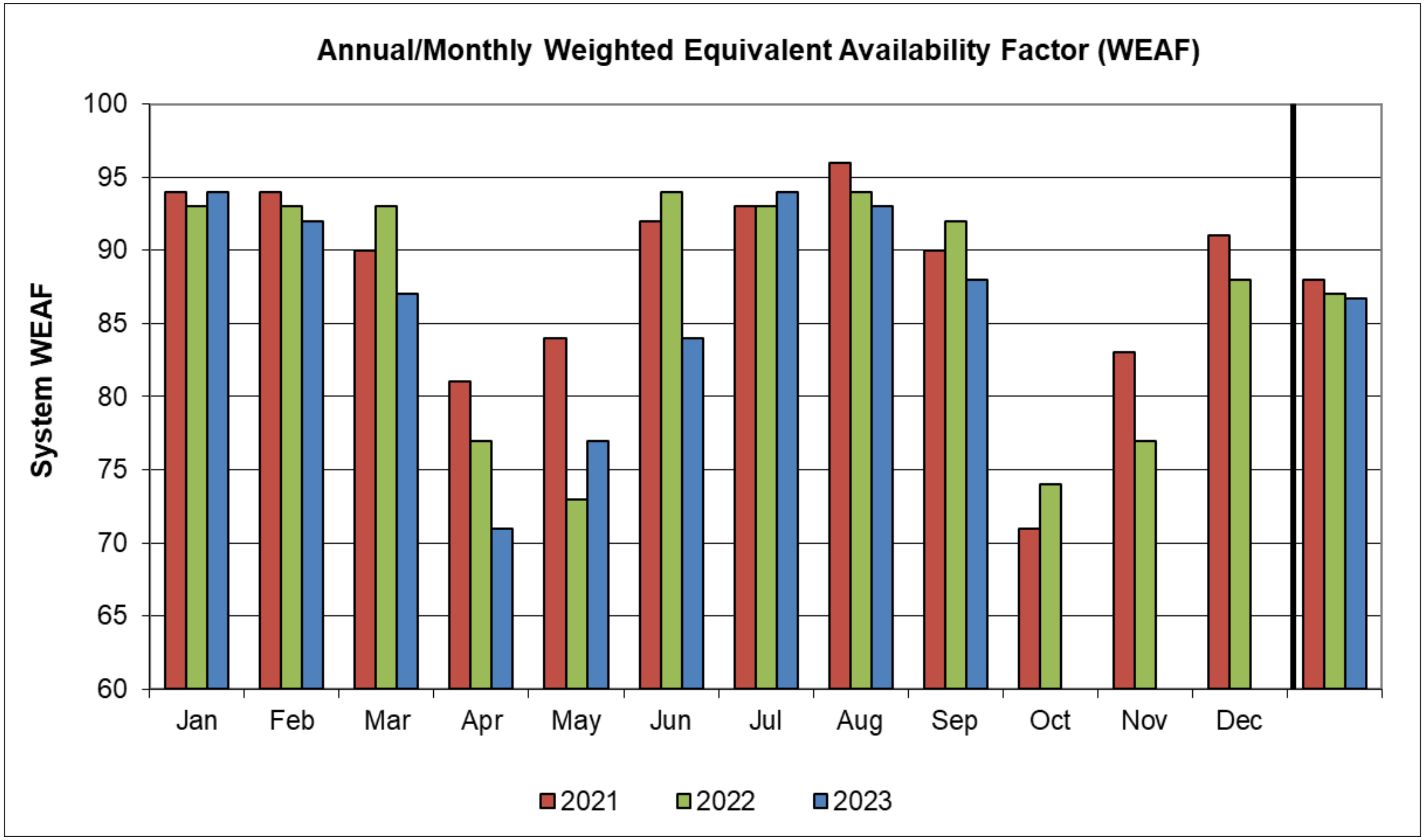
Hourly DA LMPs, September 1-27, 2023



Hourly RT LMPs, September 1-27, 2023



System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2023	94	92	87	71	77	84	94	93	88				87
2022	93	93	93	77	73	94	93	94	92	74	77	88	87
2021	94	94	90	81	84	92	93	96	90	71	83	91	88

Data as of 9/25/2023

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for October 2023

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	48.7	201.7	0.0	250.4
NH	38.1	152.0	0.0	190.2
VT	39.5	135.9	0.0	175.4
CT	118.1	170.7	598.6	887.5
RI	22.8	321.7	0.0	344.5
SEMA	36.8	476.8	0.0	513.6
WCMA	77.6	523.4	26.6	627.6
NEMA	71.1	788.8	0.0	859.9
Total	**452.8**	**2,771.1**	**625.3**	**3,849.1**

*** Active Demand Capacity Resources**
NOTE: CSO values include T&D loss factor (8%).

NEW GENERATION

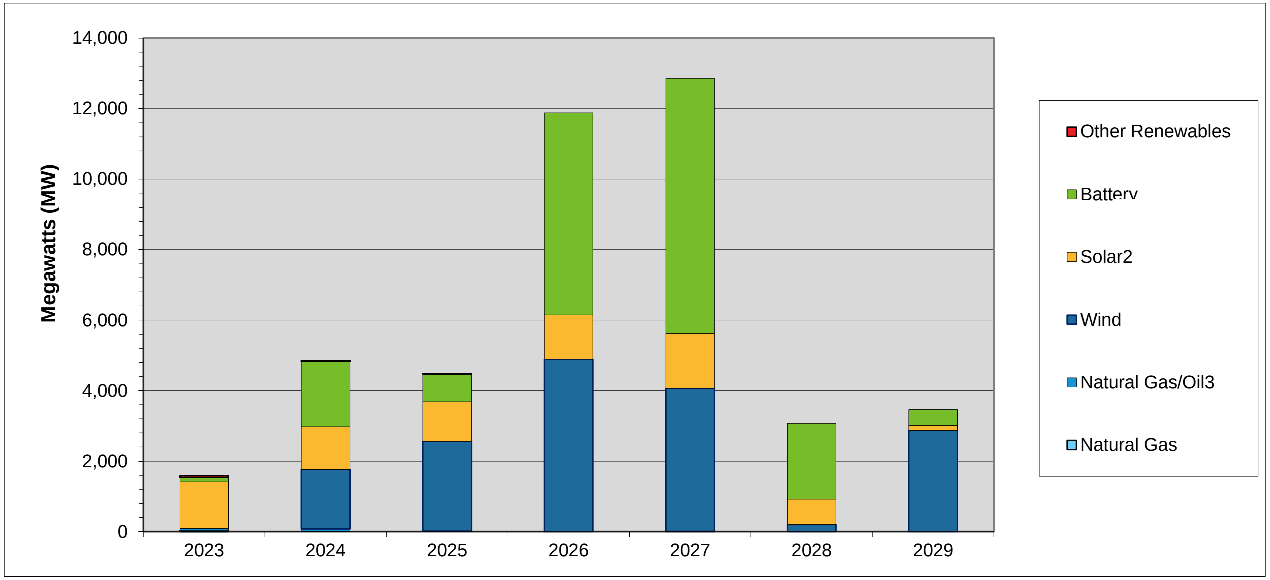
New Generation Update

Based on Queue as of 9/30/23

- Twelve projects totaling 1,143 MW were added to the interconnection queue since the last update
  - Six battery projects and six solar projects with in-service dates of 2024 to 2027
- In total, 390 generation projects are currently being tracked by the ISO, totaling approximately 42,184 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2023	2024	2025	2026	2027	2028	2029	Total MW	% of Total[1]
Other Renewables	47	30	2	0	0	0	0	79	0.2
Battery	120	1,850	788	5,734	7,234	2,150	454	18,330	43.5
Solar[2]	1,324	1,207	1,124	1,255	1,558	725	139	7,332	17.4
Wind	0	1,693	2,545	4,893	4,064	197	2,870	16,262	38.6
Natural Gas/Oil[3]	62	73	16	0	0	0	0	151	0.4
Natural Gas	26	0	0	0	4	0	0	30	0.1
Totals	**1,579**	**4,853**	**4,475**	**11,882**	**12,860**	**3,072**	**3,463**	**42,184**	**100.0**

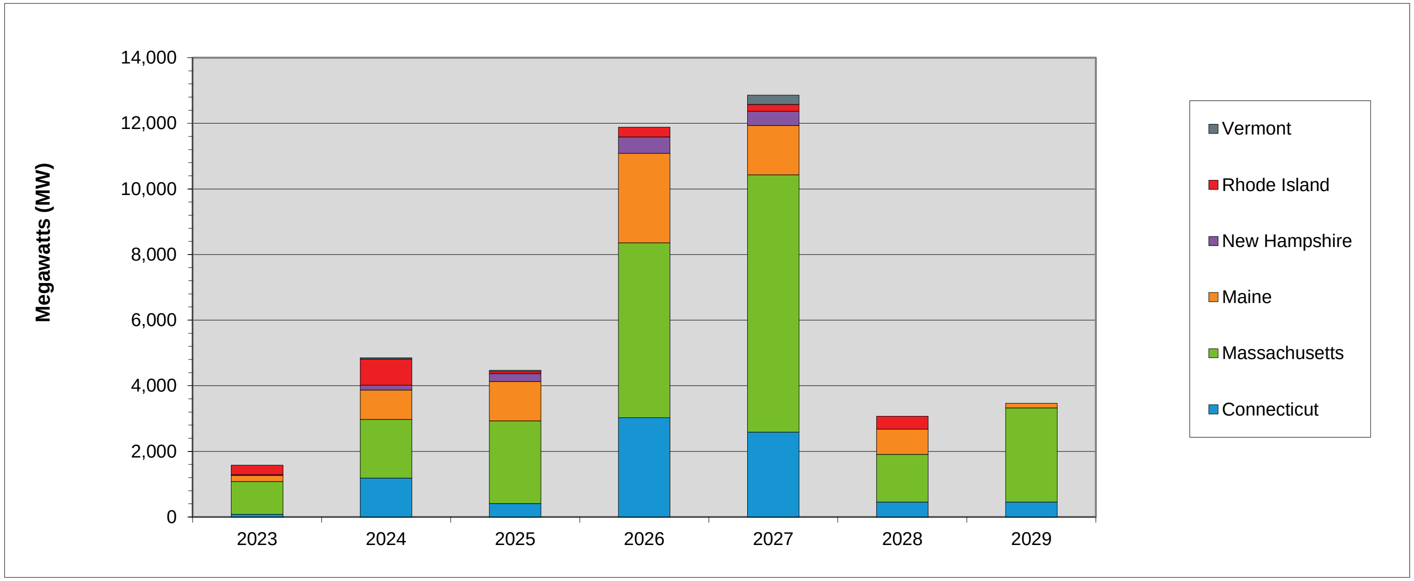
[1] Sum may not equal 100% due to rounding

[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

Actual and Projected Annual Generator Capacity Additions

By State



	2023	2024	2025	2026	2027	2028	2029	Total MW	% of Total[1]
Vermont	0	40	50	0	285	0	0	375	0.9
Rhode Island	291	794	54	295	211	400	0	2,045	4.8
New Hampshire	25	154	238	504	426	0	0	1,347	3.2
Maine	185	894	1,205	2,723	1,506	764	139	7,416	17.6
Massachusetts	996	1,783	2,520	5,336	7,844	1,453	2,870	22,802	54.1
Connecticut	82	1,188	408	3,024	2,588	455	454	8,199	19.4
Totals	**1,579**	**4,853**	**4,475**	**11,882**	**12,860**	**3,072**	**3,463**	**42,184**	**100.0**

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

New Generation Projection

By Fuel Type

	Total		Green		Yellow	
Unit Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	118	18,330	1	15	117	18,315
Fuel Cell	4	46	0	0	4	46
Hydro	2	33	1	5	1	28
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	232	7,332	15	343	217	6,989
Wind	27	16,262	1	800	26	15,462
Total	390	42,184	19	1,225	371	40,959

- 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	8	92	1	5	7	87
Intermediate	2	89	0	0	2	89
Peaker	353	25,741	17	420	336	25,321
Wind Turbine	27	16,262	1	800	26	15,462
Total	390	42,184	19	1,225	371	40,959

- 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	118	18,330	0	0	0	0	118	18,330	0	0
Fuel Cell	4	46	4	46	0	0	0	0	0	0
Hydro	2	33	2	33	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	232	7,332	0	0	0	0	232	7,332	0	0
Wind	27	16,262	0	0	0	0	0	0	27	16,262
Total	390	42,184	8	92	2	89	353	25,741	27	16,262

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 14

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

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes 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 2015-2023 CCP Monthly 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		
	Passive Demand	3,212.865	3,211.403	-1.462	3,134.652	-76.751		
Demand Total		**3,890.538**	**3,884.804**	**-5.734**	**3,714.344**	**-170.460**		
Generator	*Non-Intermittent*	28,154.203	27,714.778	-439.425	27,081.653	-633.125		
	Intermittent	1,089.265	1,073.794	-15.471	1,056.601	-17.193		
Generator Total		**29,243.468**	**28,788.572**	**-454.896**	**28,138.254**	**-650.318**		
Import Total		**1,487.059**	**1297.132**	**-189.927**	**1,249.545**	**-47.587**		
Grand Total*		**34,621.065**	**33,970.508**	**-650.557**	**33,102.143**	**-868.365**		
Net ICR (NICR)		**33,270**	**31,775**	**-1,495**	**31,545**	**-230**		

* 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 and 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 2015-2023 CCP Monthly 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 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 2015-2023 CCP Monthly 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 2015-2023 CCP Monthly 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
2019-20	Active	357.221	20.304	377.525
	Passive	2,018.20	350.43	2,368.63
	Grand Total	**2,375.422**	**370.734**	**2,746.156**
2020-21	Active	334.634	85.294	419.928
	Passive	2,236.73	554.292	2,791.02
	Grand Total	**2,571.361**	**639.586**	**3,210.947**
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**

RELIABILITY COSTS – NET COMMITMENT PERIOD COMPENSATION (NCPC) OPERATING COSTS

What are Daily NCPC Payments?

- Payments made to resources whose commitment and dispatch by ISO-NE resulted in a shortfall between the resource's offered value in the Energy and Regulation Markets and the revenue earned from output during the day
- Typically, this is the result of some out-of-merit operation of resources occurring in order to protect the overall resource adequacy and transmission security of specific locations or of the entire control area
- NCPC payments are intended to make a resource that follows the ISO's operating instructions "no worse off" financially than the best alternative generation schedule

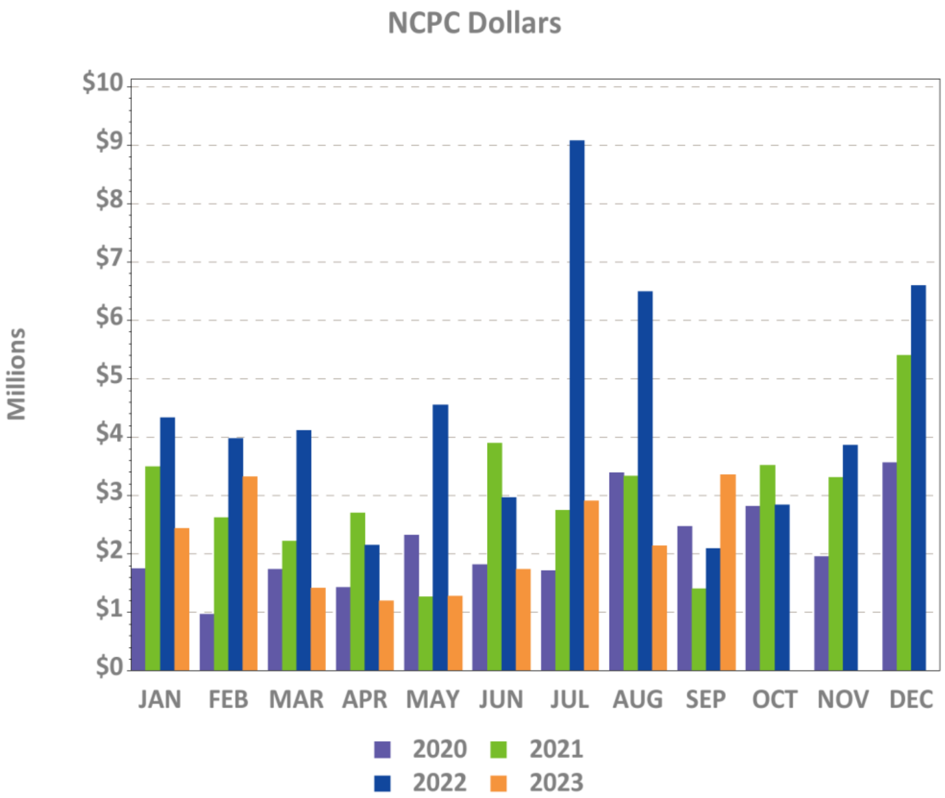
Definitions

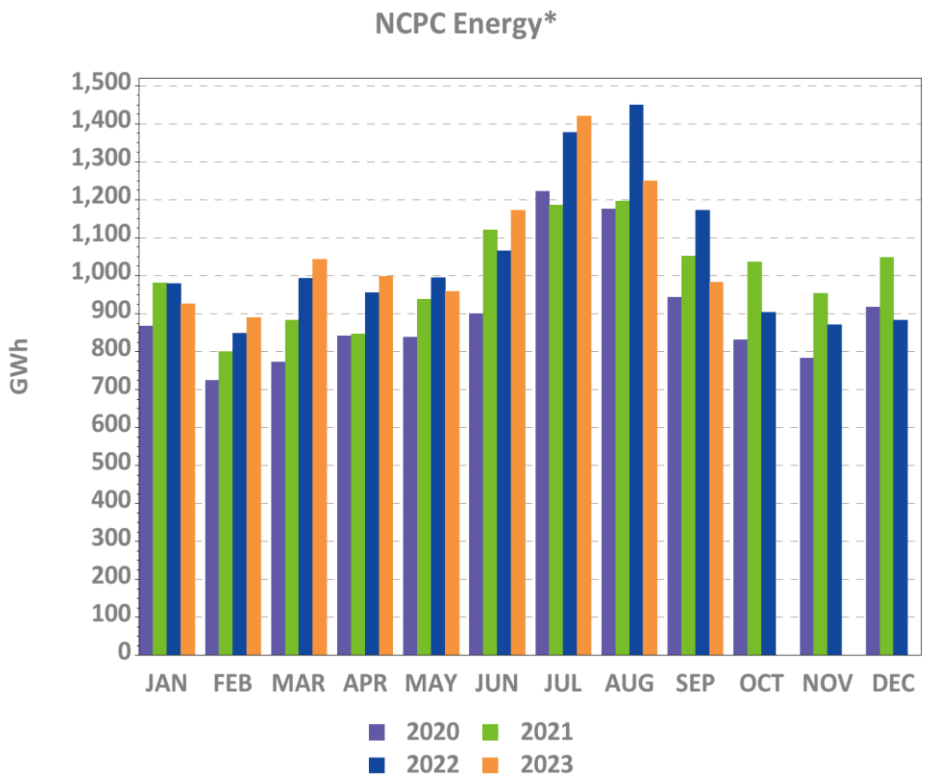
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing capacity in constrained areas to respond to a local second contingency. They are committed based on 2nd Contingency (2ndC) protocols, and are also known as Local Second Contingency Protection Resources (LSCPR)
Voltage NCPC Payments	Reliability costs paid to resources operated by ISO-NE to provide voltage support or control in specific locations
Distribution NCPC Payments	Reliability costs paid to units dispatched at the request of local transmission providers for purpose of managing constraints on the low voltage (distribution) system. These requirements are not modeled in the DA Market software
OATT	Open Access Transmission Tariff

Charge Allocation Key

Allocation Category	Market / OATT	Allocation
System 1st Contingency	Market	DA 1st C (excluding at external nodes) is allocated to system DALO. RT 1st C (at all locations) is allocated to System 'Daily Deviations'. Daily Deviations = sum of(generator deviations, load deviations, generation obligation deviations at external nodes, increment offer deviations)
External DA 1st Contingency	Market	DA 1st C at external nodes (from imports, exports, Incs and Decs) are allocated to activity at the specific external node or interface involved
Zonal 2nd Contingency	Market	DA and RT 2nd C NCPC are allocated to load obligation in the Reliability Region (zone) served
System Low Voltage	OATT	(Low) Voltage Support NCPC is allocated to system Regional Network Load and Open Access Same-Time Information Service (OASIS) reservations
Zonal High Voltage	OATT	High Voltage Control NCPC is allocated to zonal Regional Network Load
Distribution - PTO	OATT	Distribution NCPC is allocated to the specific Participant Transmission Owner (PTO) requesting the service
System – Other	Market	Includes GPA, Economic Generator/DARD Posturing, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost NCPC (allocated to RTLO); and Min Generation Emergency NCPC (allocated to RTGO).

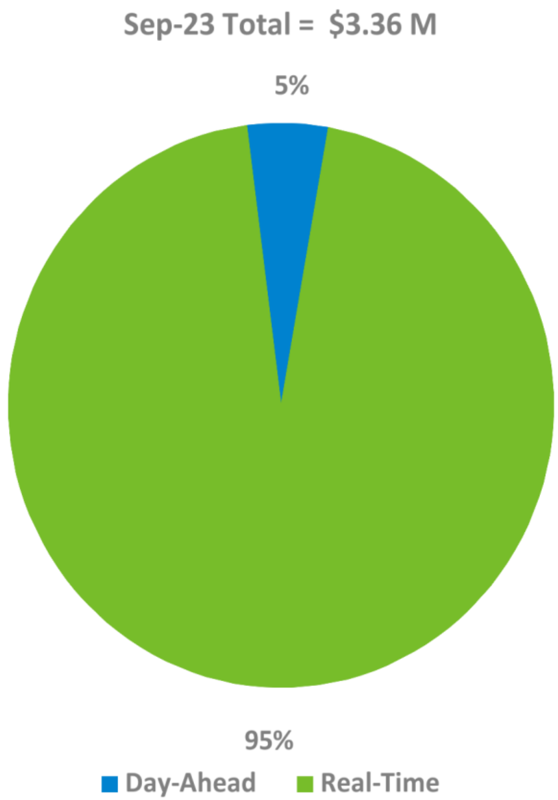
Year-Over-Year Total NCPC Dollars and Energy

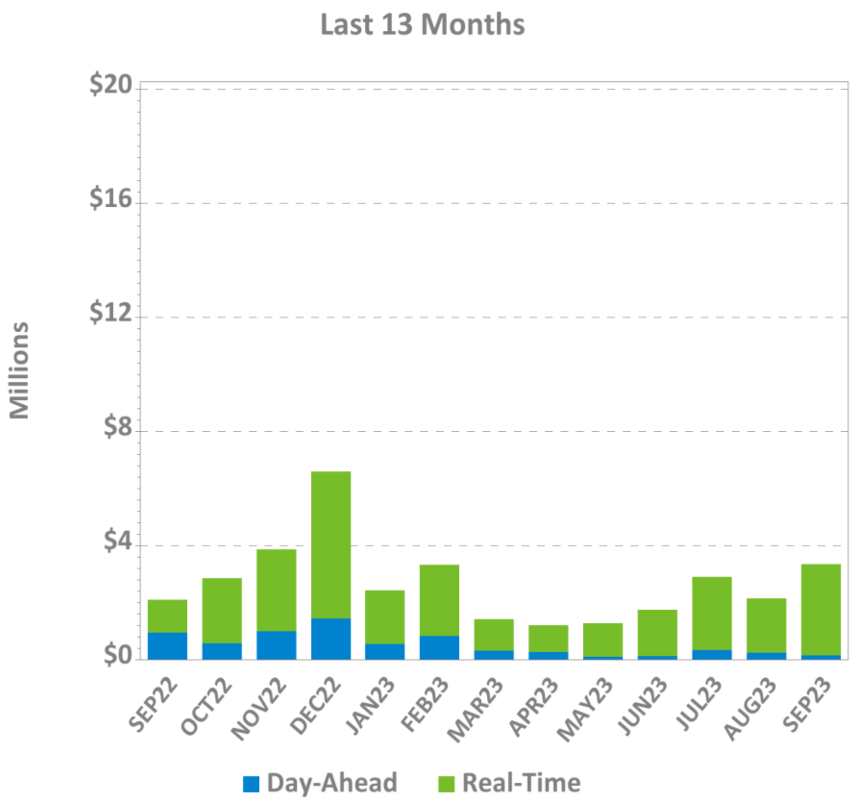




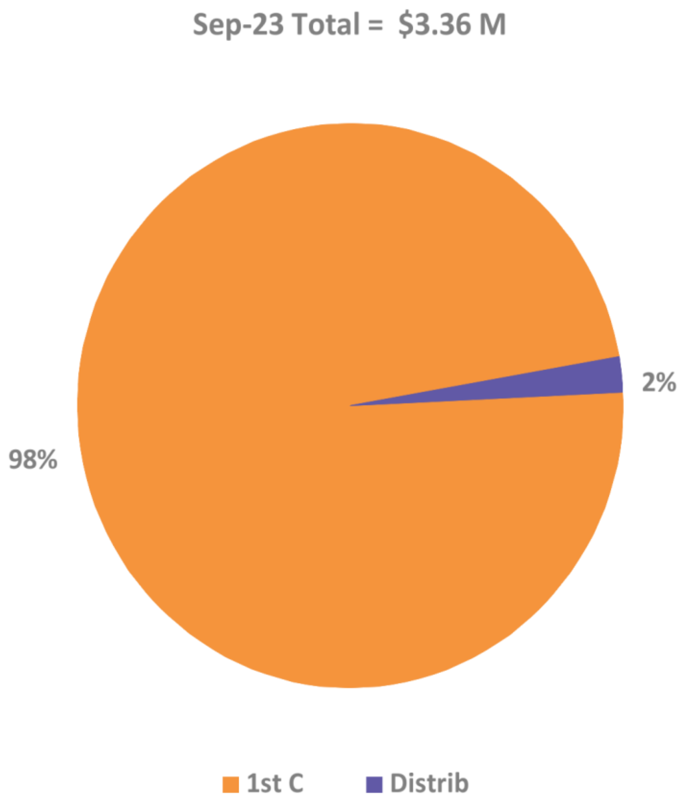
*** NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components (1st Contingency, 2nd Contingency, Voltage, and RT Distribution) are reflected.**

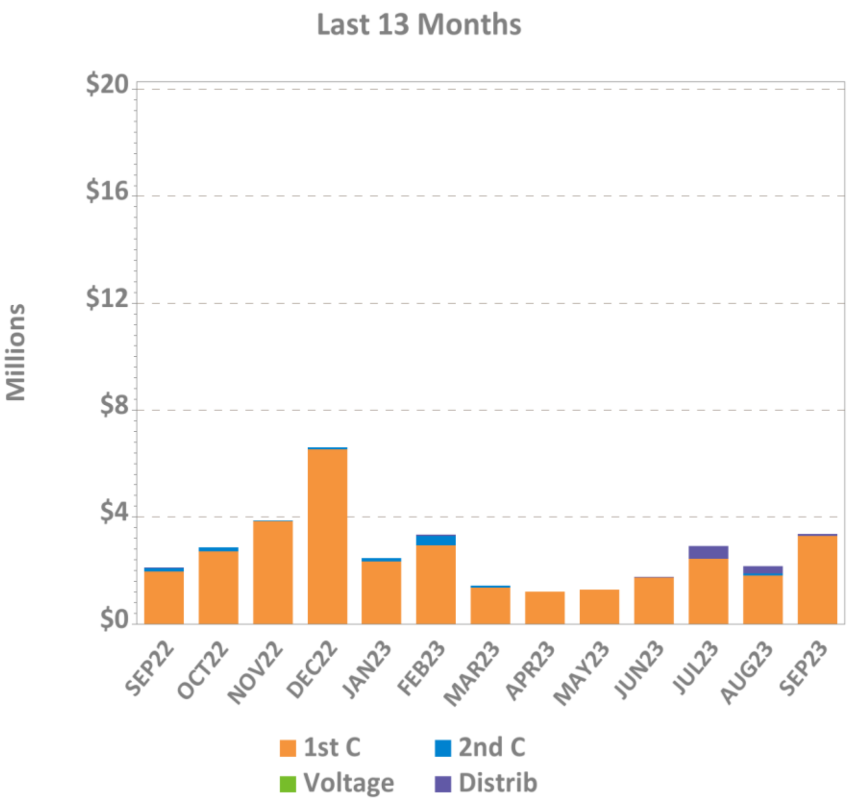
DA and RT NCPC Charges





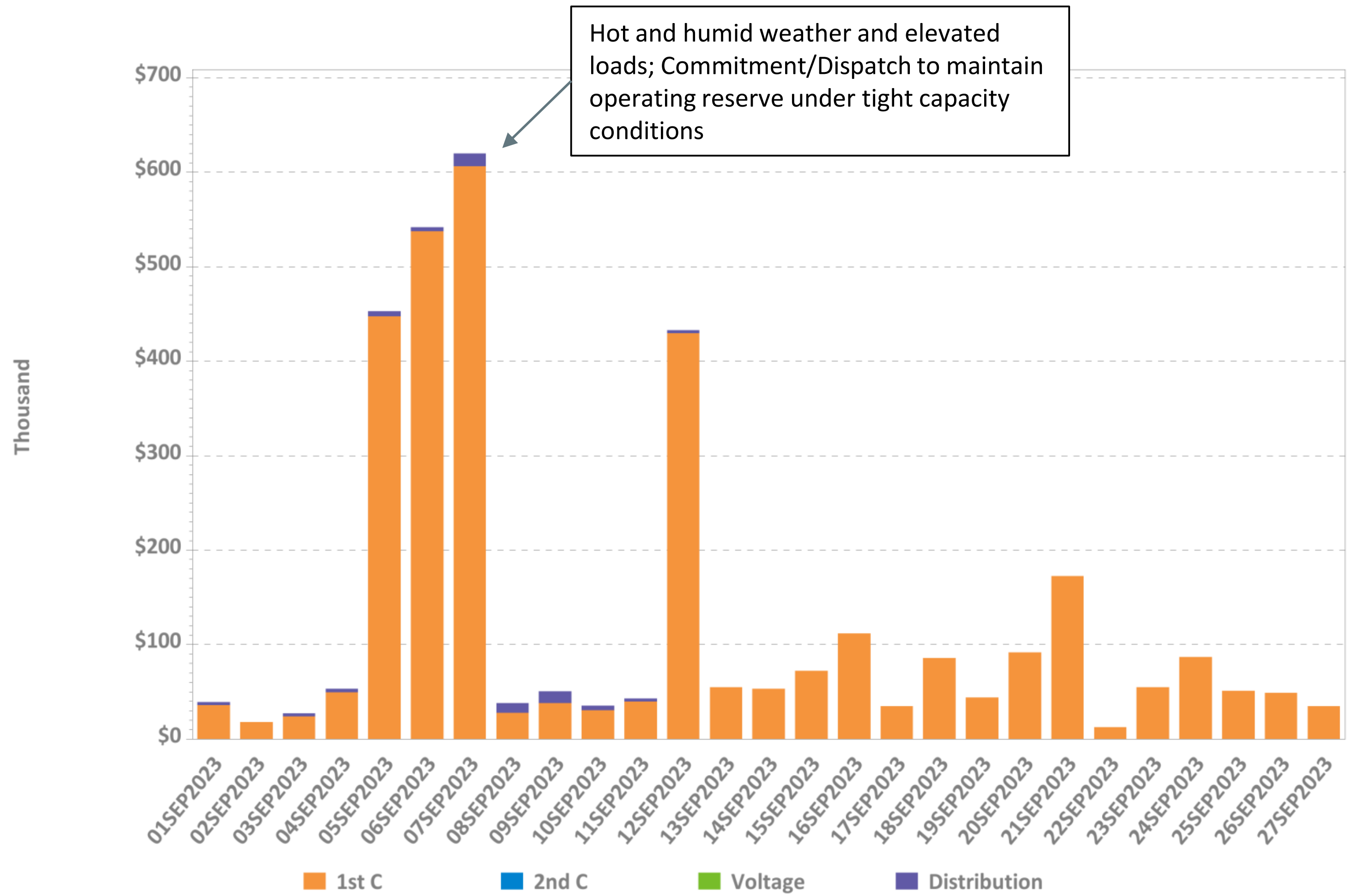
NCPC Charges by Type



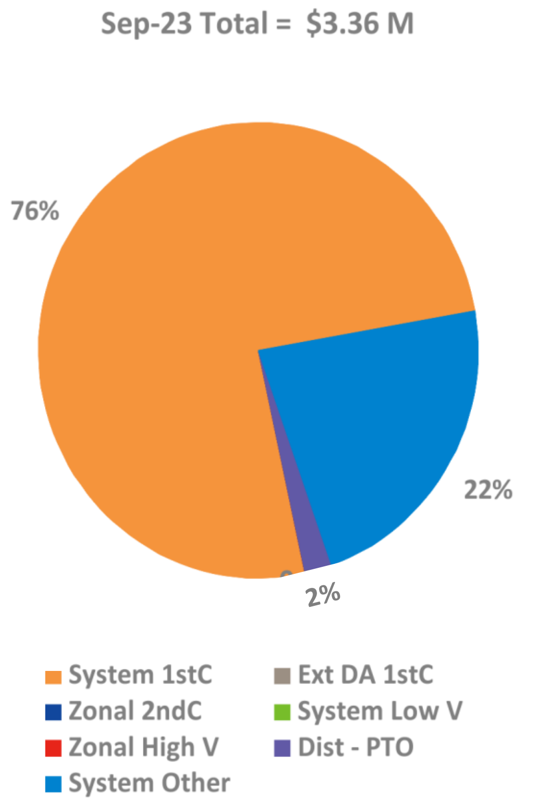


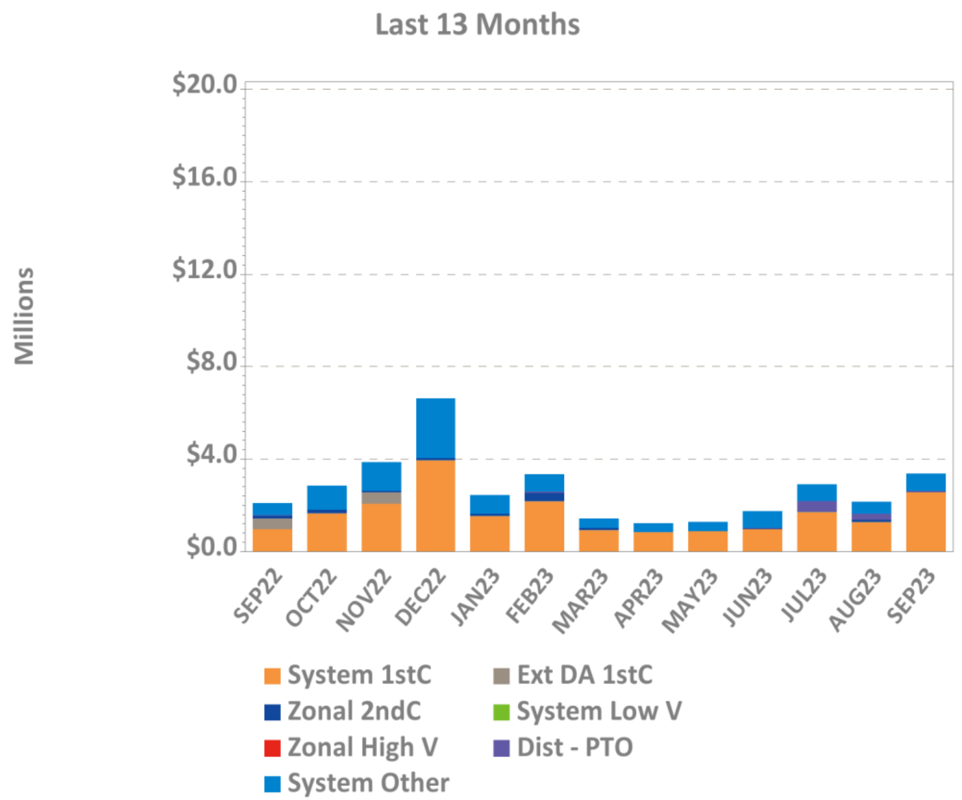
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



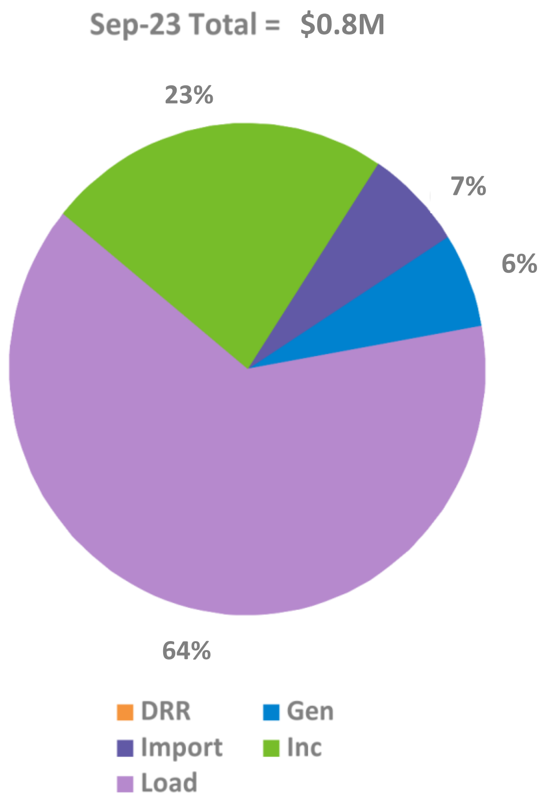
NCPC Charges by Allocation

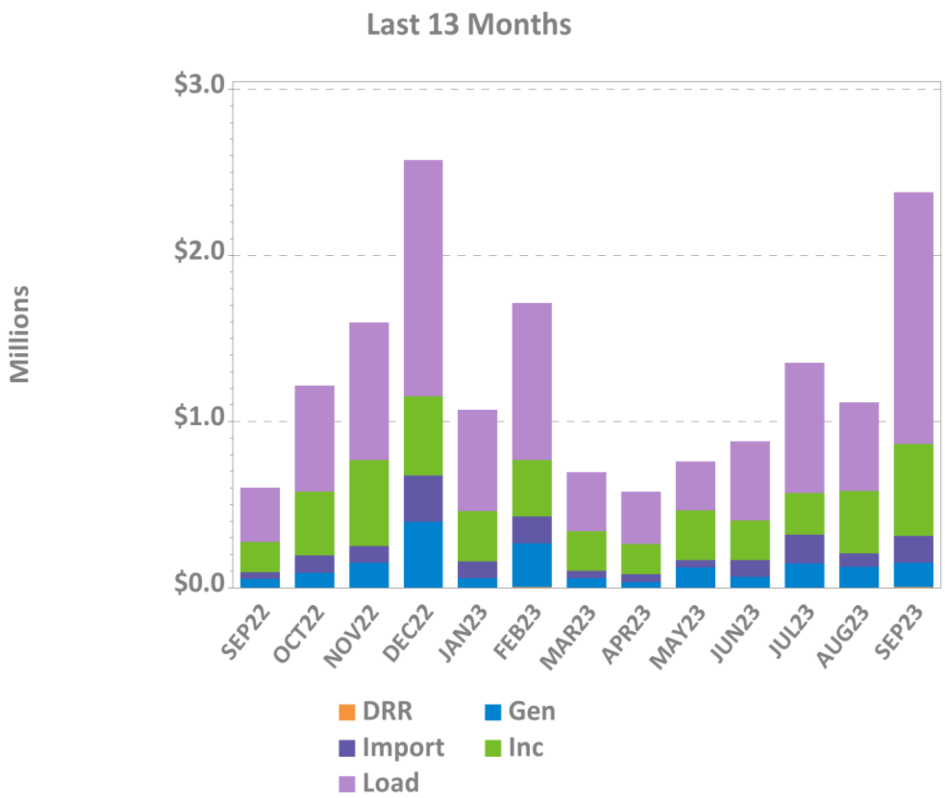




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

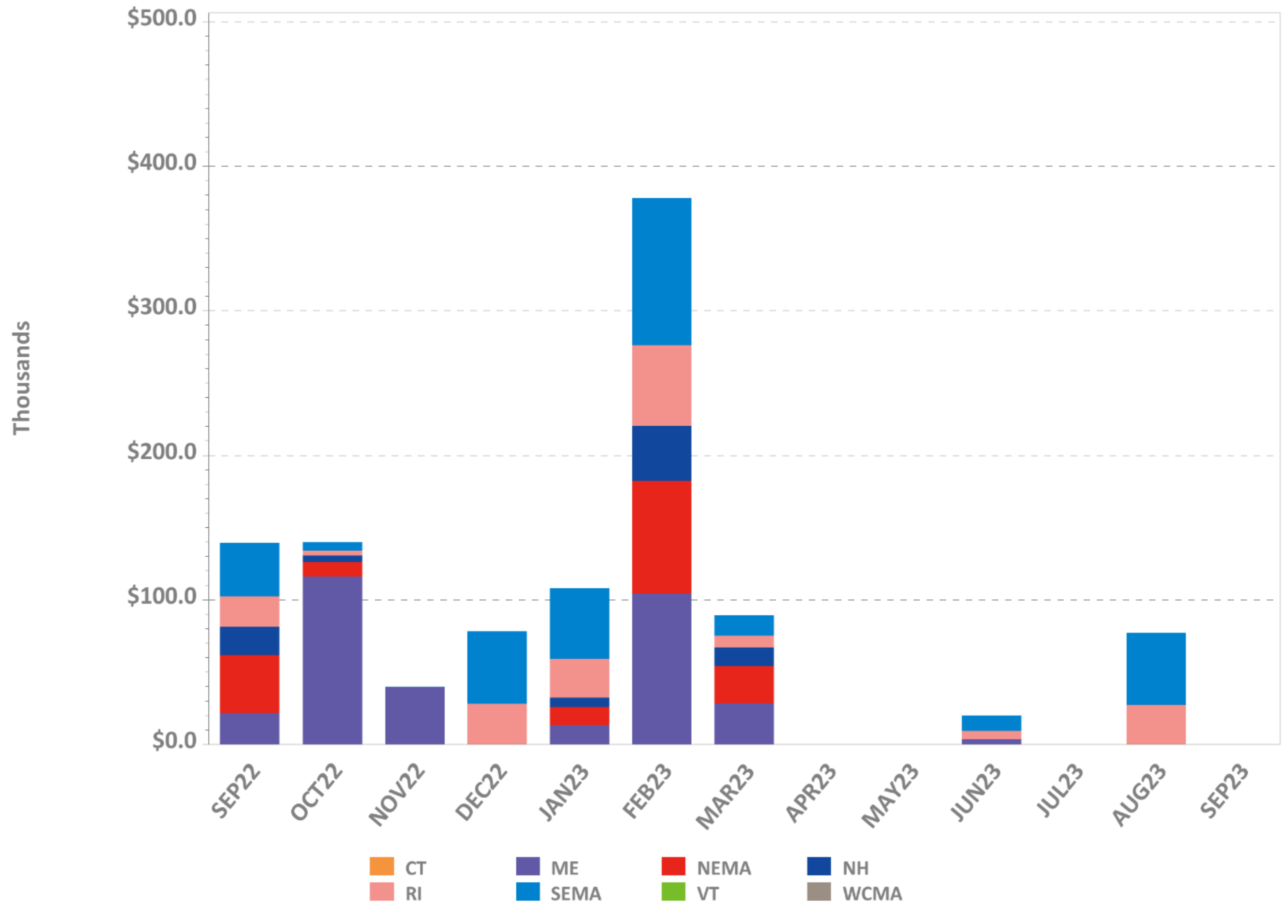
RT First Contingency Charges by Deviation Type





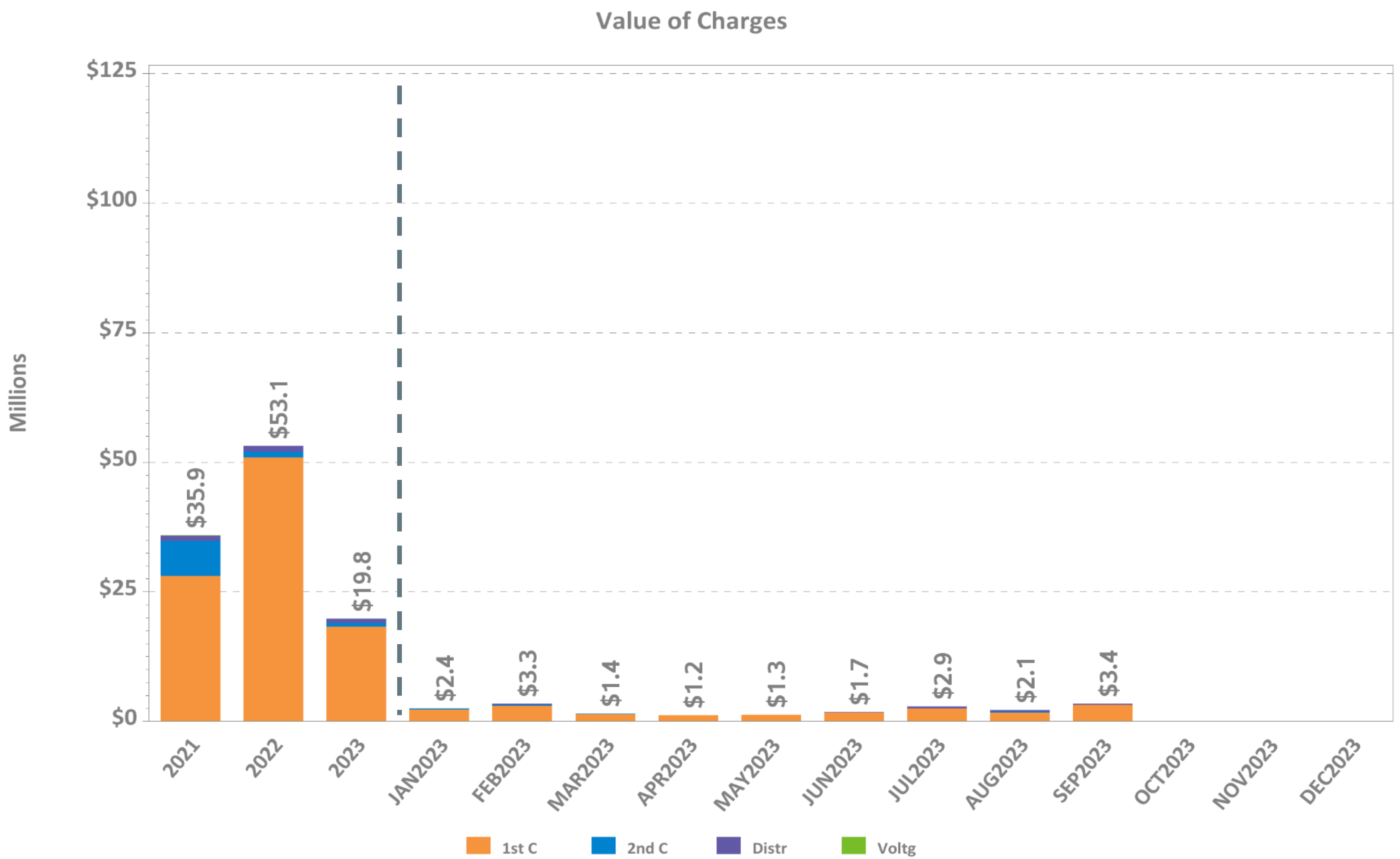
DRR – Demand Response Resource deviations
Gen – Generator deviations
Inc – Increment Offer deviations
Import – Import deviations
Load – Load obligation deviations

LSCPR Charges by Reliability Region

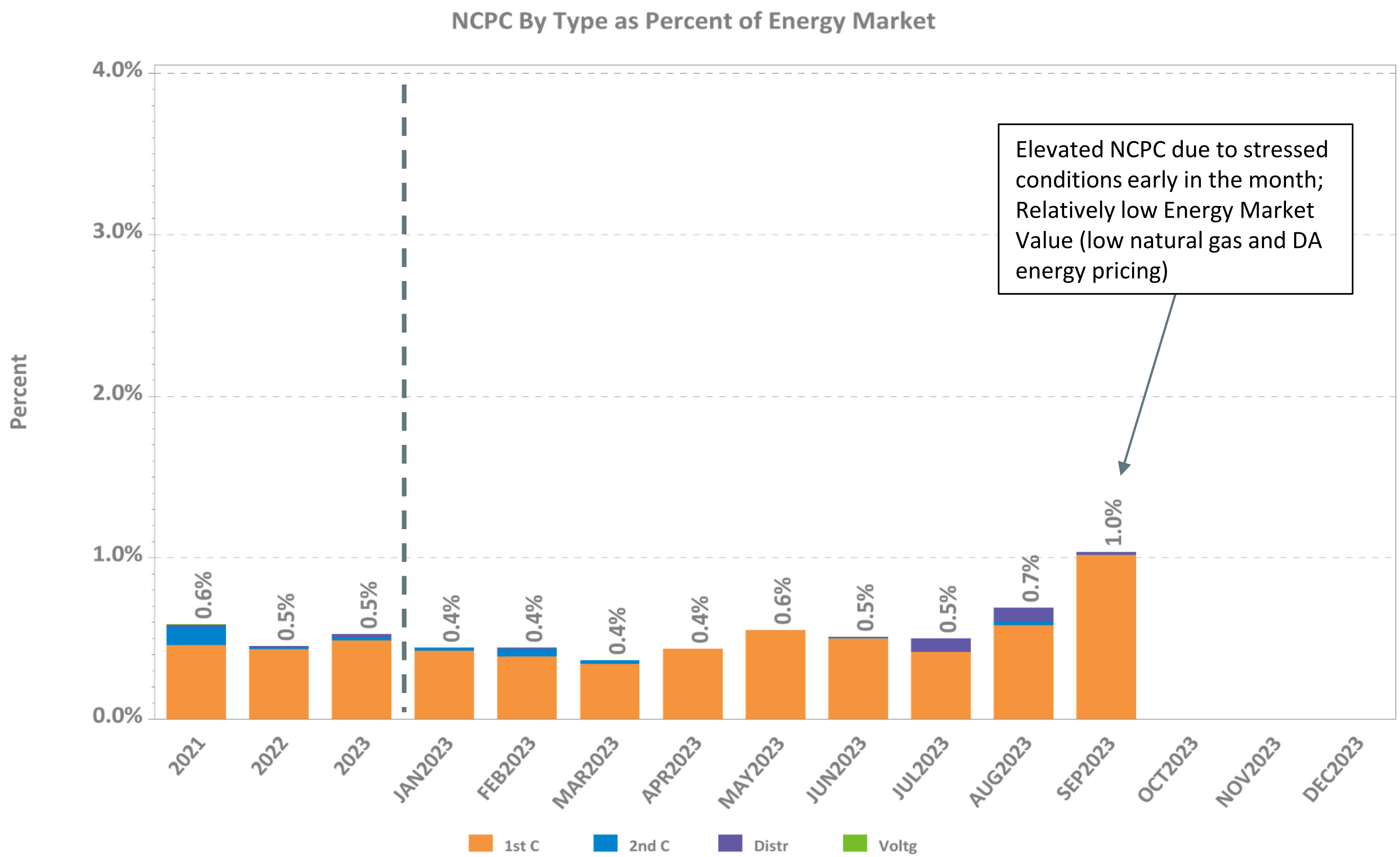


CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region
SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region

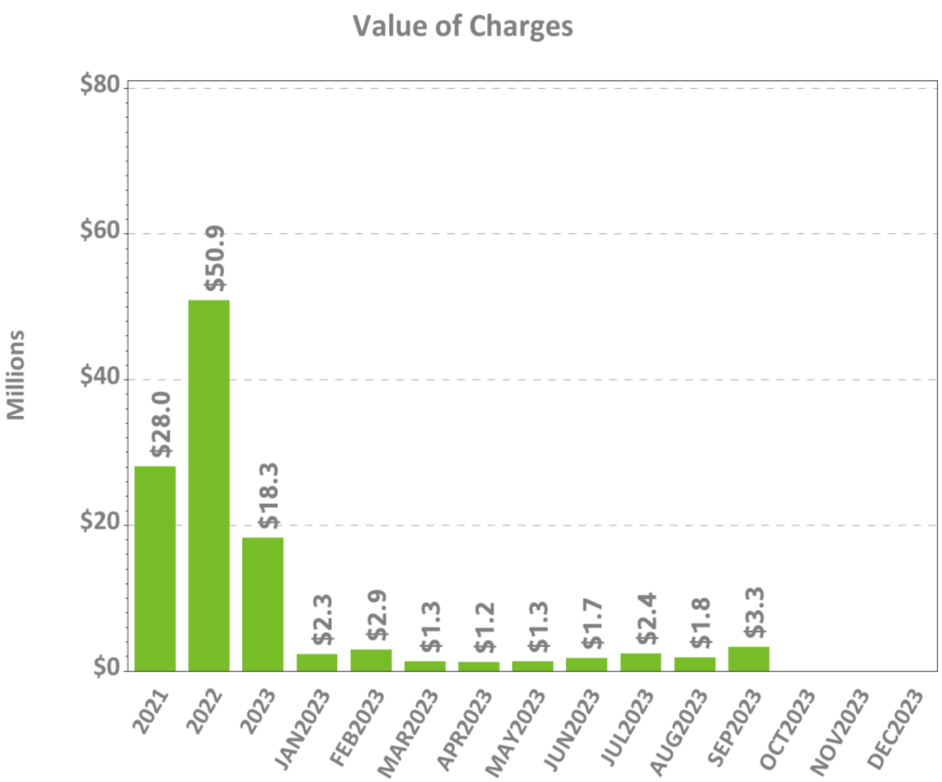
NCPC Charges by Type

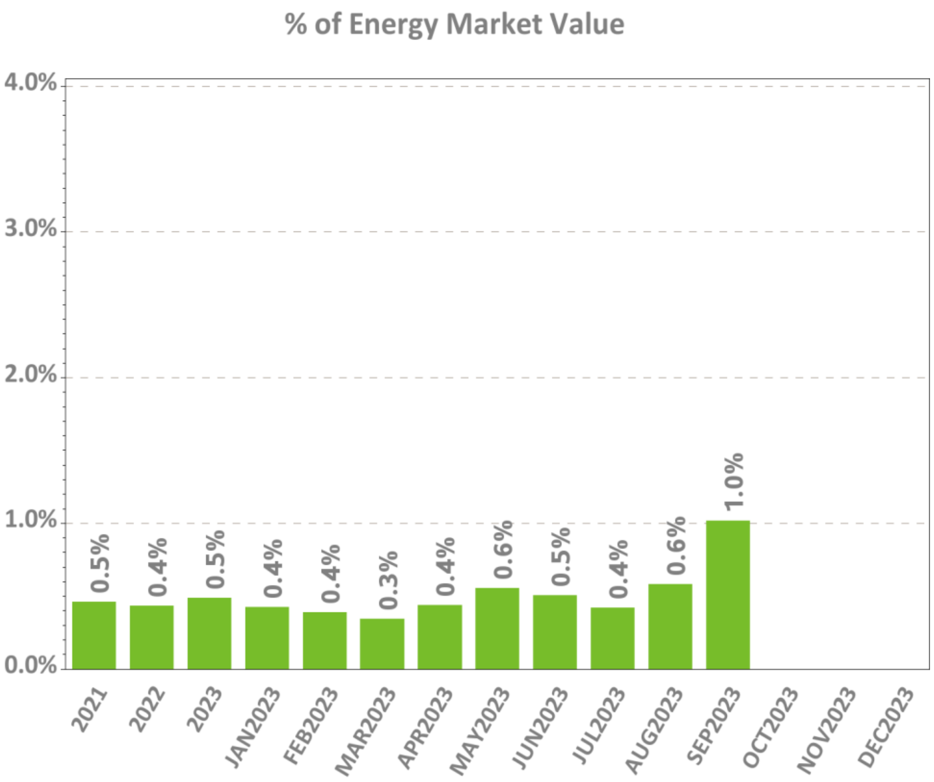


NCPC Charges as Percent of Energy Market



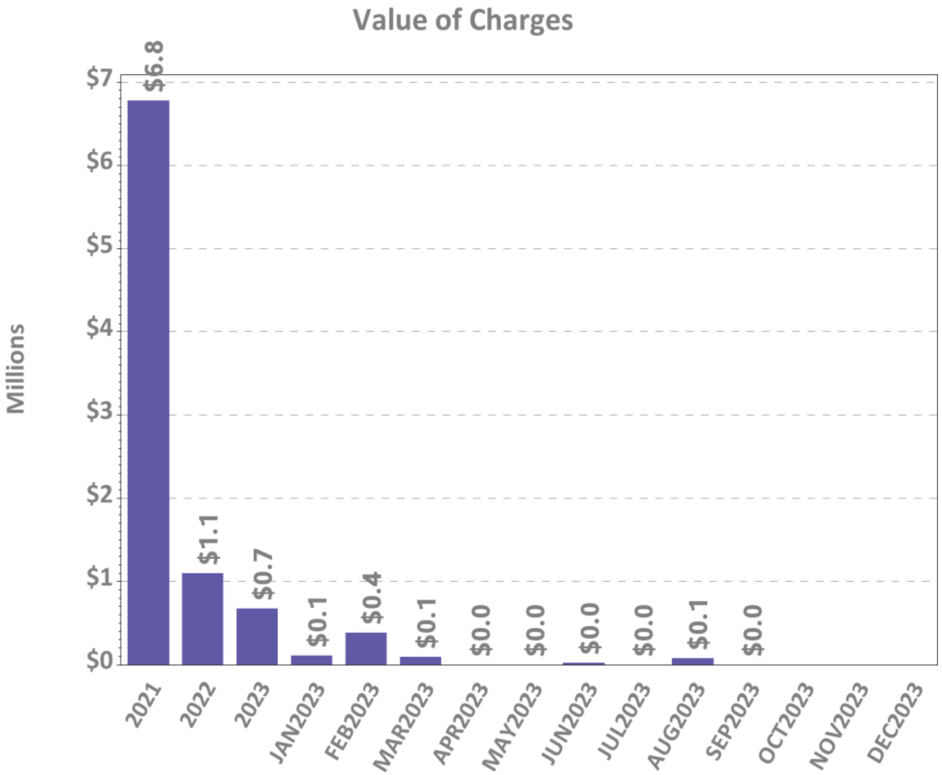
First Contingency NCPC Charges

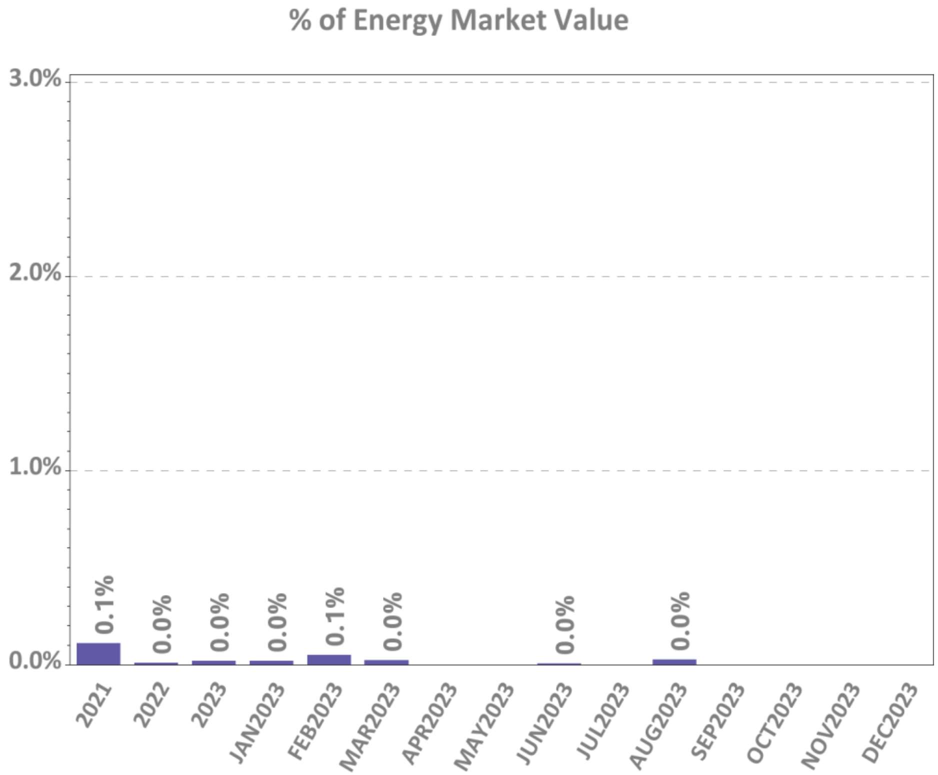




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

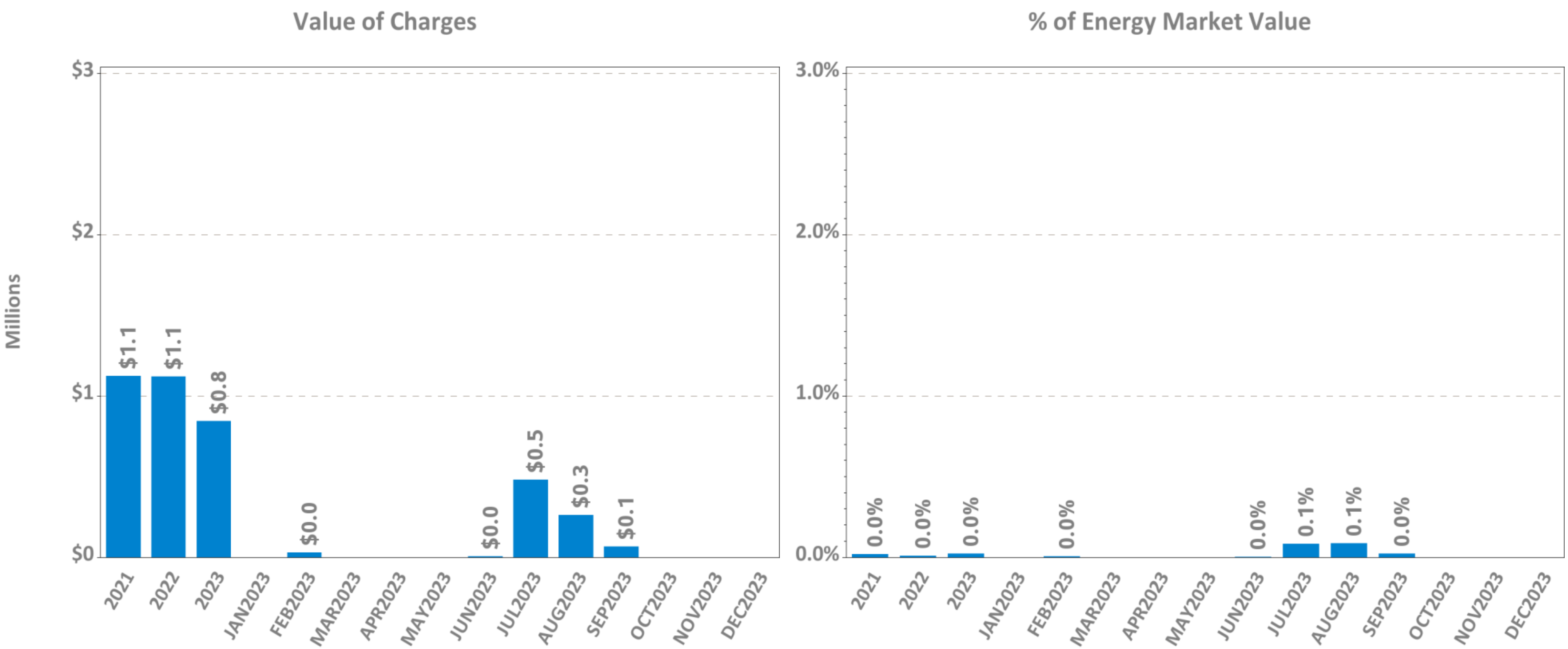
Second Contingency NCPC Charges





Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution NCPC Charges



Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

DA vs. RT Pricing

The following slides outline:

- This month vs. prior year's average LMPs and fuel costs
- Reserve Market results
- DA cleared load vs. RT load
- Zonal and total incs and decs
- Self-schedules
- DA vs. RT net interchange

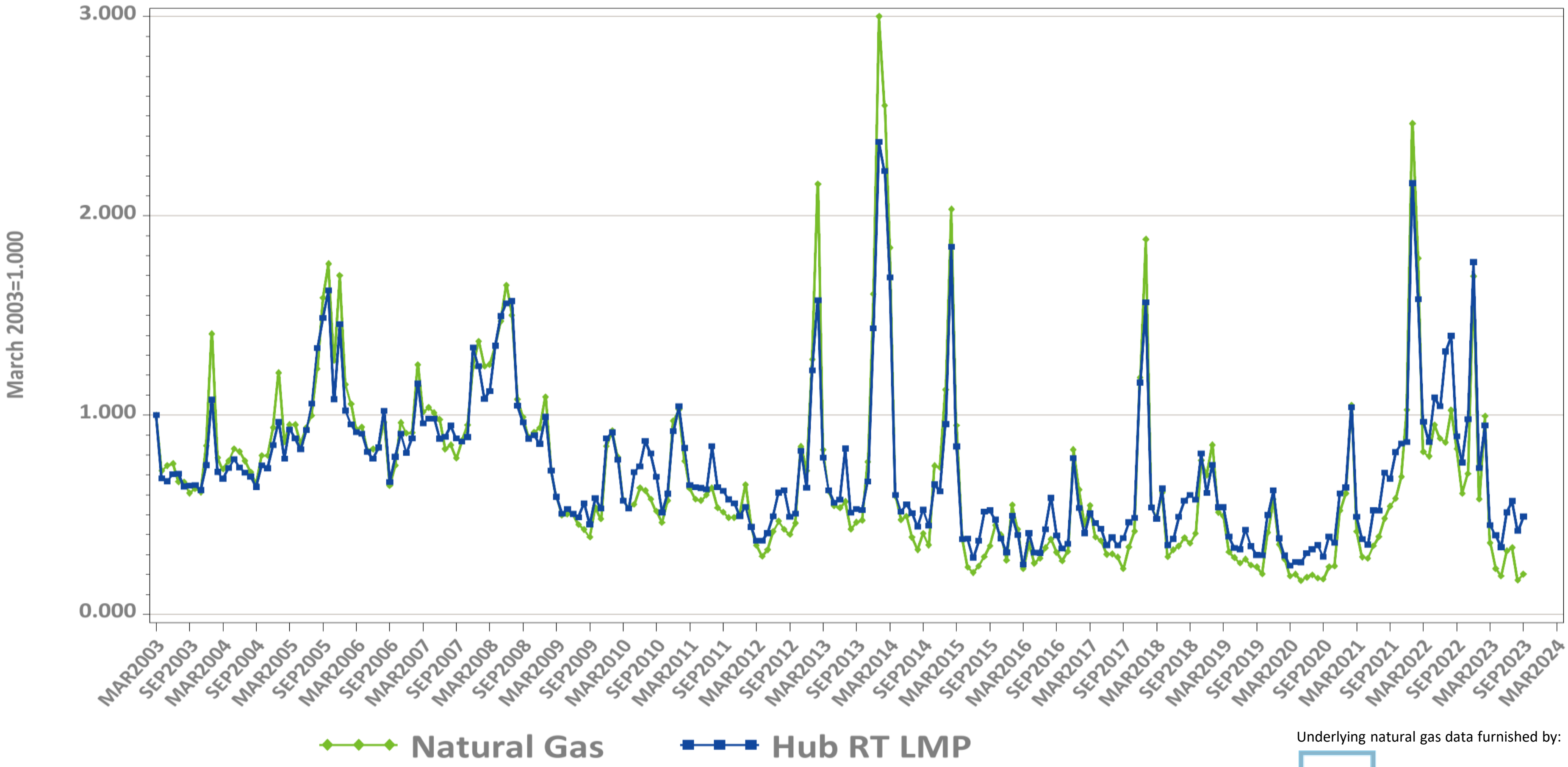
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2021	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$46.54	$44.60	$45.52	$46.27	$45.05	$45.88	$46.38	$45.91	$45.92
Real-Time	$45.25	$43.97	$44.28	$45.10	$44.15	$44.61	$45.09	$44.85	$44.84
RT Delta %	-2.8%	-1.4%	-2.7%	-2.5%	-2.0%	-2.8%	-2.8%	-2.3%	-2.3%
Year 2022	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$86.07	$84.05	$84.15	$85.73	$84.46	$85.35	$86.01	$85.66	$85.55
Real-Time	$85.42	$83.83	$83.06	$85.07	$83.67	$84.71	$85.37	$85.00	$84.92
RT Delta %	-0.8%	-0.3%	-1.3%	-0.8%	-0.9%	-0.7%	-0.7%	-0.8%	-0.7%

September-22	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$67.78	$65.80	$65.79	$67.53	$66.53	$67.02	$67.67	$67.29	$67.23
Real-Time	$61.80	$60.52	$60.09	$61.54	$60.75	$61.05	$61.73	$61.44	$61.38
RT Delta %	-8.8%	-8.0%	-8.7%	-8.9%	-8.7%	-8.9%	-8.8%	-8.7%	-8.7%
September-23	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$31.25	$30.30	$30.43	$31.16	$30.92	$30.54	$31.05	$30.95	$30.92
Real-Time	$34.11	$33.18	$33.13	$33.94	$33.59	$33.37	$33.89	$33.74	$33.69
RT Delta %	9.2%	9.5%	8.9%	8.9%	8.6%	9.3%	9.2%	9.0%	9.0%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-53.9%	-54.0%	-53.7%	-53.9%	-53.5%	-54.4%	-54.1%	-54.0%	-54.0%
Yr over Yr RT	-44.8%	-45.2%	-44.9%	-44.8%	-44.7%	-45.3%	-45.1%	-45.1%	-45.1%

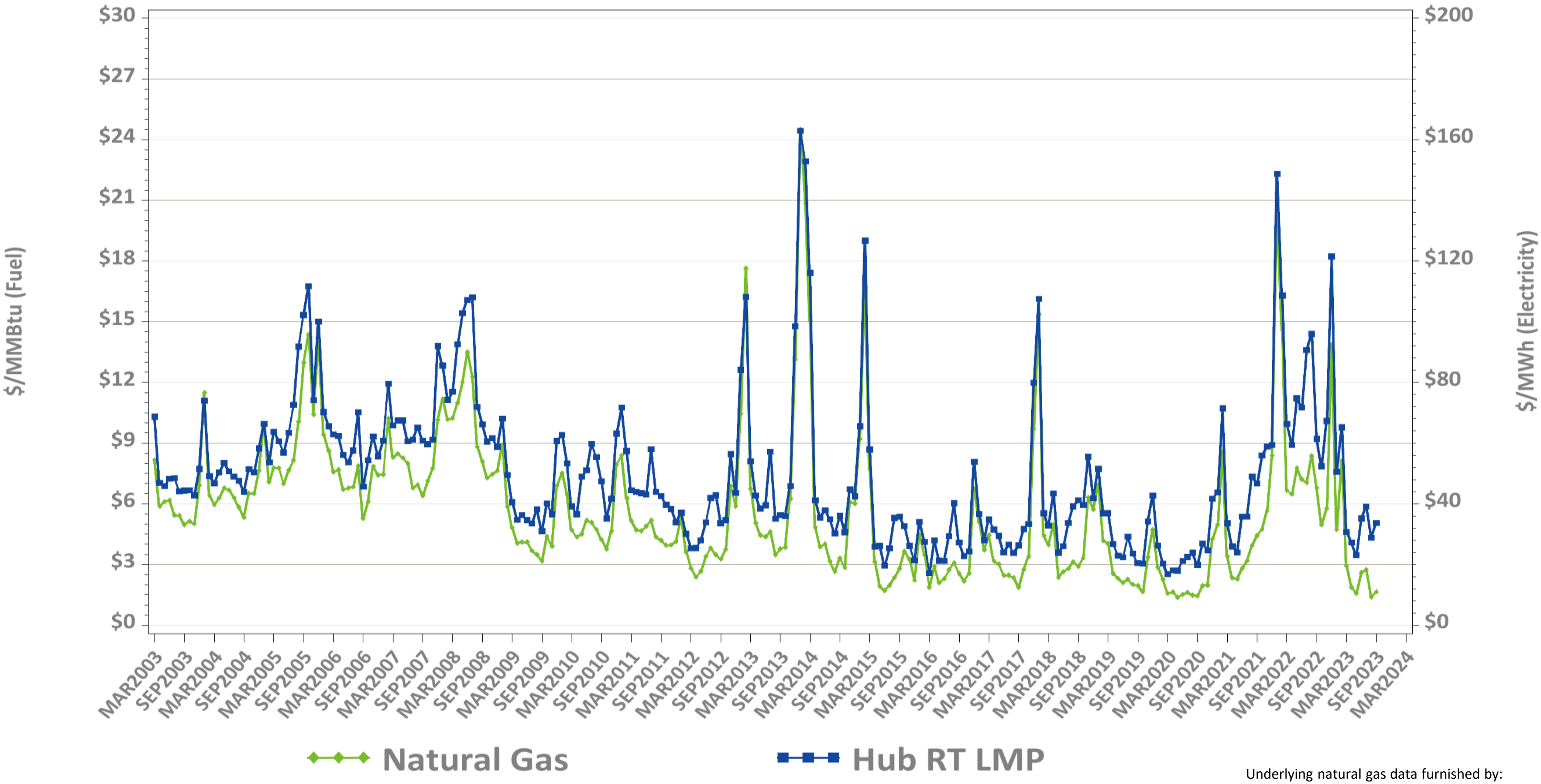
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

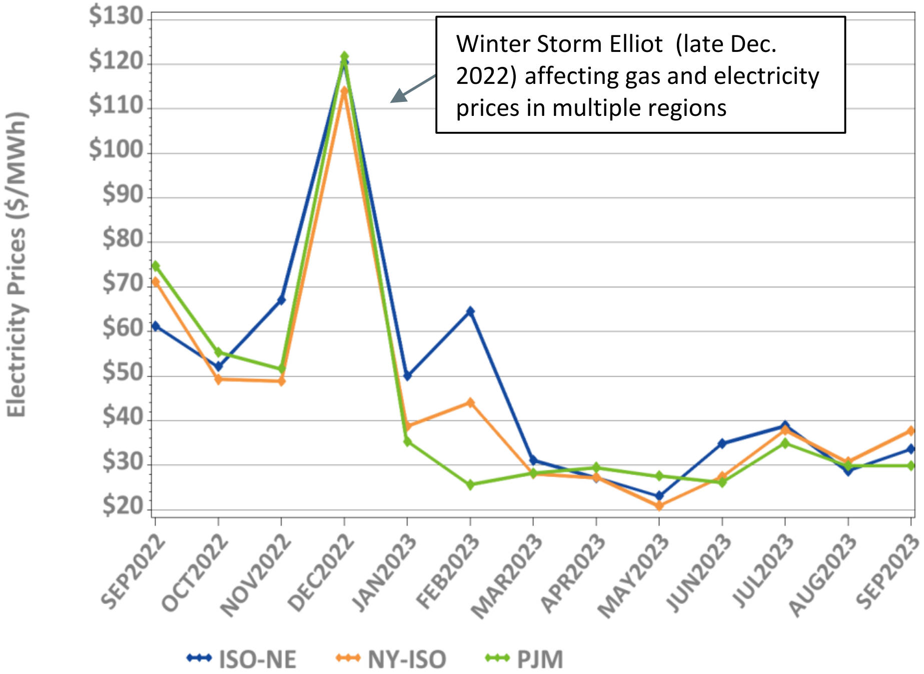
ice Global markets in clear view

Monthly Average Fuel Price and RT Hub LMP

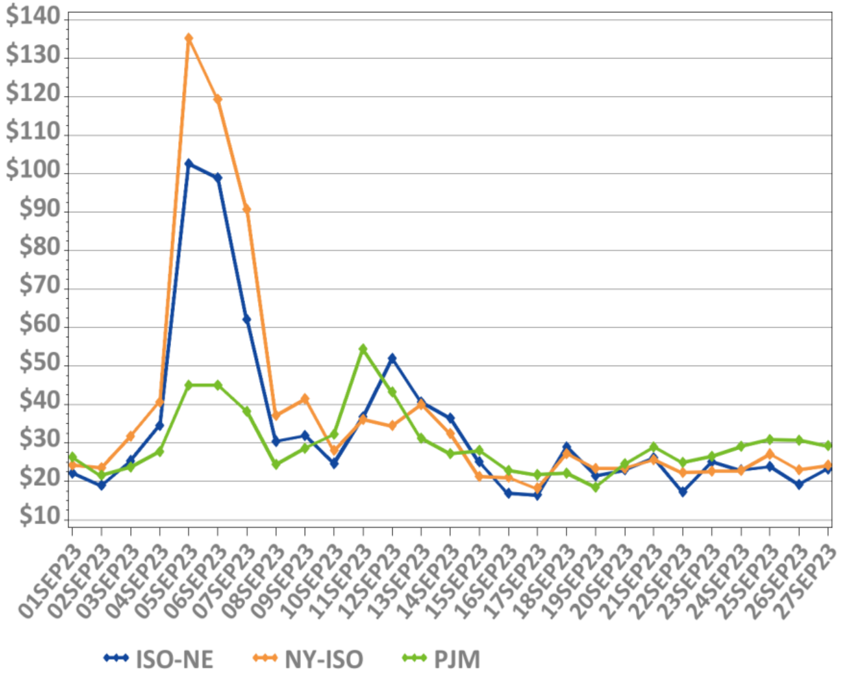


Underlying natural gas data furnished by: ice Global markets in clear view

New England, NY, and PJM Hourly Average Real Time Prices by Month

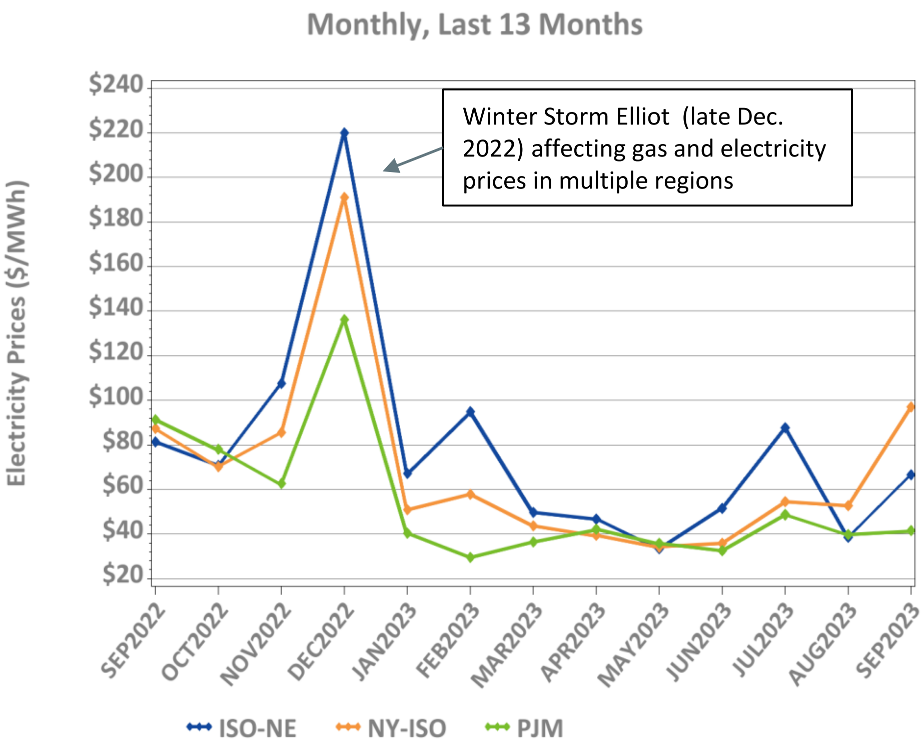


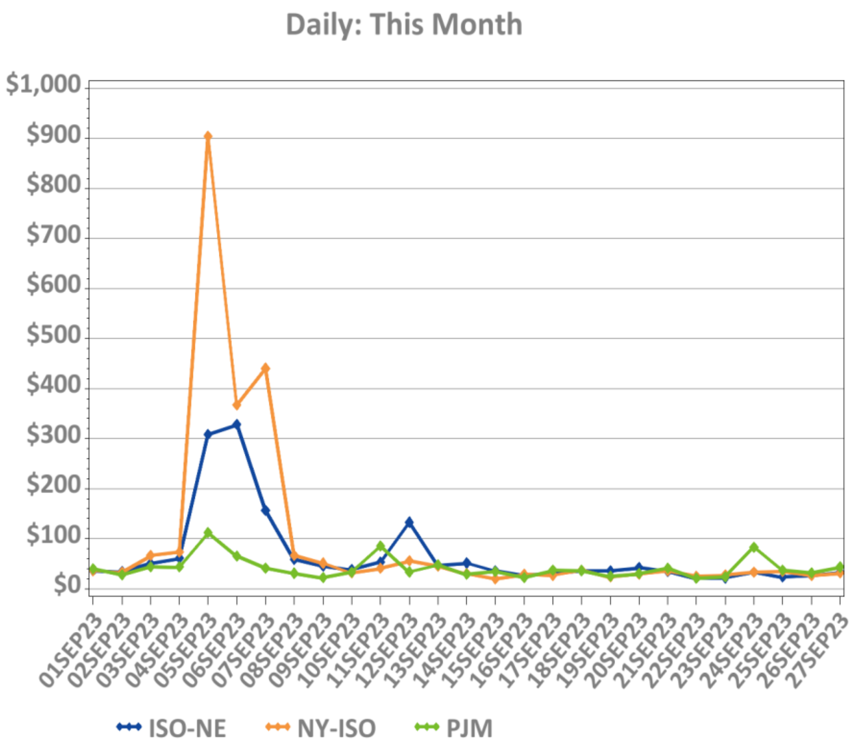
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

New England, NY, and PJM Average Peak Hour Real Time Prices





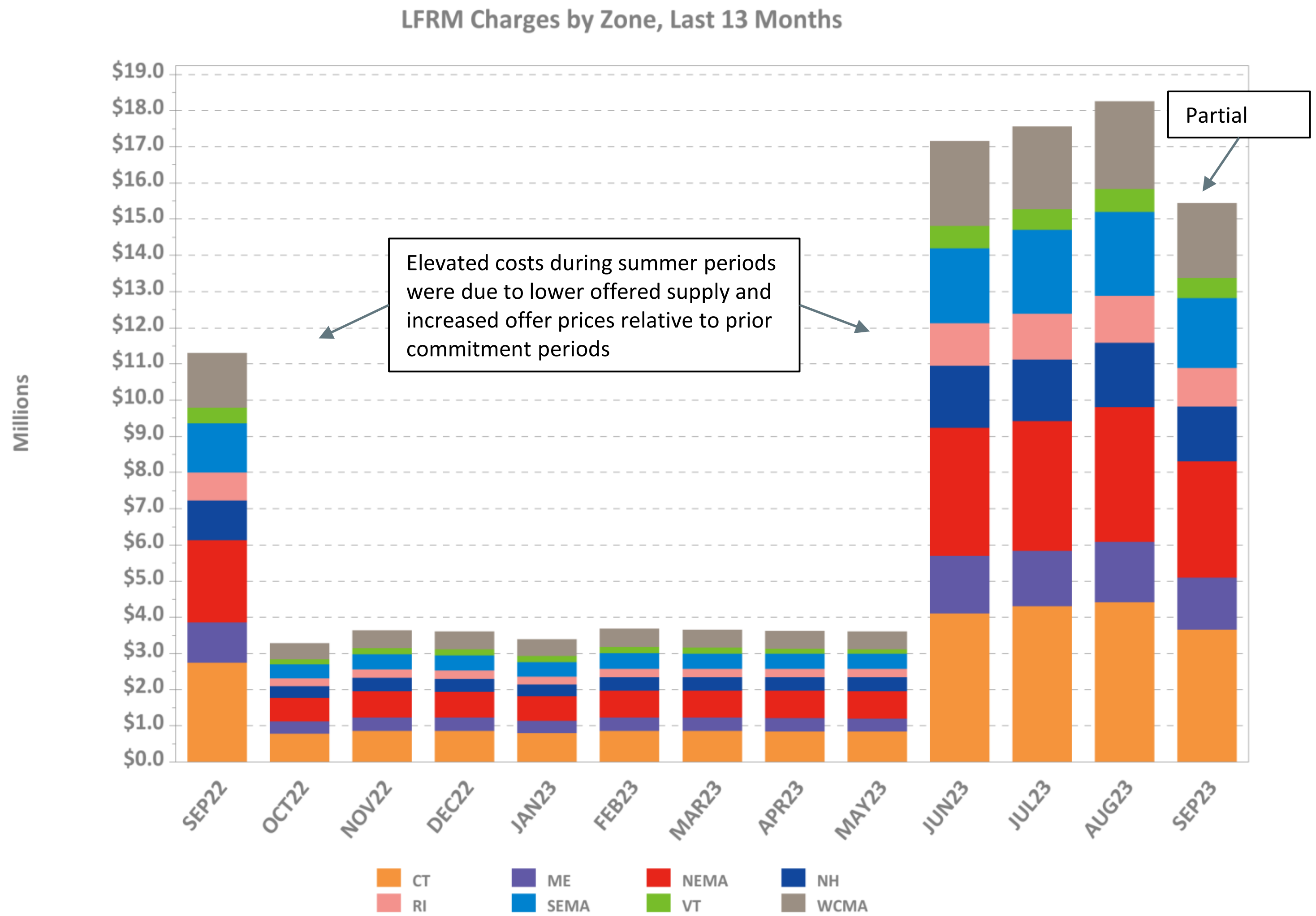
***Forecasted New England daily peak hours reflected**

Reserve Market Results – September 2023

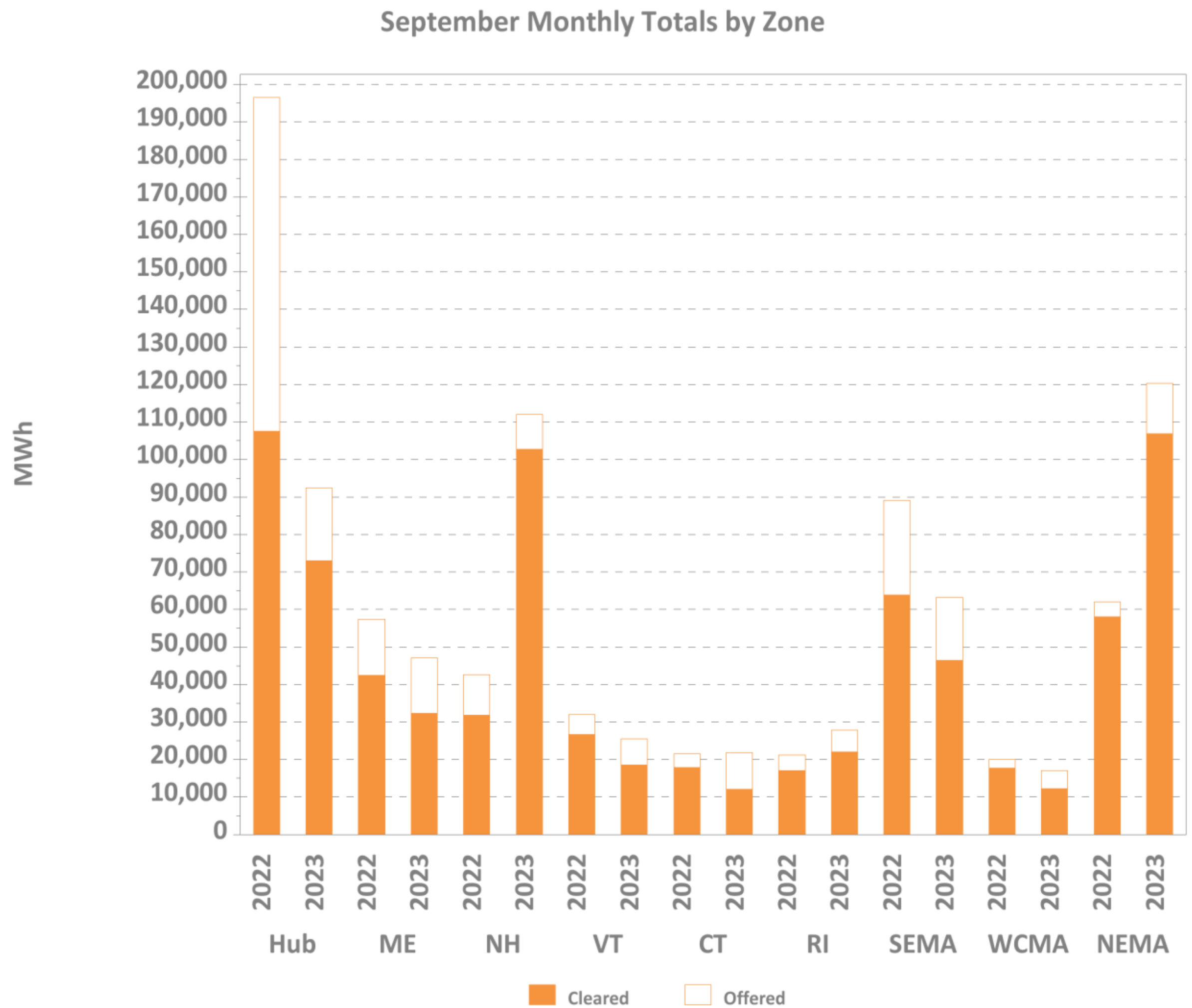
- Maximum potential Forward Reserve Market payments of $17M were reduced by credit reductions of $0.6M, failure-to-reserve penalties of $1.0M and failure-to-activate penalties of $10K, resulting in a net payout of $15.4M or 91% of maximum
  - Rest of System: $12.69M/13.96M (91%)
  - Southwest Connecticut: $0.44M/0.45M (99%)
  - Connecticut: $2.2M/2.51M (88%)
  - NEMA: $0.1M/0.1M (100%)
- $3.3M total Real-Time credits were reduced by $1.8M in Forward Reserve Energy Obligation Charges for a net of $1.5M in Real-Time Reserve payments
  - Rest of System: 177 hours, $450K
  - Southwest Connecticut: 177 hours, $580K
  - Connecticut: 177 hours, $204K
  - NEMA: 179 hours, $252K

Note: "Failure to reserve" results in both credit reductions and penalties in the Locational Forward Reserve Market. While this summary reports performance by location, there were no locational requirements in effect for the current Forward Reserve auction period.

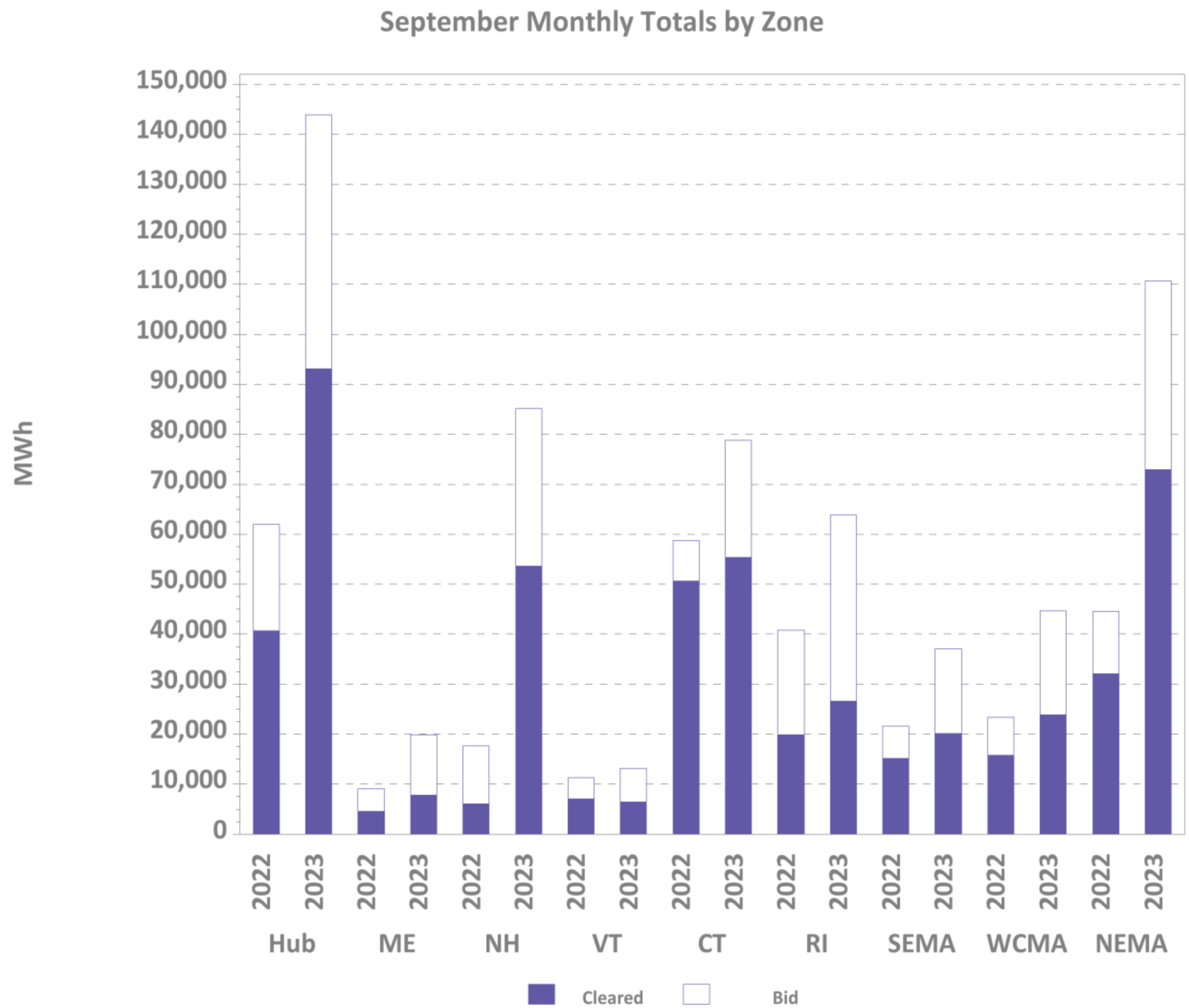
LFRM Charges to Load by Load Zone ($)



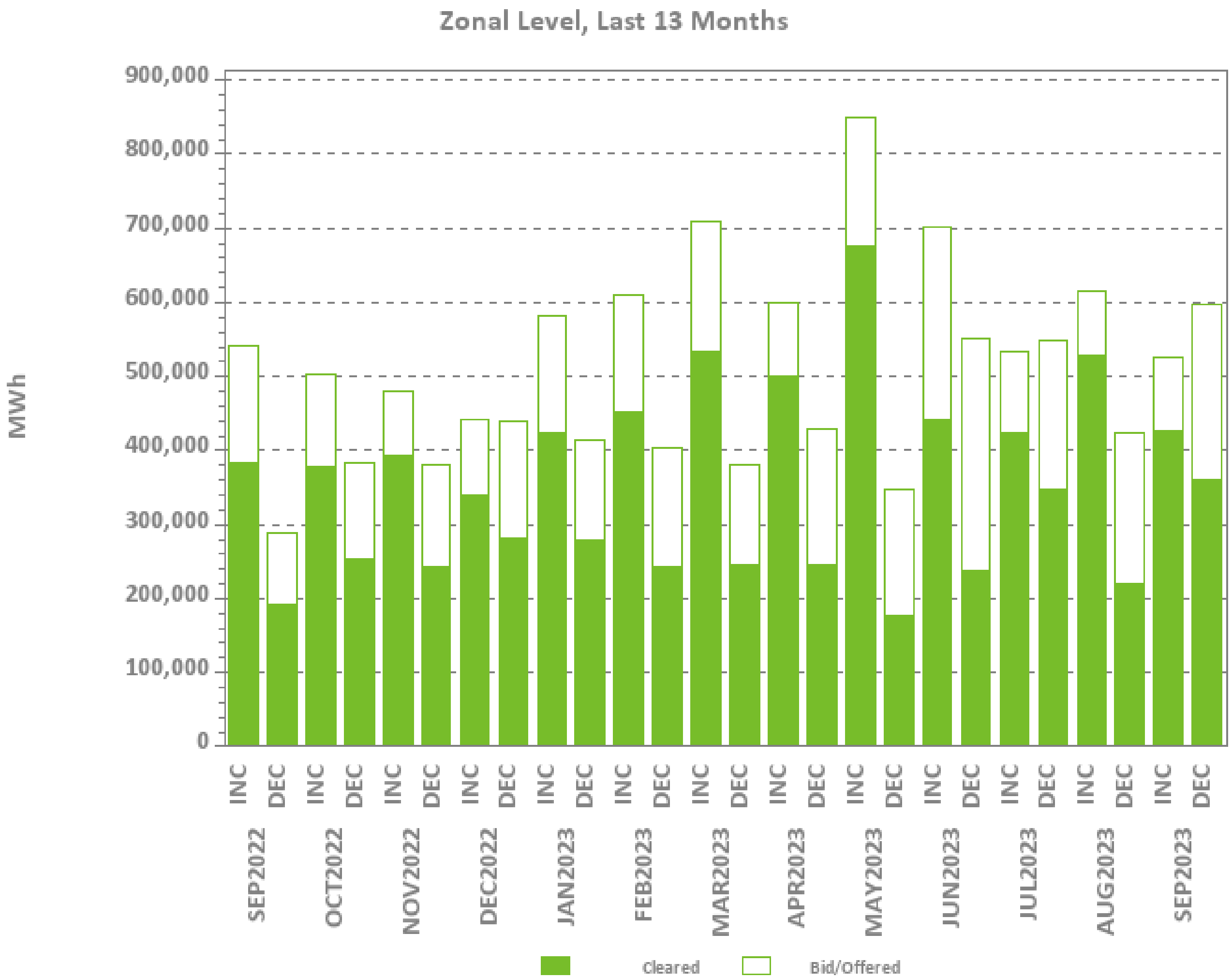
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

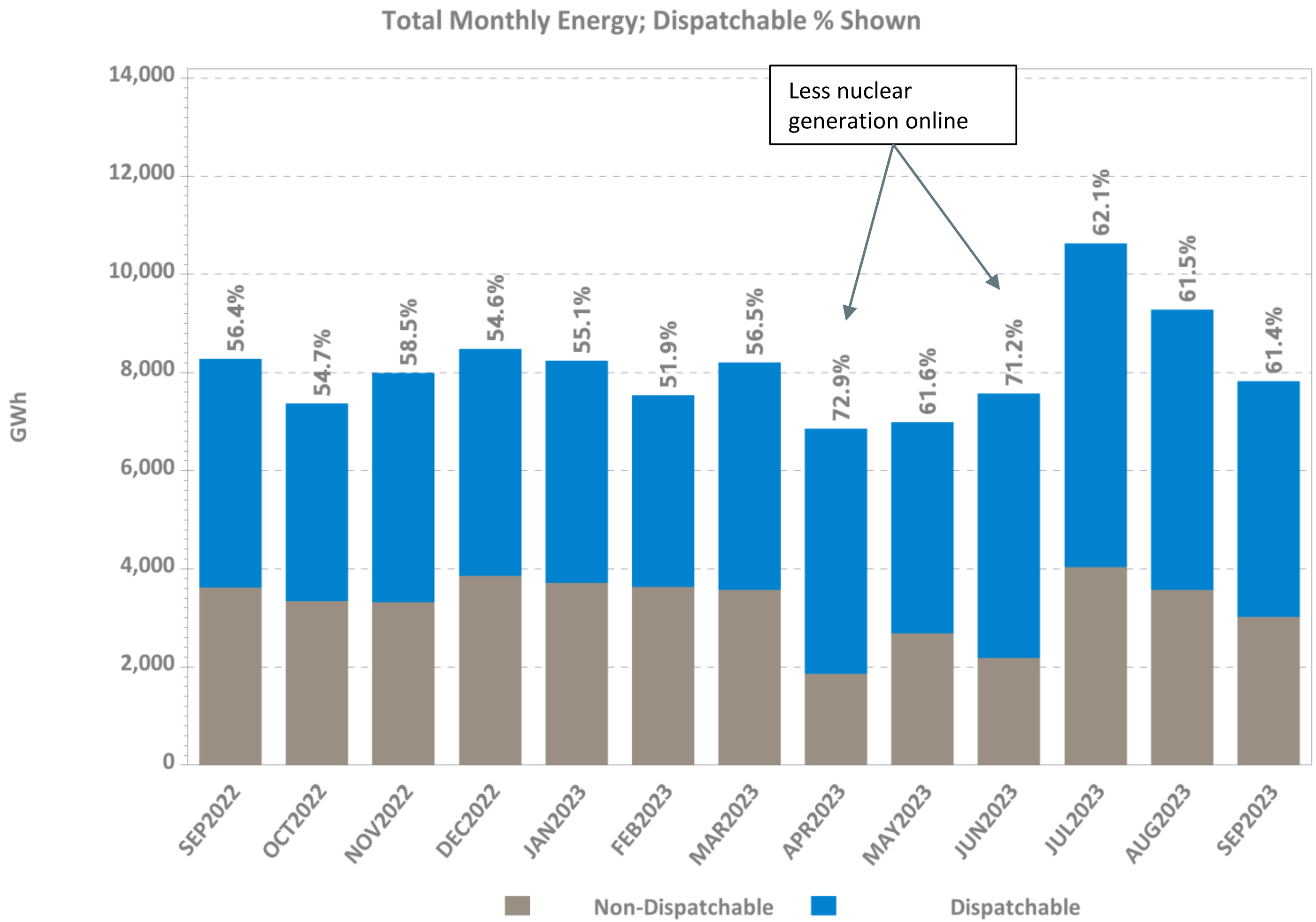


Total Increment Offers and Decrement Bids



Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



* **Dispatchable MWh here are defined to be all generation output that is not self-committed ('must run') by the customer**

REGIONAL SYSTEM PLAN (RSP)

Regional System Plan (RSP)

- 2023-24 RSP will continue the streamlining efforts started with the 2021 RSP
- 2023-24 RSP will focus on being an overview narrative about ISO's system planning and the outlook for the New England grid
- The draft 2023-24 RSP was shared with stakeholders on August 16 and comments were received
  - Few comments were submitted
- RSP Public Meeting will be held on November 1 and will be concurrent with the ISO Open Board Meeting
  - Presentation from Debra Lew, Associate Director, Energy Systems Integration Group
  - Registration is now open

Planning Advisory Committee (PAC)

- October 18 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - E183W 115 kV Line Rebuild (Rhode Island Energy)
    - M13 & L14 115 kV Line Rebuild (Rhode Island Energy)
    - S171N & T172N 115 kV Line Rebuild (Rhode Island Energy)
    - K42 Transmission Line Replacement Project Update (VELCO)
  - New England Transmission Owners "NETO" Asset Management Process
  - Economic Planning for the Clean Energy Transition (EPCET) – Additional Policy Sensitivity Results
  - 2050 Transmission Study: Final Results and Estimated Costs

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

2050 Transmission Study

- Meeting with the states was held on 10/15/21 to review the draft study scope
- The draft study scope was discussed with the PAC on 11/17/21
- ISO provided initial results at the 3/16/22 PAC meeting
- Sensitivity results, as well as a high-level approach to solutions development, were discussed at the 4/28/22 PAC meeting
- ISO discussed updated results and the approximate duration of overloads at the 7/20/22 PAC meeting
- ISO began initial discussions on solution development and lessons learned at the 12/13/22 PAC meeting
- Consultant to perform cost estimates has been selected – Electrical Consultants Inc. (ECI)
- ECI is working on developing cost estimates for potential transmission additions
- Development of transmission solutions will continue throughout the first half of 2023
- Additional discussion on solution development occurred at the 4/20/23 and 7/25/23 PAC meetings
- Discussion on potential solution costs is expected at the 10/18/23 PAC meeting
- Draft report is scheduled for release by 11/1/23

Economic Studies

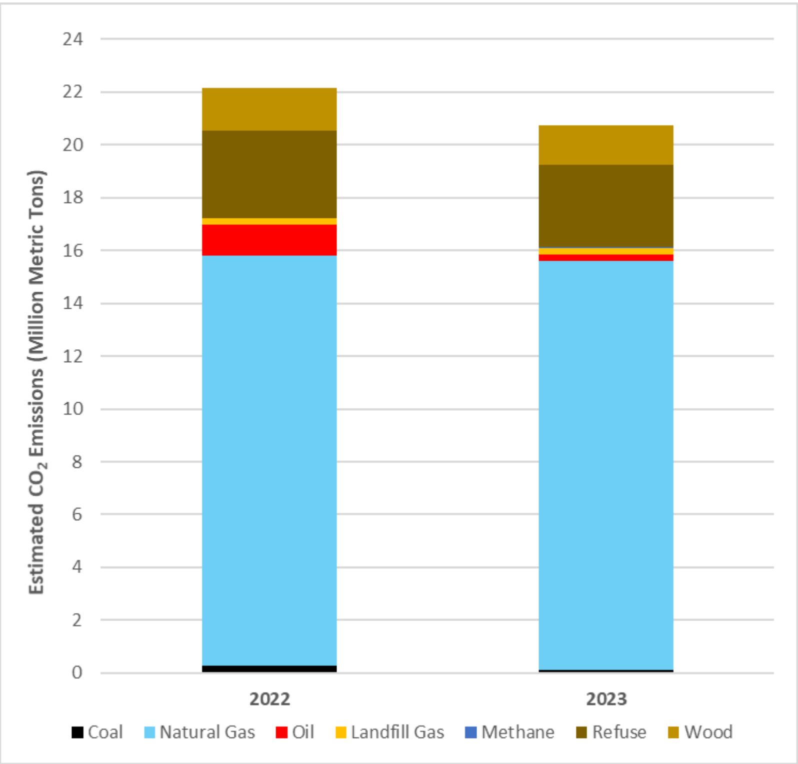
- Economic Planning for the Clean Energy Transition (EPCET) Pilot Study
  - New effort is to review all assumptions in economic planning and perform a test study consistent with the changes to the Tariff
  - PAC presentations began in April 2022. To date, the ISO has presented new modeling features, assumptions and results from the Benchmark and Market Efficiency Need scenarios, an overview of the capacity expansion model and how it will be used in the Policy scenario. The ISO presented preliminary results from the Policy scenario in June 2023. Sensitivity results were presented in July and August.
    - FGRS Phase 2 is now the Stakeholder-Requested Scenario in EPCET

Future Grid Reliability Study (FGRS)

- Phase 1
  - Studies included: Production Cost Simulations; Ancillary Services Simulations; Resource Adequacy Screen; and Probabilistic Resource Availability Analysis
  - Phase 1 work was completed as the 2021 Economic Study
- Phase 2
  - In Phase 2, modeling tools and assumptions from the Pathways and FGRS Phase 1 studies will be used to solve for the set of clean-energy resources that are revenue sufficient and meet the 1-in-10 resource adequacy standard
  - Reliability attributes/capabilities of this revenue-sufficient resource mix and any potential reliability "gaps" that remain will be identified
  - High-level outline was presented at the April PAC

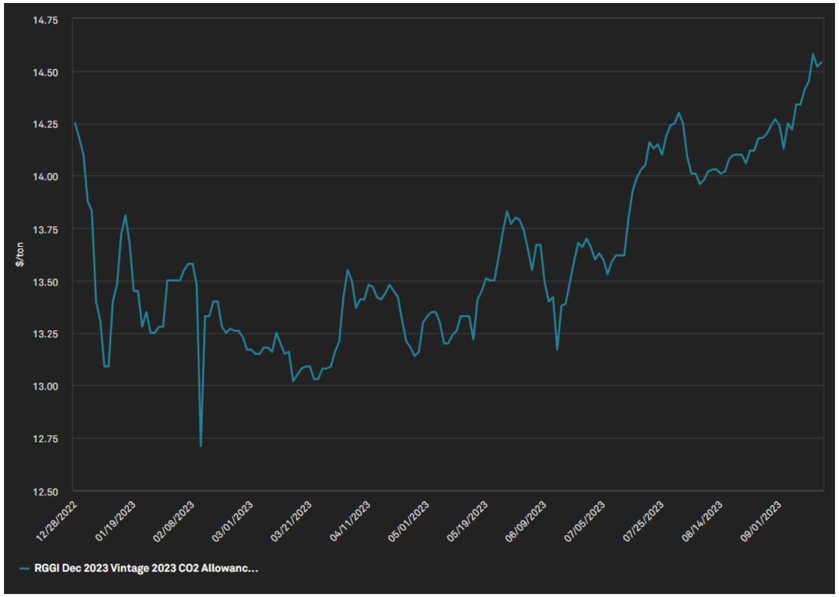
New England Power System Carbon Emissions

2022 vs. 2023 New England Power System Estimated Carbon Dioxide (CO_2) Emissions



Data as of 9/10/2023

RGGI Allowance Prices



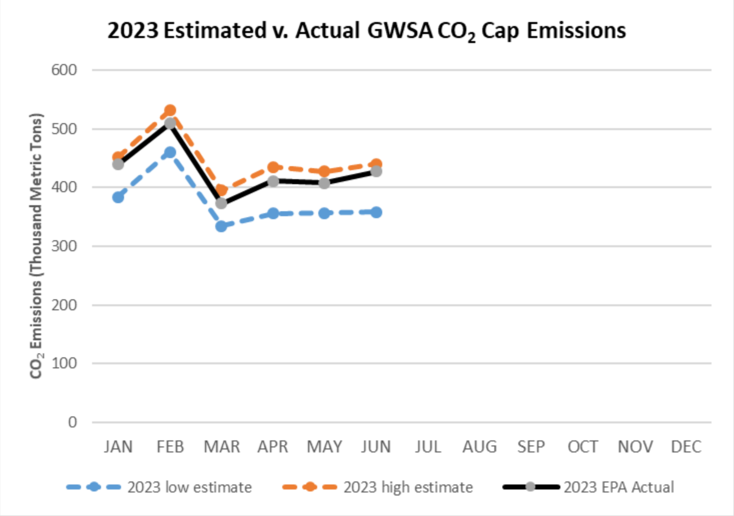
- 9/18/23: RGGI allowance spot price - $14.54
- 9/26/23: Third RGGI Program Review Public Meeting
  - Draft agenda includes an Environmental Justice and Equity section

RGGI – Regional Greenhouse Gas Initiative

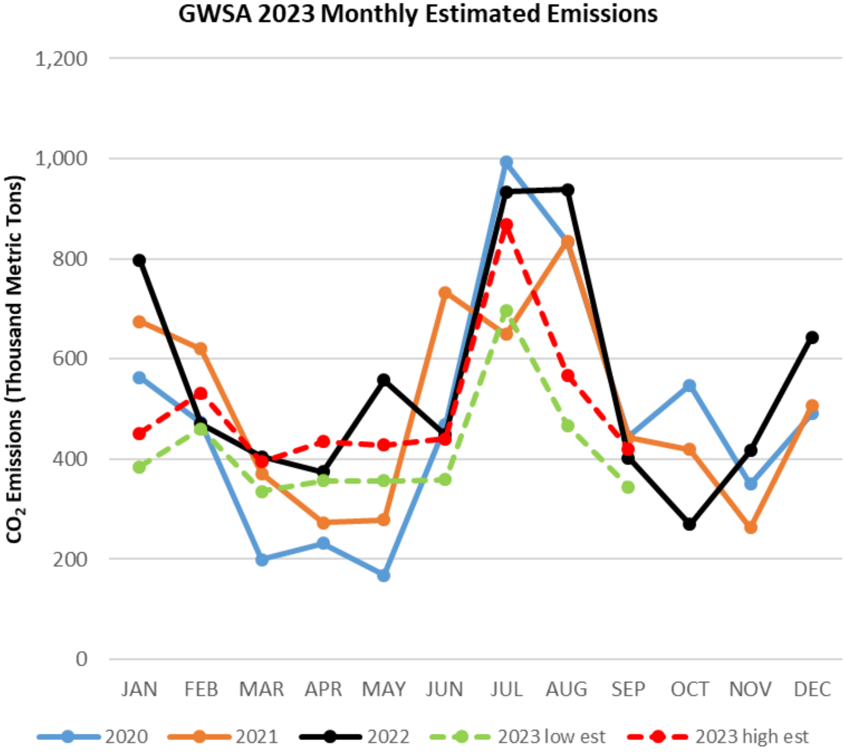
Massachusetts CO_2 Generator Emissions Cap

2023 Estimated Emissions Under CO_2 Cap

- As of 9/20/23, September 2023 estimated GWSA CO_2 emissions range between **344,257** and **419,808** metric tons
  - Year-to-date 2023 estimated emissions range between **48%** and **58%** of the 2023 cap of 7.84 MMT
- According to the EPA CAMPD, Q1 and Q2 (January-June) GWSA CO_2 emissions were **2.57** MMT. Q1 and Q2 emissions were **33%** of the 2023 cap of 7.84 MMT



2020-2023 Estimated Monthly Emissions (Thousand Metric Tons)



GWSA – Global Warming Solutions Act
MMT – Million Metric Tons

Sources: ISO-NE (estimated emissions); EPA (actual 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 9/21/2023

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*	Dec-23	3*
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

* Substation portion of the project is a Present Stage status 4

Greater Boston Projects, cont.

Status as of 9/21/2023

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 9/21/2023

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 9/21/2023

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	Dec-23	3
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 9/21/2023

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 9/21/2023

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 9/21/2023

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-26	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 9/21/2023

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	3
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	1

SEMA/RI Reliability Projects, cont.

Status as of 9/21/2023

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 9/21/2023

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 9/21/2023

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	Dec-23	3
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 9/21/2023

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 9/21/2023

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	3
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	3

New Hampshire Solution Projects

Status as of 9/21/2023

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	Sep-24	3
1879	Install a +55/-32.2 MVAR synchronous condenser at Huckins Hill 115 kV Substation with a 115 kV breaker	Dec-23	3
1880	Install a +127/-50 MVAR synchronous condenser at Amherst 345 kV Substation with two 345 kV breakers	Jun-24	3
1881	Install two 50 MVAR capacitors on Line 363 near Seabrook Station with three 345 kV breakers	Oct-23	3

Upper Maine Solution Projects

Status as of 9/21/2023

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	Jun-24	3

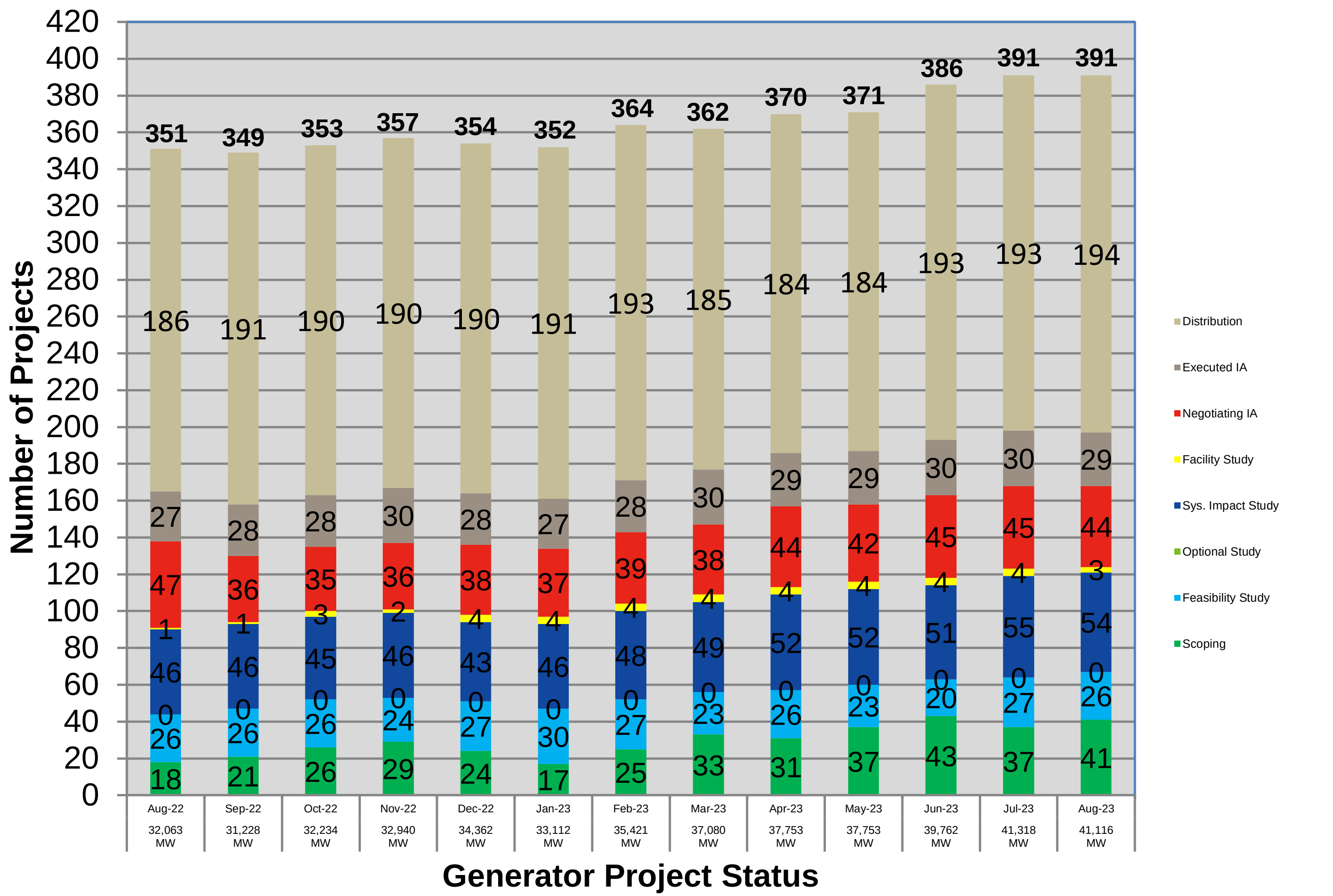
Upper Maine Solution Projects, cont.

Status as of 9/21/2023

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	Jun-24	3
1888	Install 10 MVAR reactor at Keene Road 115 kV substation	Jun-24	2
1889	Install three remotely monitored and controlled switches to split the existing Orrington reactors between the two Orrington 345/115 kV autotransformers	Dec-24	2

Status of Tariff Studies as of September 1, 2023



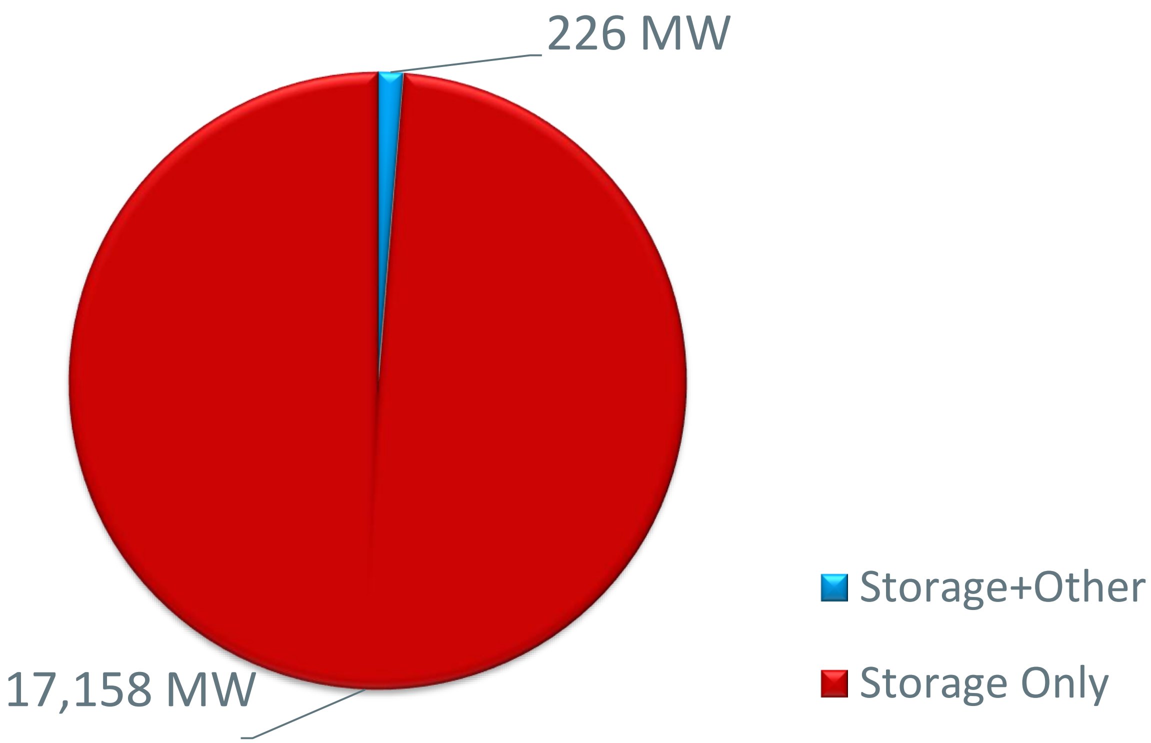
10 ETUs in Scoping, 6 in FS, 0 in SIS, 0 in OIS, 0 in FAC, 1 Negotiating IA, and 4 with Executed IA

Transmission Service Requests needing study: 2 in SIS

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

What is in the Queue (as of September 1, 2023)

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



OPERABLE CAPACITY ANALYSIS

Fall 2023 and Preliminary Winter 2023/24 Analysis

Highlights

- The lowest 50/50 and 90/10 Fall Operable Capacity Margins are projected for week beginning November 4, 2023.

- The lowest 50/50 and 90/10 Preliminary Winter Operable Capacity Margins are projected for week beginning December 9, 2023.

OPERABLE CAPACITY ANALYSIS

Fall 2023 Analysis

Fall 2023 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Nov. - 2023[2] CSO (MW)	Nov. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,237	31,743
Active Demand Capacity Resource (+) [5]	518	329
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	958	958
Non Commercial Capacity (+)	223	223
Non Gas-fired Planned Outage MW (-)	3,948	4,560
Gas Generator Outages MW (-)	2,996	3,837
Allowance for Unplanned Outages (-) [4]	3,600	3,600
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	19,392	21,256
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	17,005	17,005
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	19,310	19,310
Operable Capacity Margin	82	1,946

[1]Operable Capacity is based on data as of **September 25, 2023** 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 **September 25, 2023.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **November 4, 2023.**

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

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

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

Fall 2023 Operable Capacity Analysis

90/10 Load Forecast	Nov. - 2023[2] CSO (MW)	Nov. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,237	31,743
Active Demand Capacity Resource (+) [5]	518	329
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	958	958
Non Commercial Capacity (+)	223	223
Non Gas-fired Planned Outage MW (-)	3,948	4,560
Gas Generator Outages MW (-)	2,996	3,837
Allowance for Unplanned Outages (-) [4]	3,600	3,600
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	19,392	21,256
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	17,662	17,662
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	19,967	19,967
Operable Capacity Margin	-575	1,289

[1]Operable Capacity is based on data as of **September 25, 2023** 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 **September 25, 2023.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **November 4, 2023.**

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

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

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

Fall 2023 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

September 25, 2023 - 50-50 FORECAST using CSO MW

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

Report created: 9/25/2023

Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
10/14/2023	28364	418	941	66	5262	2388	2800	0	19339	16324	2305	18629	710	N	Fall 2023
10/21/2023	28364	418	941	66	4629	2822	2800	0	19538	16685	2305	18990	548	N	Fall 2023
10/28/2023	28237	518	958	223	4172	2768	3600	0	19396	16890	2305	19195	201	N	Fall 2023
11/4/2023	28237	518	958	223	3948	2996	3600	0	19392	17005	2305	19310	82	Y	Fall 2023
11/11/2023	28237	518	958	223	4645	1324	3600	0	20367	17347	2305	19652	715	N	Fall 2023
11/18/2023	28237	518	958	223	2543	1178	3600	192	22423	18079	2305	20384	2039	N	Fall 2023

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 2023 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).

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

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

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

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

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

Fall 2023 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

September 25, 2023 - 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 September, October & November.

Report created: 9/25/2023

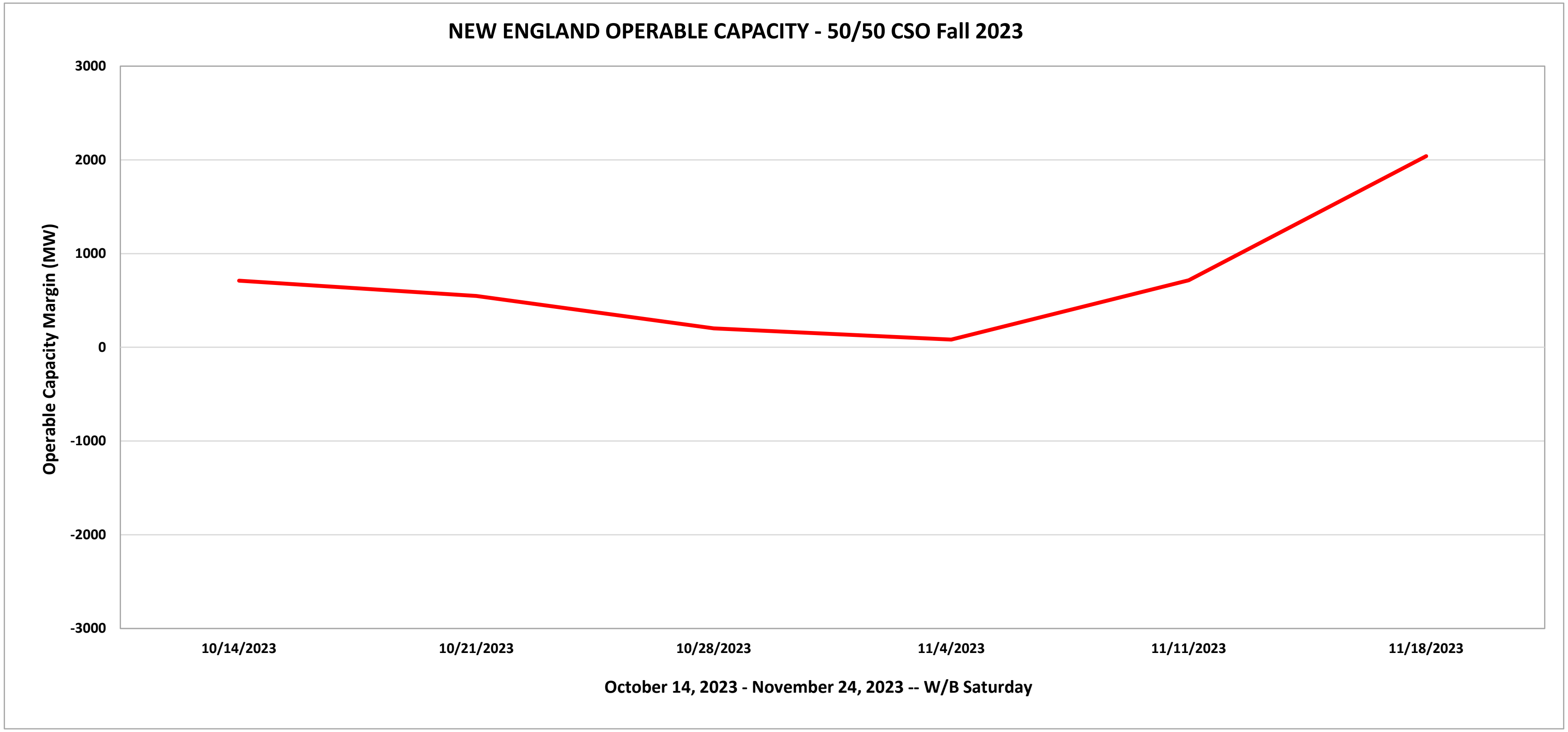
Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
10/14/2023	28364	418	941	66	5262	2388	2800	0	19339	16957	2305	19262	77	N	Fall 2023
10/21/2023	28364	418	941	66	4629	2822	2800	0	19538	17331	2305	19636	-98	N	Fall 2023
10/28/2023	28237	518	958	223	4172	2768	3600	0	19396	17543	2305	19848	-452	N	Fall 2023
11/4/2023	28237	518	958	223	3948	2996	3600	0	19392	17662	2305	19967	-575	Y	Fall 2023
11/11/2023	28237	518	958	223	4645	1324	3600	0	20367	18015	2305	20320	47	N	Fall 2023
11/18/2023	28237	518	958	223	2543	1178	3600	357	22258	18773	2305	21078	1180	N	Fall 2023

Column Definitions

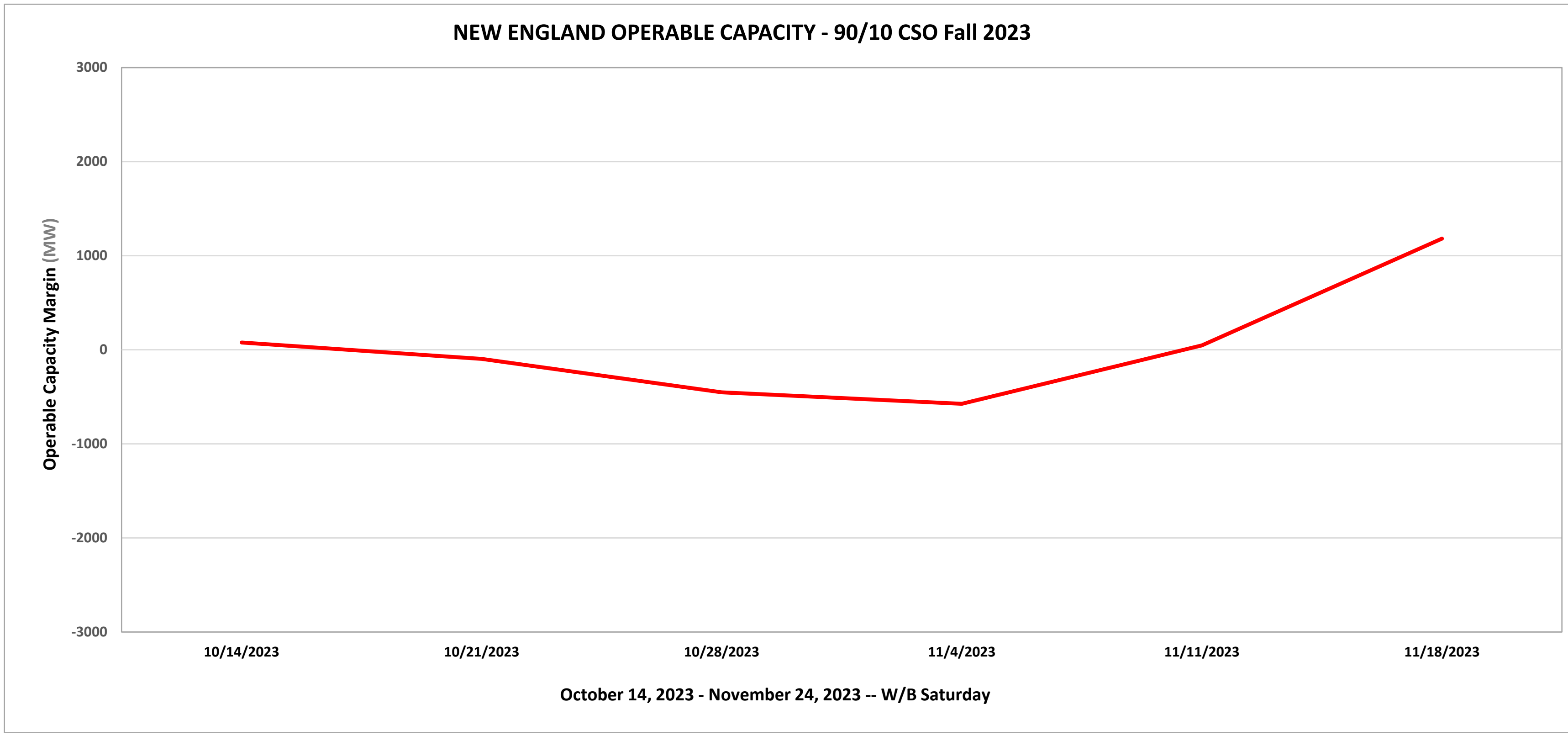
1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can 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 2023 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

Fall 2023 Operable Capacity Analysis
50/50 Forecast (Reference)



Fall 2023 Operable Capacity Analysis
90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Preliminary Winter 2023/24 Analysis

Preliminary Winter 2023/24 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Dec. - 2023[2] CSO (MW)	Dec. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,334	31,743
Active Demand Capacity Resource (+) [5]	522	329
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	958	958
Non Commercial Capacity (+)	223	223
Non Gas-fired Planned Outage MW (-)	2,200	2,378
Gas Generator Outages MW (-)	676	896
Allowance for Unplanned Outages (-) [4]	3,200	3,200
Generation at Risk Due to Gas Supply (-) [3]	1,692	1,356
Net Capacity (NET OPCAP SUPPLY MW)	22,269	25,423
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,464	19,464
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,769	21,769
Operable Capacity Margin	500	3,654

[1]Operable Capacity is based on data as of **September 25, 2023** 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 **September 25, 2023.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **December 9, 2023.**

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

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

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

Preliminary Winter 2023/24 Operable Capacity Analysis

90/10 Load Forecast	Dec. - 2023[2] CSO (MW)	Dec. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,334	31,743
Active Demand Capacity Resource (+) [5]	522	329
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	958	958
Non Commercial Capacity (+)	223	223
Non Gas-fired Planned Outage MW (-)	2,200	2,378
Gas Generator Outages MW (-)	676	896
Allowance for Unplanned Outages (-) [4]	3,200	3,200
Generation at Risk Due to Gas Supply (-) [3]	2,679	2,489
Net Capacity (NET OPCAP SUPPLY MW)	21,282	24,290
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,199	20,199
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,504	22,504
Operable Capacity Margin	-1,222	1,786

[1]Operable Capacity is based on data as of **September 25, 2023** 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 **September 25, 2023.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **December 9, 2023.**

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Preliminary Winter 2023/24 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

September 25, 2023 - 50-50 FORECAST using CSO MW

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

Report created: 9/25/2023

Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
11/25/2023	28237	518	958	223	2631	797	3600	865	22043	18794	2305	21099	944	N	Winter 2023/2024
12/2/2023	28334	522	958	223	2027	951	3200	853	23006	19177	2305	21482	1524	N	Winter 2023/2024
12/9/2023	28334	522	958	223	2200	676	3200	1692	22269	19464	2305	21769	500	Y	Winter 2023/2024
12/16/2023	28334	522	958	223	1339	731	3200	2014	22753	19475	2305	21780	973	N	Winter 2023/2024
12/23/2023	28334	522	958	223	0	421	3200	2713	23703	19537	2305	21842	1861	N	Winter 2023/2024
12/30/2023	28334	522	958	223	0	366	2800	3367	23504	19808	2305	22113	1391	N	Winter 2023/2024
1/6/2024	28334	522	958	223	0	366	2800	3362	23509	20269	2305	22574	935	N	Winter 2023/2024
1/13/2024	28334	522	958	223	0	366	2800	3217	23654	20269	2305	22574	1080	N	Winter 2023/2024
1/20/2024	28334	522	958	223	0	366	2800	2768	24103	20269	2305	22574	1529	N	Winter 2023/2024
1/27/2024	28334	522	958	223	59	33	3100	2802	24043	20049	2305	22354	1689	N	Winter 2023/2024
2/3/2024	28334	522	958	223	59	33	3100	2503	24342	19784	2305	22089	2253	N	Winter 2023/2024
2/10/2024	28334	522	958	223	59	33	3100	2204	24641	19755	2305	22060	2581	N	Winter 2023/2024
2/17/2024	28334	522	958	223	0	33	3100	1755	25149	19495	2305	21800	3349	N	Winter 2023/2024
2/24/2024	28334	522	958	223	52	33	3100	1456	25396	18516	2305	20821	4575	N	Winter 2023/2024
3/2/2024	28334	522	958	223	105	33	2200	381	27318	18170	2305	20475	6843	N	Winter 2023/2024
3/9/2024	28334	522	958	223	1354	404	2200	0	26079	17976	2305	20281	5798	N	Winter 2023/2024
3/16/2024	28334	522	958	223	1354	501	2200	0	25982	17614	2305	19919	6063	N	Winter 2023/2024
3/23/2024	28334	522	958	223	1361	778	2200	0	25698	17054	2305	19359	6339	N	Winter 2023/2024
3/30/2024	28232	518	958	223	815	1796	2700	0	24620	16379	2305	18684	5936	N	Winter 2023/2024

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 2023 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Preliminary Winter 2023/24 Operable Capacity Analysis 90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

September 25, 2023 - 90/10 FORECAST using CSO MW

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

Report created: 9/25/2023

Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
11/25/2023	28237	518	958	223	2631	797	3600	1779	21129	19512	2305	21817	-688	N	Winter 2023/2024
12/2/2023	28334	522	958	223	2027	951	3200	1841	22018	19903	2305	22208	-190	N	Winter 2023/2024
12/9/2023	28334	522	958	223	2200	676	3200	2679	21282	20199	2305	22504	-1222	Y	Winter 2023/2024
12/16/2023	28334	522	958	223	1339	731	3200	3133	21634	20211	2305	22516	-882	N	Winter 2023/2024
12/23/2023	28334	522	958	223	0	421	3200	3859	22557	20274	2305	22579	-22	N	Winter 2023/2024
12/30/2023	28334	522	958	223	0	366	2800	4042	22829	20555	2305	22860	-31	N	Winter 2023/2024
1/6/2024	28334	522	958	223	0	366	2800	4173	22698	21032	2305	23337	-639	N	Winter 2023/2024
1/13/2024	28334	522	958	223	0	366	2800	3965	22906	21032	2305	23337	-431	N	Winter 2023/2024
1/20/2024	28334	522	958	223	0	366	2800	3666	23205	21032	2305	23337	-132	N	Winter 2023/2024
1/27/2024	28334	522	958	223	59	33	3100	3999	22846	20804	2305	23109	-263	N	Winter 2023/2024
2/3/2024	28334	522	958	223	59	33	3100	3550	23295	20530	2305	22835	460	N	Winter 2023/2024
2/10/2024	28334	522	958	223	59	33	3100	3251	23594	20500	2305	22805	789	N	Winter 2023/2024
2/17/2024	28334	522	958	223	0	33	3100	2653	24251	20231	2305	22536	1715	N	Winter 2023/2024
2/24/2024	28334	522	958	223	52	33	3100	2204	24648	19218	2305	21523	3125	N	Winter 2023/2024
3/2/2024	28334	522	958	223	105	33	2200	1278	26421	18860	2305	21165	5256	N	Winter 2023/2024
3/9/2024	28334	522	958	223	1354	404	2200	802	25277	18659	2305	20964	4313	N	Winter 2023/2024
3/16/2024	28334	522	958	223	1354	501	2200	0	25982	18285	2305	20590	5392	N	Winter 2023/2024
3/23/2024	28334	522	958	223	1361	778	2200	0	25698	17705	2305	20010	5688	N	Winter 2023/2024
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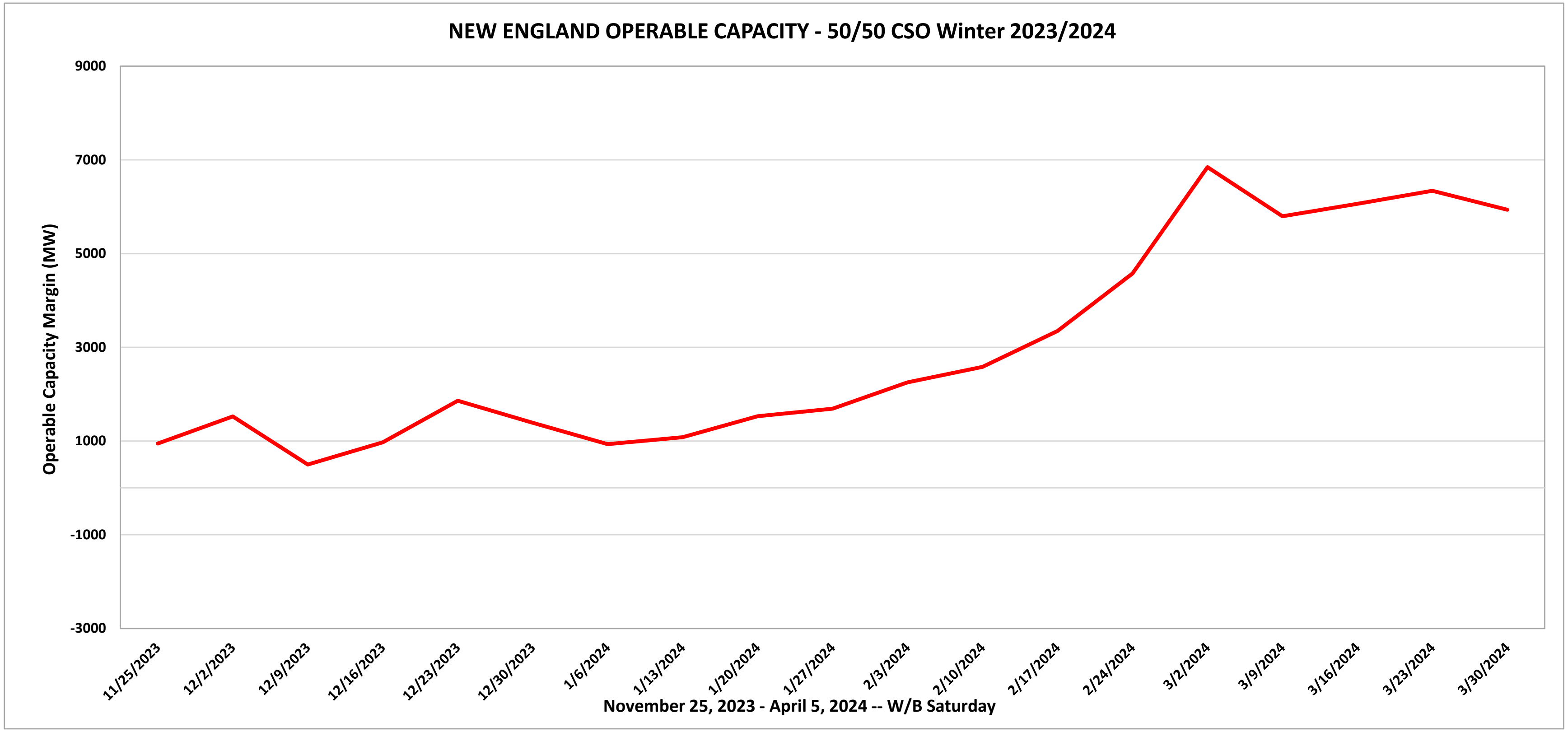
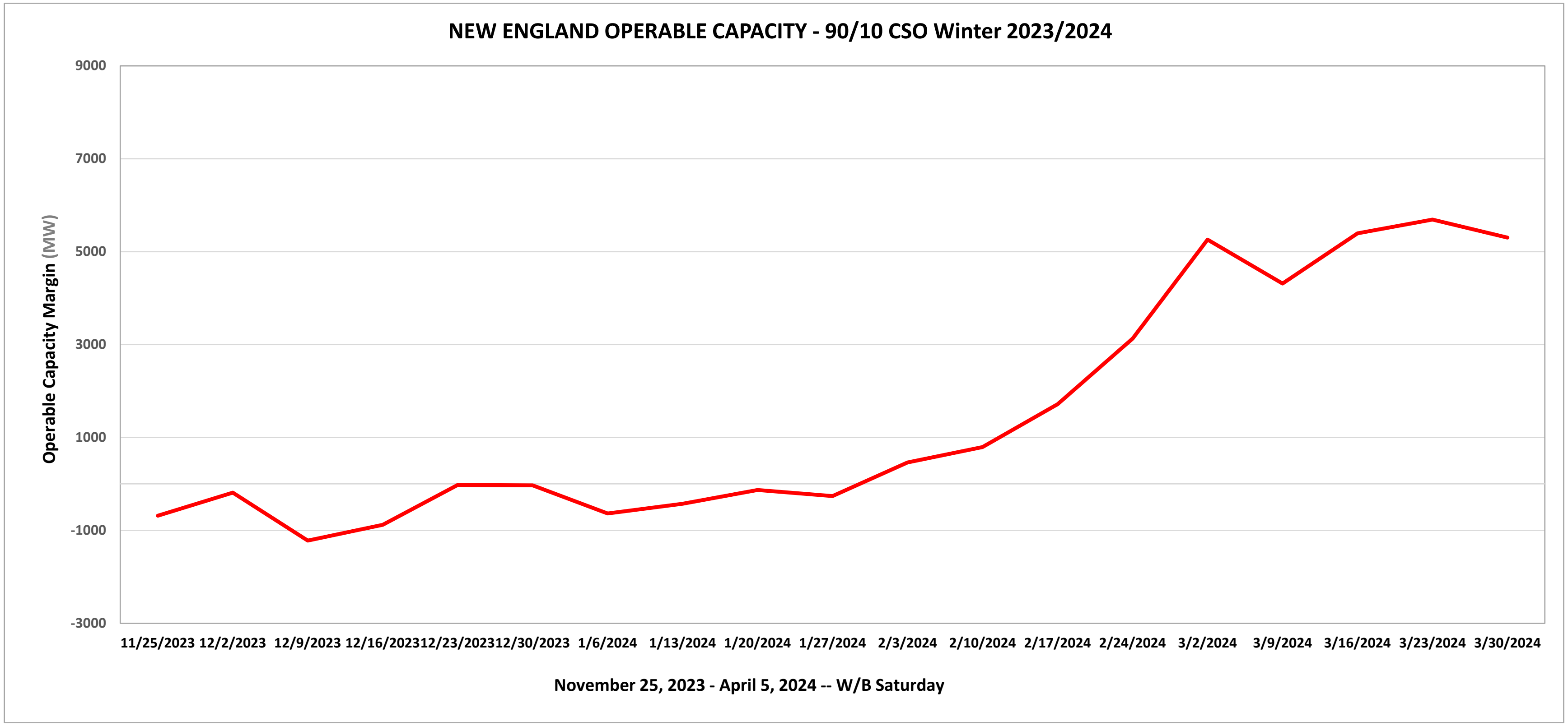
Preliminary Winter 2023/24 Operable Capacity Analysis

50/50 Forecast (Reference)



Preliminary Winter 2023/24 Operable Capacity Analysis
90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4: Appendix A

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

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

Possible Relief Under OP4: Appendix A

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

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

SEPTEMBER 21, 2023

ISO New England's Draft 2024 Annual Work Plan (AWP)

For Discussion at the October 5, 2023, NEPOOL Participants Committee Meeting

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

2024 Objectives and Highlights

Advancing a reliable clean-energy transition through innovation and collaboration

- **Anchor projects** require dedicated focus and a regional commitment to securing power system reliability while facilitating the integration of clean-energy and distributed-energy resources
  - **Resource Capacity Accreditation in the FCM** to continue developing a framework that will more appropriately accredit resource contributions to resource adequacy as resource mix transforms
  - **Assess Alternative FCM Commitment Horizons** to continue evaluating changing the FCA to a prompt auction that runs shortly before the capacity commitment period and/or restructuring the capacity commitment period from annual to seasonal (sub-annual) commitment periods
  - **Energy Adequacy Threshold Determination** to finalize reporting on results from the Probabilistic Energy Adequacy Tool (PEAT) and establish a Regional Energy Shortfall Threshold (REST) for the region to determine the level of reliability risk over next decade requiring regional solutions
  - **FERC Order No. 2023 (RM22-14) Implementation** to take actions needed to effectuate the rule's directives, some of which may fulfill generator interconnection-related NEPOOL priority requests
  - **Extended-Term Transmission Planning Phase 2** to develop Tariff changes allowing a process to move policy-related transmission investments forward and allocate the costs
  - **Day-Ahead Ancillary Services Initiative (DASI) Implementation** to develop the extensive software and business processes needed to support DASI implementation in 2025
  - **nGem Real-Time Market Clearing Engine** to develop the new real-time market clearing engine software and infrastructure that is foundational to supporting an exponentially complex system
- **Notable initiatives** target innovation, advance efficiency, and help manage risks across markets, planning, operations, and software structures

Effects of Shifting Priorities

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

- Plans may need to adjust over time to reflect emerging requests, regulations, trends, and risks
  - Increased or expanded stakeholder requests, regional policy interests, and new issues can affect project schedules of planned efforts
  - Upfront agreement on priority work, including NEPOOL and state priorities, are intended to keep listed projects and schedules on track
  - Unknown timing and topics of Federal Energy Regulatory Commission (FERC) actions (orders, notices of proposed rulemaking) and policy directives can shift priorities
  - For this cycle, scopes and schedules for some initiatives continue to evolve; more precise plans will be reflected in the Spring 2024 AWP Update
- Note that the AWP identifies key initiatives and not the full ISO workload; the ISO's annual budget incorporates the full volume of ISO work, including initiatives in the AWP as well as:
  - Work on smaller projects or projects nearing completion
  - Work to implement projects already through design, stakeholder, and regulatory phases
  - Work representing the ISO's extensive day-to-day operations related to running the grid, markets, IT infrastructure, and its organization

ANCHOR PROJECTS

Enhancements for the Current and Future Grid

Markets Anchor Projects

Scopes and schedules for these top regional priorities will be further defined in the Spring AWP Update

- **Resource Capacity Accreditation (RCA) in the Forward Capacity Market (FCM)**
  - This effort already underway seeks to implement new methodologies to quantify/accredit resources' capacity contributions to regional resource adequacy, which will be critical to reliability and market efficiency as the resource mix transforms
  - Plans for FERC filing and implementation timeframes will be communicated in Q3-Q4 2023
- **Assessing Alternative FCM Commitment Horizons (Prompt/Seasonal)**
  - Through Q2 2024, the ISO will continue discussing with stakeholders the following potential changes to the FCM
    - Replacing the current Forward Capacity Auction that has a three-year forward planning horizon with a prompt capacity auction (i.e., an auction with a short commitment horizon much closer to the capacity commitment period)
    - Restructuring the capacity commitment period from annual to seasonal (sub-annual) commitment periods
  - Design work would follow in 2024 once a path forward on scope and timing is determined; design and implementation require extensive efforts across ISO processes and systems, spanning several years

Operations Anchor Project

Identifying and addressing reliability risks from severe events as grid supply and demand transform is a primary priority for the ISO, NEPOOL, and the states

- **Energy Adequacy Threshold Determination**
  - After finalizing its operational impacts of extreme weather study results from the Probabilistic Energy Adequacy Tool (PEAT), including stakeholder-requested sensitivities, the ISO will present its proposed scope of work for developing a Regional Energy Shortfall Threshold (REST) by the end of 2023
  - In Q1-2 2024, using PEAT results, the ISO plans to work with regional stakeholders to establish a REST that determines the acceptable level of reliability risk
  - The ISO can then evaluate if meeting the REST requires development of specific regional solutions
    - Possible solutions could range from market designs to infrastructure investments to dynamic retail pricing and responsiveness by end-use consumers
  - Further analysis of scope, timing, and feasibility of any such solutions would follow in 2024-2025 as needed

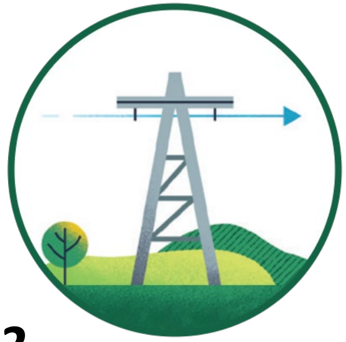
Planning Anchor Projects

FERC compliance work takes priority in the AWP

- **FERC Order No. 2023 (RM22-14) Implementation:** Focused compliance efforts are underway in 2023, with work continuing into 2024 to fully implement the Final Rule's new interconnection paradigm. Some directives are anticipated to converge with NEPOOL's priority requests, including the following two requests related to Planning Procedures, which will be timed according to the Final Rule's implementation schedule.
  - **Assess Interconnection Standard for Charging of Electric Storage Resources (ESRs):** PP5-6 requires that ESRs are studied in charging mode at peak load conditions so that the system is assessed and protected for under that operating condition. NEPOOL members seek, and the states support, modifications to this requirement, which the ISO is addressing via Order No. 2023 compliance. In Q1 2024, the ISO will determine if additional assessments or changes are needed to align with the priority request.
  - **Improvements to the Proposed Plan Application (PPA) Process for TO-LED PPA Studies (including for Distributed Generation Interconnections):** Improvements to the PPA process and to PP 5-1 will be assessed and addressed in the context of compliance with Order No. 2023. Requests for improvements to the process for dealing with clerical errors in participant submissions also will be considered in that context. Requested efforts to formalize and structure the ISO's role in clustered DER interconnection studies would follow completion of Order compliance and implementation work, as the Final Rule focuses on processes for large generators, and those processes would be addressed first.

Planning Anchor Projects, cont'd

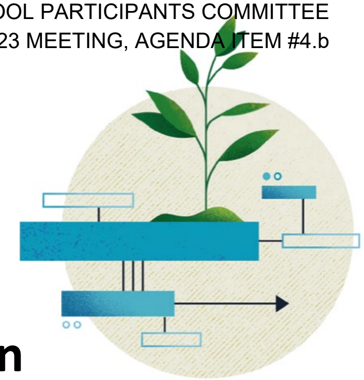
Providing longer-term transmission planning for a reliable, clean-energy future grid in response to the New England States' Energy Vision



- **Extended-Term/Longer-Term Transmission Planning Phase 2**
  - In 2022, the ISO created a process under Attachment K of the OATT, allowing the New England States to request planning analyses that may extend beyond the 10-year planning horizon, which would identify transmission investments in furtherance of state energy policy objectives
  - This second phase of Tariff changes would add a process to operationalize transmission investments resulting from the above analyses, and will include a cost-allocation mechanism for those transmission improvements (i.e., the process would enable conversion of longer-term public policy transmission studies, like the 2050 Transmission Study Solutions, into developable projects)
  - Stakeholder discussions on Phase 2 are expected to begin in Q4 2023, with a potential FERC filing in late Q1 or early Q2 2024
  - Following FERC approval of Phase 2 tariff changes, the ISO would be able to commence initiation of a competitive solicitation resulting from the 2050 Transmission Study

Technology Anchor Projects

Overhauling market software and systems to manage an exponentially complex future grid



- **Day-Ahead Ancillary Services Initiative (DASI) Implementation**
  - A significant initiative throughout 2024, the ISO will develop the extensive software and business process changes needed to support DASI implementation in Q1 2025
  - DASI creates pricing incentives for specific energy and reserve capabilities needed for reliability as regional supply and demand transform
- **nGem Real-Time Market Clearing Engine**
  - Since 2020, in collaboration with MISO and PJM, the ISO has been working to replace its 20+ year old Market Management System (MMS) with the next Generation Electricity Management (nGEM) platform that is foundational to supporting a system with a growing number and type of grid assets, new and more complex market features, multiplying security threats, and advancing IT technologies
  - In 2023, the ISO completed the complex processes for customizing and implementing the day-ahead version of the new market clearing engine (MCE) software and infrastructure service
  - Work on the real-time MCE software and infrastructure will take place throughout 2024, with implementation targeted for Q2 2025

NOTABLE INITIATIVES

Other Major Initiatives Identified for 2024

Notable Markets Initiatives

Improving services and incentives for a reliable future grid

- **Storage Modeling Market Enhancements**
  - The ISO is evaluating opportunities to more efficiently integrate energy storage resources into the energy and ancillary service markets. Stakeholder discussions of proposed day-ahead market enhancements are expected to begin in mid-2024.
- **Day-Ahead and Real-Time Energy Shortage Pricing Assessment**
  - The ISO has been evaluating how a load-shed event is treated in the energy and ancillary services market pricing software and whether enhancements may be needed to signal appropriate day-ahead and real-time prices in the event of an energy shortage. The ISO expects to present concepts to stakeholders in 2024.
- **Flexible Response Services (formerly “Replacement Energy Reserves”) Assessment**
  - In 2024, the ISO will evaluate the system’s needs for flexible response capabilities to address greater operational uncertainties with an increasingly weather-dependent resource mix. This evaluation is expected to consider new, longer-duration reserve products (in the Day-Ahead and Real-Time markets) as potential market-based solutions to these flexibility needs. Stakeholder discussions are targeted to begin in 2025.

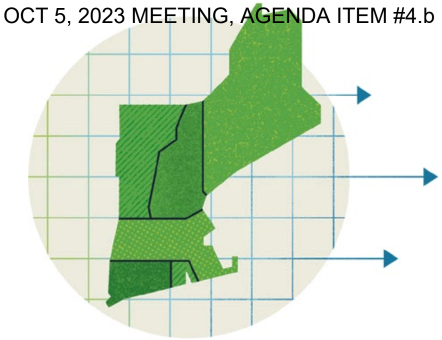
Notable Markets Initiatives, cont'd

Work on these FCM-related initiatives will be further refined in the 2024 Spring AWP Update as needed

- **Contingent Work on FCM-Related Initiatives**
  - Work may be needed in 2024 to conform or extend certain FCM initiatives underway or planned for 2023 that are potentially affected by FCM Prompt/Seasonal considerations and/or an FCA 19 delay, including:
    - FCM Retirement Reforms: Bid Flexibility
    - FCM Retirement Reforms: Return to Service
    - FCM Financial Assurance Policy/Entry-Related Improvement
    - FCM Net CONE Updates Supporting MOPR Reforms for FCA 19
    - Order No. 2222 Participation of DER Aggregations for FCA 19

Notable Planning Initiatives

Assessments related to interconnection with neighbors



- **Evaluate Tie Benefits and HQICCs**
  - As requested by NEPOOL, beginning in Q4 2023 and extending into Q4 2024, the ISO is conducting and reporting on a broad evaluation of the reliability inputs for tie benefits, in which the ISO will evaluate past performance and modeling of tie benefits and expected short- to mid-term future performance
  - Any market or contract changes that may be identified as a result of this evaluation would need to be discussed and scoped separately after the evaluation
  - This effort is distinct from the ISO's current proposal under RCA to incorporate summer and winter components in its accounting for tie benefits in the FCM
- **Evaluate Single Source Contingency Limit Increase**
  - In 2023, the ISO initiated a study request with PJM and NYISO to determine if the current 1,200 MW single source contingency (loss of source) limit is still appropriate, if a higher number can be supported by the current transmission infrastructure, and what potential ISO-NE/NYISO/PJM upgrades, including estimated cost, would be necessary to support a 2,000 MW minimum loss of source limit
  - An inter-regional study would align with NEPOOL's request and state support for such analyses and is anticipated to take approximately two years to complete once underway; beginning in 2024, the ISO will provide updates to stakeholders throughout the study process
  - Moving forward with upgrades identified from the study would be a separately-scoped, subsequent initiative

Notable Planning Initiatives

Assessing the future of the regional power system in light of state energy and environmental laws

- **Economic Planning for the Clean Energy Transition (EPCET) Pilot Study**
  - The ISO is performing a trial run of its Economic Study Process Improvement changes to Attachment K by testing modeling changes and new economic planning software through the EPCET initiative
  - Remaining reliability and market study work from the New England's Future Grid Initiative (both Pathways to the Future Grid and Future Grid Reliability Study (FGRS) Phase 2),which have reflected priorities by NEPOOL and the states, will be completed via the EPCET policy scenario in this initiative
  - EPCET analysis and stakeholder discussions have been taking place throughout 2023 and are expected to continue into Q1 2024, with a summary report planned for issue in Q2 2024

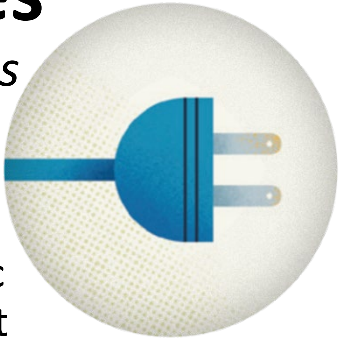
Notable Planning Initiatives

Thoughtful, well-planned transmission investment is critical to achieving a clean, reliable, and affordable regional grid

- **Transmission Asset Condition Process Improvements and Sizing for the Clean Energy Transition**
  - The New England's States and Transmission Owners (TOs) have been discussing improvements to the transmission asset condition processes to enhance the information, criteria, and cost estimates submitted by transmission owners
    - Successively, they seek to consider how future sizing needs can be incorporated into transmission project processes
  - Pending the outcome of those discussions, the ISO will proceed with an initiative to help implement improvements to the asset condition process in support of state and TO efforts
  - This work would pair with the ISO's efforts with the states and stakeholders to develop a regional approach ensuring that transmission projects—including asset condition projects—are sized for the future given the anticipated transition of the system over the life of the asset

Notable Technology & Security Initiatives

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

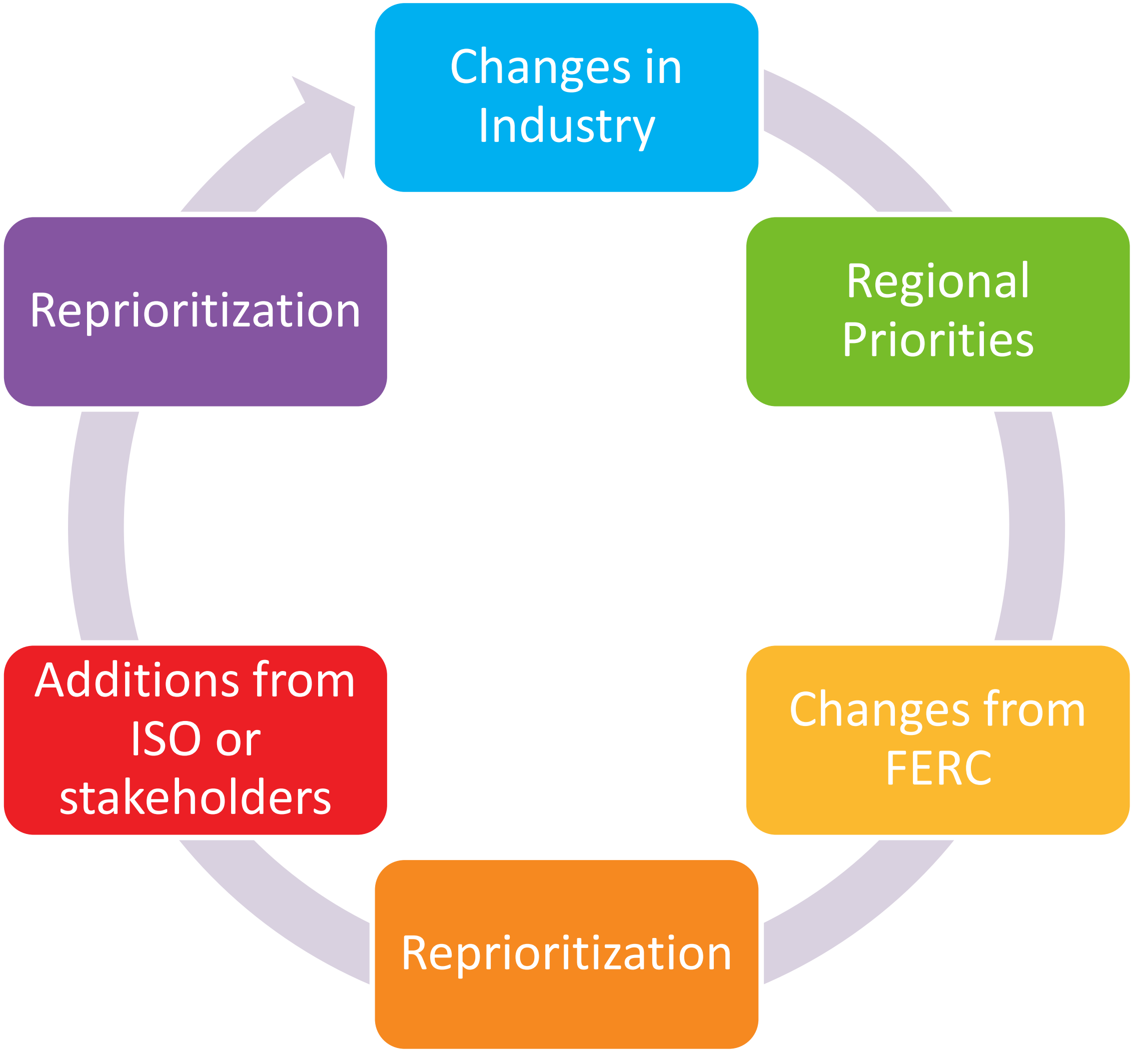


- **Inverter-Based Resource (IBR) Integration & Modeling:** In 2024, the ISO will complete the development of an inter-departmental electromagnetic transient (EMT) model management process for all computer models that represent how each inverter-based resource interacts with the grid, and optimize software programs and hardware used to run computer simulations based on those models
- **Synchrophasor Enhancements for Future Grid:** In Q4 2024, the ISO is implementing synchrophasor improvements to better understand the performance of IBRs and distributed energy resources during system events and monitor their dynamic behaviors in real-time; this work includes enhancing the Oscillation Source Location tool; enhancing Phasor Measurement Unit (PMU) situational awareness displays in the control room; streamlining PMU support and maintenance processes; and developing a roadmap to secure the synchrophasor systems for mission critical operations
- **Cloud Computing:** The ISO is implementing cloud infrastructure to reduce reliance on energy-heavy data centers, make system deployment more efficient as resource numbers increase, and enable faster computing performance as resource data grows
- **Cyber Security:** The ISO is implementing a portfolio of projects, including modernized identity management and protection systems, phase 2 updates to the CIP Electronic Security Perimeter, and other improved detection and response capabilities

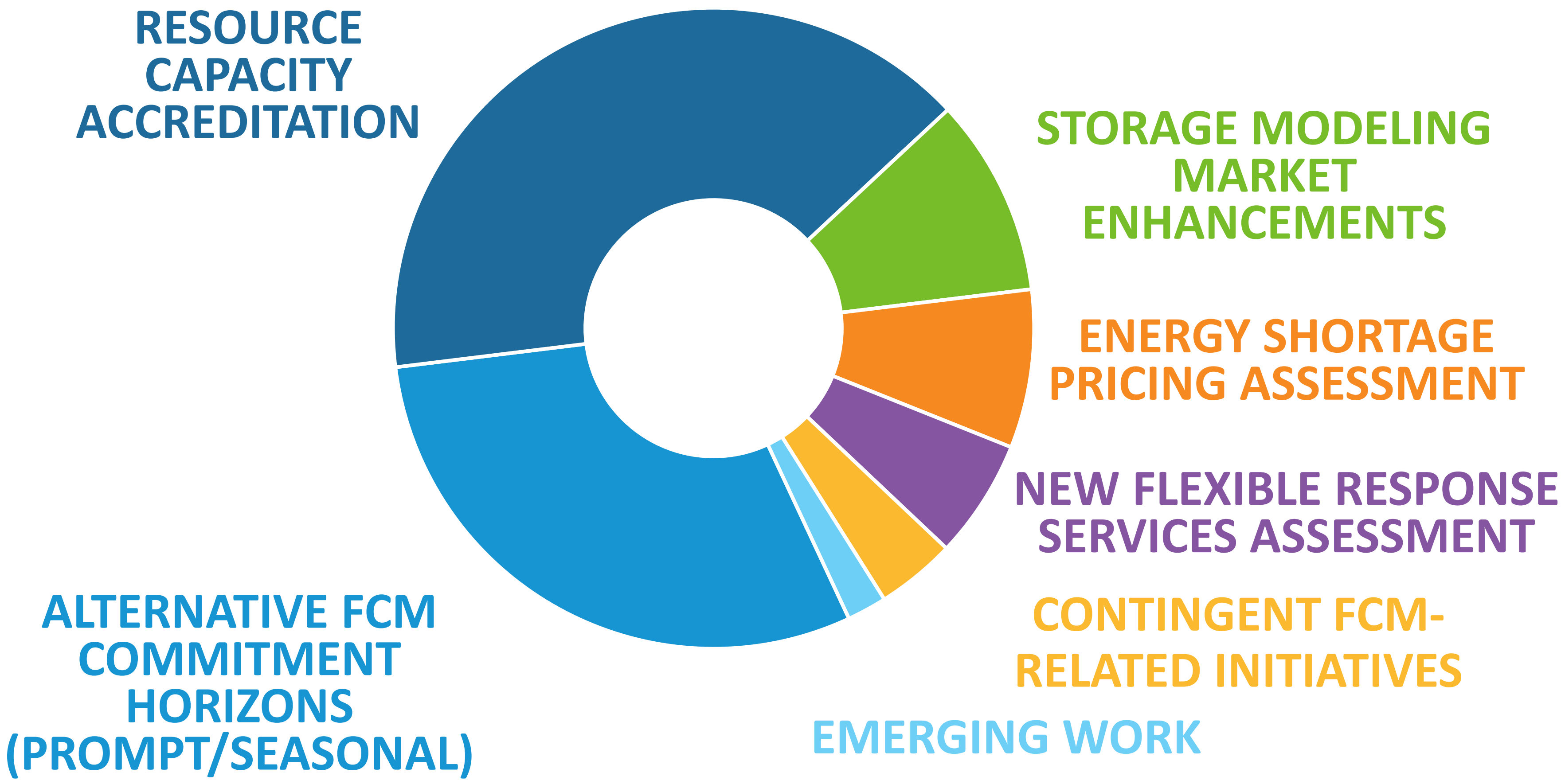
WORK PLAN PRIORITIZATION

Prioritization Process

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



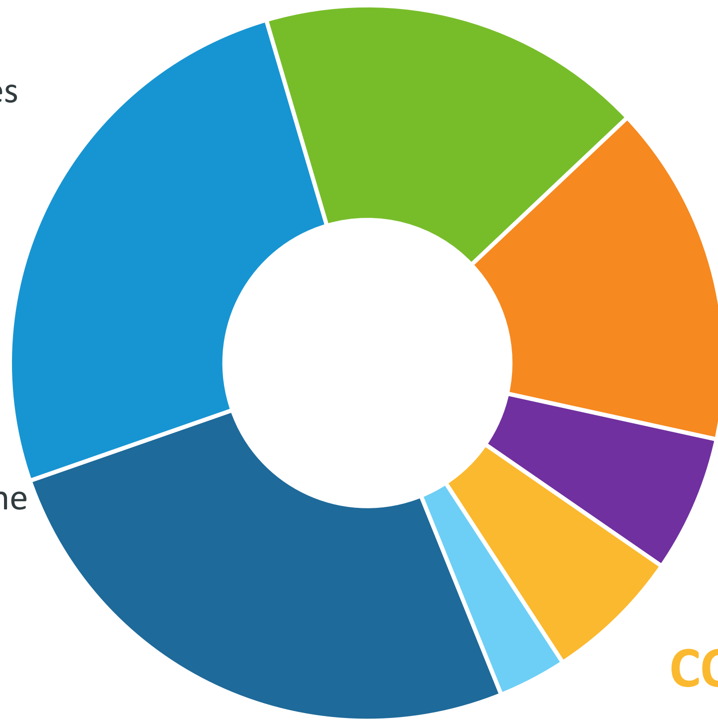
Markets-Related Priorities Include:



Planning/Operations Priorities Include:

OTHER INITIATIVES

- Implement Probabilistic Energy Adequacy Tool into ISO processes
- Annual Economic Study and process improvements
- Provide technical support to states for DOE RFPs re Interregional Transmission Planning for Offshore Wind
- SATOA implementation
- Update to PP7 to support of Order 881, Ambient Adjusted Line Ratings implementation in 2025
- Assess possible solutions for legacy distributed energy resources (DERs) tripping

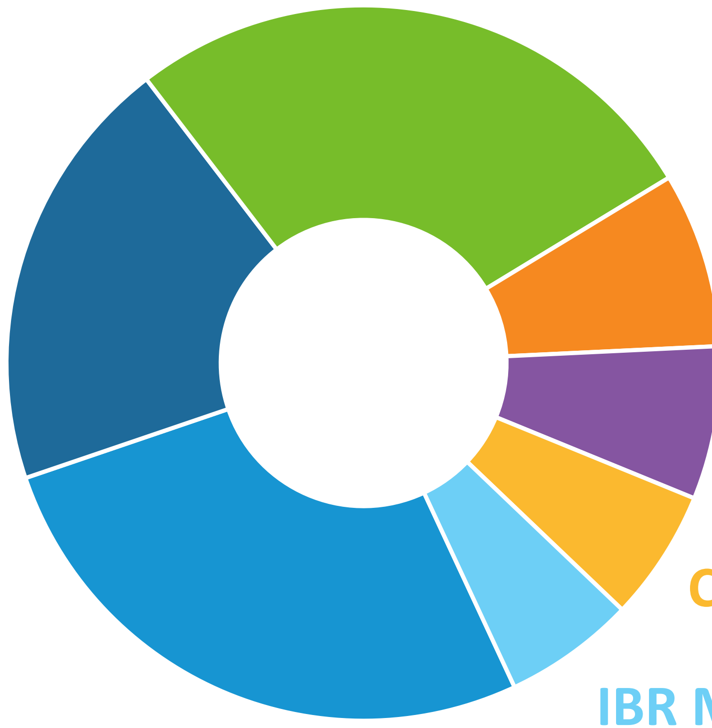


Capital Project Priorities Include:

APPLICATION AND DATABASE ENHANCEMENTS

- Software development for FERC Order No. 881 Ambient Adjusted Line Ratings implementation in 2025
- Software design for FERC Order No. 2222
- Energy Management System Short-term Load Forecast Replacement
- Enterprise Software Upgrades
- IT Asset Workflow Integration and Updates

DASI IMPLEMENTATION



IT INFRASTRUCTURE ENHANCEMENTS

- Enterprise core network refresh
- Expansion of immutable enterprise storage capabilities
- Control room communication enhancements
- Continuation of Windows and Linux Operating System Updates

CYBER SECURITY

CLOUD COMPUTING

IBR MODELING & SYNCHROPHASOR IMPROVEMENTS

nGEM MARKET CLEARING ENGINE

2024 AWP	Q1	Q2	Q3	Q4
Markets Related	**Resource Capacity Accreditation**			
	Alternative FCM Commitment Horizons			
	Storage Modeling Market Enhancements			
	Energy Shortage Pricing Assessment			
	Flexible Response Services Assessment			
	Contingent FCM-Related Initiatives			
Operations & Planning	**Energy Adequacy**			
	FERC Order No. 2023 Implementation			
	Longer-Term Trans. Planning Phase 2			
	Tie Benefits & HQICCs Assessment			
	EPCET			
	Single Source Contingency Limit Assessment			
	Transmission Asset Condition Process Improvement/Sizing Considerations			
	Other Initiatives & Continuing Business			
Capital Priorities	**DASI Implementation**			
	nGEM Market Clearing Engine			
	Inverter-Based Resource Modeling & Synchrophasor Improvements			
	Cloud Computing & Cyber Security			

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval and Pat Gerity, NEPOOL Counsel

DATE: September 28, 2023

RE: ISO New England Inc. ("ISO") 2024 Operating and Capital Budgets
New England States Committee on Electricity ("NESCOE") 2024 Budget

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At its October 5, 2023 meeting, the Participants Committee (the "NPC") will be asked to vote on the ISO's proposed 2024 operating and capital budgets (collectively, the "ISO Budgets") and on NESCOE's 2024 operating budget (the "NESCOE Budget"). We have included with this memorandum and will post with the composite for this meeting background materials regarding these budgets.

The ISO 2024 Budgets

The ISO Budgets were prepared according to the processes included in the Participants Agreement and in the Settlement Agreement with state agencies in FERC Dockets Nos. ER13-185 and ER13-192. The ISO presented its preliminary budgets to the New England state agencies and attorneys general (the "State Agencies") on June 23 and at the June 27 NPC Summer Meeting. The ISO next presented the ISO Budgets to the NEPOOL Budget and Finance Subcommittee (the "Subcommittee") on August 11 and, at a separate meeting, to the State Agencies on August 11. Mr. Ludlow also provided an overview of the ISO Budgets at the September 7 NPC meeting and offered to answer any questions that NPC members may have on the ISO Budgets. Questions on the ISO Budgets provided by certain New England state regulators and consumer advocates, as well as the ISO's responses thereto, are posted on the ISO's website.

Included with this memorandum is a memorandum from Mr. Ludlow describing the changes that have been made to the ISO Budgets from the versions reviewed by the Subcommittee and provided previously to the NPC. That memorandum includes a link to the updated ISO Budgets presentation and a link to the comments from the New England state regulators and consumer advocates and the ISO's response to those comments. The ISO's September 25 memorandum regarding the allocation of its projected costs among the ISO Tariff Schedules is also included with this memorandum.[1]

The 2024 ISO operating budget, prior to true-ups, reflects a 15.3 percent increase over the 2023 operating budget. After accounting for the true-up mechanism in the ISO Tariff, the revenue requirement

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[1] The memo addressing the Projected 2024 Revenue Requirement, including the final true-up for 2022 and a comparison to the 2023 Revenue Requirement, a Draft 2024 Revenue Requirement by activity, and Draft 2024 Rate Components, was circulated by the ISO to Participants Committee members and alternates and Budget and Finance Subcommittee members on September 25. A copy is included and posted with this memorandum for your convenience.

to fund the 2024 operating budget (i.e., the amount collected under the ISO administrative cost tariff) will increase by 21.4 percent over the amount projected to be collected in 2023. The ISO capital budget for 2024 is $35 million. This reflects a $1.5 million increase over the amount of the 2023 capital budget.

The following form of resolution can be used by the NPC on this matter:

> RESOLVED, that the Participants Committee supports the Year 2024 operating budget and capital budget proposed by the ISO, as presented at this meeting.

The NESCOE 2024 Budget

Ms. Heather Hunt, the Executive Director of NESCOE, joined the Subcommittee's August 11 meeting and informed the Subcommittee that NESCOE expected the NESCOE Budget for 2024 to be approximately $2,596,014. NESCOE's August 11 presentation to the Subcommittee was included with the materials for the September 7 NPC meeting and Ms. Hunt offered to answer any questions that NPC members may have on the NESCOE Budget. A revised summary presentation regarding the NESCOE Budget, which reflects the actual 2024 Schedule 5 Rate as calculated by the ISO ($0.00807 per kW-mo.), rather than an estimated rate, is included and posted with this memorandum. The revised presentation is identical to the NESCOE August 11, 2023 presentation, with only slide 12 updated and marked to reflect the final 2024 Network Load factor and final Schedule 5 Rate.

The following form of resolution can be used by the NPC in its consideration of the proposed 2024 NESCOE Budget:

> RESOLVED, that the Participants Committee supports the 2024 NESCOE budget, as proposed by NESCOE at this meeting, as the Year 2024 operating budget for NESCOE.

cc: R. Ludlow
C. Arnold
H. Hunt
NEPOOL Budget and Finance Subcommittee

memo

To: NEPOOL Participants Committee

From: Robert C. Ludlow, VP & CFO

Date: September 27, 2023

Subject: ISO New England's 2024 Proposed Operating and Capital Budgets

This 2024 operating and capital budgets (the "Budgets") update is intended to provide the NEPOOL Participants Committee with information regarding the changes that have been made to the ISO's 2024 proposed Budgets since the last review of the Budgets at the September 7, 2023 NEPOOL Participants Committee ("NPC") meeting.

Summary of Changes

The 2024 operating budget, including depreciation and excluding the true-up has been reduced to $276.9M, which is a decrease of $0.2M from the operating budget presented to the NEPOOL Budget and Finance Subcommittee in August and in September to the NPC. The budget change is a result of receiving the final allocation of NPCC and NERC Dues for 2024 that were lower than estimated. The budget presentation also reflects updated compensation survey data and that the Compensation and Human Resources Committee of ISO New England's Board of Directors approved the budgeted merit and promotional increase amounts.

In summary, the 2024 operating budget, excluding the true-up, is an increase of 15.3% or $36.7M as compared to the 2023 operating budget. The 2024 operating budget, including the true-up, results in a 21.4% increase to the Revenue Requirement compared to 2023.

The 2024 capital budget amount has not changed, remaining at $35.0M. However, there are changes to the capital projects plan which include the addition of two projects for 2024 (including one that is chartered), the removal of two projects for 2024, an update for a recently chartered project, and budget updates for certain projects. Specifically, the changes to projects in planning/conceptual design and chartered include: The addition of the Operating System Server Upgrade Phase I (chartered) and FERC Order 881 Compliance projects, and the removal of the Eterra Source Project and Replace Employee & Pager Application projects to reflect changes in work prioritization. Projects previously included in the capital budget, for which budget changes have been made, include Day-Ahead Ancillary Service Improvements (which has now been chartered), and for the following projects in planning: nGEM Real-Time Market Clearing Engine Implementation, CIP Electronic Security Perimeter Redesign Phase II, Resource Capacity Accreditation, Enterprise Resource Planning System Replacement, and Microsoft 365 Service Adoption.

Materials

The August 11, 2023 budget presentation (the "Budget Presentation") presented to the NEPOOL Budget and Finance Subcommittee has been updated to reflect the changes described above. The updated Budget Presentation can be found at the following link: ISO New England Proposed 2024 Operating and Capital Budgets - Updated 09/27/2023

The 2024 state agencies' written comments and the accompanying responses can be found at the following link: States 2024 Budget Comments and ISO-NE Response

Budget Presentation Slide Changes

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

Operating Budget Slide page changes:

- To reflect budget changes as noted above for final NPCC and NERC dues: 33, 34, 35, 36, 39, 42, 50, 61, 88, 90, 92, 95, 136, 192

- To reflect updated compensation documentation and Board process: 107, 111, 120

Capital Budget Slide page changes:[1]

- Description of two additional projects as noted above: 168, 176

- Other capital budget changes including capital project budget adjustments: 82, 83, 84, 85, 165, 166, 175, 177, 178, 179, 180, 184, 186

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

[1] The *order* of the Capital Budget slides containing project descriptions, on slides 166-184 of the updated budget presentation, has changed from the original presentation because of the insertion of the newly chartered projects and changes to the budgeted amounts as noted above.

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040
413-535-4000
rludlow@iso-ne.com

memo

To: NEPOOL Budget & Finance Subcommittee and Participants Committee

From: Bob Ludlow and Cheryl Arnold

Date: September 25, 2023

Subject: Projected 2024 Revenue Requirement for ISO New England Administrative Cost Tariff Schedules

To help our Participants prepare their 2024 budgets and consistent with information provided in previous years, this memo includes a preliminary indication of ISO-NE's 2024 costs and related tariff schedules. Specifically, the memo includes (1) the estimated 2024 Revenue Requirement, including the final true-up for 2022 and a comparison to the 2023 Revenue Requirement (see Exhibit 1 below), (2) the Draft 2024 Revenue Requirement by activity (see Exhibit 2), and (3) the Draft 2024 Rate Components (see Exhibit 3). Exhibits 2 and 3 are attached and, in their final form, will be part of the ISO's budget filing with FERC. The cost assignment and allocation mechanisms that were utilized in the Draft 2024 tariff schedules were established as part of the settlement that has been in effect for the last twenty-two years.

Overall Change in Revenue Requirement

As shown in Exhibit 1 below, the overall Revenue Requirement has increased by $48.3 million year-over-year, from $225.6M for 2023 to $273.9M for 2024.[1] The change includes a $36.7 million increase in the revenue requirement before taking into account the change in prior year true-ups. Prior year true-ups resulted in an increase of $11.6M. The 2023 tariff included a $14.6M revenue requirement decrease for the final 2021 true-up, while the 2024 tariff will include a decrease of $3.0M as a result of the final 2022 true-up.

Draft Exhibit 1

ISO New England
Revenue Requirement By Tariff Schedule
2024 Estimated Amount vs. 2023 Filed Amount

	Sch 1	Sch 2	Sch 3	Total
2024 Revenue Requirement Before Prior Year True Ups	$ 57,473,726	$ 134,634,632	$ 84,788,318	$ 276,896,676
2023 Revenue Requirement Before Prior Year True Ups	49,273,547	118,209,011	72,722,598	240,205,156
$ Increase/(Decrease) from 2023 to 2024	**8,200,179**	**16,425,621**	**12,065,720**	**36,691,520**
% Increase/(Decrease) from 2023 to 2024	**16.6%**	**13.9%**	**16.6%**	**15.3%**
2024 Revenue Requirement Prior Year True Ups-Under/(Over) Collect	$ 421,994	$ (5,306,720)	$ 1,878,563	$ (3,006,163)
2023 Revenue Requirement Prior Year True Ups-Under/(Over) Collect	(3,063,761)	(7,987,289)	(3,537,695)	(14,588,745)
$ Increase/(Decrease) from 2023 to 2024	**3,485,755**	**2,680,569**	**5,416,258**	**11,582,582**
2024 Revenue Requirement Including Prior Year True-Ups	$ 57,895,721	$ 129,327,912	$ 86,666,881	$ 273,890,514
2023 Revenue Requirement Including Prior Year True-Ups	46,209,786	110,221,722	69,184,903	225,616,411
$ Increase/(Decrease) from 2023 to 2024	**11,685,935**	**19,106,190**	**17,481,978**	**48,274,103**
% Increase/(Decrease) from 2023 to 2024	**25.3%**	**17.3%**	**25.3%**	**21.4%**

[1] Minor variances may appear due to rounding among the various presentations and schedules for the 2024 Budgets.

Change in Revenue Requirement by Schedule

Before true-ups in 2024 and 2023, the 2024 Revenue Requirement reflects an overall increase of $36.7M or 15.3% over the 2023 Revenue Requirement. By tariff schedule, the changes are Schedule 1, a $8.2M or 16.6% *increase*; Schedule 2, a $16.4M or 13.9% *increase*; and Schedule 3, a $12.1M or 16.6% *increase*.

The Tariff Schedule 1 increase of $8.2M is attributable to:

- Increases that impact all three schedules including for: targeted compensation increases based on salary benchmarking data; employee benefit costs; computer service infrastructure and architecture (including transition to the cloud), cyber security, and application support; research and development including advanced modeling and the integration of new technologies; resources in Participant Relations & Services and External Affairs & Corporate Communications; interest expense; and corporate insurance policy premium increases.
- Funding for Transmission Planning and Transmission Services support of long-term transmission planning related to the transition to a carbon free power system, including resources to support expected increases in transmission RFPs, to support stakeholder requests for long-term transmission studies (including New England states' requests), for a regional study with PJM and NYISO to evaluate the impact of increasing New England's single source contingency limit, and support for distributed energy resource and minimum load studies to determine requirements for ensuring reliability under conditions where the system is powered solely by inverter-based resources.

The Tariff Schedule 2 increase of $16.4M is attributable to:

- Funding for items that impact all three schedules as noted above in the explanation for Schedule 1.
- Depreciation expense specifically affecting Schedule 2, related to the mid-2023 go-live of nGEM platform projects[2] (2024 includes a full-year of depreciation for these projects).
- Funding for Market Development resources to continue progress towards integrating renewable resources and new resource types, including large scale storage resources and batteries into the market designs for the clean energy transition.
- Funding for work that affects Schedules 2 and 3, including future grid studies for a clean-energy future, and a Participant Relations & Services resource to continue the integration of several new initiatives and projects into market training and the development of new training delivery methods.

The Tariff Schedule 3 increase of $12.1M is attributable to:

- Funding for items that impact all three schedules as noted above in the explanation for Schedule 1 and items that impact Schedules 2 and 3, as noted above in the explanation for Schedule 2.
- Funding for the assessment of alternate capacity market commitment horizons including prompt and/or seasonal markets.
- Funding for FCA 21 Cost of New Entry (CONE) parameter updates.
- Increases in Northeast Power Coordinating Council (NPCC) and North American Electric Reliability Corporation (NERC) dues.

The ISO 2024 Revenue Requirement will be reviewed and voted on at the October 5, 2023 NPC meeting. Should you have any questions regarding the information provided in this memo, do not hesitate to contact us.

[2] The nGEM Market Clearing Engine Implementation, completed in June 2023, included the following projects that began depreciating: CIMNET Simultaneous Feasibility Test with Data Transfer Enhancements, nGEM Value Added Development, nGEM Market Clearing Engine Implementation, nGEM Software Development Parts I and II, and nGEM Hardware Phase I and II.

Exhibit 2
Page 1 of 6

DRAFT

Line	Activity Code		Allocation	Self-Funding Tariff			
No.	No.	Description	Factor (1)	Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Administration-CEO**					
2	12651	Indirect Administrative Support	Total Dir Labor	$ 11,329,246	$ 2,441,453	$ 5,862,885	$ 3,024,909
3	12652	NEPOOL Committee Support	Total Dir Labor	3,113	671	1,611	831
4	12654	National Committee Support	Total Dir Labor	1,748	377	904	467
5	12657	Indirect Administrative Support for BCC	Total Dir Labor	766,042	165,082	396,427	204,533
6		Total		12,100,148	2,607,582	6,261,827	3,230,740
7							
8		**Finance**					
9	11601	Payroll Administration	Total Dir Labor	426,223	91,851	220,570	113,802
10	11701	Accounts Payable	Total Dir Labor	323,318	69,675	167,317	86,326
11	11702	Procurement	Total Dir Labor	444,107	95,705	229,825	118,576
12	11901	Settle for Power Transactions	Total Dir Labor	80,730	17,397	41,778	21,555
13	12001	Budgeting and Forecasting	Total Dir Labor	676,989	145,891	350,342	180,756
14	12005	Credit Administration	Total Dir Labor	1,865,708	402,060	965,504	498,144
15	12101	Ledger Closing, Financial Statements and Tax Reporting	Total Dir Labor	524,742	113,082	271,554	140,106
16	12201	Treasury and Cash Management	Total Dir Labor	3,037,379	654,555	1,571,843	810,980
17	92004	Depreciation Expense 2004 Assets	Alloc-Fixed	43,160	8,988	22,535	11,637
18	92005	Depreciation Expense 2005 Assets	Alloc-Fixed	773,169	163,467	402,126	207,577
19	92006	Depreciation Expense 2006 Assets	Total Dir Labor	568,947	122,608	294,430	151,909
20	92007	Depreciation Expense 2007 Assets	Total Dir Labor	156,427	33,710	80,951	41,766
21	92008	Depreciation Expense 2008 Assets	Total Dir Labor	548	118	284	146
22	92009	Depreciation Expense 2009 Assets	Total Dir Labor	1,281	276	663	342
23	92010	Depreciation Expense 2010 Assets	Total Dir Labor	2,380	513	1,231	635
24	92012	Depreciation Expense 2012 Assets	Total Dir Labor	80,431	17,333	41,623	21,475
25	92013	Depreciation Expense 2013 Assets	Total Dir Labor	833,495	179,618	431,334	222,543
26	92014	Depreciation Expense 2014 Assets	Alloc-Fixed	99,414	21,424	51,447	26,543
27	92015	Depreciation Expense 2015 Assets	Alloc-Fixed	2,290	494	1,185	612
28	92016	Depreciation Expense 2016 Assets	Alloc-Fixed	50,091	9,314	31,038	9,739
29	92017	Depreciation Expense 2017 Assets	Alloc-Fixed	394,341	22,304	346,022	26,014
30	92018	Depreciation Expense 2018 Assets	Alloc-Fixed	572,276	52,006	469,385	50,885
31	92019	Depreciation Expense 2019 Assets	Alloc-Fixed	1,055,371	130,564	788,265	136,541
32	92020	Depreciation Expense 2020 Assets	Alloc-Fixed	2,630,403	209,214	2,072,751	348,438
33	92021	Depreciation Expense 2021 Assets	Alloc-Fixed	8,197,329	903,681	5,584,178	1,709,470
34	92022	Depreciation Expense 2022 Assets	Alloc-Fixed	8,743,069	933,974	5,720,233	2,088,863
35	92023	Depreciation Expense 2023 Assets	Alloc-Fixed	7,165,172	1,137,815	3,942,894	2,084,463
36	92024	Depreciation Expense 2024 Assets	Alloc-Fixed	1,090,569	280,495	530,983	279,091
37	99707	Amortization of Land Recovery	Alloc-Fixed	39,300	2,460	24,170	12,670
38	99995	NPCC/NERC Dues	Alloc-Fixed	8,052,434	-	-	8,052,434
39	99996	Operating Contingency	Total Dir Labor	700,000	150,850	362,250	186,900
40	99996	Operating Contingency	Total Dir Labor	2,000,000	431,000	1,035,000	534,000
41	99998	Payroll & Other Accruals	Total Dir Labor	23,797,756	5,128,416	12,315,339	6,354,001
42		Total		74,428,849	11,530,859	38,369,050	24,528,940
43							
44		**Facilities & Security**					
45	12664	Building Maintenance	Total Dir Labor	3,585,823	772,745	1,855,663	957,415
46		Total		3,585,823	772,745	1,855,663	957,415
47							
48		**Strategy, Risk & Operations Compliance**					
49	14803	Regional Committee Support	OS Labor	82,109	41,054	-	41,054
50	14804	National Committee Support	OS Labor	82,387	41,193	-	41,193
51	14806	Employee Development	Alloc-Fixed	171,811	95,441	33,211	43,159
52	14807	NERC RSAW Update and Audit Prep	Alloc-Fixed	154,363	77,181	-	77,181
53	14812	NPCC MP Referral	Alloc-Fixed	49,089	19,636	19,636	9,818
54	14815	Identifications and Description of Internal Controls	Total Dir Labor	466,345	100,497	241,333	124,514
55	14816	Support NE Compliance Groups	Total Dir Labor	49,089	10,579	25,404	13,107
56	14817	AskISO Customer or Internal Inquiries	Total Dir Labor	98,178	21,157	50,807	26,213
57	22704	Record Retention Services	Alloc-Fixed	122,135	40,671	40,671	40,793
58	22705	Corporate Scorecard	Alloc-Fixed	73,633	24,520	24,520	24,594
59	22706	Document Management Services	Alloc-Fixed	159,114	63,645	47,734	47,734
60	22708	ERM Adminstration	Alloc-Fixed	7,384	1,591	3,821	1,971
61	22709	ERM Management	Alloc-Fixed	49,089	10,579	25,404	13,107
62	22719	Human Performance Improvement	Total Dir Labor	12,586	2,712	6,514	3,361
63	22721	Corp Strategic Risk	Total Dir Labor	610,355	131,532	315,859	162,965
64	22726	Project Risk Mngmt Meeting	Total Dir Labor	24,544	5,289	12,702	6,553
65	23006	Business Continuity Planning	Total Dir Labor	281,042	60,565	145,439	75,038
66	25011	Corrective Action/Preventive Action	Alloc-Fixed	309,719	103,136	103,136	103,446
67		Total		2,802,972	850,979	1,096,190	855,802
68							
69		**Market & Credit Risk**					
70	22714	FAP Analysis	Alloc-Fixed	322,918	69,589	167,110	86,219
71		Total		322,918	69,589	167,110	86,219
72							
73		**Human Resources**					
74	12661	Employee Affairs (Recreation Committee)	Total Dir Labor	55,073	11,868	28,500	14,705
75	12701	Recruiting/Interviewing	Total Dir Labor	1,114,619	240,200	576,815	297,603
76	12702	Intern Expense	Total Dir Labor	239,228	51,554	123,801	63,874
77	12801	Employee Relations	Total Dir Labor	1,706	368	883	455
78	12901	Benefit Administration	Total Dir Labor	2,180,757	469,953	1,128,542	582,262
79	12951	Compensation	Total Dir Labor	1,262,293	272,024	653,237	337,032
80	12961	HR - General	Total Dir Labor	988,201	212,957	511,394	263,850
81	12962	HR - Training	Total Dir Labor	1,225,112	264,012	633,995	327,105
82	13410	Power Training & Development	Total Dir Labor	490,380	105,677	253,771	130,931
83	13411	Markets Training & Development	Total Dir Labor	142,745	30,761	73,870	38,113
84	13412	People Training & Development	Total Dir Labor	305,997	65,942	158,353	81,701
85	13413	Business Skills Training & Development	Total Dir Labor	683,322	147,256	353,619	182,447
86	13414	Technology Training & Development	Total Dir Labor	1,250,779	269,543	647,278	333,958
87	13901	Performance Eval/Salary Review	Total Dir Labor	108,131	23,302	55,958	28,871
88		Total		10,048,341	2,165,417	5,200,016	2,682,907

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Line	Activity Code		Allocation	Self-Funding Tariff			
No.	No.	Description	Factor (1)	Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Legal Department**					
2	12422	Interconnection Queue	Alloc-Fixed	87,073	-	-	87,073
3	12502	Board of Directors	Total Dir Labor	239,436	51,598	123,908	63,929
4	12508	Energy Markets / Complaints / Rule Changes	Alloc-Fixed	1,756,700	-	1,756,700	-
5	12513	Miscellaneous Labor Matters	Total Dir Labor	120,000	25,860	62,100	32,040
6	12514	NEPOOL Participants Committee	Total Dir Labor	231,572	49,904	119,838	61,830
7	12517	Administrative and Clerical Support	Total Dir Labor	544,204	117,276	281,626	145,303
8	12543	Independent Market Advisor	Alloc-Fixed	1,300,000	-	910,000	390,000
9	12559	General Corporate	Total Dir Labor	1,796,860	387,223	929,875	479,762
10	12584	GC - SH - Installed Capacity Requirements	Alloc-Fixed	65,305	-	-	65,305
11	12587	Capacity Market Development	Alloc-Fixed	980,768	-	-	980,768
12	12606	GC - NERC	Alloc-Fixed	600	270	60	270
13	12611	GC - Ancillary Services Markets	Alloc-Fixed	87,073	-	-	87,073
14	12613	GC - CFTC/DOE/NRC/Other Federal Agency	Total Dir Labor	217,682	46,910	112,650	58,121
15	12619	Compliance	Alloc-Fixed	87,073	34,829	34,829	17,415
16	12621	GC - NOPRs and NOIs	Total Dir Labor	130,609	28,146	67,590	34,873
17	12622	Open Access Transmission Tariff	Alloc-Fixed	174,145	174,145	-	-
18	12663	Public Information	Total Dir Labor	2,009,961	433,147	1,040,155	536,660
19	12669	Government Affairs	Total Dir Labor	2,074,248	447,000	1,073,423	553,824
20	12675	Web Content Governance Steering Committee	Total Dir Labor	854,752	184,199	442,334	228,219
21		Total		12,758,062	1,980,509	6,955,090	3,822,462
22							
23		**Internal Audit**					
24	15001	Indirect Management Duties	Total Dir Labor	223,256	48,112	115,535	59,609
25	15002	Personnel Management	Total Dir Labor	59,672	12,859	30,880	15,932
26	15003	Budget & Forecasting	Total Dir Labor	14,918	3,215	7,720	3,983
27	15004	Audit Follow-up Activities	Total Dir Labor	59,672	12,859	30,880	15,932
28	15005	Audit & Finance Committee	Total Dir Labor	145,682	31,394	75,390	38,897
29	15006	Internal Audit Business Process Update	Total Dir Labor	14,918	3,215	7,720	3,983
30	15007	Annual Audit Work Plan	Total Dir Labor	130,764	28,180	67,670	34,914
31	15011	Internal Audit Meetings	Total Dir Labor	89,508	19,289	46,320	23,899
32	15013	Indirect Adminstrative Support	Total Dir Labor	56,174	12,106	29,070	14,999
33	15014	GRC Tool Admin and Development	Total Dir Labor	307,203	66,202	158,978	82,023
34	15021	Performance Measurements	Total Dir Labor	44,754	9,644	23,160	11,949
35	15022	Vendor Contracts	Total Dir Labor	14,918	3,215	7,720	3,983
36	15023	Wire Transfers	Total Dir Labor	14,918	3,215	7,720	3,983
37	15040	Audit-Operations	Total Dir Labor	223,769	48,222	115,800	59,746
38	15085	Audit - Information Technology	Total Dir Labor	564,903	121,737	292,337	150,829
39	15133	Satellite Operations Reviews	Total Dir Labor	16,202	3,492	8,384	4,326
40	15137	Satellite IT Reviews	Total Dir Labor	15,802	3,405	8,178	4,219
41	15150	Audit - Internal Audit Other	Total Dir Labor	453	98	234	121
42	15161	External Audit- Pension Audit	Total Dir Labor	81,426	17,547	42,138	21,741
43	15162	External Audit- Financial Audit	Total Dir Labor	158,455	34,147	82,000	42,307
44	15166	External Audit -Pricing Module Certification	Alloc-Fixed	143,716	-	143,716	-
45	15176	External Audit - ISO Internet Vulnerability Assessment	Total Dir Labor	14,740	3,176	7,628	3,936
46	15186	External Audit - SSAE 18 Direct Support	Total Dir Labor	44,754	9,644	23,160	11,949
47	25702	External Audit - SSAE 18 Direct Management	Alloc-Fixed	591,402	-	591,402	-
48	28005	Fraud, Waste & Abuse Program	Total Dir Labor	47,398	10,214	24,528	12,655
49	28007	Contractor/Consultant Review	Total Dir Labor	27,098	5,840	14,023	7,235
50	28173	Audit - Identity and Access Management Audit	Total Dir Labor	28,420	8,526	8,526	11,368
51	28176	CIP Oversight, Monitoring, and Reporting Processes Review	Total Dir Labor	36,541	7,875	18,910	9,757
52	28179	NERC CIP V5.0 Mock Audit	Total Dir Labor	14,918	3,215	7,720	3,983
53		Total		3,186,353	530,642	1,997,451	658,259
54							
55		**COO-Adm**					
56	19001	NEPOOL Committee Support	Total OPS Labor	273,844	73,390	131,308	69,146
57	19002	Regional Committee Support	Total OPS Labor	8,365	2,242	4,011	2,112
58	19003	National Committee Support	Total OPS Labor	12,081	3,238	5,793	3,050
59	19005	Indirect Supervision/Clerical Support	Total OPS Labor	1,585,287	424,857	760,145	400,285
60	19009	Renewable Resource Integration	Alloc-Fixed	152,955	-	-	152,955
61		Total		2,032,531	503,726	901,257	627,548
62							
63		**System Operations & Market Administration**					
64	14404	NEPOOL Committee Support	SOA Labor	1,250	432	580	238
65	14405	Indirect Supervision/Clerical Support	SOA Labor	169,040	58,387	78,469	32,185
66	14407	Regional Committee Support	SOA Labor	1,250	432	580	238
67	14408	National Committee Support	SOA Labor	58,715	20,280	27,255	11,179
68	19101	NEPOOL Committee Support	MOA Labor	64,851	-	45,396	19,455
69		Total		295,106	79,530	152,280	63,296

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Line	Activity Code		Allocation	Self-Funding Tariff			
No.	No.	Description	Factor (1)	Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Operations**					
2	14001	Generation Dispatch	Alloc-Fixed	3,848,170	-	3,232,463	615,707
3	14002	Transmission Operations	Alloc-Fixed	2,748,693	2,198,954	137,435	412,304
4	14304	Advanced Scheduling and Forecasting	Alloc-Fixed	2,205,662	110,283	1,742,473	352,906
5	14562	Ops - Regional Committee Support	OPS Labor	17,788	4,973	9,847	2,967
6	14563	National Committee Support	OPS Labor	233,594	65,313	129,317	38,963
7	14565	Employee Development	OPS Labor	23,436	6,553	12,974	3,909
8	14582	Ops - Recurring Analysis and Reporting	Total Dir Labor	227,666	49,062	117,817	60,787
9	14586	Ops - Other External Support Meetings	Alloc-Fixed	2,964	-	2,371	593
10	14589	Ops - OPTI Control Performance Monitor	Alloc-Fixed	227,666	227,666	-	-
11	14702	Procedure Documentation	Alloc-Fixed	98,178	39,271	39,271	19,636
12		Total		9,633,815	2,702,075	5,423,968	1,507,772
13							
14		**Operational Performance Trng and Integration**					
15	14402	Operations Training	Alloc-Fixed	1,128,016	451,206	451,206	225,603
16	14462	OSS - General Systems Operations Support	TSO Labor	458,296	148,350	219,111	90,834
17	14564	Indirect Supervision/Clerical Support	OPS Labor	1,647,159	460,546	911,867	274,746
18	14574	OPTI Continuing Training	Alloc-Fixed	913,628	365,451	365,451	182,726
19	14575	Ops - OPTI System Operator Initial Training	Alloc-Fixed	13,415	5,366	5,366	2,683
20	14576	Ops - OPTI Internal/External Operations Training	Alloc-Fixed	227,666	91,066	91,066	45,533
21	14577	Ops - OPTI Training Program Administration	Alloc-Fixed	227,666	91,066	91,066	45,533
22	14579	Ops - OPTI TTSE Maintenance	OPS Labor	227,666	91,066	91,066	45,533
23	14581	Application Testing and Development	Total Dir Labor	455,332	98,124	235,634	121,574
24	14583	Ops - Ad Hoc Analysis and Reporting	Total Dir Labor	227,666	49,062	117,817	60,787
25	14587	Ops - Other Internal Support Meetings	Total Dir Labor	227,666	49,062	117,817	60,787
26	15501	OA - Operations Analysis	Alloc-Fixed	751,212	112,682	525,849	112,682
27		Total		6,505,388	2,013,049	3,223,318	1,269,021
28							
29		**Operations Support Services**					
30	14453	National Committee Support	TSO Labor	28,354	9,178	13,556	5,620
31	14454	Indirect Supervision/Clerical Support	TSO Labor	621,590	201,209	297,182	123,199
32	14477	Participant project and outage coordination support	Alloc-Fixed	6,844	3,422	-	3,422
33	14756	OSS - Human Performance Improvement Program	Alloc-Fixed	229,642	-	-	229,642
34	14760	Trans Outage LT (telecommute)	Alloc-Fixed	565,713	282,856	141,428	141,428
35	18361	Transmission Studies, Operations, OASIS Support	Alloc-Fixed	3,221,415	2,577,132	161,071	483,212
36	18381	Transmission Outage Application - Short Term	Alloc-Fixed	1,131,426	905,141	56,571	169,714
37	18382	Transmission Outage Application - Long Term	Alloc-Fixed	565,713	-	-	565,713
38		Total		6,370,696	3,978,938	669,808	1,721,950
39							
40		**Market Monitoring**					
41	16101	Market Power Monitoring and Mitigation	Alloc-Fixed	5,956,229	-	4,169,360	1,786,869
42	16102	Regulatory Activities	Alloc-Fixed	2,495	-	1,747	749
43		Total		5,958,724	-	4,171,107	1,787,617
44							
45		**Market Administration & Auctions**					
46	21901	Day Ahead Price Monitoring	Alloc-Fixed	445,036	-	445,036	-
47	21902	Real Time Price Verification	Alloc-Fixed	489,540	-	489,540	-
48	21907	Indirect Supervision/Clerical Support	MA Labor	489,540	-	474,071	15,469
49	21915	FTR/Auction Administration	Alloc-Fixed	311,525	155,763	155,763	-
50	21917	Real Time Price Finalization	Alloc-Fixed	222,518	-	222,518	-
51		Total		1,958,161	155,763	1,786,929	15,469
52							
53		**Market Analysis & Settlements**					
54	1701	Billing Statements - Energy	Alloc-Fixed	97,695	-	97,695	-
55	1702	Billing Statements - Transmission	Alloc-Fixed	119,839	119,839	-	-
56	1713	Billing Statements - ISO Tariff	Total Dir Labor	14,329	3,088	7,415	3,826
57	1714	Billable Tariff Re-billings	Total Dir Labor	1,303	1,303	-	-
58	1717	Inventoried Energy Program	Alloc-Fixed	6,513	-	-	6,513
59	1718	Mystic COS	Alloc-Fixed	14,329	-	-	14,329
60	1719	FCM Daily	Alloc-Fixed	182,363	-	-	182,363
61	1722	NCC Trading FA	Alloc-Fixed	13,026	-	-	13,026
62	2047	Score Card	STLM Labor	3,908	578	1,903	1,426
63	2048	FCM	Alloc-Fixed	78,156	-	-	78,156
64	2049	Product Testing	Alloc-Fixed	18,236	-	14,589	3,647
65	2051	Legal Support	Alloc-Fixed	7,816	-	3,908	3,908
66	2005	Customer Service	STLM Labor	194,087	28,705	94,540	70,842
67	2007	Admin support - NEPOOL Committees	STLM Labor	9,161	1,355	4,462	3,344
68	2009	Indirect Supervision/Clerical Support	STLM Labor	899,001	132,962	437,903	328,135
69	2010	Employee Development	STLM Labor	206,520	30,544	100,596	75,380
70	2013	FTR Administration	Alloc-Fixed	37,775	-	37,775	-
71	2014	Billing Statements - NCPC	Alloc-Fixed	399,897	-	199,948	199,948
72	2020	Billing Disputes	Total Dir Labor	20,842	4,491	10,785	5,565
73	2021	Analysis & Reporting	Total Dir Labor	459,145	98,946	237,608	122,592
74	2024	ASM Regulation	Alloc-Fixed	29,960	-	-	29,960
75	2025	ASM Locational Forward Reserve	Alloc-Fixed	115,931	-	-	115,931
76	2026	Batch Processing	Total Dir Labor	36,473	7,860	18,875	9,738
77	2032	Billing	STLM Labor	46,893	6,936	22,842	17,116
78	2033	Market Analysis	Alloc-Fixed	183,658	-	183,658	-
79	2055	MAS - Market Monitoring Support	Alloc-Fixed	13,006	-	6,503	6,503
80		Total		3,209,858	436,606	1,481,005	1,292,247

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Line	Activity Code		Allocation	Self-Funding Tariff			
No.	No.	Description	Factor (1)	Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Market Operations Support Services**					
2	3000	Hourly Settlements Support	Alloc-Fixed	321,402	-	160,701	160,701
3	3002	Monthly Settlements Support	Alloc-Fixed	229,573	114,786	-	114,786
4	3006	Customer Service	Alloc-Fixed	114,786	-	114,786	-
5	3008	Admin Support	Alloc-Fixed	206,902	-	206,902	-
6	3009	Indirect Supervision (Principal Analysts only)	Alloc-Fixed	160,701	-	160,701	-
7	3010	Employee Development	Alloc-Fixed	27,068	-	27,068	-
8	3012	FERC Data Request	Alloc-Fixed	5,739	-	5,739	-
9	3017	Project MAS (Market Analysis & Settlements)	Alloc-Fixed	344,359	86,090	86,090	172,179
10		Total		1,410,529	200,876	761,986	447,666
11							
12		**Participant Support & Solutions**					
13	16001	Participant/membership support	Alloc-Fixed	112,241	-	56,120	56,120
14	16006	Call Support (Ask ISO)	Alloc-Fixed	1,502,114	390,550	991,395	120,169
15	16414	Direct Customer Contact	MS Labor	26,316	-	23,684	2,632
16	16419	Asset Registration Implemented	Alloc-Fixed	445,036	-	445,036	-
17	16422	Claimed Capability Audits	Alloc-Fixed	712,059	-	712,059	-
18	16432	New Generation Coordination and Registration	Alloc-Fixed	445,036	-	445,036	-
19	16434	QMS/CAPA Process and Procedure Updates	Total Dir Labor	445,036	95,905	230,306	118,825
20		Total		3,687,838	486,455	2,903,638	297,746
21							
22		**Participant Training Services**					
23	16021	Training Development	Alloc-Fixed	903,651	-	451,825	451,825
24	16436	Mkt Trng/Cus Serv Indirect Supervision	Total Dir Labor	447,370	-	447,370	-
25		Total		1,351,021	-	899,195	451,825
26							
27		**Planning Services**					
28	14313	National Committee Support	Alloc-Fixed	40,015	4,350	2,017	33,648
29	17101	Analysis	Alloc-Fixed	120,044	-	84,031	36,013
30	17131	Calculate Objective Capability	Alloc-Fixed	380,765	-	-	380,765
31	17331	NEPOOL Committee Support	Alloc-Fixed	20,012	2,175	1,009	16,828
32	17401	Indirect Supervisory Activities	Alloc-Fixed	40,019	4,350	2,017	33,652
33	17403	TCA Application Review	Alloc-Fixed	121,916	-	-	121,916
34	17405	Energy Efficiency Forecast	Alloc-Fixed	60,026	-	-	60,026
35	17409	Environmental/Emissions Supp	Total Dir Labor	200,073	-	-	200,073
36	17501	FCA - Evaluate Existing Resource De-list Bids	Alloc-Fixed	211,810	-	-	211,810
37	17503	FCA - New Resource Qualification Support	Alloc-Fixed	1,419,234	-	-	1,419,234
38	17504	FCA - Perform Transmission / Topology Assessments	Alloc-Fixed	128,379	-	-	128,379
39	17505	FCA - Perform Existing Resource Qualification	Alloc-Fixed	85,586	-	-	85,586
40	17507	FCA - Auctions & Filings	Alloc-Fixed	1,042,367	-	-	1,042,367
41	17508	FCA - Annual Reconfiguration Auction Support/Reliability Reviews	Alloc-Fixed	128,379	-	-	128,379
42	18101	Develop Load Forecast	Alloc-Fixed	637,287	127,457	127,457	382,372
43	18121	Operations Forecast Support	Alloc-Fixed	280,102	56,020	56,020	168,061
44	18131	Other Load Forecasting Activities	Alloc-Fixed	20,007	4,001	4,001	12,004
45	18133	Solar Load Forecast Development	Alloc-Fixed	140,051	28,010	28,010	84,031
46	18134	Electrification Forecasts	Alloc-Fixed	20,007	4,001	4,001	12,004
47	18135	CELT Rep-Res Outage Analysis	Alloc-Fixed	80,029	-	-	80,029
48		Total		5,176,111	230,366	308,564	4,637,181
49							
50		**System Planning**					
51	18150	Regional Transmission Expansion Plan	Alloc-Fixed	113,552	85,164	28,388	-
52	18152	States Requests	Alloc-Fixed	51,710	25,855	12,928	12,928
53	18402	Transmission Planning/Economic Studies Initiative	Alloc-Fixed	1,032,476	-	516,238	516,238
54	18562	Project Management	Alloc-Fixed	199,080	199,080	-	-
55		Total		1,396,818	310,099	557,554	529,166
56							
57		**Transmission Planning**					
58	21660	Stability Case Building	Alloc-Fixed	128,379	-	-	128,379
59	14715	Non DOE Funded/Unallowable	Alloc-Fixed	124,022	-	-	124,022
60	18201	Transmission System Assessment	Alloc-Fixed	6,418,220	6,418,220	-	-
61	18301	NEPOOL Administrative Support - Schedule 1 Tariff	Alloc-Fixed	113,880	113,880	-	-
62	18333	General SIS/FS	Alloc-Fixed	1,783,631	1,783,631	-	-
63	18334	Indirect Supervision/Clerical Support	Alloc-Fixed	1,115,348	1,115,348	-	-
64	18335	Regulatory Activities - NPCC	Alloc-Fixed	307,990	307,990	-	-
65	18336	National Activities	Alloc-Fixed	171,524	171,524	-	-
66	18337	TR - Regulatory Activities	Alloc-Fixed	31,077	31,077	-	-
67	18346	OATT and Oper. Agreement Dev., Adm. and Support	Alloc-Fixed	42,793	42,793	-	-
68	18350	States Future Planning Studies	Alloc-Fixed	254,889	254,889	-	-
69		Total		10,491,754	10,239,352	-	252,401
70							
71		**Program Management**					
72	801	Program Management - Administration	Total Dir Labor	1,024,143	220,703	529,994	273,446
73	1661	ISO Program Management	Alloc-Fixed	461,478	-	323,035	138,443
74	1665	Product and Test Mgmt.	Total Dir Labor	531,282	114,491	274,939	141,852
75	25002	PMO Support	Alloc-Fixed	890	267	312	312
76		Total		2,017,793	335,461	1,128,278	554,053

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Line No.	Activity Code No.	Description	Allocation Factor (1)	Self-Funding Tariff Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Advanced Technology Solutions**					
2	21201	Advanced Technology Solutions	Total Dir Labor	4,292,759	925,090	2,221,503	1,146,167
3	21203	Employee Development	Total Dir Labor	69,603	15,000	36,020	18,584
4	21207	Resource Capacity Accreditation	Total Dir Labor	1,813,786	-	-	1,813,786
5		Total		6,176,148	940,089	2,257,523	2,978,536
6							
7		**Market Development & Settlements Admin.**					
8	16607	National Committee Support	Total Dir Labor	29,949	6,454	15,499	7,996
9	19104	Indirect Supervision/Clerical Support	MOA Labor	369,851	-	258,896	110,955
10	21001	Market Development	Alloc-Fixed	1,195,027	-	597,514	597,514
11	21002	Administration	Total Dir Labor	610,531	131,569	315,950	163,012
12	21003	Employee Development	Total Dir Labor	222,510	47,951	115,149	59,410
13	21007	Budget/Forecast Support	Total Dir Labor	279,823	60,302	144,808	74,713
14	21010	MD - Day-Ahead Reserve Market	Alloc-Fixed	267,493	-	254,118	13,375
15	21011	Capacity Market	Alloc-Fixed	4,722,431	-	-	4,722,431
16	22401	Administration	Total Dir Labor	32,920	7,094	17,036	8,790
17	22402	Working Group Meetings and Support	Alloc-Fixed	16,460	-	8,230	8,230
18	22656	Energy, Reserve, and Regulation Markets	Alloc-Fixed	1,718,506	-	1,288,879	429,626
19	22657	Project: ORTP/CONE Updates	Alloc-Fixed	1,383,368	-	-	1,383,368
20	22658	Storage	Alloc-Fixed	401,920	-	321,536	80,384
21	22660	Energy Security	Alloc-Fixed	475,968	-	237,984	237,984
22	22661	Project: DER Participation	Alloc-Fixed	598,067	-	299,034	299,034
23		Total		12,324,826	253,371	3,874,633	8,196,823
24							
25		**Participant Relations & Services**					
26	22602	NEPOOL Committee Meetings & Support	Alloc-Fixed	358,498	-	179,249	179,249
27	22607	NEPOOL Committee Administration	Total Dir Labor	1,712,239	368,988	886,084	457,168
28	22612	Future Grid Study and Modeling	Total Dir Labor	714,172	-	285,669	428,503
29		Total		2,784,910	368,988	1,351,002	1,064,920
30							
31		**IT Management**					
32	6517	Employee Development - Hardware/Software	Total Dir Labor	83,982	18,098	43,461	22,423
33	6519	Indirect Supervision and Clerical Support	Total Dir Labor	5,537,655	1,193,365	2,865,736	1,478,554
34	6552	Security	Total Dir Labor	190,004	40,946	98,327	50,731
35	6556	Budget Preparation, Tracking & Forecast	Total Dir Labor	208,726	44,981	108,016	55,730
36	6557	Information Technology Committee	Total Dir Labor	14,659	3,159	7,586	3,914
37	22501	Change Management Support	Alloc-Fixed	249,877	112,445	112,445	24,988
38	22505	Administrative	Alloc-Fixed	620,736	211,050	204,843	204,843
39	22511	IT CM/QA - Professional Training	Alloc-Fixed	3,470	1,180	1,145	1,145
40		Total		6,909,109	1,625,223	3,441,558	1,842,328
41							
42		**IT Infrastructure Support**					
43	6510	Desktop Support - Hardware	Total Dir Labor	671,394	144,685	347,446	179,262
44	6511	Desktop Support - Software	Total Dir Labor	1,519,017	327,348	786,091	405,578
45	6512	Host Computer - Hardware	Alloc-Fixed	3,171,221	-	2,378,416	792,805
46	6513	Host Computer - Software	Alloc-Fixed	7,928,327	-	5,946,245	1,982,082
47	6514	Networking - Hardware	Total Dir Labor	1,023,505	220,565	529,664	273,276
48	6515	Networking - Software	Total Dir Labor	3,459	745	1,790	923
49	6516	Communications	Total Dir Labor	3,599,120	775,610	1,862,545	960,965
50	6619	IT - Infrastructure Coordination	Total Dir Labor	554,791	119,558	287,104	148,129
51	6602	Help Desk Support	Total Dir Labor	219,249	47,248	113,461	58,540
52	6615	Host Computer Monitoring	Alloc-Fixed	1,331,608	-	665,804	665,804
53	6616	Desktop Support	Total Dir Labor	1,014,559	218,637	525,034	270,887
54	6618	System Administration - Windows	Total Dir Labor	153,279	33,032	79,322	40,925
55	6622	CIP & Systems Compliance	Total Dir Labor	2,356,264	507,775	1,219,367	629,123
56	6623	Asset Management	Total Dir Labor	732,450	157,843	379,043	195,564
57	6624	Infrastructure Review & Planning	Total Dir Labor	341,039	73,494	176,488	91,057
58	6625	Infrastructure Patch & Vulnerability Mitigation	Total Dir Labor	263,687	56,825	136,458	70,404
59	6626	IT - Infrastructure Break-fix & Troubleshooting	Total Dir Labor	287,621	61,982	148,844	76,795
60	6627	IT - Infrastructure Support Request	Total Dir Labor	541,165	116,621	280,053	144,491
61	6628	IT - Infrastructure Cyber Security Support	Total Dir Labor	215,817	46,509	111,685	57,623
62	6629	IT - Infrastructure Refresh/Upgrade	Total Dir Labor	233,261	50,268	120,712	62,281
63	6630	IT - Infrastructure Operation Enhancement Effort	Total Dir Labor	662,055	142,673	342,613	176,769
64		Total		26,822,887	3,101,418	16,438,186	7,283,283
65							
66		**IT Cyber Security**					
67	6540	Security Compliance and Reporting	Total Dir Labor	3,726,995	803,167	1,928,720	995,108
68	6540D	Intrusion Monitoring and Response	Total Dir Labor	2,349,092	506,229	1,215,655	627,208
69	6541	Security SW Tools Program	Total Dir Labor	1,108,392	238,858	573,593	295,941
70	6543	Critical Infrastructure Protection WG (NERC)	Total Dir Labor	39,578	8,529	20,482	10,567
71	6547	Cyber Security Training	Total Dir Labor	237,170	51,110	122,735	63,324
72	6548	CIP Compliance & Monitoring	Total Dir Labor	59,291	12,777	30,683	15,831
73		Total		7,520,518	1,620,672	3,891,868	2,007,978

DRAFT

Line No.	Activity Code No.	Activity Code Description	Allocation Factor (1)	Self-Funding Tariff Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**IT Database & Analytics**					
2	6571	DBA Support - MOPS	Total Dir Labor	3,450,084	743,493	1,785,419	921,173
3	6591	Data Architect - MOPS	Total Dir Labor	430,031	92,672	222,541	114,818
4	6594	IT Data Analyst	Total Dir Labor	538,397	116,025	278,620	143,752
5	6595	IT WEB Application Support	Total Dir Labor	731,480	157,634	378,541	195,305
6	6596	IT Data Governance	Total Dir Labor	294,343	63,431	152,323	78,590
7	6597	IT - BI IT Commitments	Total Dir Labor	307,655	66,300	159,211	82,144
8	21706	Enterprise Software Support	Total Dir Labor	2,473,766	533,097	1,280,174	660,496
9	21801	Software Support - Settlements	Alloc-Fixed	953,355	-	762,684	190,671
10	21802	Software Support - Publishing	Alloc-Fixed	36,716	-	29,373	7,343
11	21803	Software Support - Finance	Alloc-Fixed	549,607	-	439,686	109,921
12	21804	Software Support - Mitigation	Alloc-Fixed	753,131	-	602,505	150,626
13	21805	Software Support - TSO	Total Dir Labor	676,168	145,714	349,917	180,537
14	21806	Software Support - Enterprise	Total Dir Labor	1,003,052	216,158	519,079	267,815
15	21807	Software Support - Planning	Alloc-Fixed	661,895	-	529,516	132,379
16	21808	Training Delivery to NON-IT	Alloc-Fixed	274,990	-	219,992	54,998
17	21811	Single Sign On Support	Alloc-Fixed	239,476	-	191,581	47,895
18	21812	GADS Support	Alloc-Fixed	146,865	-	117,492	29,373
19	21816	CMS Support	Total Dir Labor	183,583	39,562	95,004	49,017
20	21818	Discoverer Support	Total Dir Labor	84,820	18,279	43,894	22,647
21	21824	FCTS Support	Alloc-Fixed	1,394,651	-	-	1,394,651
22	21825	eTariff Support	Alloc-Fixed	73,433	-	58,746	14,687
23	21830	Annual Software Maintenance for Enterpirse Wide Software	Total Dir Labor	245,844	52,979	127,224	65,640
24	21832	GDMA/Gateway Support	Alloc-Fixed	97,530	-	78,024	19,506
25		Total		15,600,873	2,245,342	8,421,547	4,933,983
26							
27		**IT Energy Management Systems**					
28	21600	Indirect Supervision and Administration	Total Dir Labor	54,800	11,809	28,359	14,632
29	21601	Power System Modeling	Total Dir Labor	83,976	18,097	43,458	22,422
30	21602	Applications Support	Total Dir Labor	348,370	75,074	180,281	93,015
31	21603	EMS Power System Applications Support	Total Dir Labor	853,851	184,005	441,868	227,978
32	21604	Dispatcher Training Simulatory Support	Alloc-Fixed	2,807,896	2,246,317	561,579	-
33	21605	DAM FTR/ARR Support	Alloc-Fixed	2,105,078	421,016	1,263,047	421,016
34	21606	Real-time Market Support	Alloc-Fixed	3,649,446	729,889	2,189,667	729,889
35	21607	Forecast Support	Alloc-Fixed	437,385	87,477	262,431	87,477
36		Total		10,340,802	3,773,683	4,970,690	1,596,428
37							
38		**IT Enterprise Applications Development**					
39	6518	Employee Development - Software	Total Dir Labor	33,338	7,184	17,252	8,901
40	21707	Application Analysis and Conceptual Design	Alloc-Fixed	95,563	-	76,450	19,113
41	21708	Application Design Evaluation and Selection	Alloc-Fixed	414,105	-	331,284	82,821
42	21709	Technology Evaluation and Selection	Alloc-Fixed	1,093,505	-	874,804	218,701
43	21710	Indirect Supervision and Administration	Alloc-Fixed	1,118,943	-	895,154	223,789
44	21711	EWR and CAPA Analysis	Alloc-Fixed	154,993	-	123,995	30,999
45		Total		2,910,447	7,184	2,318,939	584,323
46							
47		**IT Power System Modeling Management**					
48	21650	Indirect Supervision and Administration	Total Dir Labor	198,110	42,693	102,522	52,895
49	21651	Power System Modeling	Alloc-Fixed	1,676,881	670,752	670,752	335,376
50	21652	System Application Support	Alloc-Fixed	152,726	61,091	61,091	30,545
51	21654	NX9 Administration	Alloc-Fixed	438,673	175,469	175,469	87,735
52	21655	ICCP Support	Alloc-Fixed	921,118	368,447	368,447	184,224
53	21656	Transmission Project Management	Alloc-Fixed	32,611	26,089	6,522	-
54	21657	Model On Demand Admin	Alloc-Fixed	1,049,430	-	-	1,049,430
55	21658	PSMM- Model on Demand Case Requests	Alloc-Fixed	223,026	-	-	223,026
56	21659	Synchrophasor Applications	Alloc-Fixed	83,973	12,596	12,596	58,781
57		Total		4,776,548	1,357,136	1,397,399	2,022,012
58							
59							
60		**Total ISO**		$ 276,896,676	$ 57,473,726	$ 134,634,632	$ 84,788,318

Exhibit 3

Draft 2024 Rate Components (1)

Tariff Schedule	Jan. 1, 2024
Schedule 1	
Network Load (per kW-hour)	$0.00037
Schedule 2	
TU Bids (Virtual Inc/Dec)	
Submitted	$0.00500
Cleared	$0.06000
FTR Bids	
Submitted	$2.77242
Cleared	$4.48021
TU's	
Block 1 - 1st 12,500	$0.82494
Block 2 - Next 27,000	$0.74994
Block 3 - Over 39,500	$0.67495
Volumetric	
Block 1 - 1st 250,000	$0.48178
Block 2 - Next 1,250,000	$0.43798
Block 3 - Over 1,500,000	$0.39418
Schedule 3	
R-T NCP Load Obligation	$0.34097
Export Rate	$0.70000

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

New England States
Committee on Electricity

2024 Budget Presentation

NEPOOL Budget & Finance Subcommittee

August 11, 2023

REVISED October 2023 PC

Change only to p. 12 to reflect final Network Load factor

NESCOE

Background: Budget Review

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

- Proposed 2024 budget conforms to:
  - Boundaries of 5-year pro forma (2023-2027) reviewed by Budget & Finance
  - NESCOE commitment not to seek an increase over pro forma budget of more than 10% in any 1 year: 2024 proposed budget is less than 2024 5-year pro forma budget
- Following calendar year 2022, independent auditor concluded NESCOE books conform to generally accepted accounting principles

Background: Policy Priorities

Term Sheet Provision Governing Identification of Policy Priorities:

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

Consistent with Term Sheet, 2022 *Report to the New England Governors*:

- ✓ Reviewed work in 2022
- ✓ Projected policy priorities
- ✓ Provided spending from prior year
- ✓ Projected budget information for upcoming two years

Projected Policy Priorities

✓ NESCOE provided to the Governors the ***2022 Annual Report to New England Governors***

✓ Report simultaneously released to NEPOOL & ISO-NE & circulated to the Participants Committee

✓ NESCOE identified forward looking policy priorities at Section V, pages 13

Report in “Resource Center”

www.nescoe.com


NESCOE

REPORT TO THE NEW ENGLAND GOVERNORS
2022

New England States Committee on Electricity

Representing the Collective Interests of the Six New England States

Projected Policy Priorities

- ✓ **Transmission**. Work with ISO-NE and stakeholders on tariff changes (Phase II) to enable states to consider options to address issues identified in the longer-term public policy-related transmission analysis; work with ISO-NE and Transmission Owners on reforms to bring visibility and more consistent approaches to asset condition projects and thoughtful, cost-effective approaches to right-sizing; assess the results of the 2050 Transmission Study, including the estimated costs for different potential infrastructure development pathways
- ✓ **Future Grid-Related Studies and Reforms**. Collaborate with ISO-NE and stakeholders in connection with the contemplated Phase 2 analysis to assess revenue sufficiency and system security in a gap analysis.
- ✓ **Winter**. Assess ISO-NE's analysis of the risk and implications of extreme weather events and contingencies as well as whether, and to what extent, any such risk requires market adjustments or other near-term mitigation and the effects from changes in both gas and electric infrastructure.
- ✓ **FCM Reforms.** Work with ISO-NE and stakeholders to determine the benefits and disadvantages of changes to the current FCM construct. This includes further considerations related to capacity accreditation and major design changes such as moving to a prompt, seasonal, or prompt seasonal capacity auctions.

NESCOE Organization & Misc.

Employees

- Retain and attract diversity in academic training, skills; blend of private & public sector experience
- Return to NESCOE's prior steady state employee level of six
  - New General Counsel in mid-2023
  - System planning staff in 2024

Office Space

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

Other Organization Matters

Technical Consultants

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

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

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

Legal Counsel

Litigation is not the primary means by which NESCOE seeks to accomplish its objectives & thus, greater resource and focus has historically, and thus far in 2023, been on technical consulting. Further, while NESCOE produces most legal pleadings and analysis internally, the frequency and type of litigation brought by others influences the extent to which NESCOE engages outside counsel.

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

5-Year Pro Forma

Proposed 2024 budget conforms to 2024 budget in 5-year Pro Forma Framework

✓ 2024 Projected Budget in 5-Year Pro Forma:	$2,823,665
✓ 2024 Proposed Budget:	$2,596,014
✓ 2023 Budget, for reference:	$2,691,505

The 2024 Proposed Budget

- ✓ Assumes steady state of six employees
- ✓ Reflects reduction in anticipated inflationary pressures
- ✓ Increased travel post pandemic and in lieu of office space

5-Year Pro Forma, for reference

NESCOE
PRO FORMA BUDGET 2023-2027*

Expense Category	Year 16 (2023)	Year 17 (2024)	Year 18 (2025)	Year 19 (2026)	Year 20 (2027)
Salaries and Wages					
Salaries	1,311,718	1,377,304	1,446,169	1,518,478	1,594,401
Payroll Taxes	131,172	137,731	144,617	151,848	159,440
Health and Other Benefits	110,098	115,603	121,383	127,452	133,825
Retirement §401(k)	52,469	55,092	57,847	60,739	63,776
Total, Salaries and Wages	**1,605,457**	**1,685,730**	**1,770,016**	**1,858,517**	**1,951,443**
Direct Expenses - Consulting					
Technical Analysis	342,933	353,221	363,818	374,732	385,974
Legal (FERC)	342,933	353,221	363,818	374,732	385,974
Total, Direct Expenses, Consulting	**685,866**	**706,442**	**727,635**	**749,464**	**771,948**
General and Administrative					
Rent		12,000	12,360	12,731	13,113
Utilities		2,500	2,575	2,652	2,732
Office and Administrative Expenses	50,000	51,500	53,045	54,636	56,275
Professional Services	41,500	42,745	44,027	45,348	46,709
Travel/Lodging/Meetings	60,000	61,800	63,654	65,564	67,531
Total General and Administrative	**151,500**	**170,545**	**175,661**	**180,931**	**186,359**
Capital Expendiures & Contingencies					
Computer Equipment	8,666	8,926	9,194	9,470	9,754
Contingencies	244,682	252,022	259,583	267,371	275,392
Capital Expenditures & Contingencies	**253,348**	**260,948**	**268,777**	**276,840**	**285,145**
TOTAL EXPENSES**	**2,696,171**	**2,823,665**	**2,942,090**	**3,065,753**	**3,194,896**

*Projected 5% salaries and wages annual adjustment, and projected 3% annual adjustment on all other items. Line items and categories subject to increase greater than, or decrease from, amounts projected. Any such changes will be subject to review, input, and recommendations by the NEPOOL Participants Committee (and/or its designees).

**At no time during this 5-year period will NESCOE seek a budget increase of more than 10% in any 1 year of more than 30% on a cumulative basis.

2024 Proposed Budget

NESCOE Pro Forma Budget
Proposed 2024 Budget

	2024
Salaries and Wages	
Salaries	1,154,954
Payroll Taxes	115,495
Health and Other Benefits	140,000
Retirement §401(k)	46,198
Total, Salaries and Wages	**1,456,648**
Direct Expenses - Consulting	
Technical Analysis	353,220
Legal (FERC)	353,221
Total, Direct Expenses, Consulting	**706,441**
General and Administrative	
Rent	-
Utilities	-
Office and Administrative Expenses	50,425
Professional Services	47,500
Travel/Lodging/Meetings	90,000
Total General and Administrative	**187,925**
Capital Expend. & Contingencies	
Computer Equipment	9,000
Contingencies	236,001
Capital Expend. & Contingencies	**245,001**
TOTAL EXPENSES	**2,596,014**

2022 & 2023 Spending & Implications for 2024

Unspent funds in any year credited toward future year

2022 Total Spending:	$1,548,186*
2023 Spending to end of June:	$784,144**
2023 Projected Year End:	$1,875,373 *

*Cumulative prior years' true up, including 2021, was reflected in the 2023 revenue requirement and rates. The 2022 true up will be reflected in the 2024 revenue requirement and rates (see next slide). Any 2023 true up will be reflected in the 2025 revenue requirements and rates.

** 2023 Spending through June reflects General Counsel on-boarding in June, vacant staff position (system transmission consultant began service in June 2023.)

2024 Projected Billing Rate

With thanks to ISO-NE for calculations -

2024 Budget:	$2,596,014.
Less 2022 True Up:	($862,664.)
Total Revenue Recovery:	$1,733,350.
Divided by Total Network Load:	~~225,688,515~~ 214,795,375

~~(total network load from 2023 ISO-NE tariff; no escalation or reduction used in calculation)~~

~~**2024 Schedule 5** Estimated **Rate $0.00768 per kW-month**~~

Updated: 2024 Schedule 5 *Actual* Rate $0.00807 per kW-month

(Actual Rate based on now finalized 2024 Network Load factor): $1,733,350 (revenue requirement) ÷ 214,795,375 (2024 Network Load) = $0.00807

Thank you.

Questions?

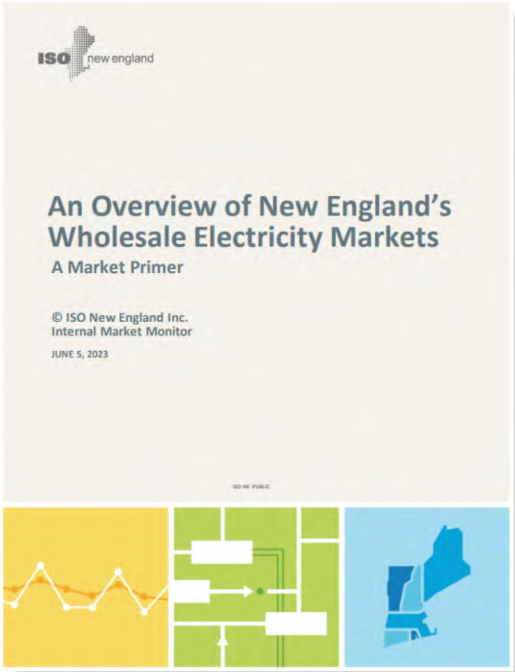
Annual Markets Report on 2022

Report Highlights

Dave Naughton

EXECUTIVE DIRECTOR, INTERNAL MARKET MONITOR

Two annual publications: Annual Markets Report and accompanying Market Primer



Feedback welcome and appreciated!

Email: dnaughton@iso-ne.com

Key Takeaways

1. Capacity, energy, and ancillary service markets generally performed well and exhibited competitive outcomes
   – Energy prices reflected changes in underlying primary fuel prices, electricity demand and the region's supply mix

2. Energy costs ($11.7 bn) drove an overall increase in wholesale costs ($16.7 bn) due to high natural gas prices [slide 6]
   – Highest natural gas prices ($9.32/MMBtu) since 2008, driven by a combination of international events and a higher New England winter basis [slide 7]
   – Energy prices ($86/MWh) were the highest since 2003, energy costs highest since 2008

3. Moderate increase in load; the long-term trend of decreasing load may have reached an inflection point [slide 10]

4. Net interchange continued to decrease [slide 13]; imports also down in the most recent annual capacity auction [slide 27]

Key Takeaways (Cont.)

6. Energy market price formation is generally robust; relatively low uplift (NCPC) and low amount of out-of-market commitments in 2022 [slides 16 -19]
   – However, we recommend a review of reserve pricing mechanics under the fast start pricing rules [slide 19]

7. Stable levels of structural market power and low energy offer mitigation
   – Economic withholding metrics indicate small price and quantity impacts of withholding
   – However, it is appropriate to review certain aspects of the mitigation rules; multiple recommendations contained in the report [slide 23-24]
   – Upward mitigation event on December 24, 2022 highlighted a number of further areas for potential improvement

8. Structural market power is a concern in the Forward Reserve Auction (FRA) [slide 25]
   – Recently recommended a review of the FRA offer/price cap (see spring 2023 quarterly report)

9. Low capacity prices reflect surplus supply conditions; older fossil-fuel generator exits with renewable and battery resource entry [slides 26 to 28]

Highlights Data

	2018	2019	2020	2021	2022	% Change '22 to '21	Sparkline
Demand (MW)							
Load (avg. hourly)	14,095	13,614	13,309	13,566	13,576	0%	
Weather-normalized load (avg. hourly)[a]	13,725	13,558	13,279	13,419	13,472	0%	
Peak load (MW)	26,024	24,361	25,121	25,801	24,780	-4%	
Generation Fuel Costs ($/MWh) [b]							
Natural Gas	38.72	25.48	16.34	36.07	72.57	101%	
Coal	54.52	40.58	37.82	67.77	144.87	114%	
No.6 Oil	127.73	130.89	89.42	138.21	221.17	60%	
Diesel	187.55	173.55	112.07	184.50	331.99	80%	
Hub Electricity Prices: LMPs ($/MWh)							
Day-ahead (simple avg.)	44.14	31.22	23.31	45.92	85.56	86%	
Real-time (simple avg.)	43.54	30.67	23.37	44.84	84.92	89%	
Day-ahead (load-weighted avg.)	46.88	32.82	24.57	48.30	91.36	89%	
Real-time (load-weighted avg.)	46.85	32.32	24.79	47.34	91.07	92%	
Estimated Wholesale Costs ($ billions)							
Energy	6.0	4.1	3.0	6.1	11.7	92%	
Capacity	3.6	3.4	2.7	2.3	2.0	-11%	
Uplift (NCPC)	0.07	0.03	0.03	0.04	0.05	49%	
Ancillary Services	0.1	0.1	0.1	0.1	0.1	127%	
Regional Network Load Costs	2.3	2.2	2.4	2.7	2.8	2%	
Total Wholesale Costs	**12.1**	**9.8**	**8.1**	**11.2**	**16.7**	**49%**	
Supply Mix [c]							
Natural Gas	40%	39%	42%	45%	45%	0%	
Nuclear	25%	25%	22%	22%	23%	0%	
Imports	17%	19%	20%	16%	14%	-2%	
Hydro	7%	7%	7%	6%	6%	0%	
Other[d]	5%	5%	5%	5%	4%	-1%	
Wind	3%	3%	3%	3%	3%	0%	
Solar	1%	1%	2%	2%	3%	0.8%	
Coal	1%	0%	0%	0%	0.3%	-0.20%	
Oil	1%	0%	0%	0%	1.5%	1.34%	

Average energy demand comparable to 2021 due to similar average weather conditions.

Prices of all major fuels increased.

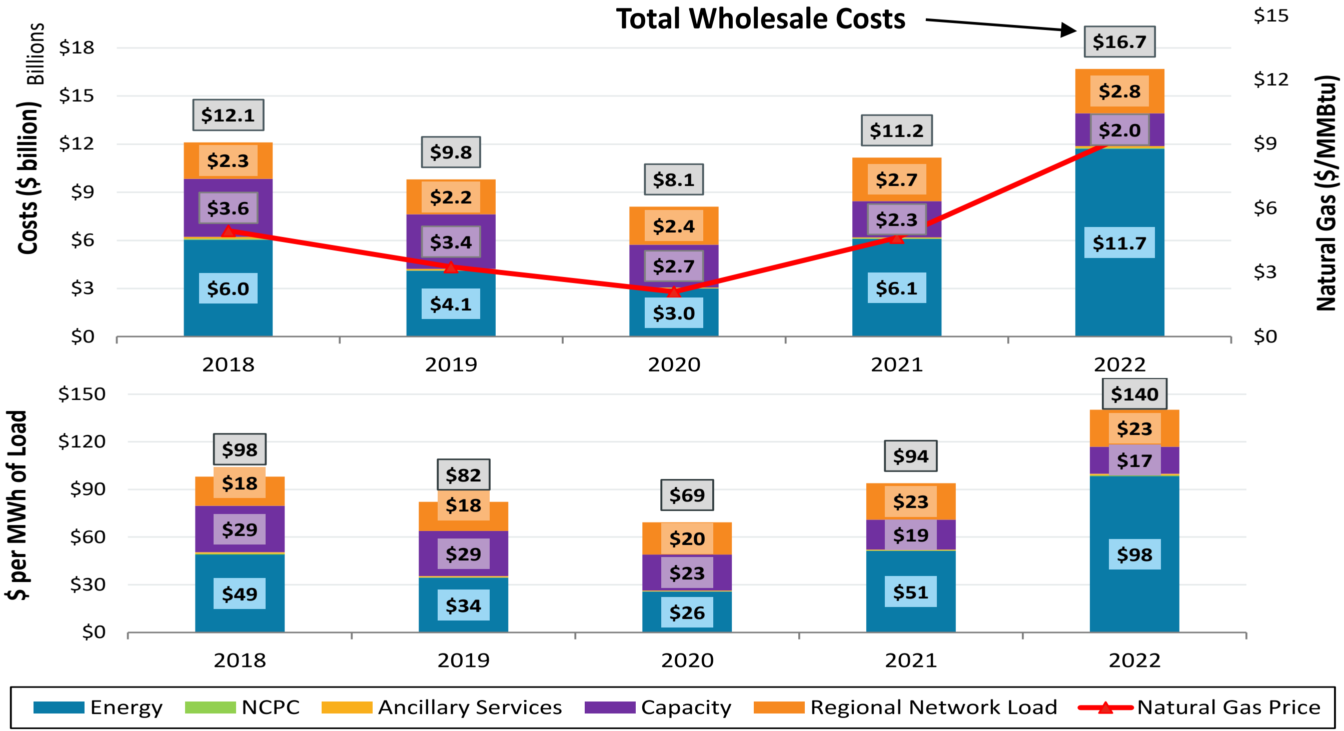
Simple- and load-weighted avg. LMPs up significantly, but not as much as the increase in gas prices. Upward pressure of natural gas on energy costs was partially offset by relatively cheaper oil prices during winter cold spells.

Energy comprised 70% of wholesale costs. Increases in all wholesale cost categories, with the exception of capacity costs.

Reduction in avg. net imports (by 231 MW per hour), mostly over the NY North interface. Increase in oil generation (by 185 MW per hour) due to oil generators being in-merit in the winter.

[a] Weather-normalized results are those that would have been observed if the weather were the same as the long-term average.
[b] Generation costs are calculated by multiplying the daily fuel price ($/MMBtu) by the average standard efficiency of generators for each fuel (MMBtu/MWh)
[c] Capacity cost in 2022 includes the Mystic cost-of-service costs of $0.17 billion.
[d] Provides a breakdown of total supply, which includes net imports. Note that section 2 provides a breakdown of native supply only.
[e] The "Other" fuel category includes landfill gas, methane, refuse and steam

Increase in wholesale costs driven by high energy and natural gas prices

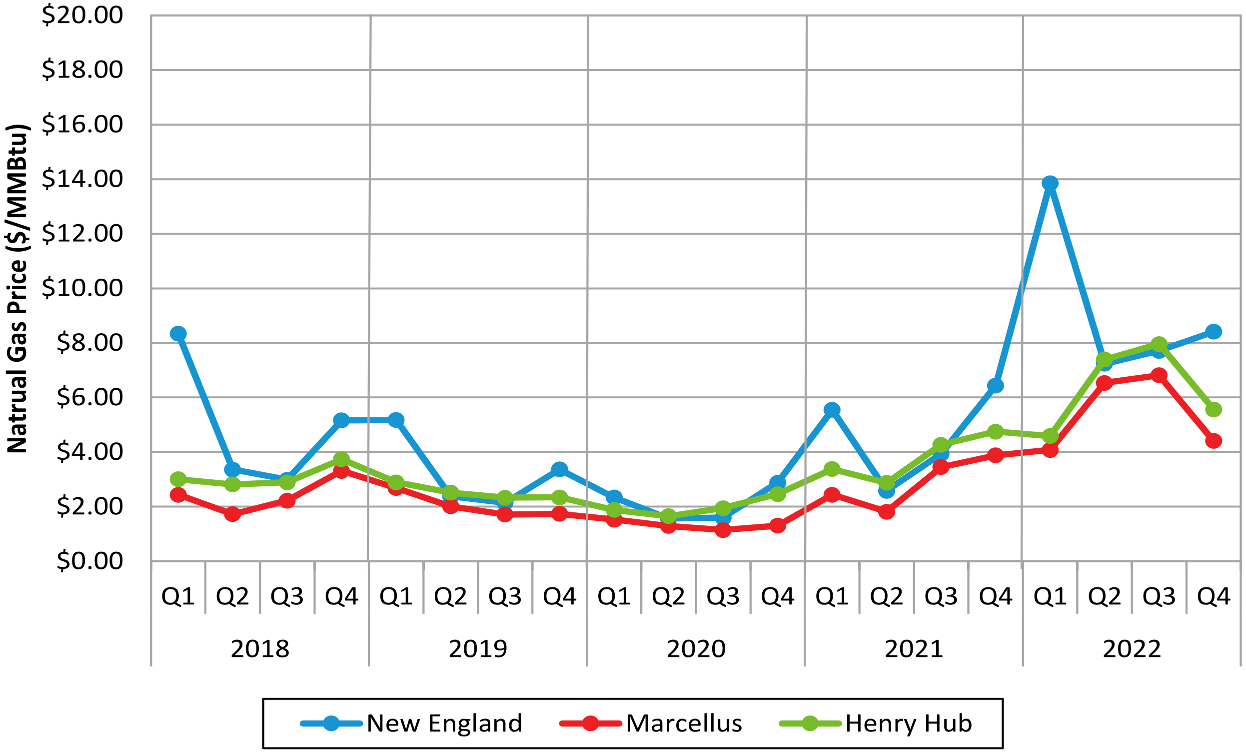


Energy costs at highest dollar level since 2008, making up over 70% of total wholesale costs. 98% of energy costs arose in the day-ahead energy market.

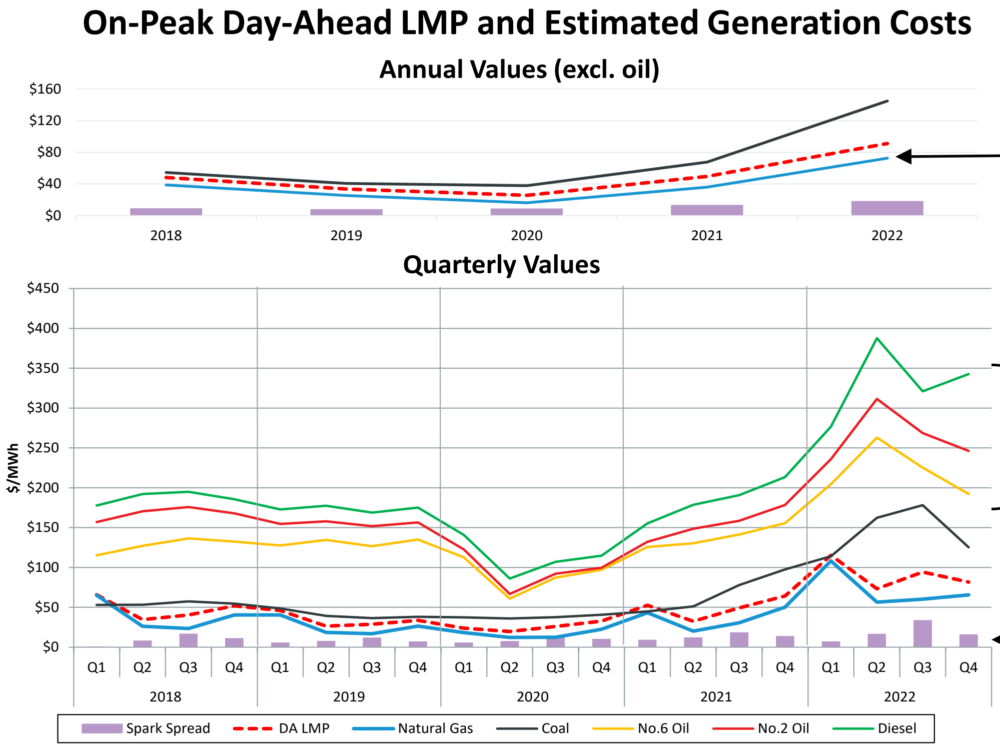
Capacity costs reflect auction prices from FCAs 12 & 13, comprising 12% of total costs. Costs will continue to decline over the next 4 years, down to ~$1 billion [slide 21].

Note: 2022 capacity cost total includes supplemental payments of $166 million under the Mystic Cost of Service agreement.

High natural gas prices driven by international events, national and New England market conditions



Highest annual average energy price since 2003, driven by high natural gas prices

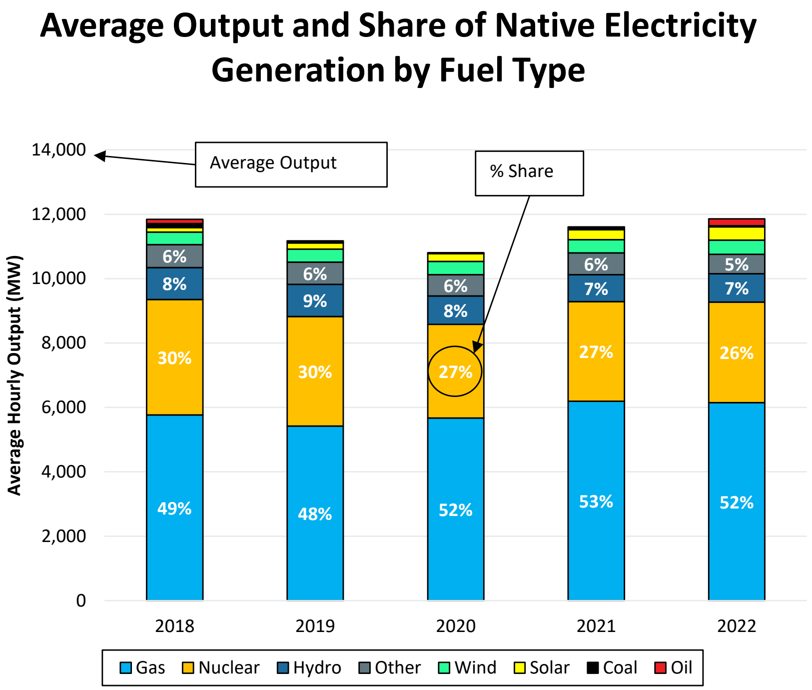


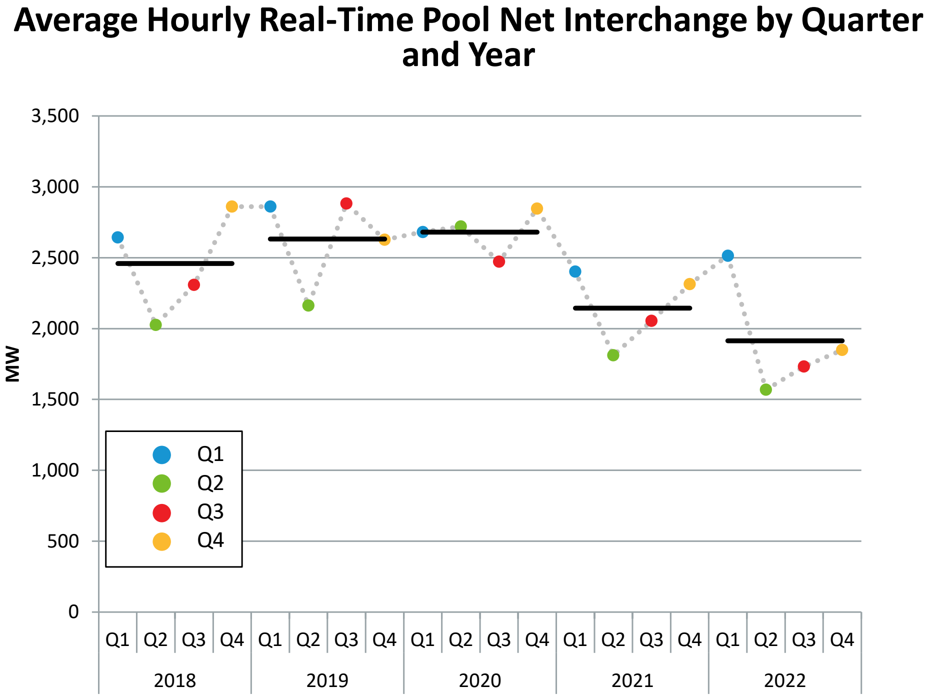
Highest annual natural gas price since 2008.

Oil prices up but lower than natural gas frequently during Q1, increasing oil generation and attenuating upward pressure of extremely high gas prices on energy prices.

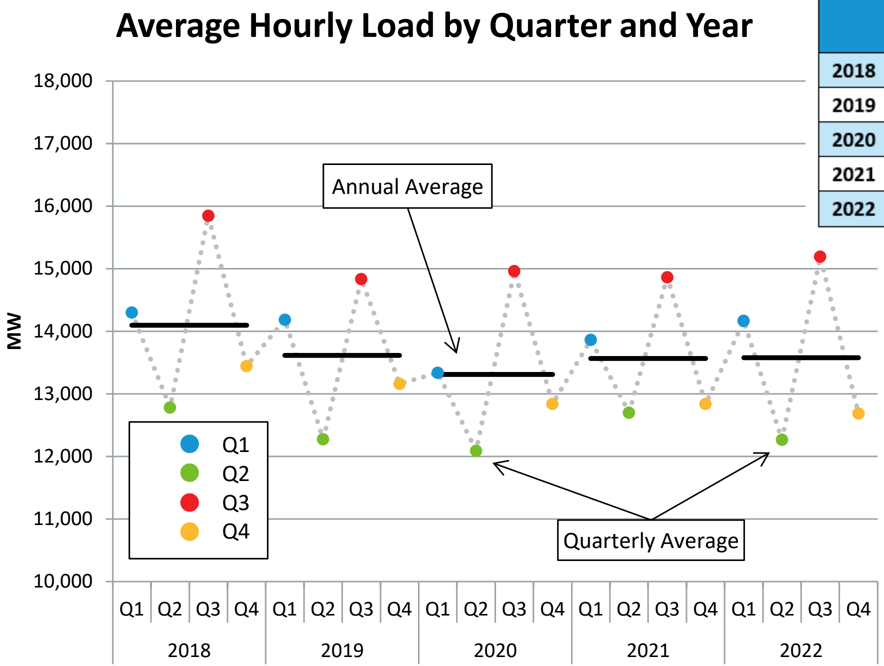
Profitability indices/metrics up on higher gas prices [see Slide 12]

Increase in native generation balanced out a reduction in net imports



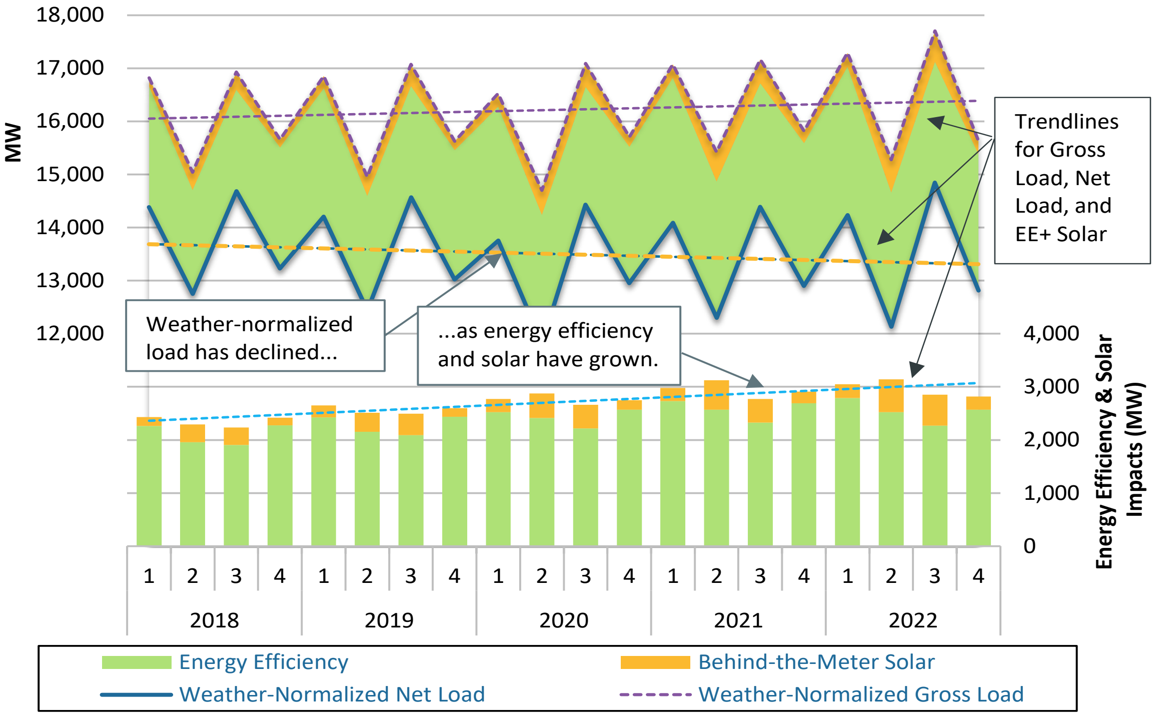


Similar average weather conditions resulted in comparable average wholesale energy demand to 2021



Year	Load (GWh)	Average Hourly Load (MW)	Peak Load (MW)	Weather Normalized Load (GWh)	Average Hourly Weather Normalized Load (MW)
2018	123,472	14,095	26,024	120,560	13,762
2019	119,235	13,614	24,361	118,772	13,558
2020	116,874	13,309	25,121	116,322	13,242
2021	118,758	13,565	25,801	117,551	13,419
2022	118,874	13,576	24,780	118,337	13,508

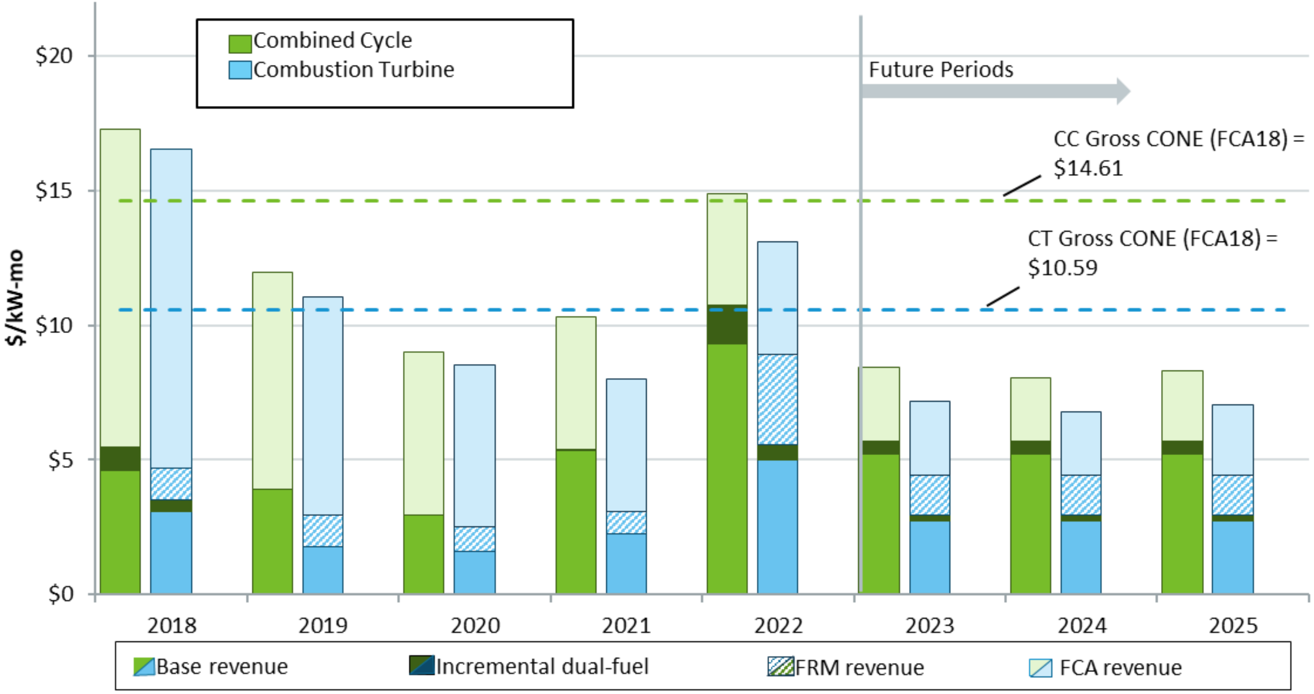
Energy efficiency and behind-the-meter solar have significant impacts on reducing wholesale demand



Behind-the-meter solar generation reduced (weather-normalized) load by 426 MW (by ~3%) or nearly 14% of estimated installed capacity (3,170 MW), a 15% increase (57 MW) compared to 2021.

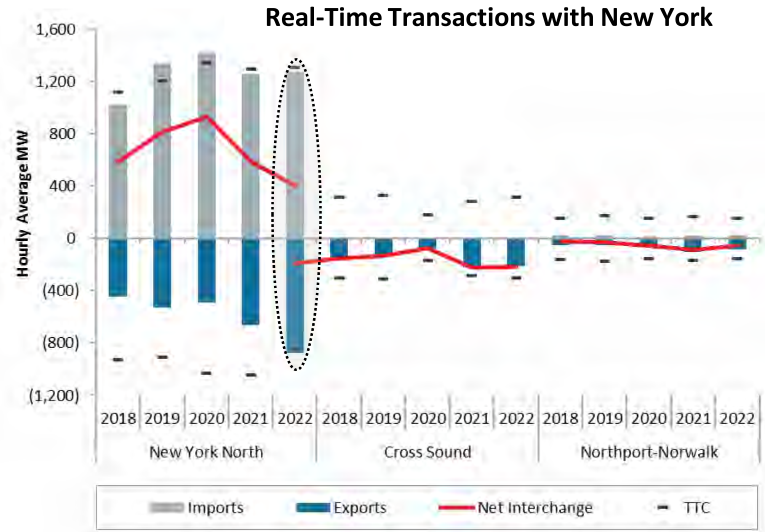
Energy efficiency reduced annual average load by an estimated 2,538 MW, a 2% decrease (40 MW) compared to 2021.

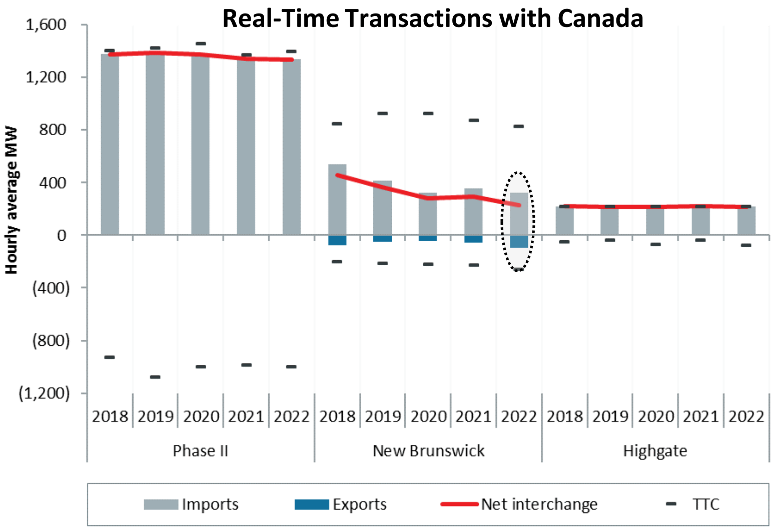
Natural gas generator profitability metrics up on higher gas prices



Lower net imports at the New York North (down 189 MW) and New Brunswick (down 68 MW) interfaces

New England was a net importer of 1,914 MW per hour in 2022, meeting 14% of load. Canadian net imports totaled 1,781 MW (similar to 2021), while New York net imports totaled 133 MW (down by 152 MW).



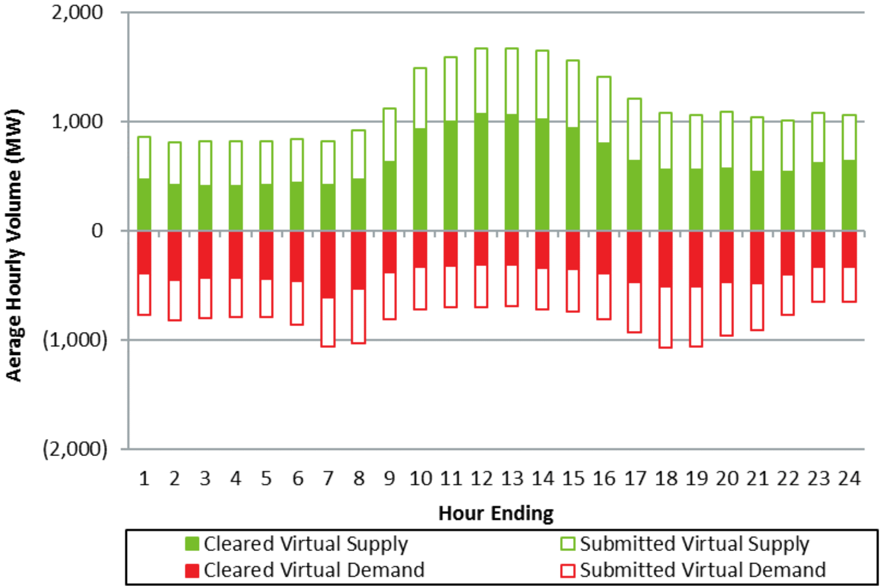


Cleared import transactions with New York were comparable to 2021, but real-time exports increased by 31% (or 209 MW). The increase in exports was due to increased congestion and higher prices in Eastern New York.

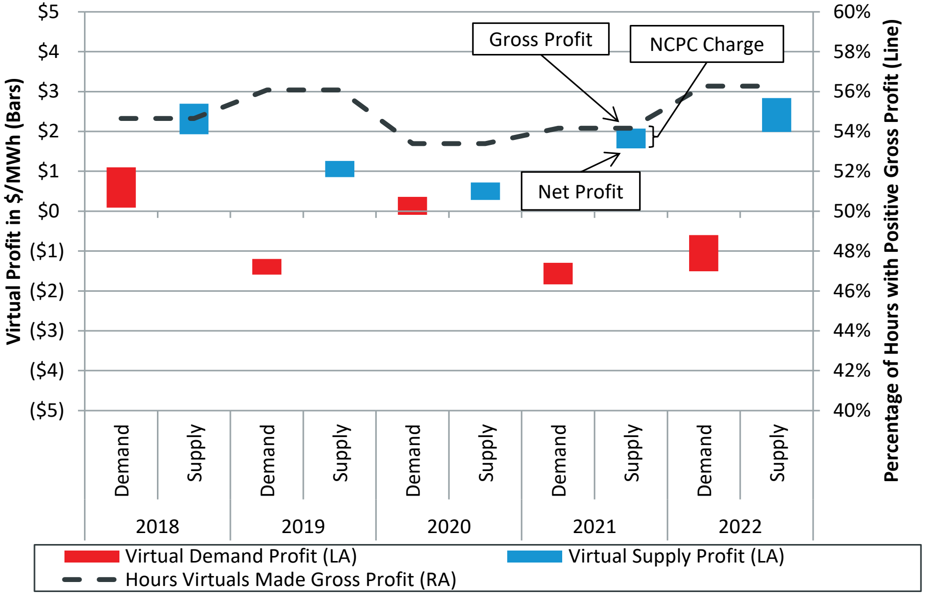
New England continues to import significantly more power from Canada than it does from New York. In 2022, a 660-MW New Brunswick nuclear generator had an extended outage, resulting in decreased imports and increased exports over the interface.

More virtual supply cleared during middle part of the day, coincident with higher solar output; profitable overall

Volume

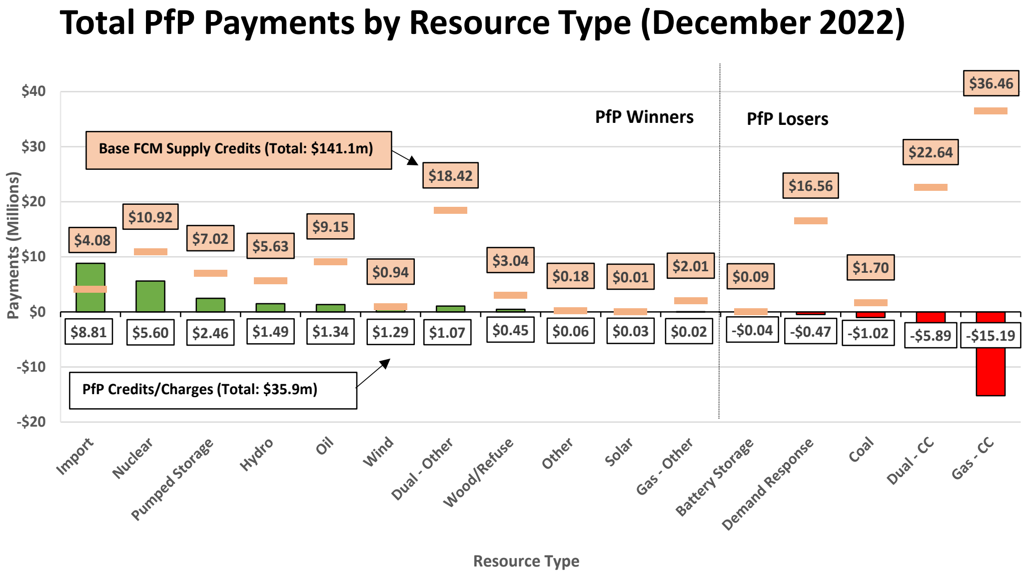


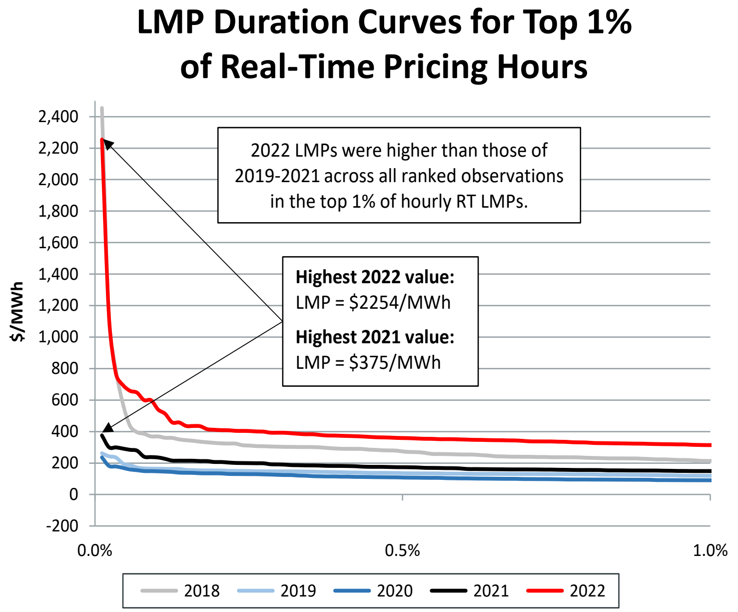
Profitability



We continue to recommend a review of NCPC allocation rules to virtual transactions (recommendation 2010-1)

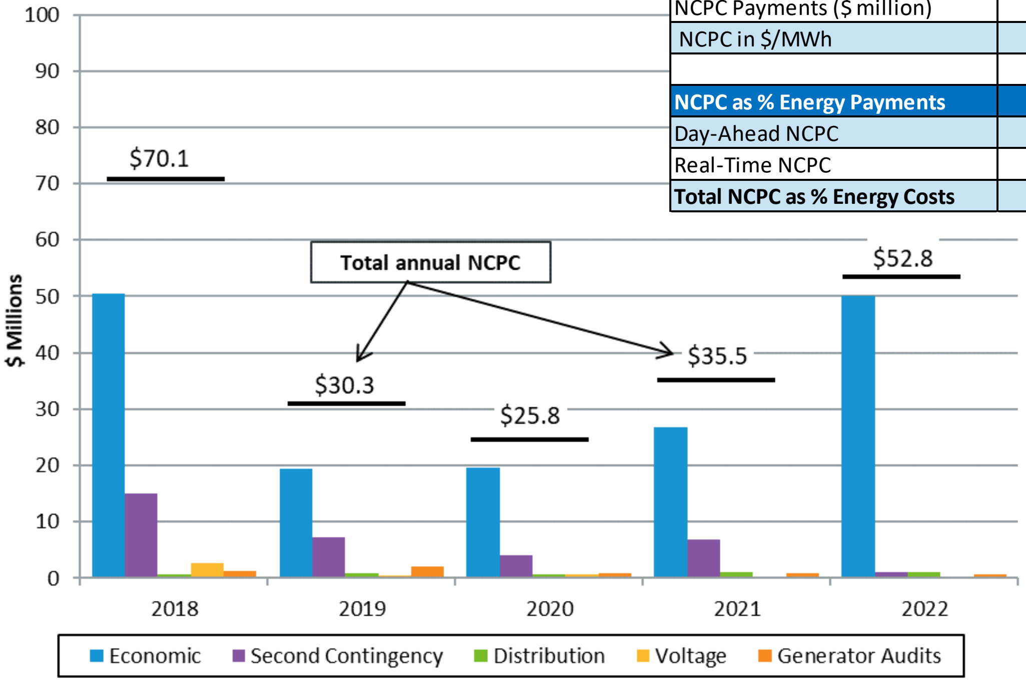
No major reliability issues in 2022; Dec. 24 saw first capacity scarcity condition for approx. 1½ hours





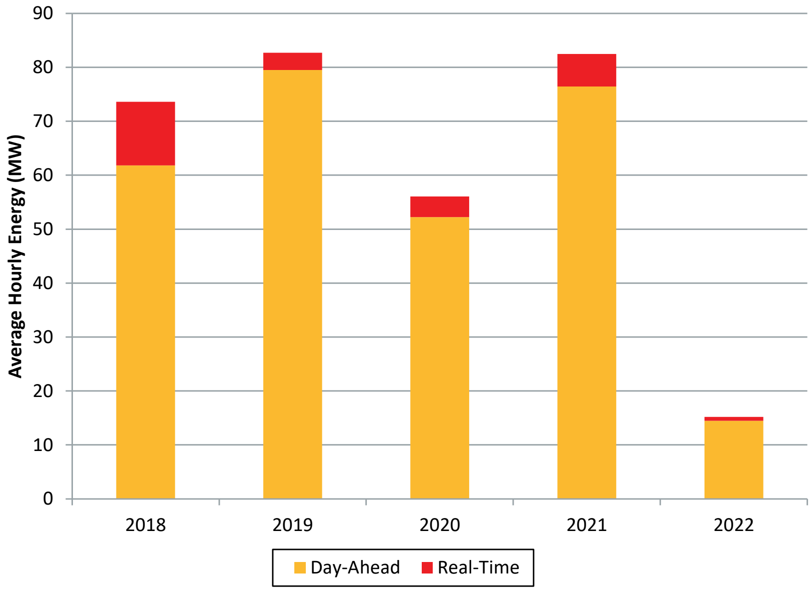
Majority of uplift costs for resources committed and dispatched in economic merit order

	2018	2019	2020	2021	2022
Energy Payments ($ millions)	$6,041	$4,105	$2,996	$6,099	$11,698
NCPC Payments ($ million)	$70.12	$30.29	$25.78	$35.49	$52.83
NCPC in $/MWh	$0.57	$0.25	$0.22	$0.30	$0.44
NCPC as % Energy Payments					
Day-Ahead NCPC	0.4%	0.3%	0.3%	0.3%	0.1%
Real-Time NCPC	0.7%	0.4%	0.5%	0.3%	0.3%
Total NCPC as % Energy Costs	**1.2%**	**0.7%**	**0.9%**	**0.6%**	**0.5%**

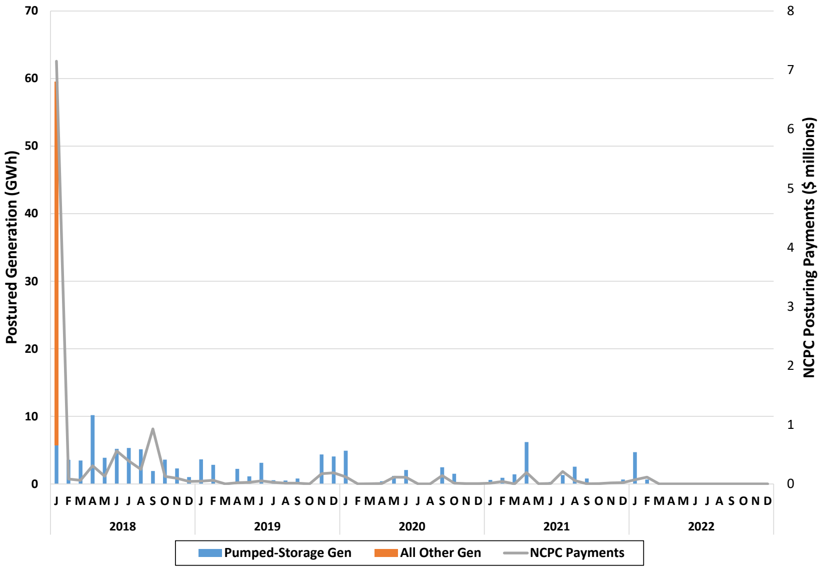


Out-of-merit commitments and posturing actions down significantly in 2022

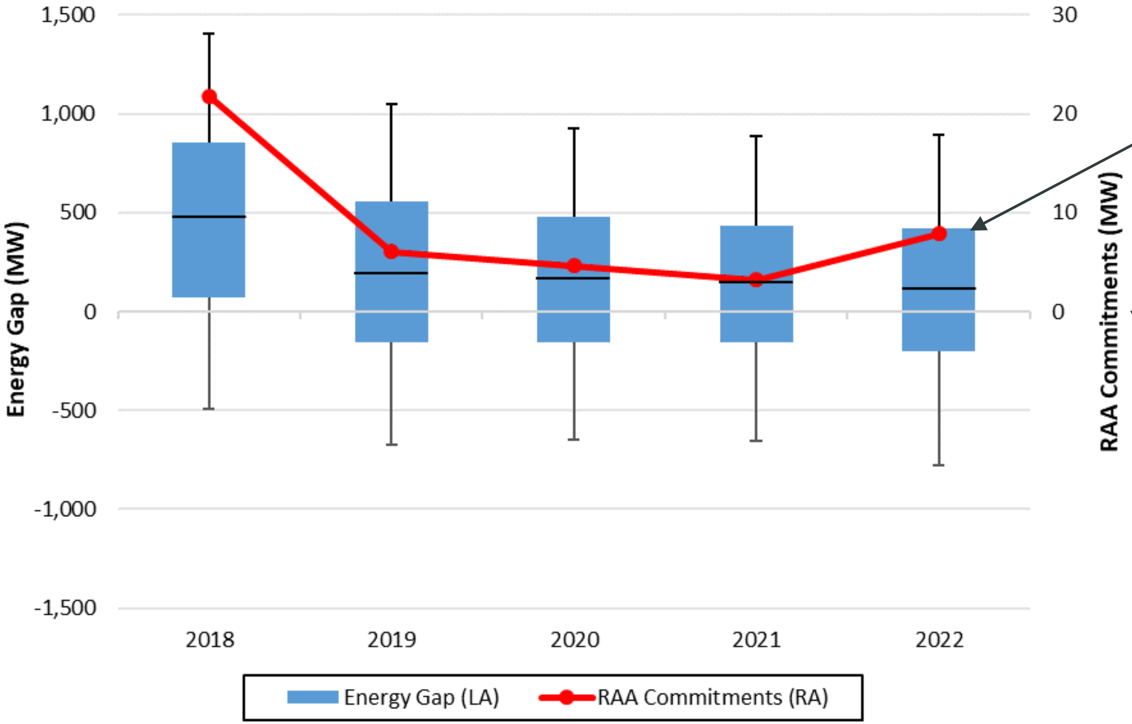
Average Hourly Energy Output from Reliability Commitments, Peak Load Hours



Monthly Postured Energy and NCPC Payments



Day-Ahead energy market continues to clear a significant share of generation to meet expected real-time energy needs



Day-ahead Ancillary Services Initiative (DASI) will procure and price physical generation to satisfy the energy gap.

Supplemental commitments of long-lead time generation in the Reserve Adequacy Analysis (RAA) were infrequent and generally small in 2022.

Recommendation to review reserve pricing logic under the fast start pricing rules

- Fast-Start Pricing is generally meeting its key design objective of improving real-time price formation
- However, we observe frequent non-zero reserve pricing when the reserve constraint is not physically binding
- Function of the tradeoff in separating dispatch and pricing and relaxing EcoMin for energy but not for reserves.
- In 2022, $13.7 million in reserve payments were made when there was a reserve surplus (over half of the $26.9 million in total reserve payments during the year).

Reserve Prices in the Pricing vs. Dispatch Software on December 12, 2022

Energy and capacity markets outcomes competitive, while market power in forward reserve market is a concern

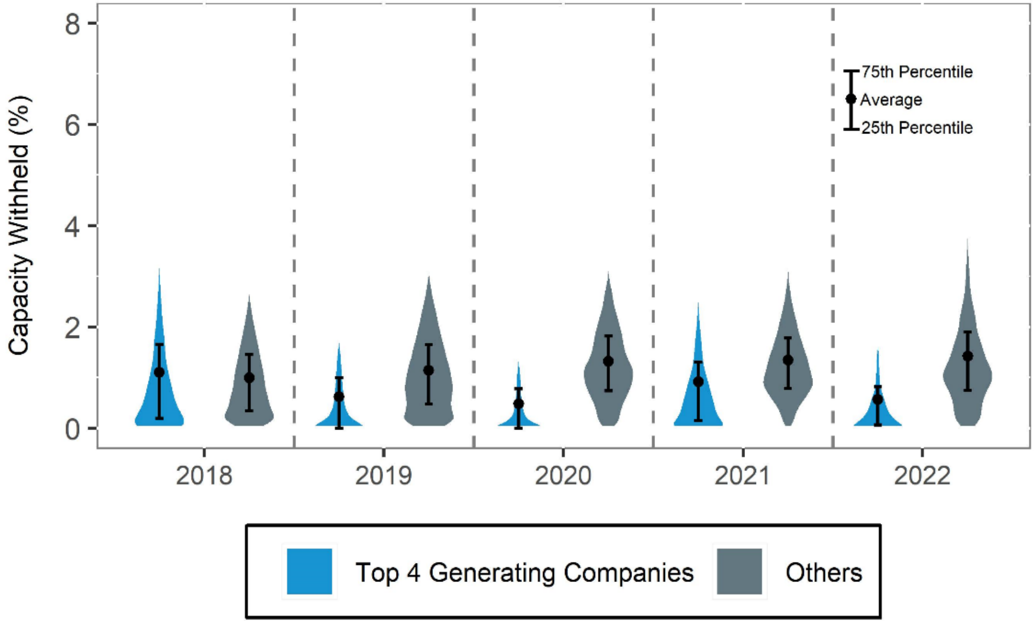
- Energy supply concentration in line with prior years; at least one pivotal supplier in about 25% of hours
- Withholding metrics indicate low price and quantity impact of energy supply offers above competitive levels; mitigation of energy offers was infrequent
  - However, a review of several aspects of the energy market mitigation rules is recommended, particularly conduct and impact thresholds
- Capacity market structurally competitive with enough existing supply to meet the capacity requirement at system and zonal levels
- Forward reserve auction prices have increased significantly in recent auctions; summer auctions are not structurally competitive

Energy market economic withholding metrics indicate competitive outcomes

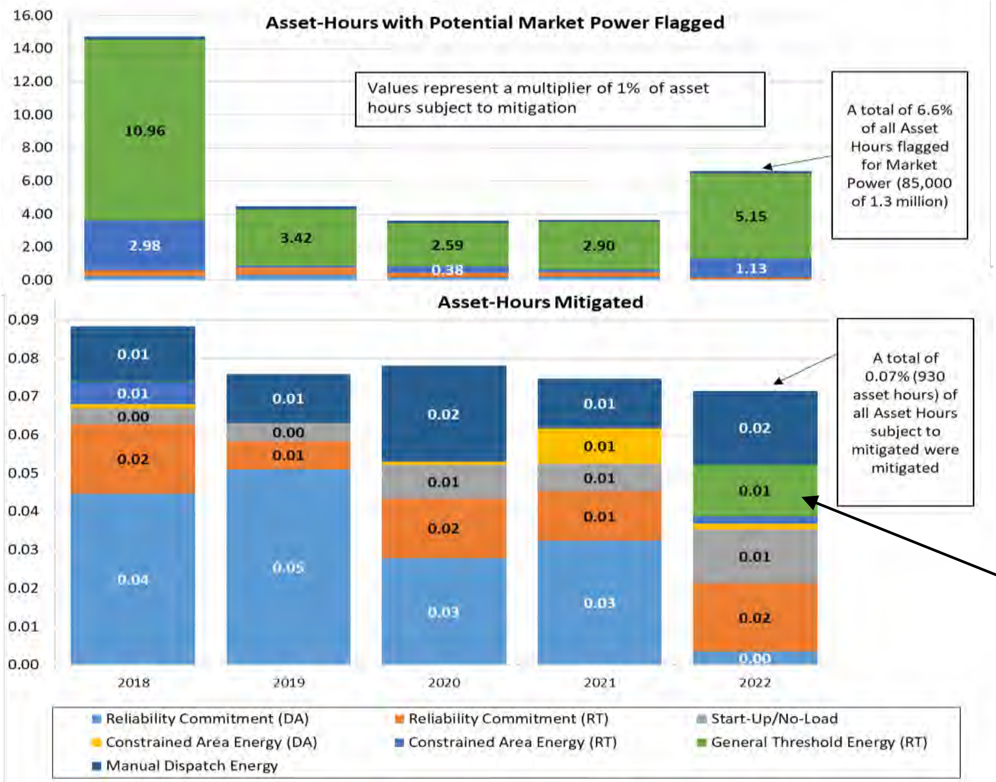
Day-Ahead Price-Cost Markup

Year	Price-Cost Markup
2018	-4.0%
2019	-2.4%
2020	0.9%
2021	-0.6%
2022	-1.8%

Real-time Economic Withholding During On-Peak Hours



Energy market mitigations remained low; but appropriate to review rules under a range of supply/demand scenarios



Potential design enhancements also revealed by systemwide mitigation and cost recovery issues on December 24, 2022.

Recommendation to review aspects of the energy market mitigation design

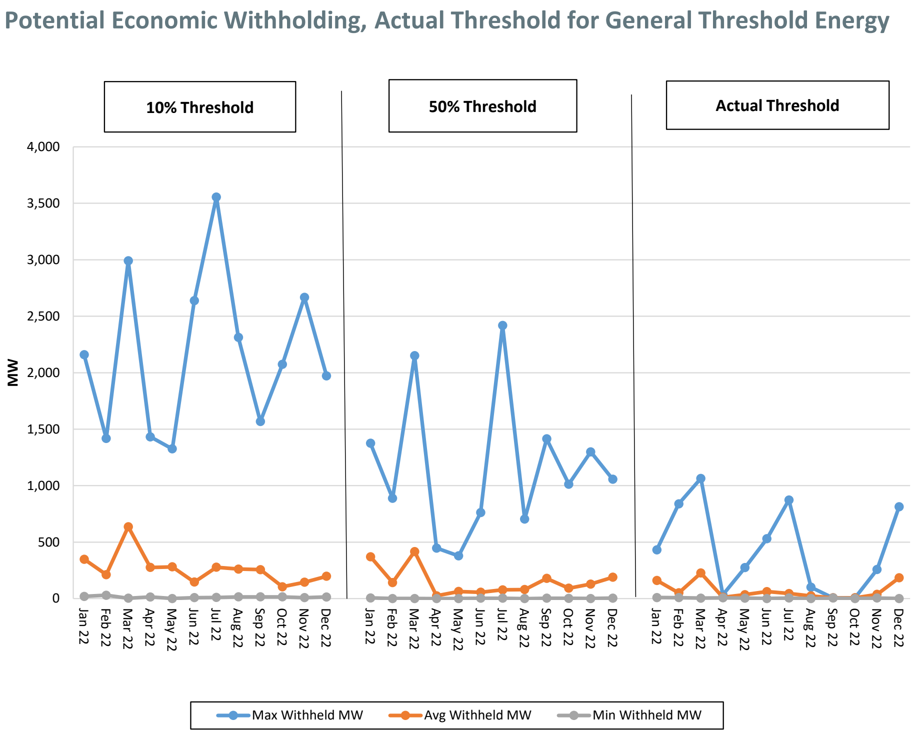
1. Review mitigation thresholds for system-wide and local market power. The current thresholds allow for considerable latitude in supply offers levels over competitive benchmarks (300% and 50%) and have been in place for many years with little empirical support

2. Eliminate the energy offer mitigation exemption for non-capacity resources in the day-ahead energy market

3. Extend the scope of offer mitigation to cover the potential exercise of market power in export-constrained areas

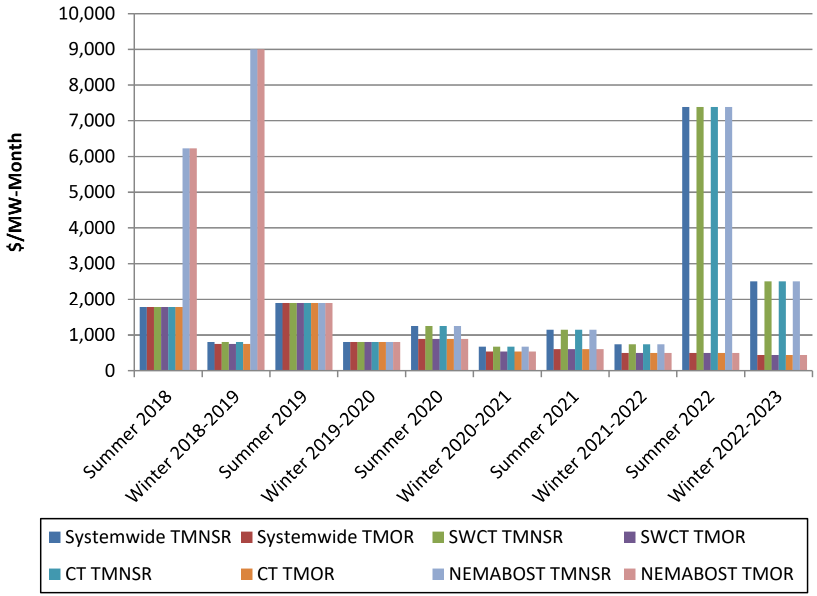
4. Review the methodologies for determining reference levels, which are used to evaluate if an offer is competitive (the “conduct test”). We recommend that only marginal cost-based reference levels be relied on for generators that have robust cost estimates with the IMM. Reference levels based on historical fuel-adjusted accepted supply offers or LMPs can produce unreasonably high reference levels

Potential economic withholding at various conduct threshold levels



Structural market power in forward reserve market persists, with an offer cap the only mitigation mechanism

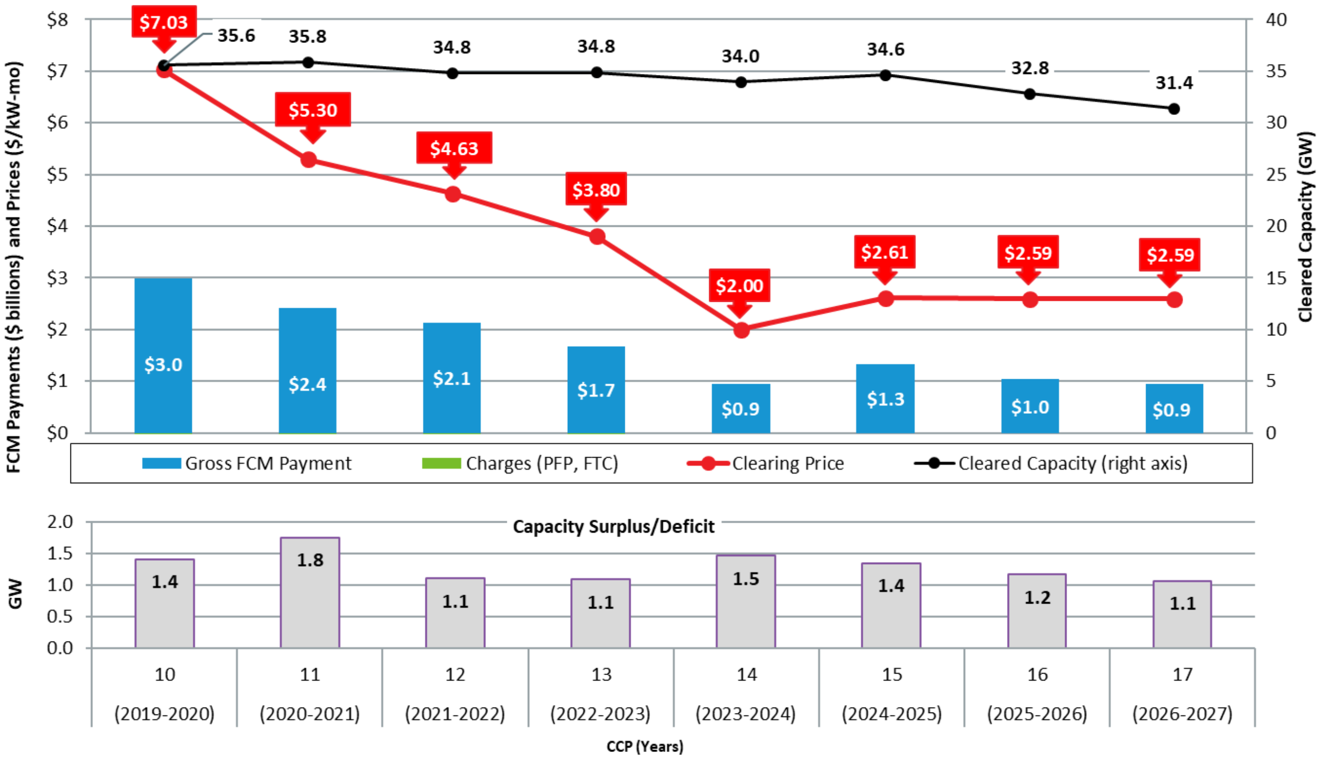
Forward Reserve Prices by FRM Procurement Period



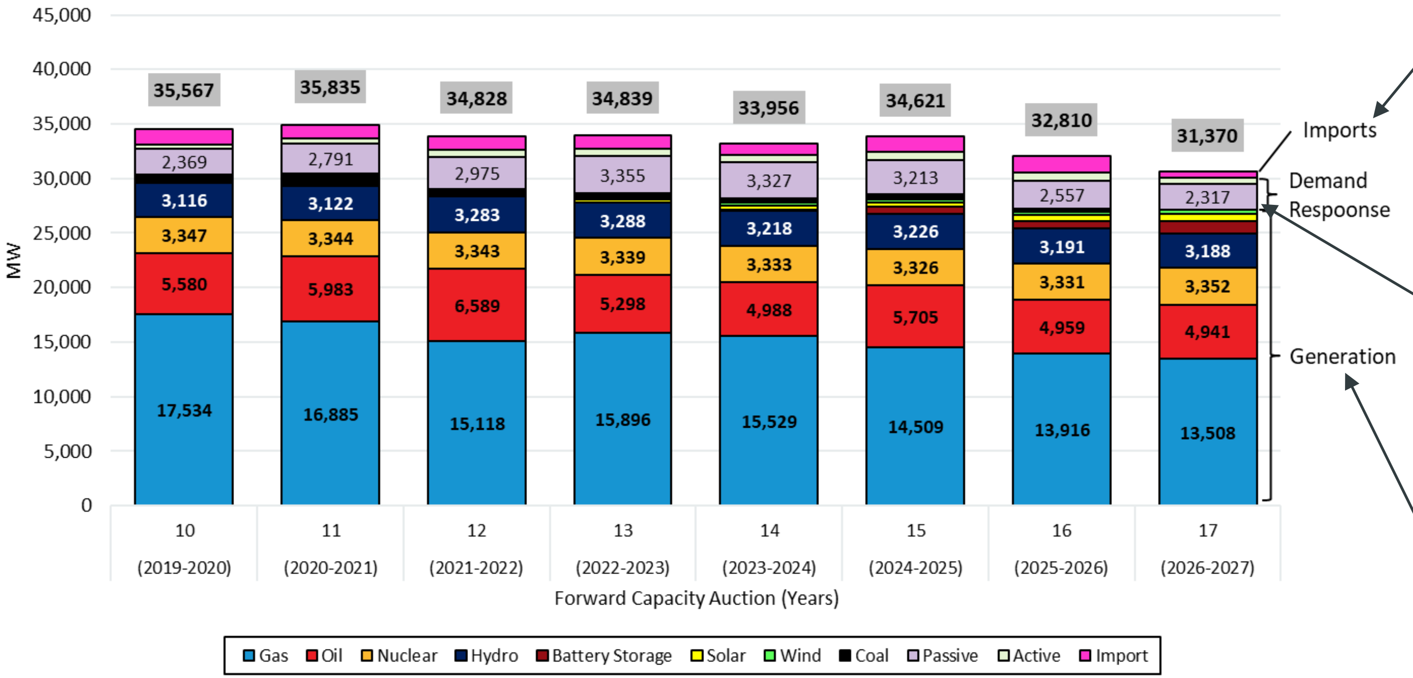
Offer RSI in the FRM for TMNSR and TMOR (system-wide)

Procurement Period	Offer RSI TMNSR (System-wide)	Offer RSI Total Thirty (System-Wide))
Summer 2018	112	108
Winter 2018-19	127	127
Summer 2019	90	97
Winter 2019-20	120	118
Summer 2020	84	97
Winter 2020-21	102	115
Summer 2021	92	108
Winter 2021-22	110	116
Summer 2022	78	90
Winter 2022-23	109	112

Low capacity costs continue under surplus capacity market conditions



Contracted capacity falling with lower capacity requirement and low prices



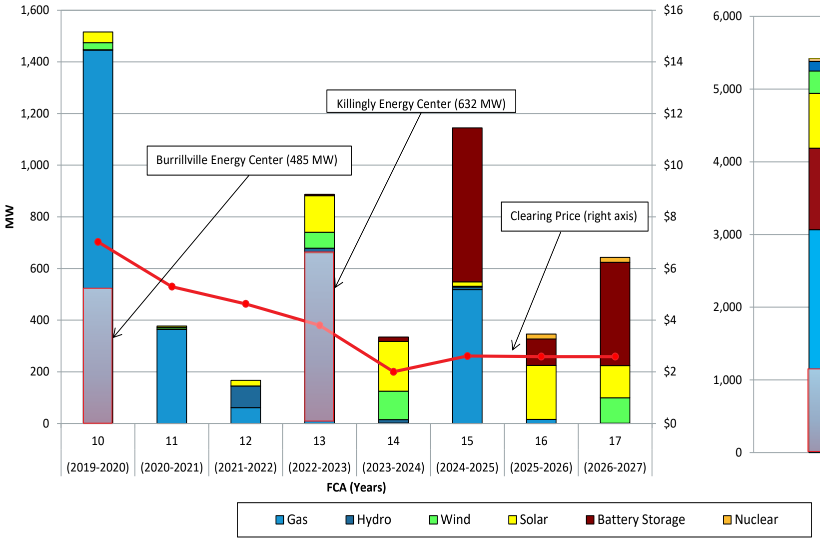
Reduction in import resources in most recent auction.

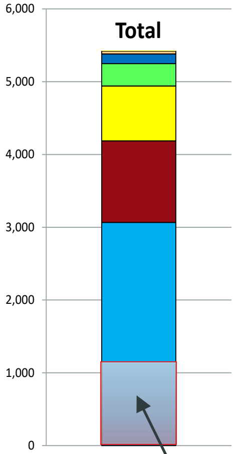
Energy Efficiency capacity declining due to rising costs of eligible EE measures and associated baselines.

Gas and oil capacity declining due to combination of retirements and single-year exits; in FCA 17 over 2,000 MW of existing oil, gas and coal capacity de-listed for one year.

Battery, solar and wind resources comprise most recent new entry, with no significant retirements in past two auctions

New Generation Capacity by Fuel Type





Non-commercial new capacity that cleared in FCAs 10-17

Generating Resource Retirements over 50 MW

FCA # (Commitment Period)	Resource Name	Fuel Type	Capacity Zone	FCA MW
FCA 10 (2019/20)	Pilgrim Nuclear	Nuclear	SEMA	677
FCA 12 (2021/22)	Bridgeport Harbor 3	Oil	Connecticut	383
FCA 13 (2022/23)	Mystic 7	Oil	NEMA/Boston	575
FCA 14 (2023/24)	Yarmouth 1	Oil	Maine	50
FCA 14 (2023/24)	Yarmouth 2	Oil	Maine	51
FCA 14 Total (resources > 50 MW)				101 MW
FCA 15 (2024/25)	Mystic 9	Gas	NEMA/Boston	710
FCA 15 (2024/25)	Mystic 8	Gas	NEMA/Boston	703
FCA 15 (2024/25)	West Springfield 3	Gas	WCMA	95
FCA 15 (2024/25)	CDECCA	Gas	Connecticut	52
FCA 15 Total (resources > 50 MW)				1,560 MW
FCA 16 (2025/26)	Potter 2 CC	Gas	SEMA	72
Total Major Retirements since FCA 10				3,368 MW

Questions

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings as of October 3, 2023

The following activity, as more fully described in the attached Litigation Report, has occurred since the report dated September 6, 2023 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

I. Complaints/Section 206 Proceedings

	1	206 Proceeding: Brookfield IEP Complaint (IEP Exclusion of Pumped Storage ESFs) (EL23-89)	Sep 21	FERC grants Brookfield's Complaint
	2	206 Proceeding: FTR Collateral Show Cause Order (EL22-63)	Sep 21	FERC terminates the Section 206 proceeding it instituted, finding ISO-NE's tariff remains just and reasonable in the absence of a volumetric alternative minimum collateral requirement

II. Rate, ICR, FCA, Cost Recovery Filings

	6	BHD Regulatory Asset-Establishment & Recovery Through Rates (ER23-1598-002)	Sep 22	Versant files Settlement Offer to resolve all issues raised by the MPUC; comments due on or before ***Oct 12, 2023***; reply comments, ***Oct 23, 2023***
	7	**Mystic 8/9 COSA (ER18-1639)**		
	7	(-000) *Third* CapEx Info Filing (ER18-1639)	Sep 15	Mystic submits 2023 Capital Expenditures Informational Filing covering the Jan 2024-May 31, 2024 period
	8	(-023) 30-Day Compliance Filing (Revised COSA)	Sep 8	FERC accepts compliance filing, eff. *Jun 1, 2022*
	10	Transmission Rate Annual (2024) Update/Informational Filing (ER20-2054-003)	Sep 15	MOPA intervenes

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

	11	Waiver Request: FCA18 Summer Qualified Capacity (Yarmouth 4) (ER23-2356)	Sep 14	FERC grants waiver request

IV. OATT Amendments / TOAs / Coordination Agreements

*	15	Attachment F Corrections & Updates (ER23-2940)	Sep 28	PTO AC submits proposed revisions to OATT Attachment F to correct minor errors in certain worksheets of the "Formula Rate Template" contained in Appendices A and B to Attachment F; comment deadline ***Oct 19, 2022***

V. Financial Assurance/Billing Policy Amendments

No Activities to Report

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

*	16	Schedule 21-GMP: National Grid/Green Mountain Power LSA (ER23-2804)	Sep 11	ISO-NE, National Grid file 20-year LSA with Green Mountain Power (to replace LSA that expired Sep 30, 2022)

	17	Schedule 21-VP: 2022 Annual Update Settlement Agreement (ER20-2054-003)	Sep 15	MPUC intervenes

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activities to Report

VIII. Regional Reports

	18	Reserve Market Compliance (35th) Semi-Annual Report (ER06-613)	Sep 29	ISO-NE submits 35th semi-annual report

IX. Membership Filings

*	18	Oct 2023 Membership Filing (ER23-2966)	Sep 29	***New Members:*** KCE CT 10, LLC; KCE CT 11, LLC; Sierra Club; ***Termination:*** BP Energy Holding Company; comment deadline ***Oct 20, 2023***
	18	Aug 2023 Membership Filing (ER23-2514)	Sep 29	FERC accepts the NEPOOL membership of Clover Energy (Supplier Sector), eff. *Aug 1, 2023*

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

	19	NERC Report on Evaluation of Physical Reliability Standard (CIP-014) (RD23-2)	Sep 20-21	Post-tech. conf. comments filed by AEP, PJM, EEI, Electricity Canada, EPSA, FRS, Criticality Services, Grid Coalition, ITC, NATF, Secure the Grid, L. Fitzgerald, T. Holiday, S. Naumann
			Oct 3	Final transcript of Aug 10 Atlanta Joint NERC-FERC Tech Conf posted
	19	CIP Standards Development: Info Filings on Virtualization and Cloud Computing Srvs. Projects (RD20-2)	Sep 15	NERC files required quarterly report with revised schedule for Project 2016-02 (projected filing of revised standards now **Jan 2024**)

XI. Misc. - of Regional Interest

	21	203 Application: Energy Harbor / Vistra (EC23-74)	Sep 15	Vistra/Energy Harbor answer FEA letter
			Sep 18	Vistra/Energy Harbor file Deficiency Letter Response; comment date ***Oct 10, 2023***
			Sep 20, 29	OH OCC, NOPEC comment on Deficiency Letter Response
*	21	PURPA Enforcement Petition: Allco Finance Ltd (VT PUC) (EL23-92)	Sep 14	VT PUC answers Allco Complaint
	22	PURPA Enforcement Petition: Allco Finance Ltd. (MA State Agencies) (EL23-84)	Sep 22	FERC issues a notice of its intent not to initiate an enforcement action in response to the Allco MA State Agencies PURPA Complaint
	22	LGIAs: RIE/ISO-NE/RISEC & Tiverton (ER23-2494 and ER23-2491)	Sep 19	FERC accepts LGIAs, each eff. *Jan 1, 2023*
	23	Changes to Depreciation Rates in MPD OATT Formula Rate (ER23-2085)	Sep 11	Versant submits supplemental information that, as a result of bilateral discussions with the MPUC, the MPUC's concerns with respect to the Depreciation Rate changes have been satisfied
			Sep 26	MPUC withdraws its June 28, 2023 comments

XII. Misc. - Administrative & Rulemaking Proceedings

*	24	ACPA Petition for Capacity Accreditation Tech Conf (AD23-10)	Sep 22-Oct 2	IRC opposes Petition; comments supporting, or not opposing, a tech conf were filed by, among others: ACRE, AEU, Calpine, Colorado PUC, EPSA, NYU Law School Policy Integrity Institute, Pine Gate, SCE, SEIA, Sierra Club, UCS, and Univ. of Chicago Law School

26	*Order 2023*: Interconnection Reforms (RM22-14)	Sep 13	***EEI*** requests an extension of time to the earlier of (i) 90 days after the FERC issues a substantive order addressing arguments on clarif. and reh'g (as requested by the Joint RTOs) or (ii) Mar 4, 2024
		Sep 26	***Joint California Utilities*** request an extension of time to 90 days after the FERC accepts CAISO's compliance filing
		Sep 28	FERC issues *Order 2023 Allegheny Notice*
		Oct 2	***NEPOOL*** requests a 45-day extension of time, to Jan 19, 2024
			Absent FERC action, compliance filings due on or before ***Dec 5, 2023***
28	*Order 895*: ISO/RTO Credit Information Sharing (RM22-13)	Sep 8	FERC grants SPP 14-day extension of time to submit its compliance filing; remaining ISO/RTO compliance filings due ***Oct 20, 2023***
29	NOPR: Transmission Siting (RM22-7)	Sep 28	Chairman Danly's response to Senator Schumer's Jun 20, 2023 letter posted to eLibrary

XIII. FERC Enforcement Proceedings

Natural Gas-Related Enforcement Actions

* 31	Georgia-Pacific Crossett LLC (IN23-12)	Sep 13	FERC approves Stipulation and Consent Agreement that resolves OE's investigation into GPC's abandonment of the Crosett Pipeline; GPC must pay a ***$1.2 million civil penalty***

XIV. Natural Gas Proceedings

No Activity to Report

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

35	Seabrook Dispute Order (23-1094, 23-1215) (consol.)	Sep 28	FERC files Respondent's Brief
36	2nd Revised Narragansett LSA Orders (22-1161, 22-1108) (consol.)	Sep 19	Court issues formal mandate denying Petition
38	Northern Access Project (22-1233)	Sep 18	Oral argument held
38	Algonquin Atlantic Bridge Project Orders (22-1146, 22-1147) (consol.)	Sep 11, 13	Petitioners ask, and the Court orders, that the remaining consolidated cases remain in abeyance and directs the parties to file motions to govern future proceedings by ***Oct 27, 2023***
38	*Order 872* (20-72788 et al.) (consol.) (9th Cir.)	Sep 5	Court, largely upholding *Order 872*, grants in part, and denies in part, SEIA's Petition

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: October 4, 2023

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

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"),[1] state regulatory commissions, and the Federal Courts and legislatures through October 3, 2023. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

- **Brookfield IEP Complaint (IEP Exclusion of Pumped Storage ESFs) (EL23-89)**

On September 21, 2023, the FERC granted the complaint filed by Brookfield Renewable Trading and Marketing LP ("Brookfield") regarding the exclusion of pumped storage hydroelectric facilities that are Electric Storage Facilities ("ESFs") from the Inventoried Energy Program ("IEP").[2] In granting the Complaint, effective August 2, 2023, the FERC found "pumped storage [ESFs] are similarly situated to battery storage [ESFs] for purposes of participation in the [IEP] … [agreed] with Brookfield that the ISO-NE Tariff is unduly discriminatory because it prohibits pumped storage [ESFs] from similarly participating in the [IEP]".[3] Accordingly, the FERC ordered ISO-NE to revise its Tariff. Any challenges to the *Brookfield IEP Complaint Order* are due on or before October 23, 2023. The changes to the Tariff in response to the *Order* are to be reviewed by the Markets Committee in October and voted by the Participants Committee in November. 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).

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

As reported below, this Section 206 proceeding, 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),[4] is being held in abeyance. Parties to this proceeding include: NEPOOL, Calpine, Connecticut Office of Consumer Counsel ("CT OCC"), Massachusetts ("MA") Attorney General ("MA AG"), NEPGA, New England States Committee On Electricity

[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] *Brookfield Renewable Trading and Marketing LP v. ISO New England Inc.*, 184 FERC ¶ 61,169 (Sep. 21, 2023) ("*Brookfield IEP Complaint Order*").

[3] *Id.* at P 31.

[4] *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.

(NESCOE"), Public Systems,[5] Electric Power Supply Association ("EPSA"), MA Department of Public Utilities ("MA DPU"), Maine Public Utilities Commission ("MPUC"), and Public Citizen.

Being Held In Abeyance. 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 ***February 1, 2024***.

If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **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,[6] 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 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, CMMEC, 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 no activity since the last Report. As noted, this matter remains pending before the FERC. If you have questions on this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

- **206 Proceeding: FTR Collateral Show Cause Order (EL22-63)**

On September 21, 2023, the FERC terminated the Section 206 proceeding[7] it instituted on July 28, 2022 requiring ISO-NE Tariff to show cause why the absence of volumetric minimum collateral requirements for FTR Market Participants ("volumetric FTR collateral requirements") does not render the ISO-NE Tariff unjust and unreasonable.[8] The FERC found that "ISO-NE's currently effective tariff remains just and reasonable in the absence of a volumetric alternative minimum collateral requirement because the existing measures in ISO-NE's tariff, which include an alternative approach that uses FTR path-specific proxy prices, ensure that market participants maintain some minimal level of collateral that scales with the size of their FTR portfolio and cannot

[5] "Public Systems" for purposes of this proceeding are, collectively: the Connecticut Municipal Electric Energy Cooperative ("CMEEC"), Massachusetts Municipal Wholesale Electric Company ("MMWEC"), New Hampshire Electric Cooperative ("NHEC"), and Vermont Public Power Supply Authority ("VPPSA").

[6] 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.

[7] *ISO New England Inc.,* 184 FERC ¶ 61,165 (Sep. 21, 2023) ("*Order Terminating FTR Collateral Show Cause Order*").

[8] *CAISO, ISO-NE, NYISO, and SPP*, 180 FERC ¶ 61,049 (July 28, 2022) ("*FTR Collateral Show Cause Order*").

minimize their required collateral without correspondingly reducing their risk, which addresses the Commission's concerns in the *[FTR Collateral] Show Cause Order*."[9] If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@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,[10] 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*).[11] However, the FERC's orders were challenged, and in *Emera Maine,*[12] 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)[13] and third (EL14-86)[14] 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.[15] 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*.

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[9] *Order Terminating FTR Collateral Show Cause Order* at P 23.

[10] 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*")).

[11] *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*").

[12] *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).

[13] 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%.

[14] 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.

[15] *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*").

- ***Base ROE Complaint IV (EL16-64)***. The fourth and final ROE proceeding[16] also went to hearing before an Administrative Law Judge ("ALJ"), Judge Glazer, who issued his initial decision on March 27, 2017.[17] 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.[18] 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.[19] 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*[20] (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.[21]

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

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

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

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

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

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

[21] *Id.* at P 19.

model. For a single utility of average risk, the FERC will average the medians rather than the midpoints. The FERC said that it would continue to use the same proxy group criteria it established in *Opinion 531* to run the ROE models, but it made a significant change to the manner in which it will apply the high-end outlier test.

The FERC provided preliminary analysis of how it would apply the proposed methodology in the Base ROE I Complaint, suggesting that it would affirm its holding that an 11.14% Base ROE is unjust and unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[22] 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[23] 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*[24] 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

- **Stonepeake Kestrel CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER23-2429)**

Still pending is the request by Stonepeake Kestrel Energy Marketing LLC ("Stonepeake Kestrel") that the FERC accept its revised rate schedule to allow recovery of eligible medium-impact Interconnection Reliability Operating Limits ("IROL") critical infrastructure protection ("CIP") costs ("CIP-IROL Costs") under Schedule 17 of the ISO-NE Tariff, effective September 16, 2023. Stonepeake Kestrel initially sought recovery of $1,605,854 in incremental medium impact CIP-IROL Costs incurred between March 29, 2021 and March 31, 2023. Stonepeake Kestral revised is initial (July 18) request to remove certain capital and interest on operations and maintenance

[22] *Id.* at P 59.

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

[24] *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).

costs from its revised rate schedule,[25] reducing the recovery it seeks to ***$1,483,297*** in CIP-IROL Costs. No comments were filed either on Stonepeake Kestrel's initial or amended filing. Doc-less interventions were filed by NEPOOL and NESCOE. 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).

- **Bucksport Generation (Schedule 17) Section 205 Cost Recovery Filing (ER23-2428)**

Similarly, Bucksport Generation LLC ("Bucksport Generation") has also requested that the FERC accept its revised rate schedule to allow recovery of its eligible medium-impact CIP-IROL Costs. For the same reasons articulated by Stonepeake Kestrel, Bucksport Generation also amended its initial filing (removing certain capital and interest on operations and maintenance costs from its revised rate schedule) and now seeks to recover ***$251,419*** in incremental medium impact CIP-IROL Costs incurred between March 29, 2021 and March 31, 2023. No comments were filed either on Bucksport Generation's initial or amended filing. NEPOOL and NESCOE filed doc-less interventions. 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).

- **BHD Regulatory Asset - Establishment & Recovery Through Rates (ER23-1598)**

On April 7, 2023, Versant Power requested authorization to (i) establish a regulatory asset for the Bangor Hydro District ("BHD") totaling $15,622,081 in capitalized regulatory overhead costs (identified in a recent FERC audit as incorrectly allocated as construction costs) as of January 1, 2024, and amortize this asset over a period of 16 years on a straight-line basis beginning January 1, 2024, subject to FERC approval; and (ii) recover as an expense in transmission rates under the ISO-NE OATT a return of the unamortized balance of the regulatory asset effective January 1, 2026 and continuing for 16 years. Comments on Versant's request were due on or before April 28, 2023. On May 3, the MPUC moved to intervene out-of-time and protest. In its protest, the MPUC requested that Versant be required to refund retail customers for the improper collection of "Allocation of Overhead Costs to Construction Work in Progress" and to provide additional detail regarding the amounts included. On May 5, 2023, Versant answered the MPUC protest.

Deficiency Letter and Deficiency Letter Response. On June 5, 2023, the FERC issued a deficiency letter directing Versant to provide additional information related to inputs to Filing Exhibits 1 and 2, which support the amount of the proposed regulatory asset. Specifically, Versant was directed to provide "all records that Versant provided to Commission audit staff in Docket No. FA20-9-000 related to the proposed regulatory asset and explain how these records support the instant filing". Versant filed its response on July 5, 2023 (which re-set the filing date and deadline for FERC action (see below)). Comments on Versant's deficiency letter response were due on or before July 26, 2023; none were filed. On July 19, the Maine Office of the Public Advocate ("MOPA") filed a motion to intervene (out-of-time).

Joint Offer of Settlement (-002). On September 22, Versant filed a joint offer of settlement ("Settlement Offer") between itself, the MPUC and MOPA. Versant stated the Settlement Offer, if accepted, would resolve all issues raised by the MPUC in this proceeding, including those described above. Comments on the Settlement Offer are due on or before ***October 12, 2023***; reply comments, if any, by ***October 23, 2023***.

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

[25] Stonepeake Kestrel explained that it removed working capital and interest on operations and maintenance costs for the purposes of this filing in order to avoid a deficiency letter similar to the one received by CSC in Docket No. ER23-1826, and to obtain an affirmative order in this proceeding as expeditiously as possible.

- **Mystic COS Agreement Updates to Reflect Constellation Spin Transaction[26] (ER22-1192)**

As previously reported, on May 2, 2022, the FERC accepted and suspended in part Constellation Mystic Power, LLC's ("Mystic's") changes to its Amended and Restated Cost-of-Service Agreement ("COSA") to reflect Mystic's current upstream ownership.[27] The changes were accepted effective as of June 1, 2022, but subject to refund and to the outcome of paper hearing (or settlement procedures) on the issues of capital structure and cost of debt raises issues. Mystic filed an offer of settlement on September 8, 2022 to resolve all issues set for hearing and settlement proceedings and the FERC accepted that offer of settlement on November 2, 2022,[28] directing Mystic to make a compliance filing with revised tariff records in eTariff format reflecting the FERC's action in the November 2 order. Mystic submitted that compliance filing on December 2, 2022 (ER22-1192-003). No comments were received by the December 23, 2022 comment date, and there was no activity in this proceeding since the last Report. This compliance filing remains pending before the FERC. FERC action on the compliance filing will conclude this proceeding. If you have questions on any aspect of this proceeding, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@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[29] 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*.

Public Systems' Request for Disclosure of Audit Information. On May 19, 2023, Public Systems[30] requested that the FERC direct ISO-NE to release additional information concerning ISO-NE's audit of performance under Mystic COSA ("Audit Information Request"). Public Systems asserted that ISO-NE has released almost no information concerning the audits or the bases for their conclusions that Mystic's performance is consistent with its obligations under the COSA. Answers to Public Systems' Audit Information Request were filed by Constellation ***Mystic*** Power LLC ("Mystic") (opposing the Audit Information Request), ***ISO-NE*** (which proposed, in addition to the summary of COSA-related audits that ISO-NE posted shortly after Public Systems filed the Request, to make available redacted versions of the FSA audit reports, prepare a narrative of its meetings with Mystic and CLNG regarding the fuel supply plan, and make a member of Levitan & Associates' audit team available to answer questions on three occasions over the remainder of the COSA's term) and ***CT Parties*** (urging the FERC to grant the Audit Information Request). Public Systems answered the Mystic and ISO-NE answers on July 5, 2023. Mystic answered Publicly Systems'' July 5 answer on July 14, 2023. The Audit Information Request is pending before the FERC.

(-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 will not be noticed for public comment by the FERC.

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[26] In the Spin Transaction, Constellation's and Mystic's corporate parent changed from Exelon Corporation to a newly-created holding company, Constellation Energy Corporation ("Constellation Corporation"). Mystic continues to be an indirect wholly-owned subsidiary of Constellation Energy Generation, LLC, which in turn is a direct, wholly-owned subsidiary of Constellation Corporation.

[27] *Constellation Mystic Power, LLC*, 179 FERC ¶ 61,081 (May 2, 2022) ("*May 2, 2022 Order*").

[28] *Constellation Mystic Power, LLC*, 181 FERC ¶ 61,099 (Nov. 2, 2022).

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

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

(-025) First CapEx Settlement Agreement Tariff Sheets Filing. As directed in the August 1, 2023 order conditionally approving the First CapEx Settlement Agreement,[31] Mystic filed, on August 31, 2023, revised tariff records in eTariff format, effective *June 1, 2022*, to reflect the FERC's action ("Tariff Sheets Filing"). Comments, if any, on the Tariff Sheets filing were due on or before September 20, 2023; none were filed. The Tariff Sheets filing is pending before the FERC.

(-024) Mystic Request for Rehearing of Mystic I Order on Remand Denied By Operation of Law. On April 27, 2023, Mystic requested rehearing and/or clarification of the March 28, 2023 *Mystic I Order on Remand*.[32] 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 12, ENECOS answered Mystic and urged the FERC to require that Mystic submit full data on its Revenue Credit and sliding-scale revenue sharing calculations in the Information Exchange and Challenge procedure under Schedule 3A to the COSA. On May 15, ISO-NE filed limited comments to provide the FERC with further information and to note that should the Commission allow interested parties to review Mystic's revenue credits during the true-up process, the review should be facilitated by Mystic. ISO-NE stated that the data involved in the calculation of Mystic's revenue credits are confidential under ISO-NE's Information Policy but Mystic is provided with the necessary data to calculate the revenue credits. On May 25, 2023, Mystic moved to lodge ISO-NE's May 25, 2023 Audit Controls Memorandum to provide the FERC with a more complete description of the various controls and audits that apply to the Mystic COSA.

On May 30, 2023, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[33] The Notice confirmed that the 60-day period during which a petition for review of the *Mystic I Order on Remand* can be filed with an appropriate federal court was triggered when the FERC did not act on Mystic's request for clarification and/or rehearing of the *Mystic I Order on Remand*. The Notice also indicated that the FERC may address, as is its right, the 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." No action has been taken since the last Report.

(-023) 30-Day Compliance Filing (Revised COSA). As directed in the *Mystic I Order on Remand*, Mystic filed, on April 27, 2023, an amended COSA to reinstate the previous revenue sharing mechanism. An effective date of June 1, 2022 was requested. Comments on the 30-Day Compliance Filing were due on or before May 18, 2023; none were filed. The 30-Day Compliance Filing was accepted on September 8, 2023 (effective *June 1, 2022*, as requested).[34]

(-018) Second CapEx Info Filing. Still pending is Mystic's September 15, 2022 "Second 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, 2023 to December 31, 2023 ("2023 CapEx Projects"). Formal challenges to the Second CapEx Info Filing were submitted by NESCOE and ENECOS. Comments on NESCOE's and ENECOS' challenges were due on

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[31] *Constellation Mystic Power, LLC*, 184 FERC ¶ 61,070 (Aug. 1, 2023) ("*Mystic First CapEx Info Settlement Order*").

[32] *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). In the *Mystic I Order on Remand*, the FERC (1) found the initial allocation of 91% of Everett's fixed operating costs to Mystic remains just and reasonable and required that the revenue sharing mechanism be reinstated in the COSA; (2) held its ruling on the clawback issue in abeyance pending resolution in the settlement proceeding; (3) found that the existing language of the COSA mitigates the incentive to unduly delay capital projects; and (4) clarified that all interested parties can review and challenge Mystic's revenue credits and tank congestion charges during a subsequent true-up process. The FERC directed Mystic to submit a 30-day compliance filing, on or before April 27, 2023, revising the COSA to reinstate the revenue sharing mechanism (*see* -023).

[33] *Constellation Mystic Power, LLC*, 183 FERC ¶ 62,115 (May 30, 2023) ("*Mystic I Order on Remand Allegheny Notice*").

[34] *Constellation Mystic Power, LLC*, Docket No. ER18-1639-023 (Sep. 8, 2023) (unpublished letter order).

or before November 16, 2022 and November 17, 2022, respectively. Mystic responded separately to NESCOE's and ENECOS' challenges. MMWEC/NHEC filed comments supporting ENECOS' formal challenge, emphasizing its support for formal challenge to the pass through of charges incurred by Everett for pipeline transportation reservations. On December 6, 2022, ENECOS answered Mystic's November 17, 2022 answer. Later, on December 22, 2022, Mystic filed a response to ENECOS' December 6 answer, and requested that the FERC reject the Formal Challenges, and accept the Second Filing as expeditiously as possible.

On August 15, 2023, NESCOE, as it had agreed to in the FERC-approved First CapEx Settlement Agreement, submitted a notice that it was withdrawing its October 17, 2022 Formal Challenge No. III.A to the 2022 Informational Filing (its challenge that the 2023 CapEx Projects were unsupported). FERC action on the Second CapEx Info Filing remains pending.

***(-014) Revised ROE (Sixth) Compliance Filing**.* Also still pending is Mystic's December 20, 2021 filing in response to the requirements of the *Mystic ROE Allegheny Order*.[35] 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*,[36] 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 is pending before the FERC. If you have questions on any aspect of these proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

[35] 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.

[36] *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).

- **Transmission Rate Annual (2024) Update/Informational Filing (ER20-2054-003)**

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 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 states that the annual updates results in a Pool "postage stamp" RNS Rate of $154.35/kW-year effective January 1, 2024, an increase of $12.71 /kW-year from the charges that went into effect on January 1, 2023. In addition, the filing includes 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. Public comments on this filing were due on or before September 19, 2023; none were filed. MOPA filed a doc-less intervention.

The July 31 filing also triggered the commencement of an Information Exchange Period and a Review Period under the Protocols. Interested Parties had until September 15, 2023 to submit information and document requests, and the PTOs are required to make a good faith effort to respond to all requests within 15 calendar days, but by no later than October 15, 2023. During the Review Period, Interested Parties have until ***November 15, 2023*** to submit Informal Challenges to the PTOs, and the PTOs are required to make a good faith effort to respond to any Informal Challenges no later than December 15, 2023. Interested Parties have until ***January 31, 2024*** to file a Formal Challenge with the FERC.

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

On August 30, 2023, Versant submitted a Joint Offer of Settlement ("Versant MPD OATT 2022 Annual Update Settlement Agreement") between itself and the Maine Wholesale Customer Group, the Aroostook Energy Association, MOPA, and the Maine Public Utilities Commission (together, the "Maine Parties") which, if approved, would resolve all issues raised by the Maine Parties with regards to Versant's 2022 annual update to the transmission charges under the MPD OATT. Comments on the Versant MPD OATT 2022 Annual Update Settlement Agreement are due on or before September 20, 2023; none were filed. The Versant MPD OATT 2022 Annual Update Settlement Agreement is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@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[37] remains pending before the FERC. In the Challenge, RENEW asserted that (i) the TOs failed to provide adequate rate input information in the Annual Informational Filing and in the Information Exchange Period under the Interim Formula Rate Protocols regarding inclusion or exclusion of "O&M costs" on Network Upgrades that the TOs directly assign to Interconnection Customers (and thereby failing to demonstrate that such O&M costs are not being double counted in transmission rates); and (ii) the TO's Interpretation of "Interested Party" to exclude RENEW violated the Interim Formula Rate Protocols. RENEW thus asked that the FERC (a) require the TOs to show the calculation of the annual O&M charges with sources of data inputs and show how such O&M charges are not being double recovered in transmission rates, and (b) determine that an entity such as RENEW is an Interested Party under the Interim Formula Rate Protocols and that its Information Requests seeking rate inputs and support for the O&M charges on Network

[37] 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.

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, RENEW answered the comments and protests to its Challenge. Subsequently, on April 14, Eversource answered RENEW's March 31 answer. There was no activity since the last Report. This matter is pending before the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

- **Waiver Request: FCA18 Summer Qualified Capacity (Yarmouth 4) (ER23-2356)**

On September 14, 2023, the FERC granted the unopposed request by FPL Energy Wyman IV LLC ("Wyman IV") for a one-time waiver of the Tariff to allow an incremental increase in the summer Qualified Capacity at W.F. Wyman Station Unit 4 ("Yarmouth 4").[38] As previously reported, Wyman IV explained in its Waiver Request how, as a result of the failure by Yarmouth 4's Lead Market Participant (NextEra Energy Marketing, LLC ("NextEra EM")) to re-submit by the applicable April 6, 2023 FCA18 deadline a restoration plan related to a forced outage during Yarmouth 4's summer claimed capability audit,[39] Yarmouth 4's FCA18 Summer Qualified Capacity (for the 2027-2028 Capacity Commitment Period ("CCP 2027-2028")) was reduced to approximately 432 MW, rather than 595 MW, under the Tariff rules. The waiver allows ISO-NE to revise Yarmouth 4's Summer Qualified Capacity to reflect its higher capability consistent with the Tariff. In granting the Waiver, the FERC found that the request was prospective and met its criteria for granting waiver requests.[40] Unless the *Yarmouth IV Waiver Order* is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **IEP Parameter Updates (ER23-1588)**

On August 4, 2023, the FERC accepted ISO-NE and NEPOOL's proposed revisions to Appendix K to Market Rule 1 to update certain parameters within the Inventoried Energy Program ("IEP Parameter Updates").[41] Specifically, the IEP Parameter Updates: (i) replace the IEP's fixed rate with an indexed rate that automatically adjust to account for changes in gas markets prior to each winter period, (ii) modify natural gas contracting requirements to align the IEP more closely with common industry and commercial practices and the nature of firm pipeline service available in New England; and (iii) are meant to clarify and improve the administration of the IEP. The IEP Parameter Updates were accepted effective as of *August 4, 2023*.

Request for Rehearing. On September 5, 2023, Public Interest Organizations ("PIOs")[42] requested rehearing of the *IEP Parameter Updates Order*. The PIOs' request for rehearing is pending, with FERC action required on or before October 5, 2023, or the request will be deemed denied by operation of law. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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[38] *FPL Energy Wyman IV LLC*, 184 FERC ¶ 61,154 (Sep. 14, 2023) ("*Yarmouth IV Waiver Order*")

[39] Section III.13.4.2.1.3 of the Tariff allows adjustments for significant decreases to be made if the Lead Market Participant submits to ISO-NE a FCM Restoration Plan describing the measures taken to demonstrate "that the resource will be able to provide an amount of capacity consistent with its total CSO for the CCP by the start of all months in that CCP in which the resource has a CSO." ISO-NE must receive the Plan by no later than 10 Business Days after the Lead Market Participant is notified of the resource's Summer ARA Qualified Capacity and Winter ARA Qualified Capacity for ARA3.

[40] *Yarmouth IV Waiver Order* at PP 14-15. Commissioner Danly dissented, stating that "[t]he Commission is as powerless to grant this waiver as it is to travel back in time itself to ensure the deadline is met. Of the two options, at least time travel is legal." *Id.*, Danly, Commissioner, dissenting at P 2.

[41] *ISO New England Inc. and New England Power Pool Participants Comm*., 184 FERC ¶ 61,082 (Aug. 4, 2023) ("*IEP Parameter Updates Order*").

[42] "PIOs" are for purposes of this proceeding: the Sierra Club and Conservation Law Foundation ("CLF").

- **SATOA Revisions (ER23-739; ER23-743)**

The SATOA Revisions remain pending before the FERC.[43] On December 29, 2022, ISO-NE, NEPOOL and the PTO AC filed revisions to the Tariff and the TOA, in two parts, to enable electric storage facilities to be planned and operated as transmission-only assets ("SATOA") to address system needs identified in the OATT's regional system planning process ("SATOA Revisions"). The SATOA Revisions were supported by the Participants Committee at its October 6, 2022 meeting (Agenda Item #7). ISO-NE requested a FERC order by March 29, 2023 and indicated that it intends to implement the SATOA Revisions effective *July 1, 2024*. ISO-NE committed to submit a filing specifying the precise effective date prior to implementation. For eTariff reasons, Part I included the ISO-NE Tariff revisions (ER23-739); Part II, the TOA revisions (ER23-743). Comments on the SATOA Revisions were due on or before January 19, 2023.

On January 19, 2023, comments and protests were filed by: Advanced Energy United ("AEU"), FirstLight, National Grid, NEPGA, NESCOE, UCS, and VELCO. Doc-less interventions only were filed by Avangrid, Vistra, MA DPU, LSP Transmission Holdings, RENEW, RI Energy, ACPA, and EPSA. On February 3, 2023, NEPOOL answered VELCO's comments and ISO-NE answered VELCO's comments and National Grid's limited protest. NEPGA answered VELCO's comments and National Grid's limited protest on February 7. In turn, on February 16, National Grid answered NEPGA's and ISO-NE's answers. ISO-NE answered National Grid's February 16 answer.

Deficiency Letter; ***Response (-001)***. On May 15, 2023, FERC staff issued a deficiency letter requiring additional information to be submitted on or before June 14, 2023. ISO-NE filed its response to the Deficiency Letter in this proceeding on June 14, 2023, re-setting the filing date and deadline for FERC action. Comments on the Deficiency Letter response were due on or before ***July 5, 2023*** and were filed by Elevate Renewables F7, LLC ("Elevate Renewables"). Elevate Renewables urged the FERC to accept ISO-NE's filing as submitted, without condition or modification. On July 12, National Grid requested that the FERC reject Elevate Renewables' July 5 comments (as an impermissible, untimely answer to National Grid's January 19, 2023 pleading filing in this proceeding and as beyond the scope of the questions in or responses to the Deficiency Letter). Elevate Renewables answered National Grid's motion to reject on July 27, urging the FERC to reject that motion.

The SATO Revisions, including the Deficiency Letter and all of the pleadings filed in this proceeding are again pending before the FERC. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

[43] Because the SATOA Revisions are proposed to become effective June 1, 2024, the FERC, notwithstanding ISO-NE's request that it act earlier, is not under a statutory obligation to act before the proposed effective date.

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

In a lengthy compliance Order[44] issued March 1, 2023, the FERC approved in part, and rejected in part, ISO-NE, NEPOOL and the PTO AC's ("Filing Parties") *Order 2222* compliance filing[45] ("*Order 2222 Compliance Order*").[46]

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*:

- ***30-Day Compliance Requirements (-003)***. ISO-NE was directed to submit two filings by March 31, 2023. The first, a compliance filing to explain how current Tariff capacity market mitigation rules would apply to Distributed Energy Capacity Resources ("DECR") participating in FCA18. The second, an informational filing that provides an update on implementation timeline milestones associated with DECR participation in FCA18 and the other markets. Those compliance filings were submitted on March 31, 2023. Comments on the DECR compliance filing (ER22-983-003) were due on or before April 21, 2023; none were filed. The March 31 informational filing was not noticed for public comment. The DECR compliance filing is pending before the FERC.

- ***60-Day Compliance Filing (-004)***. In a 60-day compliance filing, the FERC ordered ISO-NE:
  - ♦ 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

[44] 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."

[45] 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.

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

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.

The 60-day compliance changes were filed on May 9, 2023, except for the requirement related to the submission of metering data, which is the subject of an ISO-NE rehearing request. Comments on the 60-day compliance filing were due on May 30, 2023 and were filed by NEPOOL (supplementing the record) and jointly by AEU/PowerOptions/SEIA ("AEU *et al*.") (who jointly protested what they asserted was a failure to make any adjustments to facilitate participation by DERs located behind a customer meter, and a failure to justify the metering and telemetry provisions as directed by the FERC). On June 14, 2023, ISO-NE answered the May 30 protest of AEU *et al*. On June 28, 2023, AEU *et al.* filed answer to ISO-NE's June 14 answer. The 60-day compliance changes are pending before the FERC.

- ***180-Day Compliance Filing (-005)***. On or before August 28, 2023, the FERC directed ISO-NE to file a further compliance filing explaining how the current Tariff capacity market mitigation rules would apply to DECRs participating in FCA19 and beyond.

  On August 28, 2023, ISO-NE and NEPOOL jointly filed the 180-day compliance changes ("Mitigation Compliance Revisions"). ISO-NE requested a March 1, 2024 effective date for the Mitigation Compliance Revisions. Further, ISO-NE asked that the FERC issue an order accepting the Mitigation Compliance Revisions no later than November 1, 2023 to allow sufficient time for implementation of the proposed revisions prior to the scheduled qualification process for FCA19. Also, consistent with the requests made in ISO-NE's Request for Rehearing and 30-Day Informational and Compliance Filing in this docket, ISO-NE proposed March 1, 2024 as the new effective date for the rules allowing DECRs to participate in the FCM. Comments on the Mitigation Compliance Revisions were due on or before September 18, 2023; none were filed. The Mitigation Compliance Revisions are pending before the FERC.

Requests for Rehearing and/or Clarification (-002). On March 31, 2023, ISO-NE and New England Public Utilities[47] requested rehearing and/or clarification of the *Order 2222 Compliance Order*. ***ISO-NE*** urged the FERC to reconsider allowing DECRs to participate in FCA18 and designating the DER Aggregator as the entity responsible for transmitting DERA metering data. ***New England Public Utilities*** urged the FERC to adopt the DER metering and settlement approach proposed by the Filing Parties (*Order 2222* Changes) and clarify (1) that PTOs and distribution utilities are not prohibited from requiring metering and settlement data from DERs to satisfy their obligations to perform wholesale settlement and retail customer billing and (2) that it would not be unjust and unreasonable for utilities to recover costs related to investment and expenses incurred to modify its metering, billing, settlement, cyber security and other systems, to accommodate submetering of Behind-the-Meter DER participating in the wholesale market as part of a DERA. On April 14, 2023, ***MA AG*** answered New England Public Utilities' request for rehearing and clarification and requested that the FERC address the recovery of costs necessary to implement Behind-the-Meter DER submetering and the allocation of costs to DER aggregators and program participants. On April 17, ***AEU*** answered ISO-NE's request for rehearing (urging the FERC to not reconsider its decision designating the DER Aggregator as the entity responsible for transmitting DERA metering data); ISO-NE answered the AEU answer on May 2, 2023. Answers to ISO-NE's March 31 request for rehearing were filed by May 5 by the ***MPUC*** (urging the FERC to consider ISO-NE's request to allow PTOs and distribution utilities to meter and transmit DERA

[47] "New England Public Utilities" are: National Grid USA on behalf of Massachusetts Electric Co., Nantucket Electric Co., and New England Power Co. ("NGUSA"); Avangrid Networks, Inc. on behalf of CMP and UI ("Avangrid Networks"); and Eversource on behalf of The Connecticut Light and Power Co. ("CL&P"), Public Service Co. of New Hampshire ("PSNH"), and NSTAR Electric Co. ("NSTAR").

data) and May 22 by NECPUC (who also supported ISO-NE's request regarding the entity responsible for transmitting DERA metering data to ISO-NE).

Order 2222 Compliance Allegheny Notice. On May 1, 2023, the FERC issued a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration".[48] That Notice confirmed that the 60-day period during which a petition for review of the *Order 2222 Compliance Order* 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 the *Order 2222 Compliance Order*. 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."

Federal Court (DC Circuit) Appeals. 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 will be reported on in Section XVI below.

If you have any questions concerning this matter, 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

- **Attachment F Corrections & Updates (ER23-2940)**

On September 28, 2023, the PTO AC filed proposed revisions to Attachment F of the OATT to correct minor errors in certain worksheets of the "Formula Rate Template" contained in Appendices A and B to Attachment F. The PTO AC stated that the filing is limited to proposed Tariff revisions that fall within Moratorium Exception (i) subpart (o) of Attachment F and that the corrections and updates will not result in any additional costs being paid by New England ratepayers. An effective date of November 23, 2023 was requested. Comments on this filing are due on or before ***October 19, 2023***. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Versant Power Att. F App. D Depreciation Rate Change (ER23-2483)**

On July 26, 2023, Versant Power ("Versant") proposed updated depreciation rates for its local transmission facilities in eastern and coastal Maine (the "Bangor Hydro District" or "BHD") set forth in Appendix D to Attachment F of the ISO-NE OATT. A January 1, 2025 effective was proposed. On August 8, Versant supplemented its filing with exhibits that were inadvertently excluded from its initial filing. Comments on this filing were due on or before August 16, 2023; none were filed. There was no action on this matter since the last Report and this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- ***Order 676-J* Compliance Filings Part II (ER23-1771; ER23-1774; ER23-1782; ER23-1785)**

On May 1, 2023, in accordance with Order 676-J,[49] the following second *Order 676-J* compliance filings to incorporate, or seek waiver of, the remainder of the WEQ Version 003.3 Standards, were submitted:

  - Order 676-J Compliance Filing Part II (ISO-NE and NEPOOL-Tariff Schedule 24) (ER23-1771);
  - Order 676-J Compliance Filing Part II (CSC-Schedule 18-Attachment Z) (ER23-1774);
  - Order 676-J Compliance Filing Part II (Versant-MPD OATT) (ER23-1782); and

[48] *ISO New England Inc. and New England Power Pool Participants Comm.*, 183 FERC ¶ 62,050 (May 1, 2023) ("*Order 2222 Compliance Allegheny Notice*").

[49] *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-J, 175 FERC ¶ 61,139 (May 20, 2021) ("*Order 676-J*").

- Order 676-J Compliance Filing Part II (TOs'-Schedules 20A-Common and 21-Common) (ER23-1785).

Comments on the compliance filings were due on or before May 22, 2023; none were filed. These compliance filings remain pending before the FERC. If there are questions on any of these filings, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 881* Compliance Filing: New England (ER22-2357)**

On June 15, 2023, the FERC conditionally accepted the proposed revisions to the OATT in response to the requirements of *Order 881*[50] ("OATT *Order 881* Compliance Changes").[51] The OATT *Order 881* Compliance Changes were accepted effective as of *July 12, 2025*, subject to two compliance filings – on due on or before ***August 14, 2023*** (60-day compliance filing); the other, ***November 12, 2024*** (the AAR explanation filing). The 60-day compliance filing must (i) revise the Tariff to specify that transmission service at ISO-NE's seams use AARs as the basis for evaluation for near-term transmission service requests (or explain why ISO-NE should not be required to do so); (ii) revise the Tariff to include the examples listed in the FERC's *pro forma* Attachment M (or explain why ISO-NE should not be required to do so); (iii) remove proposed revisions to Schedule 18 excepting the Cross-Sound Cable from the requirements of *Order 881* (or explain why such changes should not be required); and (iv) revise the Tariff to require ISO-NE in a database that it maintains (rather than dividing responsibility between ISO-NE and transmission owners) to host all transmission line ratings, ratings methodologies, and exceptions or alternate ratings (or explain why they should not be required to do so). The AAR explanation filing must explain the timelines for calculating or submitting AARs.

(-001) 60-Day Compliance Changes. On August 14, 2023, ISO-NE, NEPOOL, the PTO AC, and CSC jointly filed revisions to Section II of the OATT in response to the requirements of the *New England Order 881 Compliance Order.* The further compliance changes (i) clarify that ISO-NE will use AARs at its seams; (ii) reinsert the list of exceptions in Attachment Q, and specify that the specific criteria for determining whether a transmission line is eligible for an exception will be detailed in ISO-NE's Planning and Operating Procedures; (iii) remove revisions to Schedule 18 proposed to except CSC from the requirements of *Order 881*; and (iv) modify both Attachment Q to the ISO OATT and Attachment M to Schedule 21-Common to require that ISO-NE host all ratings, ratings methodologies, and exceptions in its database. Comments on the further compliance changes were due on or before September 5, 2023; none were filed. The *Order 881* 60-Day Compliance Changes are pending before the FERC.

If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

No Activities to Report

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

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

On September 11, 2023, ISO-NE and New England Power ("National Grid") filed a 20-year Local Service Agreement ("LSA") by and among National Grid, ISO-NE and Green Mountain Power ("GMP").[52] The filing

[50] *Managing Transmission Line Ratings*, Order No. 881, 177 FERC ¶ 61,179 (Dec. 16, 2021); *Managing Transmission Line Ratings*, Order No. 881-A, 179 FERC ¶ 61,125 (May 19, 2022) (together, "*Order 881*").

[51] *ISO New England Inc.*, 183 FERC ¶ 61,180 (June 15, 2023) ("*New England Order 881 Compliance Order*").

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

parties stated that the LSA conforms to the *pro forma* LSA contained in the ISO-NE Tariff and supersedes and replaces another conforming LSA among ISO-NE, NEP, and GMP that lists an expiration date of September 30, 2022 (TSA-NEP-25). The LSA was filed separately given the requested effective date (October 1, 2022). Comments on the LSA filing were due on or before October 2, 2023; none were filed. The LSA is 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: 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").[53] 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 refund requirement.[54] 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 is 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. MPUC intervened doc-lessly on September 15, 2023. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activities to Report

VIII. Regional Reports[55]

- **Capital Projects Report - 2023 Q2 (ER23-2620)**

On August 11, 2023, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the second quarter ("Q2") of calendar year 2023 (the "Report"). ISO-NE is required to file the Report under section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Report highlights include the following new projects: (i) nGEM Software Development Part III ($4.5 million); (ii) IMM Data Analysis Phase IV ($1.2 million); (iii) Energy Management System Short-term Load Forecast Replacement ($1.2 million); (iv) Elimination of Minimum Offer Price Rule ($528,600); (v) Energy Management System Host Monitoring Software Replacement ($280,600); and (vi)

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

[54] 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.

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

Market Information Server Reporting by Sub-Accounts ($276,000). Projects with a significant change (amounts returned to the Emerging Work Fund) were (i) Solar Do-Not-Exceed Dispatch Phase II ($144,100); (ii) Forecast Enhancements ($173,000); and (iii) Windows Server 2019R2 Deployment Phase I ($185,500). Comments on this filing were due on or before September 1, 2023. NEPOOL filed comments supporting the 2023 Q2 Report. Eversource and National Grid filed doc-less interventions only. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **Reserve Market Compliance (35th) Semi-Annual Report (ER06-613)**

As directed by the original ASM II Order,[56] as modified,[57] ISO-NE submitted its 35th semi-annual reserve market compliance report on September 29, 2023. In the 35th report, ISO-NE stated that it "The ISO is currently discussing with stakeholders the development of Day-Ahead Ancillary Services ("DASI"), and it anticipates filing proposed market design changes on or around October 31, 2023, including a ten-minute spinning reserve product procured in the Day-Ahead market, which should satisfy the region's need for a forward TMSR market." The ISO committed to continue to update the FERC on the progress of the DASI project and its relation to a forward TMSR market through future reports in this docket. The September 29 report will not be noticed for public comment. If there are questions on this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

IX. Membership Filings

- **October 2023 Membership Filing (ER23-2966)**

On September 29, 2023, NEPOOL requested that the FERC accept: (i) the following Applicants' membership in NEPOOL: KCE CT 10, LLC and KCE CT 11, LLC [Provisional Members, Related Persons to KCE CT 5, LLC et al. (AR Sector, Distributed Generation Sub-Sector)]; and Sierra Club (effective *December 1, 2023*, End User Sector); and (ii) the termination of the Participant status of BP Energy Holding Company [Related Person to BP Energy Company et al. (Supplier Sector)]. Comments on this filing are due on or before ***October 20, 2023***.

- **September 2023 Membership Filing (ER23-2756)**

On August 31, 2023, NEPOOL requested that the FERC accept: (i) the following Applicant's membership in NEPOOL: Phoenix Energy Group, LLC (Supplier Sector); and 3Degrees Group, Inc. (GIS-Only Participant); (ii) the termination of the Participant status of: Just Energy (U.S.) Corp. [Related Person to Just Energy Limited and Hudson Energy Services (Supplier Sector)]; NRG Power Marketing LLC, Norwalk Power LLC and Somerset Power LLC [all Related Persons to NRG Business Marketing et al. (Supplier Sector)]; and WP&G Holdings, LLC (Supplier Sector); and (iii) the Name Change of NRG Business Marketing, LLC (f/k/a Direct Energy Business Marketing, LLC). Comments on this filing were due on or before September 21, 2023; none were filed. This matter is pending before the FERC.

- **August 2023 Membership Filing (ER23-2514)**

On September 29, 2023, the FERC accepted the NEPOOL membership of Clover Energy LLC (Supplier Sector).[58] Unless the September 29 order is challenged, this proceeding will be concluded.

[56] *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).

[57] *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")).

[58] *New England Power Pool Participants Comm.*, Docket No ER23-2514-000 (Sep. 29, 2023) (unpublished letter order).

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

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).

- **NERC Report on Evaluation of Physical Reliability Standard (CIP-014) (RD23-2)**

As directed by the FERC's December 15, 2022 order,[59] NERC, on April 14, 2023, provided an updated evaluation of CIP-014 (its "Physical Security Reliability Standard"). NERC concluded that CIP-014 applicability criteria is meeting its objective to "appropriately focus[] limited industry resources on risks to the reliable operation of the BPS associated with physical security incidents at the most critical facilities" and the objective is broad enough to capture the subset of applicable facilities that TOs should identify as "critical" pursuant to the risks assessment mandated by Requirement R1. NERC did not find evidence that an expansion of the applicability criteria would identify additional substations that would qualify as "critical" substations under the CIP-014 Requirement R1 risk assessment, declined to recommend expansion of the CIP-014 applicability criteria, but committed to continued evaluation of the adequacy of the applicability criteria in meeting the objective of CIP-014. Comments on NERC's report were due on or before May 15, 2023 and were filed by, among others: ISO-NE, Trade Associations, and WIRES.

August 10, 2023 Joint Technical Conference. On August 10, 2023, FERC and NERC staff convened an in-person technical conference at NERC's headquarters in Atlanta, GA. The conference discussed physical security of the Bulk-Power System ("BPS"), including the adequacy of existing physical security controls, challenges, and solutions. Speaker materials are posted in the FERC's eLibrary. Those interested were invited to file post-technical conference comments to address issues raised during the technical conference. Those submitting comments included: AEP, PJM, EEI, Electricity Canada, EPSA, Foundation for resilient Societies ("FRS"), Criticality Services, Grid Coalition, ITC, North American Transmission Forum ("NATF"), Secure the Grid, L. Fitzgerald, T. Holiday, and S. Naumann. On October 3, the FERC posted in eLibrary a final transcript of the August 10 joint technical conference.

- **Inverter-Based Resource Registration (RD22-4)**

As directed in the FERC's order accepting NERC's work plan to address registration of Inverter-Based Resources ("IBRs") that are connected to the BPS but not within NERC's definition of the bulk electric system ("non-BES IBRs"),[60] NERC filed on August 16, 2023, its first progress update on activities by the ERO Enterprise (NERC and the Regional Entities) to execute the Work Plan and initiate revisions to the NERC Registry Criteria to register owners and operators of non-BES IBRs that, in the aggregate, have a material impact on BPS reliability. NERC reported on its plans to post proposed Registry Criteria revisions on the NERC website for a 45-day formal comment in early September. On August 31, 2023, APPA filed comments on the IBR Work Plan Update.

- **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"))[61] on September 15, 2023. Project 2016-02 focuses on modifications to the CIP Reliability Standards to incorporate applicable protections for virtualized environments. In the September 15 report, NERC reported that, because ballot body

[59] *N. Amer. Elec. Rel. Corp.*, 181 FERC ¶ 61,230 (Dec. 15, 2022).

[60] *N. Amer. Elec. Rel. Corp.*, 183 FERC ¶ 61,116 (May 18, 2023) ("*IBR Work Plan Order*") (requiring NERC to file progress reports every 90 days detailing the progress towards identifying and registering owners and operators of unregistered IBRs).

[61] 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.

approval was again not achieved for two related Reliability Standards, the schedule for Project 2016-02 has been further revised and now calls for final balloting of revised standards in November 2023, NERC Board of Trustees Adoption in December 2023 and filing of the revised standards with the FERC in January 2024.

- **NOPR: IBR Reliability Standards (RM22-12)**

On November 17, 2022, the FERC issued a notice[62] proposing to direct NERC (i) to develop new or modified Reliability Standards that address the following reliability gaps related to IBRs: data sharing; model validation; planning and operational studies; and performance requirements; and (ii) to submit a 90-day compliance filing that includes a detailed, comprehensive standards development and implementation plan to ensure all new or modified Reliability Standards necessary to address the IBR-related reliability gaps identified in the final rule are submitted to the FERC within 36 months of FERC approval of the plan. Initial comments were due February 6, 2023[63] and were filed by nearly 20 parties, including, among others, ISO-NE, the IRC, SPP, CAISO, Advanced Energy United, ACPA/SEIA, EEI, and EPRI. Reply comments were due on March 6, 2023 and were filed by ISO-NE, APPA, and CA DWP. This matter is pending before the FERC.

- **Changes to NERC ROPs (RR23-4)**

On September 15, 2023, NERC proposed revisions to its Rules of Procedure ("RoPs") regarding Reliability Standards (specifically, Section 300 (Reliability Standards Development) and Appendix 3A (Standard Processes Manual)). The proposed revisions include new rules and authorities by which the NERC Board of Trustees may direct the development of needed Reliability Standards on its own initiative, subject to FERC approval. The proposed revisions also include streamlined comment and ballot procedures for draft Reliability Standards, as well as revisions that would both allow NERC the flexibility to implement the streamlined comment and ballot procedures proposed in the petition and consider other streamlining enhancements that may be appropriate and consistent with a fair and open process in the future. Comments on the proposed revisions to NERC's RoPs are due on or before ***October 6, 2023***.

- **2024 NERC/NPCC Business Plans and Budgets (RR23-3)**

On August 24, 2023, NERC submitted its proposed Business Plan and Budget, as well as the Business Plans and Budgets for the Regional Entities, including NPCC, for 2024. FERC regulations[64] require NERC to file its proposed annual budget for statutory and non-statutory activities 130 days before the beginning of its fiscal year (January 1), as well as the annual budget of each Regional Entity for their statutory and non-statutory activities, including complete business plans, organization charts, and explanations of the proposed collection of all dues, fees and charges and the proposed expenditure of funds collected. NERC reports that its proposed 2024 funding requirement represents an overall increase of approximately 12.5% over NERC's 2023 funding requirement. The NPCC U.S. allocation of NERC's net funding requirement is $12.26 million. NPCC has requested $22.01 million in statutory funding (a U.S. assessment per kWh (2022 NEL) of $0.000021) and $1.15 million for non-statutory functions. No comments related to NPCC were filed. This matter is pending before the FERC.

- **Report of Comparisons of 2022 Budgeted to Actual Costs for NERC and the Regional Entities (RR23-2)**

On May 31, 2023, NERC filed its annual comparisons of actual to budgeted costs for 2022 for NERC and the six Regional Entities operating in 2022,[65] 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 2020

[62] *Reliability Standards to Address Inverter-Based Resources*, 181 FERC ¶ 61,125 (Nov. 17, 2022) ("*IBR NOPR*").

[63] The *IBR NOPR* was published in the *Fed. Reg.* on Dec. 6, 2022 (Vol. 87, No. 233) pp. 74,541-74,563.

[64] 18 CFR § 39.4(b) (2014).

[65] 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").

budgets and actual results. Comments on this filing were due on or before June 21, 2023; none were filed. This matter is pending before the FERC.

XI. Misc. - of Regional Interest

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

On July 28, 2023, the FERC authorized[66] the disposition and consolidation of jurisdictional facilities and the lease of an existing generation facility that will result from the commencement of a master lease agreement ("Lease") between Three Corners Solar, LLC ("Lessor") and Three Corners Prime Tenant, LLC ("Lessee") pursuant to which Lessee will lease, operate, and control an approximately 112 MWac solar photovoltaic ("PV") electric generation facility owned by Lessor in Kennebec County, Maine (the "Transaction"). 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).

- **203 Application: Energy Harbor / Vistra (EC23-74)**

On April 17, 2023, Energy Harbor Corp., on behalf of Energy Harbor, LLC and Energy Harbor Nuclear Generation LLC (collectively, the "Energy Harbor Public Utilities"), and Vistra Corp. ("Vistra"), requested FERC authorization for a proposed transaction pursuant to which the Energy Harbor Public Utilities and certain Vistra subsidiaries that are public utilities will become indirectly owned by a newly-formed subsidiary holding company of Vistra – Vistra Vision. Comments on this 203 application were due on or before June 23, 2023. Protests and comments were filed by Northeast Ohio Public Energy Council ("NOPEC"), Office of the Ohio Consumers' Counsel ("OH OCC"), and Monitoring Analytics, LLC (the PJM IMM). Public Citizen filed a doc-less intervention. Vistra and the Energy Harbor Public Utilities responded to the protests and comments. Answers to that answer were filed by PJM's IMM. Comments were filed by the Justice Department's Antitrust Division on August 22; Vistra and Energy Harbor answered those comments on September 5.

Deficiency Letter. on August 17, 2023, the FERC issued a deficiency letter identifying the additional information that it needs to process the application. Vistra and Energy Harbor responded to the deficiency letter on September 18, 2023 ("Deficiency Letter Response"). The Deficiency Letter Response constituted an amendment to the application. Comments on the Deficiency Letter Response are due on or before ***October 10, 2023***. Thus far, comments have been filed by NOPEC and OH OCC.

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

- **PURPA Enforcement Petition: Allco Finance Limited (VT PUC) (EL23-84)**

On August 14, 2023, Allco Finance Limited ("Allco") petitioned the FERC to initiate an enforcement action against the Vermont Public Utility Commission ("VT PUC") to remedy what it asserts is the VT DPUC's improper implementation of PURPA. Allco states that the VT PUC has implemented a state law that (i) purports to redefine the size of a Qualifying Facility ("QFs") under PURPA in Vermont, (ii) bars the use of the FERC's least-cost interconnection cost responsibility for a QF's interconnection cost, and (iii) empowers the VT DPUC to exclude all non-hydroelectric QFs greater than 2.2 MW from participating in solicitations for energy and capacity for Vermont's utilities. VT PUC filed a doc-less intervention. On August 24, 2023, VT PUC requested an extension of time to answer the Allco complaint. On August 30, 2024, the FERC granted VT PUC an extension of time, to September 15, 2023, to answer the complaint. On September 14, 2023, VT PUC answered the Allco Complaint. 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).

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

- **PURPA Enforcement Petition: Allco Finance Limited (MA State Agencies) (EL23-84)**

As explained below, the FERC has decided not to act on Allco's MA State Agencies Enforcement Petition. As previously reported, Allco petitioned the FERC on July 24, 2023, to initiate an enforcement action against the Massachusetts DPU and DOER (collectively, the "MA State Agencies") to remedy what it asserts if the MA State Agencies' improper implementation of PURPA. Allco states that the MA State Agencies have implemented a state law that empowers the MA State Agencies to compel wholesale energy transactions outside the confines of PURPA, and that empowers those Agencies to exclude all QFs from participating in solicitations for energy and capacity for Massachusetts utilities. Doc-less interventions were filed by MA DOER, MA DPU, HQUS, MOPA, NEPGA, Public Citizen, MA AG, National Grid, and NECEC Transmission LLC.

On August 14, 2023, MA State Agencies filed a Joint Motion for Extension of Time to file comments, from August 14, 2023 to October 23, 2023 (stating that additional time was needed to consult with the MA AG). On August 21, the FERC issued a notice extending the comment deadline only to August 24, 2023. Accordingly, on August 24, MA State Agencies protested Allco's complaint. Protests were also filed by NECEC Transmission, and the Maine Office of Public Advocate ("MOPA").

FERC Notice of Intent Not to Act. On September 22, 2023, the FERC issued a notice of its intent not to initiate an enforcement action in response to the Allco MA State Agencies PURPA Complaint.[67] The FERC's decision not to act means that Allco may itself bring an enforcement action against the MA State Agencies in the appropriate court.[68] If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement Amendment: PSNH/NECEC (ER23-2645)**

On August 17, 2023, Public Service Company of New Hampshire ("PSNH") filed an amendment to the First Engineering, Design and Procurement Agreement ("D&E Agreement") with NECEC Transmission LLC ("NECEC") that was accepted by the FERC as Service Agreement No. IA-PSNH-13. The revised D&E Agreement sets forth the terms and conditions under which PSNH was to undertake certain design and engineering activities for the mitigation of violations identified in the preliminary initial interconnection analysis summary for NECEC's proposed 1,200 MW high-voltage direct current ("HVDC") line from Québec to Lewiston, ME (Queue Position #979). PSNH requested an August 18, 2023 effective date. Comments on this filing were due on or before September 7, 2023; none were filed. National Grid filed a doc-less motion to intervene. 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: RIE/ISO-NE/RISEC & Tiverton (ER23-2494, ER23-2491)**

On September 19, 2023, the FERC accepted,[69] effective January 1, 2023, the following two revised LGIAs filed by ISO-NE and Rhode Island Energy ("RIE") to reflect RIE as the new Interconnecting Transmission Owner:

  - **ER23-2494**: Second Revised LGIA that governs the interconnection of Rhode Island State Energy Center, LP's ("RISEC") 209 MW facility located in Johnston, RI; and
  - **ER23-2491:** First Revised LGIA that governs the interconnection of Tiverton's 305 MW generating facility located in Newport County in Tiverton, RI.

Unless the September 19 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).

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[67] *Allco Finance Ltd. v. Mass. Dept. of Pub. Utils. and Mass. Dept. of Energy Resources*, 184 FERC ¶ 61,192 (Sep. 22, 2023).

[68] 16 U.S.C. § 824a-3(h)(2)(B).

[69] *ISO New England Inc.*, Docket No. ER23-2494-000 (Sep. 19, 2023) (unpublished letter order); *ISO New England Inc.*, Docket No. ER23-2491-000 (Sep. 19, 2023) (unpublished letter order).

- **Changes to Depreciation Rates in MPD OATT Formula Rate (ER23-2085)**

On June 7, 2023, Versant Power filed a revised Attachment J to its OATT for Maine Public District (the "MPD OATT") to (i) revise its Transmission Plant depreciation rates to reflect a recent depreciation study; and (ii) harmonize the General Plant depreciation rates set forth the MPD OATT with those recently approved by the MPUC for distribution ratemaking purposes. Versant requested a June 1, 2024 effective date (which is the first date of the next rate year under the MPD OATT formula rate), but action on the filing by August 7, 2023. Comments on this filing were due on or before June 28, 2023 and were filed by the Maine PUC. Versant answered the June 28 comments of the Maine PUC on July 13, 2023, and the Maine PUC answered Versant's July 13, 2023 comments on July 18, 2013. On July 31, 2023, Versant Power asked the FERC to delay action on this filing until ***October 9, 2023*** to allow for a possible resolution of the MPUC's questions and concerns.

On September 11, 2023, Versant submitted supplemental information that, as a result of bilateral discussions with the MPUC, the only intervenor in this proceeding, MPUC's concerns with respect to the Depreciation Rate changes to the MPD OATT have been satisfied. For its part, the MPUC, on September 26, 2023, withdrew its June 28, 2023 comments. Accordingly, this now unopposed matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LSAs: RI Energy/ISO-NE/BIPCO (ER23-1003; ER23-1000)**

On January 31, 2023, ISO-NE and RIE filed two Local Service Agreements ("LSAs"), as replacements to two current New England Power TSAs (TSA-NEP-83 and TSA-NEP-86), to allow RI Energy to fully recover the Block Island Transmission System ("BITS") surcharge now that it is both Transmission Owner and Customer under these arrangements. On March 31, 2023, the FERC conditionally accepted the LSA replacing TSA-NEP-86 (ER23-1003), effective January 1, 2023, [70] and directed RI Energy, on or before May 1, 2023, to add language to the LSA to make explicit that the BITS Surcharge shall be subject to the Protocols for Schedule 21-RIE. That compliance filing was submitted on May 1, 2023 as directed. Also on March 31, 2023, FERC also issued a deficiency letter asking for additional information regarding whether the LSA replacing TSA-NEP-83 (ER23-1000) is subject to the Schedule 21-RIE Protocols. The response to the deficiency letter was also filed, as directed, on May 1, 2023. Comments on both May 1 filings were due on or before May 22, 2023. On May 22, RI Division of Public Utilities and Carriers ("RI Division") filed a protest requesting that the FERC reject RIE's May 1 compliance filing and direct it to amend the TSA to incorporate the formula rate protocols contained in ISO-NE OATT Attachment F, Appendix C (ER23-1003). No comments on RIE's May 1 deficiency letter response were filed (ER23-1000-001). On June 27, ISO-NE and RIE filed a joint motion requesting the FERC hold both proceedings in abeyance to allow RIE to continue discussions with the RI Division to resolve concerns raised by the Division, the resolution of which will affect the LSAs. RIE continues to seek January 1, 2023 as the effective date for the LSAs. There has been no activity in this proceeding since ISO-NE and RIE asked that the proceedings be held in abeyance. If you have any questions, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **VEC-HQUS Use Rights Transfer Agreement (NJ23-12)**

On September 27, 2023, the FERC accepted VEC's filing of Agreement for the Transfer of Use Rights on the Phase I/II HVDC Transmission Facilities ("Transfer Agreement") between itself and HQUS.[71] The Transfer Agreement was accepted effective as of July 1, 2023. Unless the September 27 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).

[70] *ISO New England Inc.*, Docket No. ER23-1003-000 (Mar. 31, 2023) (unpublished letter order).

[71] *Vt. Elec. Coop., Inc.*, Docket No. NJ23-12-001 (Sep. 27, 2023) (unpublished letter order).

XII. Misc. - Administrative & Rulemaking Proceedings[72]

- **ACPA Petition for Capacity Accreditation Technical Conference (AD23-10)**

On August 22, 2023, the American Clean Power Association asked the FERC to convene a technical conference "to explore ways to improve the accreditation of resources' capacity value in ISO/RTO regions with and without capacity markets, as well as in non-ISO/RTO regions. Comments on the ACPA request were due on or before October 2, 2023. The IRC opposed the ACPA request. Comments supporting, or not opposing, a technical conference were filed by, among others: ACRE, AEU, Calpine, Colorado PUC, EPSA, NYU Law School Policy Integrity Institute, Pine Gate Renewables, SCE, SEIA, Sierra Club, UCS, and University of Chicago Law School. This matter is pending before the FERC.

- **Interregional Transfer Capability Transmission Planning & Cost Allocation Requirements (AD23-3)**

On December 5-6, 2022, the FERC held a workshop to discuss whether and how the FERC could establish a minimum requirement for Interregional Transfer Capability for public utility transmission providers in transmission planning and cost allocation processes. Specifically, topics included: how to determine the need for and benefit of setting a minimum requirement for Interregional Transfer Capability; what to consider in establishing a potential Interregional Transfer Capability requirement, including who would be responsible for determining a minimum Interregional Transfer Capability requirement and what would be the objective and drivers of such a requirement; what process could be used in establishing a minimum Interregional Transfer Capability requirement to determine key data inputs, modeling techniques, and relevant metrics; and how costs for transmission facilities intended to increase Interregional Transfer Capability should be allocated and how to ensure a minimum amount of Interregional Transfer Capability is achieved and maintained. On February 28, 2023, the FERC invited all those interested to file post-workshop comments to address issues raised during the workshop and the questions listed in the workshop's Supplemental Notices issued on November 30 and December 2, 2022. Comments were due on or before May 15, 2023. Post-workshop comments were filed by, among others: Advanced Energy United ("AEU"), Invenergy, Vistra/NRG, ACPA, ACRE, APPA, ELCON, NRECA, Public Interest Orgs, Eastern Interconnection Planning Collaborative, and the US DOE. Reply comments were due on or before June 28, 2023 and were filed by, among others: AEP, AEU, Clean Energy Buyers Assoc., EEI, EPSA, ITC, MISO, NRDC, Vistra/NRG. Since the last Report, Commissioner Danly responded to US Senator Charles Shumer's June 20, 2023 letter addressing FERC's proposed rulemakings related to transmission planning and cost allocation. This matter is pending before the FERC.

- **New England Gas-Electric Forums (AD22-9)**

The Second New England Gas-Electric Forum (June 20, 2023 in Portland, ME). As discussed and summarized at the 2023 Summer Meeting, the FERC held on June 20, 2023, in Portland Maine, a second New England Winter Gas-Electric Forum to discuss possible solutions to the electricity and natural gas challenges facing the New England region. Pre-Forum Comments and Position Statements were filed by: ISO-NE (Ltr, Opening Presentation, Extreme Weather Risks), Constellation (Allen), Eversource (Daly, Divatia), NEPGA (Dolan), NextEra (Gardner), NHOCA, Vistra, NERC/NPCC, Excelerate, Orsted (DiOrio), National Grid (Holodak), Enbridge, Kinder Morgan, Berkshire Environmental Action Team, and Repsol.

On July 10, 2023, the FERC issued a notice inviting parties to submit comments regarding the topics discussed at the Second Forum. Comments were due by August 24, 2023 and were filed by, among others: NEPOOL, NESCOE, Acadia Center, AEU, Avangrid, Calpine, CLF/UCS/Sierra Club, Constellation, Eversource, FirstLight, Generation Bridge, IECG, LS Power, CT OCC, Maine OPA, MA AG, NH OCA, National Grid, NECOS, New England LDCs, New Leaf, PowerOptions, Public Systems, Repsol, RI Energy, VEIC, Maine PUC, MA DPU, EPSA,

[72] Reporting on the following Administrative proceeding has been suspended since the last Report and will be continued if and when there is new activity to report: Interregional HVDC Merchant Transmission (AD22-13); Transmission Planning and Cost Management Technical Conference (AD22-8); and Modernizing Electricity Market Design - Resource Adequacy (AD21-10).

INGAA, NGA, Berkshire Envir. Action Team, Fix the Grid Campaign, and Potomac Economics. A final transcript of the Forum was posted to eLibrary on July 21, 2023.

The First New England Gas-Electric Forum (September 8, 2022 in Burlington, VT). The purpose of the First Forum was to discuss and achieve a greater understanding among stakeholders in defining the electric and natural gas system challenges in the New England Region. Topics discussed included the historical context of New England winter gas-electric challenges, concerns and considerations for upcoming winters such as reliability of gas and electric systems and fuel procurement issues, and whether additional information or modeling exercises are needed to inform the development of solutions to these challenges. On September 21, 2022, the FERC invited parties wishing to submit comments regarding the topics discussed at the Forum to do so on or before November 7, 2022. Post-Forum Comments were submitted by: ISO-NE, Acadia, AEU, AIM, Calpine, Constellation, Excelerate, FirstLight, LS Power, NECOS, NEPGA, NESCOE, Public Systems, Repsol, TOs, VELCO, Vistra, Potomac Economics, CT DEEP, AEMA, APGA, EPSA, INGA, NE LDCs, NGSA, New England Council, NEPPA, NH BIA, PIOs, RENEW/ACPA, Berkshire Action Team, Greater Concord Chamber of Comm., Mass. Alliance for Econ. Dev., Mass. Business Roundtable, Mass. Coalition for Sustainable Energy, Mass. United Assoc. of Journeymen, Middlesex County Chamber of Commerce, Public Citizen, Western Mass. Economic Dev. Council, and Individual Citizens (M. Axner, E. Blank, S. Botkin, D. Heimann, J. Krieger, B. Little, I. McDonald, J. Neville, W. Persons, R. Spector). On November 22, National Grid filed reply comments.

- **Joint Federal-State Task Force on Electric Transmission (AD21-15)**

As previously reported, a transcript of the last (7th) meeting[73] of the FERC-established Joint Federal-State Task Force on Electric Transmission ("Transmission Task Force" or "JFSTF") is posted in eLibrary.[74] In addition, on August 29, 2023, the FERC issued an order listing the state commission representatives who will serve on the Task Force, each for a one-year term, commencing September 1, 2023, and expiring August 31, 2024, including Commissioner Riley Allen (VT PUC) and Chair Marissa Gillett (CT PURA) from the NECPUC region.[75]

- **NOPR: Duty of Candor (RM22-20)**

On July 28, 2022, the FERC issued a NOPR[76] proposing to add a new section to its regulations to require that any entity communicating with the FERC or other specified organizations (e.g. ISO/RTOs, FERC-approved market monitors, NERC and its Regional Entities, or transmission providers) related to a matter subject to FERC jurisdiction submit accurate and factual information and not submit false or misleading information, or omit material information ("Duty of Candor Requirements"). An entity would be shielded from violation of the new regulation if it has exercised due diligence to prevent such occurrences. The FERC's current regulations prohibit, in defined circumstances, inaccurate communications to the FERC and other organizations upon which the FERC relies to carry out its statutory obligations. However, because those requirements cover only certain

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[73] Summaries of the first – sixth meetings of the Transmission Task Force can be found in previous Reports.

[74] *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).

[75] The 2023/24 State Commissioner Transmission Task Force members are: (1) Commissioner John Howard, NY PSC; (2) President Joseph Fiordaliso, NJ BPU; (3) Chair Andrew French, KS Corp. Comm.; (4) Chair Dan Scripps, MI PSC; (5) Commissioner Riley Allen, VT PUC; (6) Chair Marissa Gillett, CT PURA; (7) Commissioner Kimberly Duffley, NC Utils. Comm.; (8) Chair Tricia Pridemore, GA PSC; (9) Commissioner Darcie Houck, CA PUC; and (10) Chair Thad LeVar, Utah PSC. *Joint Federal-State Task Force on Electric Transmission*, 184 FERC ¶ 61,126 (Aug. 29, 2023) (Order on Nominations).

[76] *Duty of Candor*, 180 FERC ¶ 61,052 (July 28, 2022) ("*Duty of Candor NOPR*").

communications and impose a patchwork of different standards of care for such communications, the FERC believes that a broadly applicable duty of candor will improve its ability to effectively oversee jurisdictional markets. It further indicated that its proposed due 'diligence standard' and other limitations are intended to minimize the additional burdens to industry that come with the new Duty of Candor Requirements.

On September 1, 2022, Joint Associations[77] requested an additional month to submit comments.[78] On September 14, 2022, the FERC granted that request. Accordingly, initial comments were due November 11, 2022 and over 30 sets of comments were filed, including by: ISO-NE, ISO-NE IMM, ISO-NE EMM, PJM IMM, ABA, AGA, APGA, APPA, EEI, Energy Trade Associations, INGA, NGSA, Nodal Exchange, NRECA, State Agencies, US Chamber of Commerce, DE Riverkeeper Network, New Civil Liberties Alliance, and Nodal Exchange. The US Chamber of Commerce filed reply comments on December 12, 2022. There was no activity in the proceeding since the last Report. This matter is pending before the FERC.

- ***Order 897*: Extreme Weather Vulnerability Assessments (RM22-16; AD21-13)**

On June 15, 2023, the FERC adopted a reporting requirement[79] that directs transmission providers to file a one-time informational report describing their current or planned policies and processes for conducting extreme weather vulnerability assessments[80] (whether and how transmission providers establish a scope for their extreme weather vulnerability assessments, develop inputs, identify vulnerabilities and determine exposure to extreme weather hazards, estimate the costs of impacts, and develop mitigation measures to address extreme weather risks). Each transmission provider must file the one-time informational report required by *Order 897* on or before ***October 25, 2023***.[81]

- ***Order 2023*: Interconnection Reforms (RM22-14)**

On July 28, 2023, the FERC issued Order 2023,[82] its final rule on proposed reforms to the *pro forma* Large Generator Interconnection Procedures ("LGIP"), *pro forma* Small Generator Interconnection Procedures ("SGIP"), *pro forma* Large Generator Interconnection Agreement ("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;[83] (ii) increase the speed of

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[77] "Joint Associations" included the following trade associations on behalf of their respective members: the American Gas Assoc. ("AGA"), American Public Gas Assoc. ("APGA"), Interstate Natural Gas Assoc. of America ("INGA"), Edison Electric Institute ("EEI"), EPSA, Energy Trading Institute ("ETI"), Natural Gas Supply Assoc. ("NGA"), and Process Gas Consumers Group ("PGCG").

[78] The *Duty of Candor NOPR* was published in the *Fed. Reg.* on Aug. 12, 2022 (Vol. 87, No. 155) pp. 49,784-49,793.

[79] *One-Time Informational Reports on Extreme Weather Vulnerability Assessments; Climate Change, Extreme Weather, and Elec. Sys. Rel.*, Order No. 897, 183 FERC ¶ 61,192 (June 15, 2023) ("*Order 897*").

[80] The FERC defines an extreme weather vulnerability assessment as any analysis that identifies where and under what conditions jurisdictional transmission assets and operations are at risk from the impacts of extreme weather events, how those risks will manifest themselves, and what the consequences will be for system operations.

[81] *Order 897* was published in the *Fed. Reg.* on June 27, 2023 (Vol. 88, No. 122) pp. 41,477-41,499.

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

[83] 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 interconnection queue processing;[84] and (iii) incorporate technological advancements into the interconnection process.[85] Many of the reforms adopted in *Order 2023* closely track the reforms set out in the FERC's Notice of Proposed Rulemaking.[86] However, the FERC did revise aspects of the reforms.[87] *Order 2023* will become effective November 6, 2023,[88] which is 60 days from the September 6, 2023 publication of *Order 2023* in the *Federal Register* ("Publication Date").

Importantly, the FERC is requiring the submission of compliance filings within 90 calendar days of the Publication Date, or ***December 5, 2023*** (rather than the 180 days proposed in the NOPR). The FERC said it "believe[s] that it is important to implement this final rule in a timely manner, given the pressing need to reform the interconnection processes, as discussed in this final rule." The FERC went on to explain that, on the FERC-approved effective date of the transmission provider's compliance filing with this final rule, the transmission provider will commence the transition study process. After the conclusion of the transition study process, the transmission provider will begin the first standard cluster study process, and in its compliance filing, the transmission provider will indicate the number of calendar days after the conclusion of the transition study process when it will begin this first standard cluster study process (e.g., 30 calendar days after the conclusion of the transition study process).

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. Absent further changes to the compliance schedule, there will be much to accomplish in a relatively short amount of time.

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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.

[84] 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.

[85] 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.

[86] *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.

[87] 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.

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

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".[89] 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."

Requests for Extension of Time. As previously reported, PJM, MISO and SPP ("***Joint RTOs***") requested an extension of time, to at least 90 days after the FERC issues a substantive order addressing the arguments on clarification and rehearing, with a request that an order on that request be issued by September 27, 2023. At least as of the date of this report, the FERC has not taken any action on the Joint RTOs' request. In addition, since the last Report, ***NEPOOL*** requested on October 2, 2023 a 45-day extension of time, to January 19, 2024, to permit adequate regional stakeholder consideration of, input into, and a vote on ISO-NE's proposed *Order 2023* compliance filing. ***EEI*** on September 13, 2023, while supporting Joint RTOs' approach, proposed an alternative that would : extend the compliance deadline until the later of: (i) 90 days after the FERC issues a substantive order addressing arguments on clarification and rehearing (as requested by the Joint RTOs) or (ii) 180 days after Order 2023 was published in the *Federal Register*, or March 4, 2024. ***Joint California Utilities***[90] requested an extension of their deadline to 90 days following the FERC's approval of CAISO's compliance filing. The FERC has not acted (nor it is required to act) on any of the requests for extension of time.

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 895*: ISO/RTO Credit Information Sharing (RM22-13)**

On June 15, 2023, the FERC amended its regulations to require ISO/RTOs to have tariff provisions that permit credit-related information sharing with other ISO/RTOs to ensure that credit practices in those markets result in jurisdictional rates that are just and reasonable.[91] *Order 895* will not permit information sharing to be conditioned on the specific consent of the market participant, would permit the receiving ISO/RTO to use market

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

[90] "Joint California Utilities" are: Pacific Gas and Electric Co.; ("PG&E"), San Diego Gas & Electric Co. ("SDG&E"), and Southern California Edison Co. ("SCE").

[91] *Credit-Related Info. Sharing in Organized Wholesale Elec. Mkts*, Order No. 895, 183 FERC ¶ 61,193 (June 15, 2023) ("*Order 895*").

participant credit-related information received from another ISO/RTO to the same extent and for the same purposes that the receiving ISO/RTO may use credit-related information collected from its own market participants, and would not change the existing discretion an ISO/RTO has to act on credit-related information, regardless of the source of that information. The FERC stated that the ability of ISO/RTOs to share credit-related information among themselves will improve their ability to accurately assess market participants' credit exposure and risks related to their activities across organized wholesale electric markets and should also enable ISOs/RTOs to respond to credit events more quickly and effectively, minimizing the overall credit-related risks of unexpected defaults by market participants in organized wholesale electric markets. *Order 895* became effective *August 21, 2023*.[92] SPP asked for a 14-day extension of time for the submission of its compliance filing, which was granted since the last Report on September 8, 2023.[93] No other ISO/RTO requested an extension of time and their compliance filings are due on or before October 20, 2023. ISO-NE's proposed compliance changes will be acted on via the October 5 Consent Agenda (Item # 6).

- **NOPR: Transmission Siting (RM22-7)**

On December 15, 2022, the FERC issued a NOPR[94] proposing to revise its regulations governing applications for permits to site electric transmission facilities under section 216 of the FPA, as amended by the Infrastructure and Jobs Act. The *Transmission Siting NOPR* is intended to ensure consistency with the Infrastructure and Jobs Act's amendments to FPA section 216, to modernize certain regulatory requirements, and to incorporate other updates and clarifications to provide for the efficient and timely review of permit applications. Following a NARUC request for an extension of time granted by the FERC, comments on the *Transmission Siting NOPR* were due on or before May 17, 2023. Comments were filed by CLF, AL PSC, National Wildlife Federation Action Fund, National Wild Life Federation and State-Affiliated Organizations, AEU, CLF (May 16), NESCOE, ACPA, ACRE, Clean Energy Buyers Assoc., EDF, EEI/WIRES, Joint Consumer Advocates, Public Interest Organizations, SEIA, and US Chamber of Commerce. Commissioner Phillips' and each of the Commissioners' responses to Senator Schumer's and Senator Barrasso's letters have been posted to eLibrary. This matter is pending before the FERC.

- ***Transmission NOPR* (RM21-17)**

Following its ANOPR process,[95] the FERC issued on April 21, 2022 a NOPR[96] that would require public utility transmission providers to:

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[92] *Order 895* was published in the Fed. Reg. on June 22, 2023 (Vol. 88, No. 119) pp. 40,696-28,125.

[93] *See* Notice Granting Extension of Time to Submit Compliance Filing, *Credit-Related Info. Sharing in Organized Wholesale Elec. Mkts.*, Docket No. RM22-13-000 (Sep 8, 2023).

[94] *Applications for Permits to Site Interstate Electric Transmission Facilities*, 181 FERC ¶ 61,205 (Dec. 15, 2022) ("*Transmission Siting NOPR*").

[95] *See Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 176 FERC ¶ 61,024 (July 15, 2021) ("*Transmission Planning & Allocation/Generation Interconnection ANOPR*"). The FERC convened a tech. conf. on Nov. 15, 2021, to examine in detail the issues and potential reforms described in the *ANOPR*. Speaker materials and a transcript of the tech. conf. are posted in FERC's eLibrary. Pre-technical conference comments were submitted by over 175 parties, including by: NEPOOL, ISO-NE, AEU, Anbaric, Avangrid, BP, CPV, Dominion, EDF, EDP, Enel, EPSA, Eversource, Exelon, LS Power, MA AG, MMWEC, National Grid, NECOS, NESCOE, NextEra, NRDC, Orsted, Shell, UCS, VELCO, Vistra, Potomac Economics, ACORE, ACPA/ESA, APPA, EEI, ELCON, Industrial Customer Orgs, LPPC, MA DOER, NARUC, NASUCA, NASEO, NERC, NRECA, SEIA, State Agencies, TAPS, WIRES, Harvard Electric Law Initiative; NYU Institute for Policy Integrity, New England for Offshore Wind Coalition, and the R Street Institute. *ANOPR* reply comments and post-technical conference comments were filed by over 100 parties, including: by: CT AG, Acadia Center/CLF, CT AG, Dominion, Enel, Eversource, LS Power, MA AG, MMWEC, NESCOE, NextEra, Shell, UCS, Vistra, ACPA/ESA, AEU, APPA, EEI, ELCON, Environmental and Renewable Energy Advocates, EPSA, Harvard ELI, NRECA, Potomac Economics, and SEIA. Supplemental reply comments were filed by WIRES, a group of former military leaders and former Department of Defense officials, and ACPA/AEU/SEIA.

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

(i) conduct long-term regional transmission planning on a sufficiently forward-looking basis to meet transmission needs driven by changes in the resource mix and demand;

(ii) more fully consider dynamic line ratings and advanced power flow control devices in regional transmission planning processes;

(iii) seek the agreement of relevant state entities within the transmission planning region regarding the cost allocation method or methods that will apply to transmission facilities selected in the regional transmission plan for purposes of cost allocation through long-term regional transmission planning;

(iv) adopt enhanced transparency requirements for local transmission planning processes and improve coordination between regional and local transmission planning with the aim of identifying potential opportunities to "right-size" replacement transmission facilities; and

(v) revise their existing interregional transmission coordination procedures to reflect the long-term regional transmission planning reforms proposed in this NOPR.

In addition, the *Transmission NOPR* would not permit public utility transmission providers to take advantage of the construction-work-in-progress ("CWIP") incentive for regional transmission facilities selected for purposes of cost allocation through long-term regional transmission planning and would permit the exercise of federal rights of first refusal ("ROFR") for transmission facilities selected in a regional transmission plan for purposes of cost allocation, conditioned on the incumbent transmission provider with the federal ROFR for such regional transmission facilities establishing joint ownership of the transmission facilities. While the ANOPR sought comment on reforms related to cost allocation for interconnection-related network upgrades, interconnection queue processes, interregional transmission coordination and planning, and oversight of transmission planning and costs, the *Transmission NOPR* does not propose broad or comprehensive reforms directly related to these topics. The FERC indicated that it would continue to review the record developed to date and expects to address possible inadequacies through subsequent proceedings that propose reforms, as warranted, related to these topics.

A number of the elements of the *Transmission NOPR*, if adopted as part of a final rule, would result in some significant changes to how the region's transmission needs are identified, solutions are evaluated and selected, and costs recovered and allocated. A more fulsome high-level summary from NEPOOL Counsel of the *Transmission NOPR* was distributed to, and was reviewed with, the Transmission Committee.

Comments. Following a number of requests for extensions of time, comments on the *Transmission NOPR* were due August 17, 2022.[97] Nearly 200 sets of comments were filed, including comments by NEPOOL, ISO-NE, Acadia/CLF, Anbaric, AEU, Avangrid, BP, Dominion, Enel, Engie, Eversource, Invenergy, LSP Power, MOPA, MMWEC/CMEEC/NHEC/VPPSA, National Grid, NECOES, NESCOE, NextEra, NRG, Onward Energy, Orsted, PPL, Shell, Transource, VELCO, Vistra, ISO/RTO Council, NERC, US DOJ/FTC, MA AG, State Agencies, VT PUC/DPS, Potomac Economics, ACPA, ACRE, APPA, EEI, EPSA, Industrial Customer Organizations, LPPC, NASUCA, NRECA, Public Interest Organizations, SEIA, TAPS, WIRES, Harvard Electricity Law Initiative, New England for Offshore Wind, and the R Street Institute.

Reply Comments. Reply comments were due September 19, 2022. Nearly 100 sets of reply comments were filed, including by: ISO-NE, AEU, Anbaric, Avangrid, CT DEEP, Cypress Creek, Dominion, ENGIE, Eversource, Invenergy, LS Power, MA AG, NECOS, NESCOE, NextEra, Shell, Transource, UCS, ACPA, ACRE, APPA, EEI, Industrial Customer Organizations, LPPA, NRECA, Public Interest Organizations, R Street, and SEIA. On November 28, 2022, the New Jersey BPU moved to lodge its recently issued Board Order selecting transmission projects to be built pursuant to PJM's State Agreement Approach ("SAA") for the purpose of supporting New Jersey's offshore wind

[97] A July 27, 2022, request by the Georgia Public Service Commission ("GA PUC") for an additional 30 days of time to submit comments and reply comments was denied on Aug. 9, 2022.

("OSW") goals, the Brattle Group's SAA Evaluation Report, and PJM's SAA Economic Analysis Report, which it stated demonstrates that competitive transmission solicitations can provide significant value to consumers. In December 2022, the Harvard Electricity Law Initiative, and P. Alaama submitted further comments.

LS Power and NRG filed comments in this proceeding, as well as in (Transmission Planning and Cost Management Joint Federal-State Task Force on Electric Transmission) (AD22-8) and JFSTF proceeding (AD21-15). They asserted that the FERC "cannot sufficiently address the transmission planning issues raised in its Transmission NOPR without addressing the intertwined cost management issues raised in AD22-8-000 and during the October 6, 2022 Technical Conference in AD22-8.

This matter remains pending before the FERC. If you have any questions concerning the *Transmission NOPR*, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

(no activity to report)

Natural Gas-Related Enforcement Actions

- **Georgia-Pacific Crossett LLC (IN23-12)**
  On September 13, 2023, the FERC approved a Stipulation and Consent Agreement with Georgia-Pacific Crossett LLC ("GPC")[98] that resolved OE's investigation into whether GPC violated FERC statues and regulations in connection with the abandonment of the Crosett Pipeline. The Office of Enforcement determined that GPC abandoned the pipeline without prior FERC approval (contrary to the requirements of section 7(b) of the Natural Gas Act) and GPC's abandonment application included inaccurate statements and omissions, including a false statement that the abandonment work would be undertaken in the future (even though it had already occurred). Under the Stipulation and Consent Agreement, in which GPC neither admits nor denies the alleged violations, GPC agreed to pay a ***$1.2 million civil penalty***. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

Procedural Schedule Suspended. As previously reported, on May 24, 2022, the Honorable Judge Karen Gren Scholer of the U.S. District Court for the Northern District of Texas ("Northern District") issued an order staying this proceeding. Consistent with that order and out of an abundance of caution, ALJ Joel DeJesus, who will be the presiding judge for hearings in this matter,[99] 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 Commission issued an Order on Presiding Officer Reassignment,[100] which (i) directed the Chief ALJ to reassign this proceeding to another ALJ not previously involved in the proceeding (i.e., designate a new presiding officer) once the *June 14 Order* takes effect; (ii) held that the *June 14 Order* will take effect once the Northern District clarifies or lifts its stay for the limited purpose of allowing the *June 14 Order* to take effect or the stay is lifted or dissolved such that hearing procedures may resume; and (iii) stated that this proceeding otherwise

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[98] *Georgia-Pacific Crossett LLC*, 184 FERC ¶ 61,151 (Sep. 13, 2023).

[99] 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.

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

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

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

On December 16, 2021, the FERC issued a show cause order[101] 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,[102] 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;[103] (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.[104] This matter is pending before the FERC.

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

On April 28, 2016, the FERC issued a show cause order[105] 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.[106]

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

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

[102] *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").

[103] 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.

[104] *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.

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

[106] 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.

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.[107] 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.[108]

On June 14, 2023, the Commission issued an Order on Presiding Officer Reassignment,[109] 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).

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.[110] 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

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

[108] *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).

[109] *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*").

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

equivalent to those in its precedent agreements, prior to commencing construction. The March 25, 2022 order also approved, as modified, Iroquois' proposed incremental recourse rate and incremental fuel retention percentages as the initial rates for transportation on the Enhancement by Compression Project.

- On April 18, 2022, Iroquois accepted the certificate issued in the *Iroquois Certificate Order*.
- On June 17, 2022, in accordance with the *Iroquois Certificate Order,* Iroquois submitted its Implementation Plan, documenting how it will comply with the FERC's Certificate conditions.
- In its September 8, 2023 monthly status report, Iroquois indicated that it is awaiting issuance of air permits from the New York State Department of Environmental Conservation and the Connecticut Department of Energy and Environmental Protection. Iroquois has not yet requested or received authorization to commence construction; accordingly, no construction activities were undertaken in August 2023 and no construction was planned for September.

XV. State Proceedings & Federal Legislative Proceedings

- **Maine - NECEC Transmission LLC et al. v. Bureau of Parks and Lands et al. (BCD-21-416)**

On August 30, 2022, the Maine Supreme Judicial Court concluded that the legislation enacted as a result of the passage of Maine's November 2, 2021 ballot question,[111] and that effectively halted construction of the NECEC Project,[112] was unconstitutional to the extent it required the legislation to be applied retroactively to the certificate of public convenience and necessity ("CPCN") issued for the Project if NECEC had acquired vested rights to proceed with Project construction (by undertaking substantial construction consistent with and in good-faith reliance on the CPCN before the Initiative was enacted). The Court remanded to the Business and Consumer Docket the factual question of whether NECEC performed substantial construction in good faith according to a schedule that was not created or expedited for the purpose of generating a vested rights claim (which it suggested appeared to be the case from the limited record developed in connection with the request for preliminary injunctive relief in this matter).

On April 20, 2023, after a week-long trial, a jury ruled 9-0 that developers had completed enough work in good faith before the passage of the ballot question to have a constitutional right to proceed with construction. Based on that verdict, a state judge is expected to conclude that the referendum was unconstitutional. The decision will almost certainly be appealed to the Maine Supreme Judicial Court for a final say.

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

[111] The ballot question, approved by 59% of Maine voters, which summarized the citizen's initiative pursued under Maine's constitutional provision for direct initiative of legislation (ME. Const. Art. IV, pt. 3, § 18), read: "Do you want to ban the construction of high-impact electric transmission lines in the Upper Kennebec Region and to require the Legislature to approve all other such projects anywhere in Maine, both retroactively to 2020, and to require the Legislature, retroactively to 2014, to approve by a two-thirds vote such projects using public land?"

[112] The New England Clean Energy Connect ("NECEC") project (the "NECEC Project") is designed to transmit power generated in Québec through Maine and into Massachusetts. The Project includes a new 145.3-mile, high-voltage direct current ("HVDC") transmission line, proposed to run from the Maine-Québec border in Beattie Township, ME to a new converter station in Lewiston, ME and from there to an existing substation by a new 1.2-mile, high-voltage alternating current transmission line.

NEPOOL has no organizational interest but that may be of interest to Participants. For further information on any of these proceedings, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Order 2222 Compliance Orders (23-1167, 23-1168, 23-1169, 23-1170)(consolidated)**
  Underlying FERC Proceeding: ER22-983[113]
  Petitioners: Eversource, ISO-NE, National Grid, and CMP/UI
  Status: Being Held In Abeyance Pending Further FERC Order on Rehearing in ER22-983

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*.[114] On July 3, 2023, the Court consolidated the cases, with Case No. 23-1667 as the lead case. On July 24, 2023, the FERC moved to have the consolidated cases held in abeyance pending the issuance of the Commission's further order on rehearing. The Court granted that motion on July 27, 2023, with the case to be held in abeyance pending further order of the Court. The parties were directed to file motions to govern future proceedings in this case by ***October 10, 2023***. Motions to intervene by non-appealing parties have been filed by Versant Power.

- **Seabrook Dispute Order (23-1094, 23-1215) (consolidated)**
  Underlying FERC Proceeding: EL21-6, EL 23-3[115]
  Petitioner: NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC
  Status: Briefing Underway

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.[116] NextEra subsequently petitioned the Court for review of the June 15, 2023 *Seabrook Dispute Allegheny*

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[113] *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*").

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

[115] *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*").

[116] 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.

Order, which was consolidated with Case No. 23-1094. As previously reported, initial submissions have been filed,[117] as have the Certified Index to the Record, NextEra's Petitioners' Brief, and the FERC's Brief (filed on September 28, 2023). Remaining submissions include: Intervenors for Respondent's Joint Brief (***October 12, 2023***); Petitioners' Reply Brief (***October 26, 2023***); Joint Appendix (***October 30, 2023***); and Final Briefs (***November 3, 2023***). The parties will be informed later of the date of oral argument and the composition of the merits panel.

- ***2nd Revised Narragansett LSA Orders*** **(22-1161, 22-1108) (consolidated)**
  Underlying FERC Proceeding: ER22-707[118]
  Petitioner: Green Development
  Status: Petitions for Review Denied; Mandate Issued

As previously reported, the DC Circuit issued an order on July 28, 2023 denying Green Development's petitions for review. The Court held that each of Green Development's four grounds for vacatur lacked merit. The formal mandate of the Court was issued on September 19, 2023, concluding this proceeding.

- **Mystic II (ROE & *True*-Up)**
  (21-1198; 21-1222, 21-1223, 21-1224, 22-1001, 22-1008, 22-1026) (consolidated)
  Underlying FERC Proceeding: EL18-1639-010, -011,[119] **-013**[120] **-017**[121]
  Petitioners: Mystic, CT Parties,[122] **MA AG, ENECOS**
  Status: Being Held in Abeyance; Motions to Govern Future Proceedings Due Oct 25, 2023

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*,

[117] Initial submissions include 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 (filed May 8, 2023), the Certified Index to the Record (filed July 21, 2023), and motions for leave to intervene (filed Apr. 14, 2023 by NECEC Transmission LLC and Avangrid, Inc. (collectively, "Avangrid") in support of the FERC).

[118] *ISO New England Inc. and New England Power Co. d/b/a National Grid*, 178 FERC ¶ 61,115 (Feb. 18, 2022) ("*2nd Rev Narragansett LSA Order*"). *ISO New England Inc. and New England Power Co. d/b/a National Grid*, 179 FERC ¶ 62,035 (Apr. 18, 2022) (notice of denial of rehearing by operation of law and providing for further consideration). Together, these orders referred to as the "*2nd Revised Narragansett LSA Orders*".

[119] *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).

[120] *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).

[121] *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*).

[122] In this appeal, "CT Parties" are the CT PURA CT PURA, Connecticut Department of Energy and Environmental Protection ("CT DEEP"), and the CT OCC.

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 July 24, 2023, Constellation reported that all parties agree and asked the Court that this case should remain in abeyance for an additional 90 days pending FERC action on remand in the *MISO TOs* case. On July 27, 2023, the Court issued an order that these cases remain in abeyance and that the parties file motions to govern future proceedings by ***October 25, 2023***.

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  Underlying FERC Proceeding: ER18-619[123]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF
  Status: Being Held in Abeyance (until March 1, 2024)

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

Petitioners have moved to hold this matter in abeyance three times. The Court has granted each request. The most recent request was submitted on July 22, 2022 (third abeyance request) and the Court granted a few days later the request to hold this matter in abeyance until March 1, 2024, the date on which the elimination of MOPR is to be implemented, with motions to govern due 30 days thereafter.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[124]
  Petitioners: TOs' (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[125] 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*[126] 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

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

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

[125] 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.

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

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 Commission remain ongoing and that this appeal should continue to remain in abeyance, was filed on August 3, 2023.

Other Federal Court Activity of Interest

- ***Northern* Access *Project (22-1233)***
  Underlying FERC Proceeding: *CP15-115*[127]
  Petitioners: Sierra Club
  Status: Oral Argument Held Sep 18, 2023; Awaiting Decision
  On September 6, 2022, the Sierra Club petitioned the DC Circuit for review of *Northern Access Project Add'l Extension Order*. Briefing is complete. Oral argument before Judges Henderson, Pan and Rogers was held on September 18, 2023. This matter is pending before the Court.

- ***Order 872* (20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[128]
  Petitioners: SEIA et al.
  Status: Decision Issued Granting in Part and Denying in Part SEIA's Petition
  On September 17, 2020, SEIA petitioned the 9th Circuit Court of Appeals for review of *Order 872*.[129] Briefing was completed and oral argument held March 8, 2022 before Judges Nguyen, Miller and Bumatay. On September 5, 2023, the Court issued a decision largely upholding *Order 872*. In its opinion, the 9th Circuit rejected Petitioners' objections to FERC's reforms, finding that PURPA provided the FERC discretion to construe PURPA and that FERC's interpretation of the statute in *Order 872* was reasonable and neither arbitrary nor capricious. The Court did agree, however, with the environmental organizations who joined the appeal that the FERC violated the National Environmental Policy Act ("NEPA") by failing to prepare an environmental assessment before issuing *Order 872*. Accordingly, the Court remanded the order without vacating it, directing the FERC to conduct a NEPA assessment. *Order 872* will remain in force while the FERC conducts the required NEPA assessment.

- **Algonquin Atlantic Bridge Project Orders (21-1115*, 21-1138, 21-1153, 21-1155 consol.)**
  Underlying FERC Proceeding: CP16-9-012[130]
  Petitioners: LS Power, Algonquin, INGA
  Status: Being Held in Abeyance; Motions to Govern Future Proceedings Due October 27, 2023
  As previously reported, Algonquin petitioned the DC Circuit, on May 3, 2021, for review of the *Briefing Order* and the *April 19 Notice of Denial of Rehearings by Operation of Law*. Appearances, docketing statements and a statement of issues were due and filed June 4, 2021. Also on June 4, 2021, the FERC filed an unopposed

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[127] *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 179 FERC ¶ 61,226 (June 29, 2022) ("*Northern Access Project Add'l Extension Order*").

[128] *Transcontinental Gas Pipe Line Co., LLC*, 159 FERC ¶ 62,181 (Feb. 3, 2017); *Transcontinental Gas Pipe Line Co., LLC*, 161 FERC ¶ 61,250 (Dec. 6, 2017).

[129] *Order 872* approved pricing and eligibility revisions to the FERC's long-standing regulations implementing sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), including: state flexibility in setting QF rates; a decrease (to 5 MW) to the threshold for a rebuttable presumption of access to nondiscriminatory, competitive markets; updates to the "One-Mile Rule"; clarifications to when a QF establishes its entitlement to a purchase obligation; and provision for certification challenges.

[130] *Briefing Order*; *April 19 Notice of Denial of Rehearings by Operation of Law.*

motion to hold this proceeding in temporary abeyance, until August 2, 2021, including the fling of the certified index to the record, because “the May 3 petition for review no longer reflects the [FERC]’s latest determination in this matter.” The Court granted the first abeyance motion. On November 15, 2021, the Court granted a third abeyance motion by the FERC, directing the parties to file motions to govern future proceedings by January 31, 2022. On January 31, 2022, Algonquin and INGA asked the Court to extend the abeyance by an additional 120 days (to May 31, 2022). On February 15, 2022, the Court issued an order extending the abeyance and directing the Petitioners to file motions to govern future proceedings by May 31, 2022. On May 31, 2022, Petitioners asked the Court to continue to hold this proceeding in abeyance pending the First Circuit’s disposition of Algonquin’s pending motions to transfer that Court’s cases 20-1458 and 22-1201 (which also challenge the FERC’s authorization of the “Atlantic Bridge Project”).

On June 30, 2022, the First Circuit transferred cases 20-1458 and 22-1201 to the DC Circuit. The DC Circuit docketed those cases as 22-1146 and 22-1147, consolidated them with its cases challenging the Atlantic Bridge Project orders (with 21-1115 remaining the lead case), and directed the parties to file a proposed briefing schedule. On July 19, 2022, the parties filed a proposal that cases 22-1146 and 22-1147 be severed, proposed a revised briefing format and schedule for those cases, and asked the Court to continue to hold the remaining cases in abeyance (asserting that abeyance may avoid the need for briefing and adjudication of the issues that Algonquin and INGAA would press).

As previously reported, briefing was completed in Cases 22-1146 and 22-1147 and oral argument held on April 20, 2023. Since the last Report, the DC Circuit issued an order dismissing both petitions for lack of jurisdiction. The remaining matters will be returned to active consideration.

Since the last Report, Petitioners requested and the Court ordered that the remaining consolidated cases remain in abeyance pending further order of the Court and directed the parties to file motions to govern future proceedings by ***October 27, 2023***.

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