NEW ENGLAND POWER POOL

Sebastian Lombardi
Secretary

July 27, 2023

VIA E-MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of August 3, 2023 Participants Committee Teleconference Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the August 2023 meeting of the Participants Committee will be held **via teleconference/Webex on Thursday, August 3, 2023, at 10:00 a.m.** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/. The dial-in number, to be used only by those who otherwise attend NEPOOL meetings and their approved guests, is **866-803-2146; Passcode: 7169224.** To join Webex, click this link and enter the event password **nepool**.

We hope all of you are enjoying your Summers and look forward to touching base virtually on August 3.

Respectfully yours,

/s/
Sebastian Lombardi, Secretary

FINAL AGENDA

1. To approve the draft minutes of the May 4 ~~and June 27-29, 2023~~ Participants Committee meeting. A copy of the draft minutes for the May 4 meeting, marked to show the changes since the initial notice, have 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 August CEO report is included with this supplemental notice.

4. To receive a report from the ISO Chief Operating Officer. The monthly (July) Operations Report will be circulated and posted in advance of the meeting.

5. To consider and take action, as appropriate, on the ISO's proposed compliance changes in response to FERC's June 15, 2023 order conditionally accepting New England's Order 881 (Managing Transmission Line Ratings) compliance filing. Materials regarding the ISO's proposed 60-day further compliance filing changes are included and posted with this supplemental notice.

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

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

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

8. Administrative matters.

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

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

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.

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held in person on Thursday, May 4, 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.

EXECUTIVE SESSION

VOTE ON SLATE OF CANDIDATES FOR ISO BOARD

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

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

> RESOLVED, that the Participants Committee endorses the slate of candidates for the ISO Board that has been recommended by the

Joint Nominating Committee and presented to the Participants Committee in executive session at this meeting.

Members were reminded to hold in confidence the identity of the slate, particularly its new non-incumbent candidate, until the ISO publicly announced the results of the Board's final election of the slate.

GENERAL SESSION

Following a short recess, the Committee came out of executive session at 10:55 a.m. and was joined by ISO representatives, State officials and guests. Mr. Cavanaugh welcomed the members, alternates, S~~s~~tate officials, and guests who were present.

APPROVAL OF APRIL 6, 2023 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the April 6, 2023 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of that meeting were unanimously approved as circulated, with an abstention on behalf of Mr. Sam Mintz noted.

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 on behalf of Mr. Mintz noted.

ISO CEO REPORT

In the absence of the ISO Chief Executive Officer, and in light of the fact that there had not been any Board or Board Committee meetings since the April 6 Participants Committee meeting, no CEO report was presented.

ISO COO REPORT

Operations Highlights Report

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by referring the Committee to his May operations report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through April 26, 2023, unless otherwise noted. The report highlighted: (i) Energy Market value for April 2023 was $242 million, down $148 million from the updated March 2023 value and down $349 million from April 2022; (ii) April 2023 average natural gas prices were 36% lower than March average prices; (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for April ($28.09/MWh) were 8% lower than March averages; (iv) average April 2023 natural gas prices and Real-Time Hub LMPs over the period were down 71% and 53%, respectively, from April 2022 average prices; (v) average Day-Ahead cleared physical energy during the peak hours as percent of forecasted load was 101.9% during April (up from 101.4% reported for March), with the minimum value for the month of 97.3% on Thursday, April 6, 2023; (vi) Daily Net Commitment Period Compensation (NCPC) payments for April totaled $113 million, which was down $0.3 million from March 2023 and down $1.1 million from April 2022. April NCPC payments, which were 0.5% of total Energy Market value, were compromised of ~~(a)~~ $1.1 million in first contingency payments (down $0.3 million from March); there were no second contingency, voltage or distribution payments in April.

Dr. Chadalavada reported that on Sunday, April 9, 2023, the region experienced record low demand (since load had been tracked on an hourly basis) for the second time in two years (6,814 MW between 2:00 and 3:00 pm). The record low illustrated, as described at previous Participants Committee meetings, how the pace of photovoltaic (PV) installations was surpassing forecasts and decreasing the demand for energy from the system. He noted his expectation that the record was not likely to last long, and could fall, depending on circumstances, as early as Fall 2023 or Spring 2024. In response to questions, he reported that the ISO forecasting team had been working to improve forecasting by offsetting the observed bias towards under forecasting of behind-the-meter PV output. He added that cloud forecasting had become as important as temperature and wind forecasting. The ISO's manager for forecasting had committed to discuss with the appropriate Technical Committee the ISO's observations and plans for addressing this nascent forecasting area.

Turning to outages, Dr. Chadalavada reported that there were two scheduled transmission outages on Line 373 (Deerfield-to-Scobie Pond) -- the first from May 11 to May 12; the second, June 12 to June 16 – for work on breakers along the line. There would also be two upcoming outages on the Algonquin pipeline -- the first from June 23 to July 18; the second from July 20 to August 25. He reported that the ISO had studied both of those Algonquin outages for the availability of alternative paths for gas to reach generators. Based on those studies, the ISO had concluded that there would be sufficient alternate paths during the outages, and thus no adverse impacts were expected from a bulk electric systems standpoint.

Dr. Chadalavada then addressed the Mystic Cost-of-Service Agreement (Mystic COS Agreement). He confirmed that the way in which the overall cost and impact of the Agreement to the region had materialized had been a function of mild weather and cargoes purchased at indexed global prices that were ultimately higher than local, New England market prices (with the differences being covered under the COS Agreement). Looking forward to year two of the Agreement, the ISO planned during the Fall consultation period with Constellation to discuss, with the benefit of analysis, data and lessons learned from the first year, and forecasts for the second year, whether, and what, models and/or processes might be employed to better minimize cost exposure to New England. Members thanked the ISO for the preliminary information provided. Continued concerns with the overall cost of the Agreement and its impact on ratepayers were expressed. A member encouraged the ISO, to the extent possible, to explore potential improvements over the entire contract term, rather than just the late Fall to Spring period. That member also requested any analysis regarding efforts that may have been made by Constellation to sell, rather than burn, the liquefied natural gas (LNG) procured under the Agreement. Dr. Chadalavada agreed to consider, investigate, and report back on the feasibility of that request, and committed to report back also on the outcome of the consultation process with Constellation.

WINTER 2022/23 REVIEW

Dr. Chadalavada then turned to and summarized the 2022/23 Winter Review circulated and posted with the meeting materials. He referred to the December 24 energy scarcity and February 3/4 cold snap events that had been addressed at length previously with the Committee. Responding to questions about oil replenishment, particularly in the absence of a specific winter reliability program, Dr. Chadalavada attributed the robust replenishment to (i) market prices, which made replenishment economic and (ii) a response to the December 24 scarcity event, which incented Market Participants to minimize their economic exposure by self-scheduling (affording the ISO more supply than it required to operate reliably). He also confirmed that, during the Winter 2022/23 period, send out from LNG providers totaled 4.2 Bcf, the majority of which, but not all, was delivered to pipeline generators. On February 3, 2023, the LNG send out exceeded the amount of natural gas scheduled to generators, allowing for additional generation resources to run on that day.

WINTER 2023/24 OUTLOOK SCENARIOS

Dr. Chadalavada then highlighted qualitative and quantitative aspects of three scenario assessments performed by the ISO (assuming mild, moderate and severe winter weather) to prepare for the upcoming winter. The assessments and assumptions were similar to those used for Winter 2022/23, with three notable differences: (i) a higher presumed volume of behind-the-meter (BTM) PV (approximately 6,400 MW), which would reduce energy demand on the system and make additional stored fuel available for peak usage; (ii) the inclusion of incremental fuel to be available as a result of the Inventoried Energy Program (IEP) (3 Bcf of LNG and 10 million gallons of fuel oil, though intentionally on the lower end of the estimates provided by the Analysis Group); and (iii) consistent with operational observations over the past few winters, the correlation of import levels to temperature (rather than assuming a constant level of imports during each hour of the period), with imports assumed to be 1,500 MW when temperatures dip below 20° F and between 3,000 to 4,000 MW when temperatures are above 20° F. Significant generator or transmission contingencies, while studied and the impacts well understood, were not assumed; outages across the fleet, at levels experienced historically, were included in the assumptions.

In both the mild and moderate winter scenarios, the ISO anticipated sufficient capacity and energy to meet expected peak loads and energy demand. In its severe winter scenario, the ISO expected capacity deficiency actions under OP-4 (during an approximately 3-5-day stretch during the 90 days), but did not expect OP-7 actions to be needed. He contrasted these expectations to those of Winter 2022/23, attributing the more positive outlook specifically to BTM PV, the IEP, and a relatively similar peak load forecast. Against these generally positive scenarios, Dr. Chadalavada cautioned the Committee that the scenarios were not guarantees and could quickly be undermined by events and circumstances determined at that point to be unlikely to occur. He stated that, while the ISO would remain vigilant to all such contingencies, it would focus its resources and efforts on reasonably foreseeable, though not all possible, events and circumstances.

Discussion ensued regarding plans for ISO press releases and communications for Winter 2023/24, as compared to, and with lessons learned from, previous winters. Further information would be available as the winter period approached. In response to additional questions, Dr. Chadalavada committed to provide additional information on fuel oil and LNG burned in the proxy cases for the moderate and severe winter scenarios. He confirmed that unit availability in the scenarios was based on Capacity Supply Obligations (CSOs) and that the scenarios for Winter 2023/24 would have been better than those for 2022/23 given the additional BTM PV on the system.

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

WINTER 2024/25 SCENARIO ANALYSIS (WITH AND WITHOUT EVERETT)

Dr. Chadalavada introduced the quantitative analysis of Winter 2024/25 by reviewing the purpose of the analysis and highlighting the need for the ISO to reflect in its models reasonable assumptions regarding changing market conditions and the changing asset mix. He emphasized that the analysis focused on infrastructure and capacity related to, and not about the commodity that flows through, the Everett Marine Terminal (Everett). The analysis focused on moderate and severe winter scenarios.

Turning to assumptions, he reviewed and answered questions regarding the assumptions made with respect to system loads, energy demand, BTM PV capacity, incremental fuel available from the IEP, and ~~distribution of~~ fuel oil distribution. He also reviewed assumptions regarding LNG injection capability, available imports, offshore wind capacity, and forced outages. He then walked through the results of the moderate and severe winter analyses, with and without Everett. In the moderate winter sensitivity analysis, expected energy shortfall exposure was minimal. With Everett, no energy shortfall was projected in any scenario studied, while without Everett, projected energy shortfalls would be fully mitigated with increased fuel oil inventory. Similarly, in the severe winter severity analysis, no energy shortfall was projected in any scenario with Everett, while without Everett, projected energy shortfalls would be *mostly* mitigated with increased fuel oil inventory.

In response to questions, Dr. Chadalavada confirmed the relatively low percentage of MWh implicated under all scenarios and identified additional measures available to the ISO to mitigate any projected energy shortfall (e.g. posturing, calls for conservation, additional imports) prior to implementation of Operating Procedure (OP) No. 7 (load shed). He noted the ISO’s confidence in the sensitivity analyses, but cautioned that the analyses assumed that the commodity coming through Everett would be replaced (whether through St. John, the Excelerate Buoy, or the variety of dual fuel and heavy oil units on the system). If not replaced, the risk of energy shortfall increased in scenarios without Everett, and the analyses allowed for any such changes in assumptions to be reflected.

Dr. Chadalavada addressed the ISO's concerns with years beyond these analyses (i.e., the next 4-5 years). Beyond Winter 2024-25, there was more uncertainty around (i) the pace of existing infrastructure retirements and market entry of new infrastructure, (ii) offshore wind in-service dates during 2028-2032, and (iii) the pace of economy-wide electrification. There were qualitative concerns about the loss of Everett, but the concerns could not be translated to specific numbers or to a definitive need on the electric grid system-wide. He cautioned that the ISO did not have the expertise to assess the operational capability of the regional pipeline system without Everett. The ISO would rely on the expertise of the pipelines and the local distribution companies (LDCs) to identify any pipeline operational concerns and identify if and how the ISO might be able to help.

Dr. Chadalavada noted that the initial results of the 2027 study undertaken with EPRI were scheduled for release on May 12. The study would show New England's exposure to extreme weather events under a variety of scenarios, noting the probability of any projected energy shortfall associated with that scenario. The study results would also include scenarios with and without Everett. Dr. Chadalavada foreshadowed that the 2027 study results would have a data convergence similar to the 2024-2025 analysis. He added that a similar study was underway for 2032, but results of that analysis would not be ready until sometime following the release of the 2027 analysis.

Answering questions, Dr. Chadalavada restated that the retention of Everett post-expiration of the Mystic COS Agreement was beyond the ISO's jurisdiction. He committed to explore and report back on the possibility of quantifying potential energy shortfall over a ten-year period.

ORDER 2222 COMPLIANCE ORDER 60-DAY COMPLIANCE REVISIONS

Ms. Mariah Winkler, Markets Committee Chair, referred the Committee to the materials circulated in advance of and posted with the materials for the meeting. She reported that the FERC's March 1, 2023 *Order 2222* Compliance Order had accepted, in part, and rejected, in part, the region's joint *Order 2222* compliance proposal and set further compliance obligations for New England to be filed within 30, 60 and 180 days of the order, respectively. She explained that the ISO's proposed Tariff revisions in response to the FER's 60-day directives incorporated (i) clarifications to address the small utility opt-in requirements and the dispute resolution requirements; and (ii) references to existing Tariff sections of the existing Load Asset registration requirements and the application of non-performance penalties to aggregation. With respect to metering configurations, the ISO's compliance filing would further explain why the present metering proposal minimizes Distributed Energy Resource (DER) barriers to entry. In addition, the ISO planned to ask the FERC to delay the further compliance requirement on the submission of metering data by DER Aggregators because of the ISO's pending request for rehearing on the matter; any alternative metering requirements would depend on the outcome of that pending rehearing request.

Ms. Winkler then reported that, at its April 25 meeting, the Markets Committee considered and with a 78.64% Vote in favor, recommended that the Participants Committee support the ISO's proposed Tariff revisions to comply with the FERC's 60-day further compliance obligations.

The following motion duly made and seconded:

> RESOLVED, that the Participants Committee supports the revisions to Sections III.6.1(e)(i), III.6.1(f), III.6.7(c)(ii), III.6.7(c)(v), and III.6.8(d) of the Tariff, as proposed by the ISO in response to the Commission's March 1, 2023 Compliance Order (*ISO New England Inc. and New England Power Pool Participants Comm.*, 182 FERC ¶ 61,137), and as recommended by the Markets Committee at its April 25, 2023 meeting, and circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

Members opposing the proposed compliance changes explained their views, as they expressed during the Markets Committee's consideration of the changes, that the changes did not fully facilitate the participation by BTM DERs in the New England Markets or improve upon the set of market design changes first proposed in the region's initial compliance filing.

The Committee then considered and approved the main motion with a 78.62% Vote in favor (Generation Sector – 16.70%; Transmission Sector – 16.70%; Supplier Sector – 15.03%; Alternative Resources Sector – 4.30%; Publicly Owned Entity Sector – 16.70%; and End User Sector – 9.19%) (*See* Vote 1 on Attachment 2).

LS POWER-PROPOSED REVISIONS TO ADDRESS THE UNWINDING OF THE INCREMENTAL OBLIGATIONS OF FCM REPOWERING PROJECTS

Ms. Winkler then introduced the LS Power Proposal. By way of background, she explained that, in the fifteenth Forward Capacity Auction (FCA15), LS Power's Ocean State Power generating resource qualified as a repowering project and obtained a seven-year price lock. LS Power subsequently explored with the ISO whether that resource could revert back to the original and currently operational 270 MW existing resource. The ISO indicated that, if a repowered resource did not complete the repowering project as cleared in FCA15, the entire project was at risk of being terminated and removed from the Forward Capacity Market (FCM).

Accordingly, LS Power, through its Lead Market Participant Jericho Power, proposed to modify three Tariff provisions (i) to clarify that a repowering resource that withdraws from critical path schedule (CPS) monitoring can partially commercialize, (ii) to make clear that the ISO would be able to terminate the price lock of a repowered resource if it withdraws from CPS monitoring, and (iii) to make clear that a resource withdrawing from CPS monitoring may partially commercialize before being subject to termination (LS Power Proposal). At its April 25 meeting, the Markets Committee recommended Participants Committee support for the LS Power Proposal with an 83.3% Vote in favor, with a number of abstentions noted.

The Jericho Power representative further explained the intent of the LS Power Proposal, which was to permit a repowering resource to shed its incremental obligations, subject to the forfeiture of financial assurance, capacity network rights and price lock treatment for the increment that is not built, but to permit the existing portion of the resource to continue to operate in the FCM, which it further asserted would provide treatment equivalent to that available to other resources.

In response to a question, the Jericho Power representative explained that one of Ocean State's resources was running at full output on oil for all of the December 24 Scarcity Condition event. The other resource was self-scheduled and energized by the end of the event. In response to a follow-up question, Dr. Chadalavada explained that a hypothetical absence of the Ocean State Power generating resources would not have extended the duration of the December 24 event, nor would have changed the actions taken by the ISO, but would have resulted in a deeper deficiency (by the MW amount of the generating facility). There similarly would not have been any change to outcome of the February 3-4 event.

The ISO, referring to its memoranda provided to the Markets Committee, explained the reasons why it opposed the LS Power-proposed changes at that time, which included the lack of an impact assessment, or of an adequate assessment of the potential for the exercise of market power. The ISO was also concerned that the LS Power Proposal could create a scenario in which an existing resource could qualify a repowering, offer a price higher than its net risk adjusted going-forward cost of the resource, set that higher price, and in exchange for foregoing some financial assurance on the incremental portion to be shed, collect that higher clearing price on the remainder of their base unit and on other units in their portfolio, to the potential detriment of consumers in the region. While the ISO acknowledged that the continued availability of the dual-fuel resource might be preferable, and that an outcome that resulted in the complete loss of an interconnection under these circumstances might be worthy of reconsideration, additional time would be required to fully consider further options and/or changes.

Following further clarifying questions on the Proposal, as well as on the action being requested of the Committee, the following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the Market Rule 1 Tariff revisions, as proposed by LS Power, as recommended by the Markets Committee at its April 25, 2023 meeting, and as circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

Those opposing the LS Power Proposal indicated concerns with the implications of the changes, but a willingness to consider the issues raised in future Participant Processes. Some, expressing sympathy for the situation in which LS Power found itself, but noting some concerns with potential filed rate doctrine implications of the changes, indicated that they would abstain rather than support the Tariff revisions. One member suggested that discussions planned for later in the year to address the investment threshold to bring a resource back into the market might present an appropriate forum for addressing some of the concerns/challenges raised by LS Power.

Following further discussion, the motion was voted and did not pass with a 45.72% Vote in favor (Generation Sector – 16.70%; Transmission Sector – 0%; Supplier Sector – 12.52%; Alternative Resources Sector – 14.11%; Publicly Owned Entity Sector – 0%; and End User Sector – 2.39%) (*See* Vote 2 on Attachment 2).

LITIGATION REPORT

Mr. Lombardi referred the Committee to the May 4, 2023 Litigation Report that had been circulated and posted before the meeting. He highlighted the following developments:

(i) *Second New England Gas-Electric Forum (AD22-9).* Supplemental notice of the June 20 FERC Forum in Portland, Maine was issued on April 13, 2023. Individuals interested in participating as panelists were encouraged per that notice to submit a self-nomination to FERC by Friday, May 19, 2023;

(ii) *IEP Remand (ER19-1428-006).* The FERC accepted, in an April 24 order, the ISO's compliance changes, which removed nuclear, biomass, coal, and hydroelectric generators from the IEP. The order rejected a NEPOOL-supported amendment that would have allowed hydro resources to participate as Electric Storage Facilities under the IEP; and

(iii) *IEP Parameters Updates (ER23-1588).* Submitted jointly by the ISO and NEPOOL on April 7, 2023, comments supporting and protesting the filing had been filed, with litigation on-going.

COMMITTEE REPORTS

Markets Committee. Mr. Bill Fowler, MC Chair, reported that the May MC meeting had been re-scheduled as a one-day meeting, on May 9, 2023 in Marlborough, MA. The reason for the change was the identification of an error in General Electric's Multi-Area Reliability Simulation (GE MARS) software, which underpinned much of the work related to the Resource Capacity Accreditation (RCA) project. The ISO planned to take time to evaluate the impact of, and corrections to, that error and defer discussion on RCA items until the error was addressed. Looking ahead, invitations to the MC Summer Meeting at The Lodge at Spruce Peak in Stowe, Vermont had been circulated and posted on the ISO website. With space limited, all those interested were encouraged to register promptly.

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that, for the same reasons identified in the MC Report (RCA deferral), the May RC meeting had been changed to a one-day meeting (on May 16, 2023). In addition to the RC's regular business items, the 21-day energy assessment for 2027 that was to be released by May 12 would be discussed.

Transmission Committee (TC). Mr. Dave Burnham, TC Vice-Chair, reported that the May TC meeting had been canceled, but that plans were for the TC to meet next on June 23.

Budget & Finance Subcommittee (B&F). Mr. Tom Kaslow, the B&F Subcommittee Chair, reported that the B&F Subcommittee planned to meet on May 12, 2023, highlighting two new items planned for discussion: (i) a discussion regarding the eligibility of letter of credit issuers and (ii) the possibility of further accelerating settlement billing to three times a week (versus the current two times).

Membership Subcommittee. Mr. Pat Gerity, NEPOOL counsel, on behalf of Ms. Sarah Bresolin, Membership Subcommittee Chair, reported that the next Membership Subcommittee meeting was scheduled for May 15, 2023.

ADMINISTRATIVE MATTERS

Mr. Lombardi highlighted that registration was open for the Participants Committee Summer Meeting to be held June 27-29, 2023 at The Equinox in Manchester Village, Vermont. He encouraged members to register promptly and to attend (including with their families, if able). Mr. Lombardi also noted the dates of NECPUC's 2023 Symposium (May 22-24) to be held in Stowe, Vermont, notice of which had been widely circulated and posted on the NECPUC website. Those interested were encouraged to attend. Finally, Mr. Lombardi noted that the next Participants Committee was scheduled for June 1, but would at most be virtual and, if possible, would be cancelled in favor of completing all of June's business on the first day of the Summer Meeting later that month. He encouraged members to check their e-mails for further information regarding that meeting date.

There being no other business, the meeting adjourned at 3:05 p.m.

Respectfully submitted,

Sebastian Lombardi, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN MAY 4, 2023 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Advanced Energy United	Associate Non-Voting	Caitlin Marquis		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matt Ide (tel)	
Associated Industries of Massachusetts (AIM)	End User	Robert Ruddock		
AVANGRID: CMP/UI	Transmission	Alan Trotta	Jason Rauch	Alex Noviki 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	Matt Ide (tel)		
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Matt Ide (tel)	
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield (tel)		
Clearway Power Marketing LLC	Supplier			Pete Fuller (tel)
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw (tel)		
Connecticut Office of Consumer Counsel	End User	Claire Coleman	J.R. Viglione (tel)	
Conservation Law Foundation (CLF)	End User	Phelps Turner (tel)		
Constellation Energy Generation	Supplier	Gretchen Fuhr	Bill Fowler	
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
DC Energy, LLC	Supplier	Bruce Bleiweis (tel)		
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 (tel)		Bill Fowler Alex Chaplin (tel)
Elektrisola, Inc.	End User			Bill Short
Emera Energy Services	Supplier			Bill Fowler
Enel X North America, Inc.	AR-LR	Alex Worsley		
Engie Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Environmental Defense Fund	End User	Jolette Westbrook (tel)		
Eversource Energy	Transmission	James Daly	Dave Burnham	Vandan Divatia
FirstLight Power Management, LLC	Generation	Tom Kaslow (tel)		
First Point Power, LLC	Supplier		Bryan Amaral	
Galt Power, Inc.	Supplier	José Rotger		
Garland Manufacturing Company	End User			Bill Short
Generation Bridge Companies	Generation	Bill Fowler		
Generation Group Member	Generation	Dennis Duffy	Abby Krich	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Granite Shore Companies	Generation			Bob Stein
Groton Electric Light Department	Publicly Owned Entity		Matt Ide (tel)	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	AR-RG	Louis Guilbault (tel)	Bob Stein	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN MAY 4, 2023 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Hammond Lumber Company	End User			Bill Short
Hanover, NH (Town of)	End User			Bill Short
Harvard Dedicated Energy Limited	End User			Jackie Litnyski
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		Matt Ide (tel)	
Holyoke Gas & Electric Department	Publicly Owned Entity		Matt Ide (tel)	
Hull Municipal Lighting Plant	Publicly Owned Entity		Matt Ide (tel)	
Icetec Energy Services, Inc.	AR-LR	Doug Hurley		
Industrial Energy Consumer Group	End User	Dan Collins		
Ipswich Municipal Light Department	Publicly Owned Entity		Matt Ide (tel)	
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths	Nancy Chafetz (tel)	
Jupiter Power	AR-RG			Ron Carrier (tel)
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned Entity	Craig Kieny (tel)		
Long Island Power Authority (LIPA)	Supplier	Bill Kilgoar (tel)		José Rotger
Maine Public Advocate’s Office	End User			Jackie Litnyski
Maine Skiing, Inc.	End User	Dan Collins		
Mansfield Municipal Electric Department	Publicly Owned Entity		Matt Ide (tel)	
Maple Energy LLC	AR-LR			Doug Hurley
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide (tel)	
Mass. Attorney General’s Office (MA AG)	End User	Ashley Gagnon	Jaimie Donovan	
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Climate Action Network				
Mass. Dept. Capital Asset Management	End User		Paul Lopes (tel)	Nancy Chafetz (tel)
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide (tel)		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	
Mintz, Sam	End User			Michael Brooks (tel)
Moore Company	End User			Bill Short
Narragansett Electric Co. (d/b/a RI Energy)	Transmission	Brian Thomson		
Nautilus Power, LLC	Generation		Bill Fowler	
New England Power (d/b/a National Grid)	Transmission	Tim Brennan	Tim Martin	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson	Dan Dolan	
New Hampshire Electric Cooperative	Publicly Owned Entity		Brian Callnan	Brian Forshaw (tel)
New Hampshire Office of Consumer Advocate	End User			Jackie Litnyski
NextEra Energy Resources, LLC	Generation	Michelle Gardner	Nick Hutchings	Joel Gordon
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Power Marketing LLC	Supplier		Pete Fuller (tel)	
Nylon Corporation of America	End User			Bill Short
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Pawtucket Power Holding Company	Generation			Bill Fowler
Paxton Municipal Light Department	Publicly Owned Entity		Matt Ide (tel)	
Peabody Municipal Light Department	Publicly Owned Entity		Matt Ide (tel)	
PowerOptions, Inc.	End User			Jackie Litnyski

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN MAY 4, 2023 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Princeton Municipal Light Department	Publicly Owned Entity	Matt Ide (tel)		
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
RI Division of Public Utilities Carriers	End User	Paul Roberti		
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Matt Ide (tel)	
Saint Anselm College	End User			Bill Short
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User			Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matt Ide (tel)	
South Hadley Electric Light Department	Publicly Owned Entity		Matt Ide (tel)	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Matt Ide (tel)	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunnova Energy Corporation	AR-DG		David Skillman (tel)	
Sunrun Inc.	AR-DG			Peter Fuller (tel)
Tangent Energy	AR-LR	Brad Swalwell (tel)		
Taunton Municipal Lighting Plant	Publicly Owned Entity	Devon Tremont	Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Matt Ide (tel)	
Tenaska Power Services Co.	Supplier		Eric Stallings (tel)	
The Energy Consortium	End User	Bob Espindola (tel)	Mary Smith (tel)	
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny (tel)		
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corporation	AR-LR			Jackie Litynski
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw (tel)
Versant Power	Transmission		Dave Norman (tel)	Alan Trotta
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Vitol Inc.	Supplier	Joe Wadsworth (tel)		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide (tel)	
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Matt Ide (tel)	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	
ZTECH, LLC	End User			Bill Short

ATTACHMENT 2

VOTES TAKEN AT
MAY 4, 2023 PARTICIPANTS COMMITTEE MEETING

TOTAL

Sector	Vote 1	Vote 2
Generation	16.70	16.70
Transmission	16.70	0.00
Supplier	15.03	12.52
Alternative Resources	4.30	14.11
Publicly Owned Entity	16.70	0.00
End User	9.19	2.39
% IN FAVOR	78.62	45.72

GENERATION SECTOR

Participant Name	Vote 1	Vote 2
CPV Towantic, LLC	A	F
ECP Companies	Split	Split
Calpine	A	A
New Leaf Energy	A	A
FirstLight Power Management, LLC	F	A
Generation Bridge Companies	F	A
Generation Group Member	A	F
Granite Shore Power Companies	F	F
Nautilus Power, LLC	F	A
NextEra Energy Resources, LLC	F	F
Pawtucket Power Holding Co.	F	F
IN FAVOR (F)	6	5
OPPOSED (O)	0	0
TOTAL VOTES	6	5
ABSTENTIONS (A)	4	5

TRANSMISSION SECTOR

Participant Name	Vote 1	Vote 2
Avangrid (CMP/UI)	F	A
Eversource Energy	F	A
Narragansett Electric (d/b/a Rhode Island Energy)	F	O
New England Power (d/b/a National Grid)	F	O
VELCO	F	A
Versant Power	F	O
IN FAVOR (F)	6	0
OPPOSED (O)	0	3
TOTAL VOTES	6	3
ABSTENTIONS (A)	0	3

SUPPLIER SECTOR

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

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote 1	Vote 2
Renewable Generation Sub-Sector		
ENGIE Energy Marketing NA, Inc.	O	F
H.Q. Energy Services (U.S.) Inc.	F	F
Jericho Power LLC	O	F
Wheelabrator/Macquarie	F	A
Distributed Generation Sub-Sector		
CLEAResult Consulting, Inc.	A	A
Sunrun Inc.	O	A
Load Response Sub-Sector		
Enel X North America, Inc.	O	A
Icetec Energy Services, Inc.	O	F
Maple Energy	O	F
Tangent Energy Solutions, Inc.	--	F
Vermont Energy Investment Corp.	O	O
IN FAVOR (F)	2	6
OPPOSED (O)	7	1
TOTAL VOTES	9	7
ABSTENTIONS (A)	1	4

ATTACHMENT 2

VOTES TAKEN AT
MAY 4, 2023 PARTICIPANTS COMMITTEE MEETING

PUBLICLY OWNED ENTITY SECTOR

Participant Name	Vote 1	Vote 2
Ashburnham Municipal Light Plant	F	O
Belmont Municipal Light Dept.	F	O
Block Island Utility District	F	O
Boylston Municipal Light Dept.	F	O
Braintree Electric Light Dept.	F	O
Chester Municipal Light Dept.	F	O
Chicopee Municipal Lighting Plant	F	O
Concord Municipal Light Plant	F	O
Conn. Mun. Electric Energy Coop.	F	O
Danvers Electric Division	F	O
Georgetown Municipal Light Dept.	F	O
Groton Electric Light Dept.	F	O
Groveland Electric Light Dept.	F	O
Hingham Municipal Lighting Plant	F	O
Holden Municipal Light Dept.	F	O
Holyoke Gas & Electric Dept.	F	O
Hull Municipal Lighting Plant	F	O
Ipswich Municipal Light Dept.	F	O
Littleton (MA) Electric Light Dept.	F	O
Littleton (NH) Water & Light	F	O
Mansfield Municipal Electric Dept.	F	O
Marblehead Municipal Light Dept.	F	O
Mass. Bay Transportation Authority	F	O
Mass. Municipal Wholesale Electric Co.	F	O
Merrimac Municipal Light Dept.	F	O
Middleborough Gas and Elec. Dept.	F	O
Middleton Municipal Electric Dept.	F	O
New Hampshire Electric Cooperative	F	O
North Attleborough	F	O
Norwood Municipal Light Dept.	F	O
Pascoag Utility District	F	O
Paxton Municipal Light Dept.	F	O
Peabody Municipal Light Plant	F	O
Princeton Municipal Light Dept.	F	O
Reading Municipal Light Dept.	F	O
Rowley Municipal Lighting Plant	F	O
Russell Municipal Light Dept.	F	O
Shrewsbury's Electric & Cable Operations	F	O
South Hadley Electric Light Dept.	F	O
Sterling Municipal Electric Light Dept.	F	O
Stowe (VT) Electric Dept.	F	O
Taunton Municipal Lighting Plant	F	O
Templeton Municipal Lighting Plant	F	O
Village of Hyde Park (VT) Elec. Dept.	F	O
VT Electric Cooperative	F	O
VT Public Power Supply Authority	F	O
Wakefield Municipal Gas and Light Dept.	F	O
Wallingford, Town of	F	O
Wellesley Municipal Light Plant	F	O
West Boylston Municipal Lighting Plant	F	O
Westfield Gas & Electric Light Dept.	F	O
IN FAVOR (F)	51	0
OPPOSED (O)	0	51
TOTAL VOTES	51	51
ABSTENTIONS (A)	0	0

END USER SECTOR

Participant Name	Vote 1	Vote 2
Associated Industries of Mass.	A	A
Bath Iron Works Corporation	F	O
Conn. Office of Consumer Counsel	O	O
Conservation Law Foundation	O	F
Durgin and Crowell Lumber Co.	F	O
Elektrisola, Inc.	F	O
Environmental Defense Fund	O	F
Garland Manufacturing Co.	F	O
Hammond Lumber Company	F	O
Harvard Dedicated Energy Limited	A	O
High Liner Foods (USA) Inc.	F	O
Industrial Energy Consumer Group	A	A
Maine Public Advocate Office	O	O
Maine Skiing	A	A
Mass. Attorney General's Office	O	O
Mass. Climate Action Network	O	F
Mass. Dept. of Capital Asset Management	O	A
Mintz, Sam	A	A
Moore Company	F	O
New Hampshire OCA	O	O
Nylon Corporation of America	F	O
PowerOptions, Inc.	O	O
RI Division of Public Utilities Carriers	A	A
Shipyard Brewing Co.	F	O
St. Anselm College	F	O
The Energy Consortium	A	O
Z-TECH, LLC	F	O
IN FAVOR (F)	11	3
OPPOSED (O)	9	18
TOTAL VOTES	20	21
ABSTENTIONS (A)	7	6

CONSENT AGENDA

From the previously circulated notices of actions of (i) the Markets Committee's (MC) July 11, 2023 meeting (dated July 11, 2023); (ii) the Reliability Committee's (RC) July 18-19, 2023 meeting (dated July 19, 2023); and (iii) the Transmission Committee's (TC) July 18-19, 2023 meeting (also dated July 19, 2023)[1]:

1. Day-Ahead Ancillary Services Initiative (DASI) Proposal[2]

a. <u>MC: Changes to Tariff Section I.2.2 and Market Rule 1</u>

Support revisions associated with DASI to Section I.2.2 (Definitions) and Market Rule I (Section III) of the ISO New England Transmission, Markets and Services Tariff (Tariff), as recommended by the MC at its July 11, 2023 meeting, together with such further non-substantive changes as the Chair and Vice-Chair of the MC may approve.

The motion to recommend Participants Committee support was approved unanimously, with two abstentions in the Generation Sector, and one abstention in each of the Supplier and Alternative Resources (AR) Sectors.

b. <u>RC: Changes to Tariff Sections I.2.2, III.1.5.2(a), III.9.5.3.1, and III.9.5.3.2</u>

Support revisions associated with DASI to Tariff Sections I.2.2, III.1.5.2(a) (ISO-Initiated Parameter Auditing), III.9.5.3.1 (Calculating Resource CLAIM10 and CLAIM30 Values), and III.9.5.3.2 (CLAIM10 and CLAIM30 Audits), as recommended by the RC at the July 18-19, 2023 Joint RC/TC Summer Meeting, together with such further non-substantive changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was approved unanimously.

c. <u>TC: Changes to Tariff Section I.2.2</u>

Support revisions associated with DASI to the Definitions Section of the Tariff, as recommended by the TC at the July 18-19, 2023 Joint RC/TC Summer Meeting, together with such further non-substantive changes as the Chair and Vice-Chair of the TC may approve.

The motion to recommend Participants Committee support was approved unanimously.

(Cont. on Next Page)

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

[2] At its May 11, 2023 meeting, the Budget & Finance Subcommittee (B&F) also reviewed, without any objection or concern expressed, DASI-related changes to the following definitions that are used in the Financial Assurance Policy and that are included in the DASI-related changes recommended by the Markets Committee noted above: Day-Ahead Energy Market, Day-Ahead Prices and Lead Market Participant.

2. *Order 2222 180-Day Compliance Filing Proposal*

a. MC: Changes to Tariff Sections I.2.2, III.13 and III.A

Support revisions to Tariff Sections I.2.2, III.13 (Forward Capacity Market) and III.A (Appendix A - Market Monitoring, Reporting and Market Power Mitigation) (proposed in response to the FERC's March 1, 2023 order requiring further compliance with *Order 2222* by addressing how current Tariff capacity market mitigation rules would apply to Distributed Energy Capacity Resources (DECRs) participating in FCA19 and beyond), as recommended by the MC at its July 11, 2023 meeting, together with such further non-substantive 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 in the Generation Sector, and two abstentions in the AR Sector.

b. RC: Changes to Tariff Section I.2.2

Support revisions to the Definitions Section of the Tariff (proposed in response to the FERC's March 1, 2023 order requiring further compliance with Order 2222 by addressing how current Tariff capacity market mitigation rules would apply to DECRs participating in FCA19 and beyond), as recommended by the RC at the July 18-19, 2023 Joint RC/TC Summer Meeting, together with such further non-substantive changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was approved unanimously.

c. TC: Changes to Tariff Section I.2.2

Support revisions to the Definitions Section of the Tariff (proposed in response to the FERC's March 1, 2023 order requiring further compliance with Order 2222 by addressing how current Tariff capacity market mitigation rules would apply to DECRs participating in FCA19 and beyond), as recommended by the TC at the July 18-19, 2023 Joint RC/TC Summer Meeting, together with such further non-substantive changes as the Chair and Vice-Chair of the TC may approve.

The motion to recommend Participants Committee support was approved unanimously.

(Cont. on Next Page)

Reliability Committee (RC)

From the previously-circulated notice of actions of the RC's June 13, 2023 meeting, dated June 13, 2023.

3. Revisions to OP-18 and OP-18 Appendix A (Clarifications to SCADA Server and LCC Configuration Requirements)

Support revisions to ISO New England Operating Procedure (OP) No. 18 (Metering and Telemetering Criteria) and Appendix A to OP-18 (ISO New England ICCP (Inter-Control Center Communications Protocol) CNP (communications network processor) Node Requirement),[3] as recommended by the RC at its June 13, 2023 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve. **(*See* attached materials regarding an additional non-substantive change.)**

The motion to recommend Participants Committee support was approved unanimously.

4. Revisions to OP-22 (New Phasor Measurement Unit (PMU) Installation Requirements; PMU Connection Drawing Requirement Clarifications)

Support revisions to OP-22 (Disturbance Monitoring Requirements),[4] as recommended by the RC at its June 13, 2023 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 approved unanimously.

5. Revisions to OP-23 and OP-23 Appendix H; Retirement of Appendix A (Biennial Review)

Support revisions to OP-23 (Resource Auditing) and OP-23 Appendix H (Reactive Capability Audit Request Form), and the retirement of OP-23 Appendix A (Off-Line Reserve Audit Request Form),[5] as recommended by the RC at its June 13, 2023 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 approved unanimously.

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[3] The recommended revisions to OP-18 and OP-18 Appendix A included (i) requirements for new communication channels from substation RTUs to LCC SCADA for new facilities or existing facilities when making modifications; (ii) requirements for commercial telecommunication channels to register with DHS and use public safety grade cellular service; (iii) the addition of new terminology for "enabled" and "standby" control centers and requirements for both control centers to have new redundant communication paths built with diverse vendors and technologies.

[4] The recommended revisions to OP-22 require additional PMU installations (by changing the PMU installation threshold from 100 to 20 MVA/MW), clarify requirements for PMU connection drawings, and make other non-substantive changes.

[5] The recommended revisions to OP-23 and OP-23 Appendix H include (i) changes to how CLAIM10/30 Audit requests are submitted, modified, and cancelled for Generator Assets; (ii) clarifications regarding the submission of OP-23 Appendix I using ASK ISO; and (iii) the addition of a note in Appendix H regarding Reactive Resource shared equipment.

memo

To: NEPOOL Reliability Committee and NEPOOL Participants Committee

From: Emily Laine, Chair NEPOOL Reliability Committee and Robert Stein, Vice Chair NEPOOL Reliability Committee

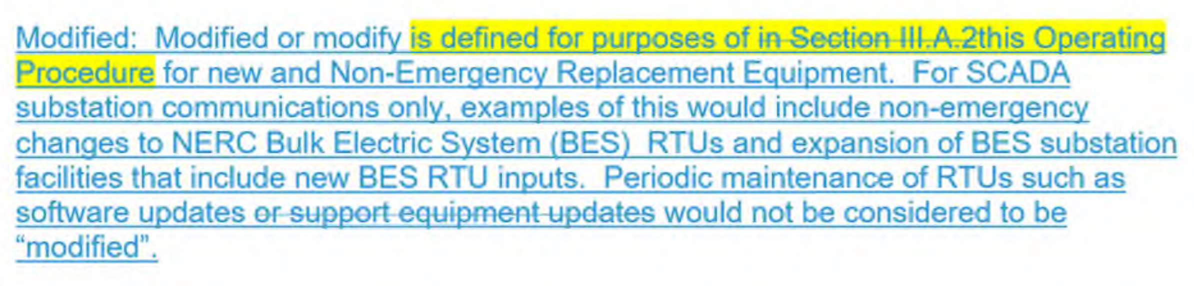
Date: August 1, 2023

Subject: Notice of Non-substantive Change to OP-18

On June 13, 2023, the Reliability Committee (RC) passed, with no opposition and no abstention, the proposal to update Operating Procedure 18 and Appendix A - Metering and Telemetering Criteria. During the final discussion on this item, it came to the RC's attention that a reference was inadvertently retained in the document. ISO's legal department confirmed that the reference to Section III.A.2 in the definition of "Modified" was an outdated cross-reference that should have been removed. As discussed at the RC, the Chair and Vice Chair have agreed that the subsequent changes correcting this error are non-substantive, the details of which are provided below.

The changes from what the RC reviewed and approved are highlighted in yellow.

OP-18: Metering and Telemetering Criteria, Section II



Modified: Modified or modify is defined for purposes of ~~in Section III.A.2~~this Operating Procedure for new and Non-Emergency Replacement Equipment. For SCADA substation communications only, examples of this would include non-emergency changes to NERC Bulk Electric System (BES) RTUs and expansion of BES substation facilities that include new BES RTU inputs. Periodic maintenance of RTUs such as software updates ~~or support equipment~~ updates would not be considered to be "modified".

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Summary of ISO New England Board and Committee Meetings

August 3, 2023 Participants Committee Meeting

Since the last update, the Compensation and Human Resources Committee, the Nominating and Governance Committee, and the System Planning and Reliability Committee met on June 27. The Information Technology and Cyber Security Committee, and the Board of Directors, met on June 28. The meetings were held in Manchester Village, Vermont.

The Compensation and Human Resources Committee discussed the 2024 medical benefit program for employees. The Committee was provided with an overview of retirement plan features, and discussed potential impacts of the federal Secure Act 2.0 legislation on those retirement plans. The Committee also received an update on the Company's people and culture, and reviewed workforce demographics, talent market dynamics, and discussed various statistics including retention and turnover rates.

The Nominating and Governance Committee discussed Board leadership, state liaison and committee assignments, and adopted a recommendation to present to the full Board in September. The Committee reviewed preliminary proposals for ongoing board education and discussed possible vendors for a session on ongoing corporate governance education. The Committee also discussed board operations and governance. Next, the Committee received an update on plans for the 2023 open board meeting in November. The Committee also received an update on communications plan activities and state issues.

The System Planning and Reliability Committee received updates on regional planning activities, the development of the 2023 Regional System Plan, and the results of the seventeenth Forward Capacity Auction. The Committee also received various updates on system forecasting, economic and special study requests, long-term transmission planning, and planned activities for the second half of 2023. The Committee reviewed the system operations outlook for summer 2023 and the 2050 Transmission Study, and discussed state communications about regional transmission planning efforts.

The Information Technology and Cyber Security Committee was provided with an update on the Company's three-year cyber security work plan, including progress made on several projects. The Committee also received an update on the nGEM project. The Committee considered topics for discussion at the annual cyber security "deep dive" for the full board in September and agreed the format would include a guest speaker from private industry focusing on an overview of current cyber security trends, and an incident response tabletop exercise. With members of the System Planning and

Reliability Committee, the Committee then conducted its annual review of the Company's IT-related business continuity plan and disaster recovery plans.

The Board of Directors held its annual meeting of members and elected Messrs. Colangelo, Ivey, and Vannoy to the Board of Directors for three-year terms, noting that the slate was previously approved by the NEPOOL Participants Committee at its May 4 meeting. The Board received a report from the CEO including an update on progress toward corporate goals. Next, the Board prepared for its meetings with the NEPOOL sectors and reviewed the discussion topics that were submitted in advance by the sectors, and also discussed energy adequacy issues and the Resource Capacity Accreditation project. The Board received reports from the standing committees, and reviewed the Company's Form 990 for 2022 to be filed with the Internal Revenue Service. During executive session, the Board discussed the Company's succession management program and board operations and governance. Lastly, since federal and state emergency health declarations and associated protocols surrounding COVID-19 have been lifted, the Board agreed with management's recommendation that it was now appropriate to likewise lift some of the Company's protocols in place for protections against COVID-19.

NEPOOL Participants Committee Report

August 2023

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Highlights

Data is through July 26th unless otherwise noted.

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: June 2023 Energy Market value totaled $342M
  - July Energy market value over the period was $452M, up $110M from June 2023 and down $835M from July 2022
    - July 2023 natural gas prices over the period were 3.9% higher than June average values
    - Average RT Hub Locational Marginal Prices ($39.45/MWh) over the period were 12% higher than June averages; Average DA Hub: $40.01/MWh
    - Average July 2023 natural gas prices and RT Hub LMPs over the period were down 62% and 56%, respectively, from July 2022 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 100.6% during July, up from 98% during June*
    - The minimum value for the month was 94.6% on Friday, July 21st
  - OP-4 and Capacity Scarcity Conditions occurred on Wednesday, July 5, 2023, resulting in elevated LMPs and Pay for Performance assessments

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

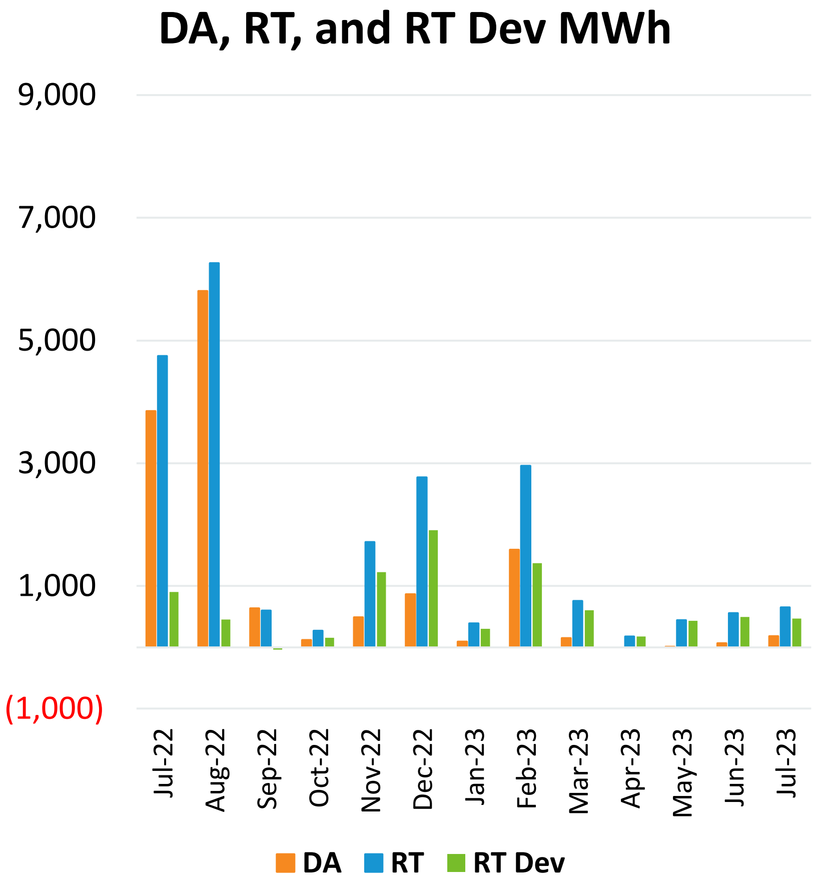
Underlying natural gas data furnished by: ICE Global markets in clear view

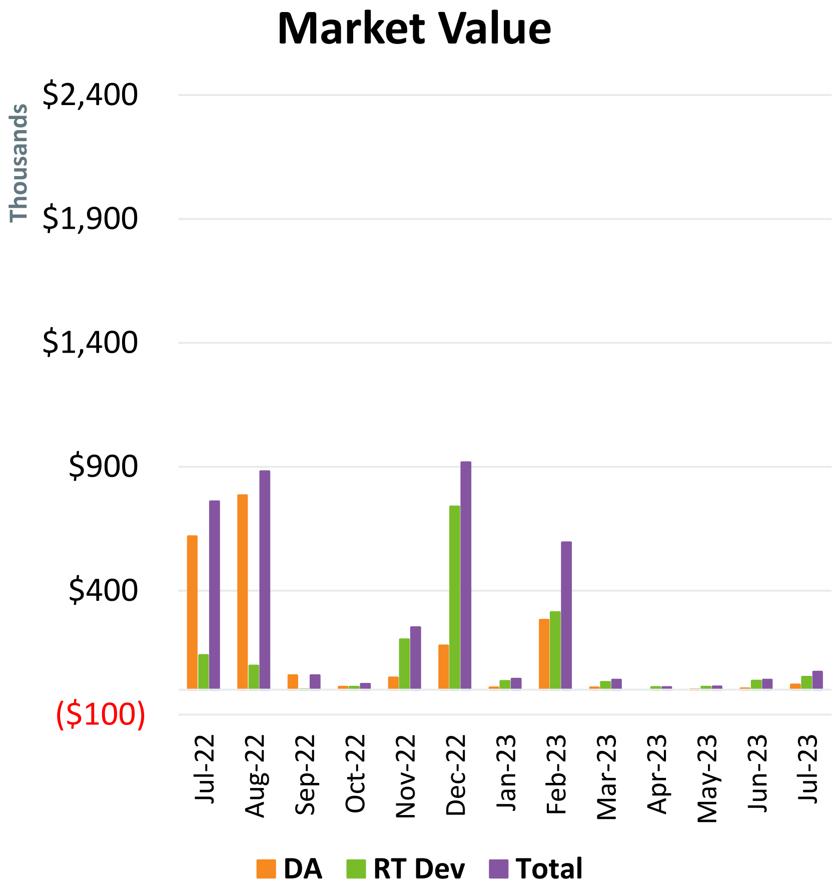
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - July 2023 NCPC payments totaled $2.4M over the period, up $0.6M from June 2023 and down $6.7M from July 2022
    - First Contingency payments totaled $2M, up $0.3M from June
      - $1.9M paid to internal resources, up $0.2M from June
        - » $247K charged to DALO, $1M to RT Deviations, $627K to RTLO*
      - $75K paid to resources at external locations, down $21K from June
        - » Charged to RT Deviations
    - Second Contingency and Voltage payments were both zero
  - NCPC payments over the period as percent of Energy Market value were 0.5%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $294K; Rapid Response Pricing (RRP) Opportunity Cost - $315K; Posturing - $18K; 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

- FERC accepted the FCA 17 results on July 18
- 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) will be held on August 1-3, and results will be posted no later than August 31
- 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)
  - ISO posted existing capacity values on March 30
  - ISO posted the Retirement and Permanent Delist Bid summary on April 12
  - Show of Interest Submission Window closed on May 8
  - At the May 31 PSPC meeting, the ISO confirmed 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 Submission Window closed on June 28
  - ISO held a PSPC meeting on July 26 and discussed the preliminary results of the tie benefits studies for FCA 18
    - The results of the ICR and related values study are expected to be presented at the August 23 PSPC meeting

System Planning Highlights

- The draft 2023-24 RSP will be shared with stakeholders in August
- The ISO is continuing to explore improvements to the long-term load forecast methodology to better support the evolving grid
  - The 2024 forecast cycle will begin in Q4 2023
- Qualified Transmission Project Sponsor (QTPS)
  - 26 companies have achieved QTPS status
    - Narragansett Electric Company d/b/a Rhode Island Energy was recently qualified

System Planning Highlights – Longer-Term Transmission Planning

- Longer-Term Transmission Planning
  - The first phase of this effort, that allows the ISO to regularly perform extended term planning at the request of the New England states, has been completed
  - The second phase of the effort will address the rules to enable the states to consider potential options for addressing the identified issues and cost allocation for associated transmission improvements
    - Discussions on the second phase will begin at the NEPOOL committees this October

AUGUST 3, 2023 | NEPOOL PARTICIPANTS COMMITTEE

July 5, 2023 OP-4 Event and Capacity Scarcity Condition

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT & CHIEF OPERATING OFFICER

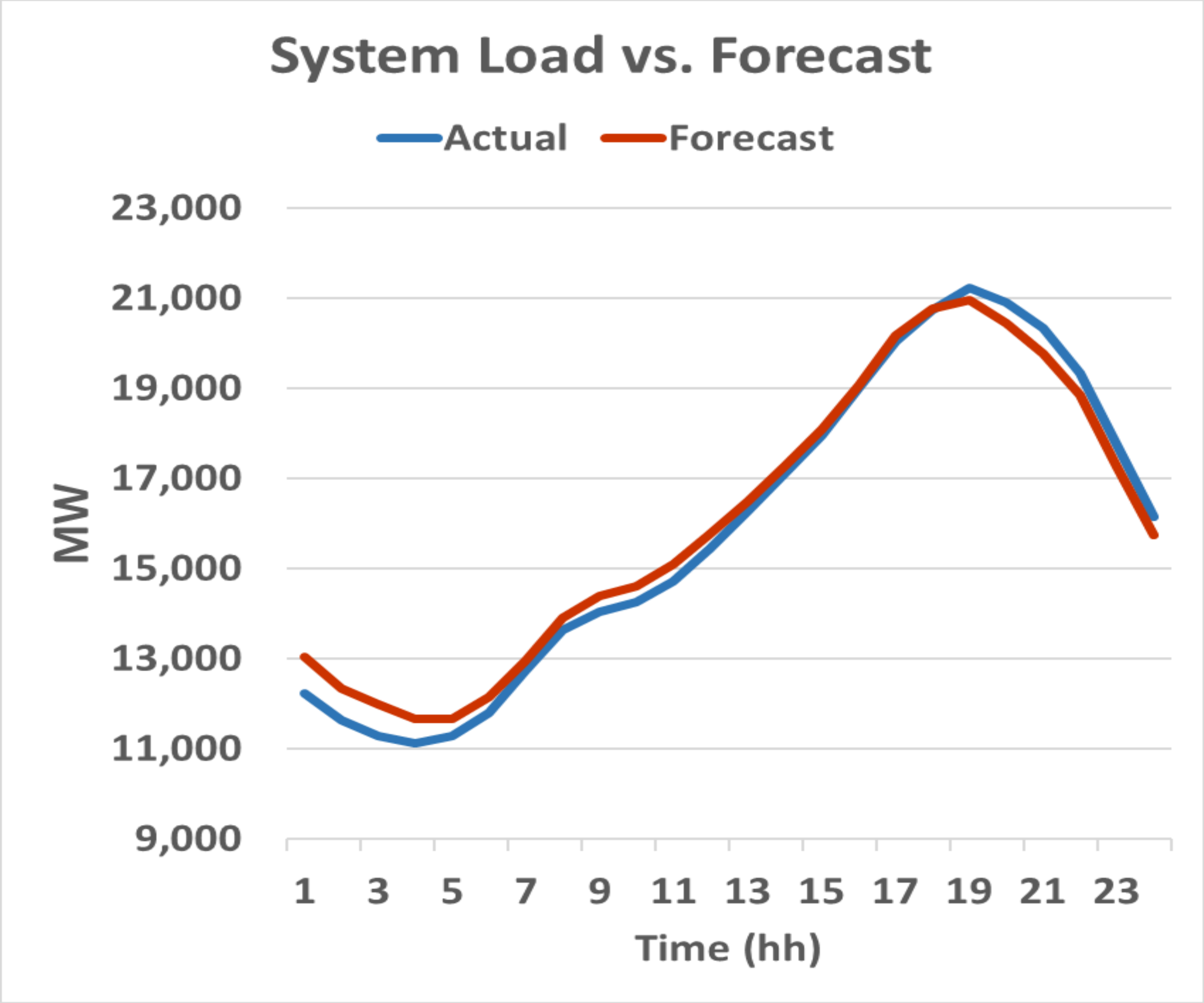
OP-4 and Capacity Scarcity Condition Wednesday, July 5, 2023

- The ISO implemented OP-4 on July 5, 2023
  - This was also a Capacity Scarcity Condition (CSC)
  - Based on Day-Ahead Market results, ISO was expecting ~2,400 MW of imports during the peak hour
  - Phase II which was scheduled to deliver ~1,300 MW during the peak hour tripped
  - Higher than forecasted temperatures contributed to higher than expected demand (~300 MW) during the peak hour
  - A small quantity of generator outages and reductions occurred during the day
- 30-minute Reserve Constraint Penalty Factor violated for the following 5-minute intervals: 18:25 – 18:50
  - $1,000/MWh Reserve Constraint Penalty Factor
- 10-minute Reserve Constraint Penalty Factor violated for the following 5-minute intervals: 18:25 – 18:35
  - $1,500/MWh Reserve Constraint Penalty Factor
- System conditions required the implementation of M/LCC 2 and OP-4
  - M/LCC 2, Abnormal Conditions Alert: 18:30 – 22:00
  - OP-4 Actions 1 and 2: 18:30 -22:00

Weather Forecast

- Temperatures were warm on July 5, but not extreme; the New England eight-city weighted average high temperature for the day was 90.0°F, with the mean temperature ~5.4°F above normal
  - The average temperature during HE 19 was ~3.4°F above forecast
- Conditions were humid; dew points were in the upper 60s to low 70s across the region
- Actual behind-the-meter (BTM) PV was higher than forecast during mid to late afternoon hours, ~338 MW greater during the peak hour
  - Additional BTM PV energy reduced load, however the higher than expected temperatures during the late afternoon offset this reduction
- The combined impacts of above-normal temperatures, humid conditions, and energy from BTM PV resulted a peak load of 21,223 MW in HE19

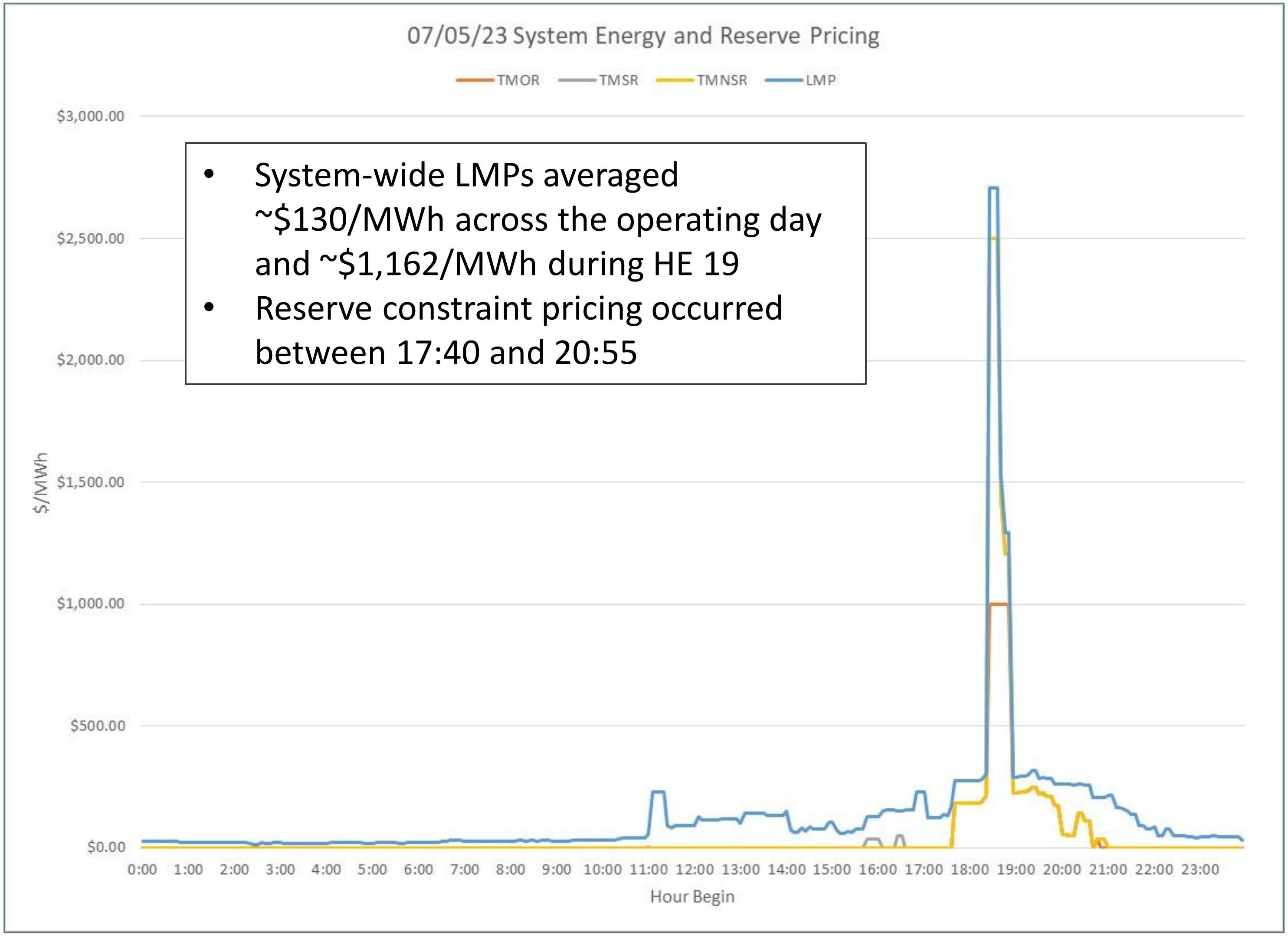
Peak Hour Load Forecast Error Was ~1.2%



Energy Imports Were Below Day-Ahead Values

- At the time OP-4 actions were implemented, net imports were ~1,700 MW less than the amount that cleared the Day-Ahead Energy Market
  - ~1,300 MW of the ~1,700 MW was expected to be imported on Phase II during the peak hour
- Following the Phase II trip, System Operators took action to curtail Real-Time Only export transactions on remaining external interfaces in accordance with Operating Procedures

Real-Time System Energy and Reserve Pricing



07/05/23 System Energy and Reserve Pricing

- System-wide LMPs averaged ~$130/MWh across the operating day and ~$1,162/MWh during HE 19
- Reserve constraint pricing occurred between 17:40 and 20:55

Summary of Capacity Scarcity Condition Intervals

5-Minute Intervals	System 30 Min Reserve Constraint Penalty Factor ($1,000 MW/hr)	System 10 Min Reserve Constraint Penalty Factor ($1,500 MW/hr)
18:25 – 18:35 (3 Intervals)	**Violated**	**Violated**
18:40 – 18:50 (3 Intervals)	**Violated**	Binding

- A Capacity Scarcity Condition results from the **violation** of the System 30 Minute Operating Reserve constraint or the System 10 Minute Operating Reserve constraint in any one 5-minute interval

July 5, 2023 LMP Finalization and Preliminary Settlement Information

- Finalized Real-Time LMPs for July 5 and the Capacity Scarcity Condition report were published to the ISO website on Thursday, July 6
- Preliminary settlement reports were released on Thursday, July 20
  - Balancing Ratios and Performance Scores published
  - The balancing ratio over each 5-min interval ranged from 0.788 – 0.798
  - The average balancing ratio over the period is 0.79
  - Final Settlement will adjust for Capacity Performance Bilateral Contracts
- Estimated Pay-for-Performance (PFP) penalties*: $10.9M
  - PFP penalties during the last event on December 24, 2022: $36M
- A knowledge article describing the July 5 FCM PFP settlements was made available by ISO on July 20

**Estimates based on available data*

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (1.5°F) Max: 91°F, Min: 61°F Precipitation: 4.27" – Above Normal Normal: 1.65"	Hartford	Temperature: Above Normal (2.8°F) Max: 93°F, Min: 60°F Precipitation: 13.9" - Above Normal Normal: 4.02"

Peak Load:	22,335 MW	July 06, 2023	19:00 (ending)

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

Procedure	Declared	Cancelled	Note
M/LCC 2	Jul 5, 2023 18:30	Jul 5, 2023 22:00	All of New England - Capacity
OP-4	Jul 5, 2023 18:30	Jul 5, 2023 22:00	All of New England - Capacity

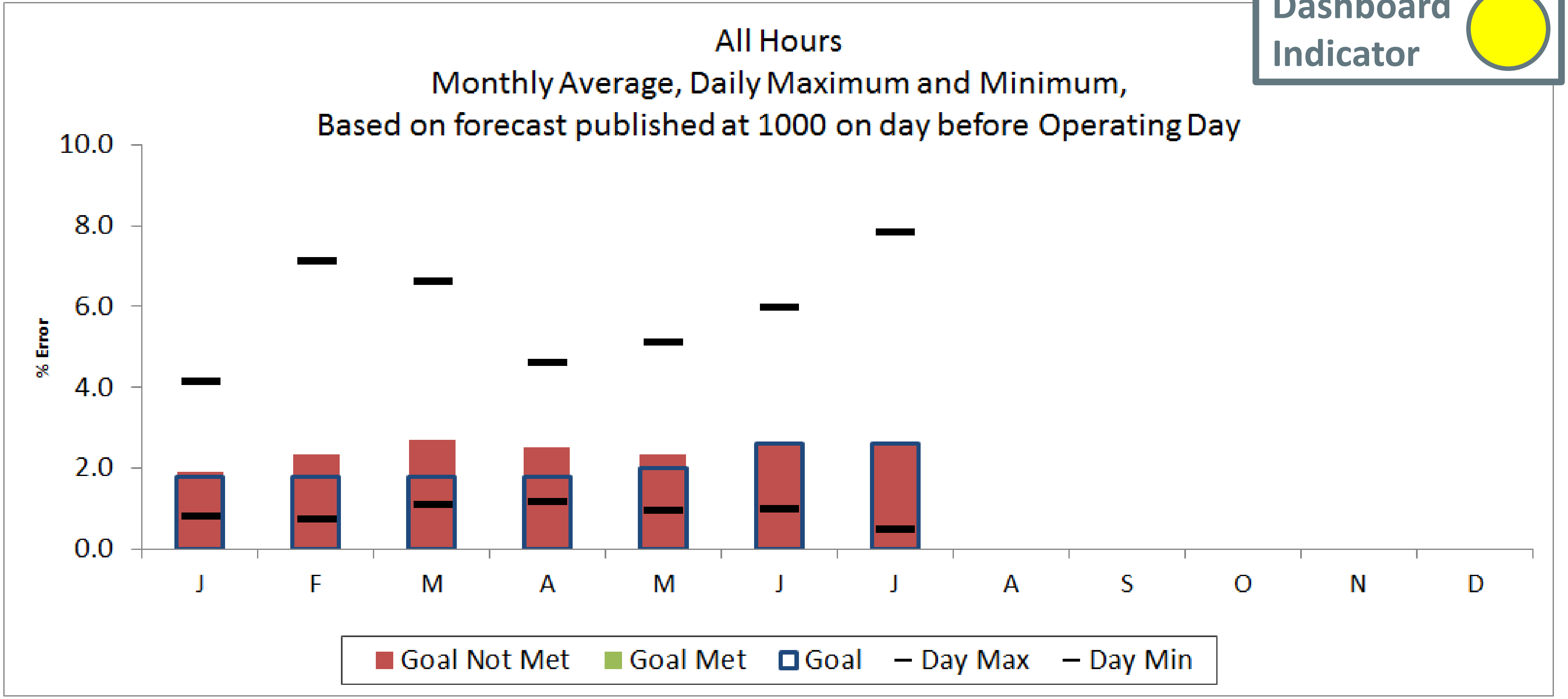
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
07/04/2023	IESO	700
07/05/2023	ISO-NE	650
07/14/2023	ISO-NE	650
07/15/2023	ISO-NE	625
07/25/2023 07/25/2023	IESO IESO	945 945
07/27/2023	ISO-NE	680
07/30/2023	ISO-NE	1250

2023 System Operations - Load Forecast Accuracy

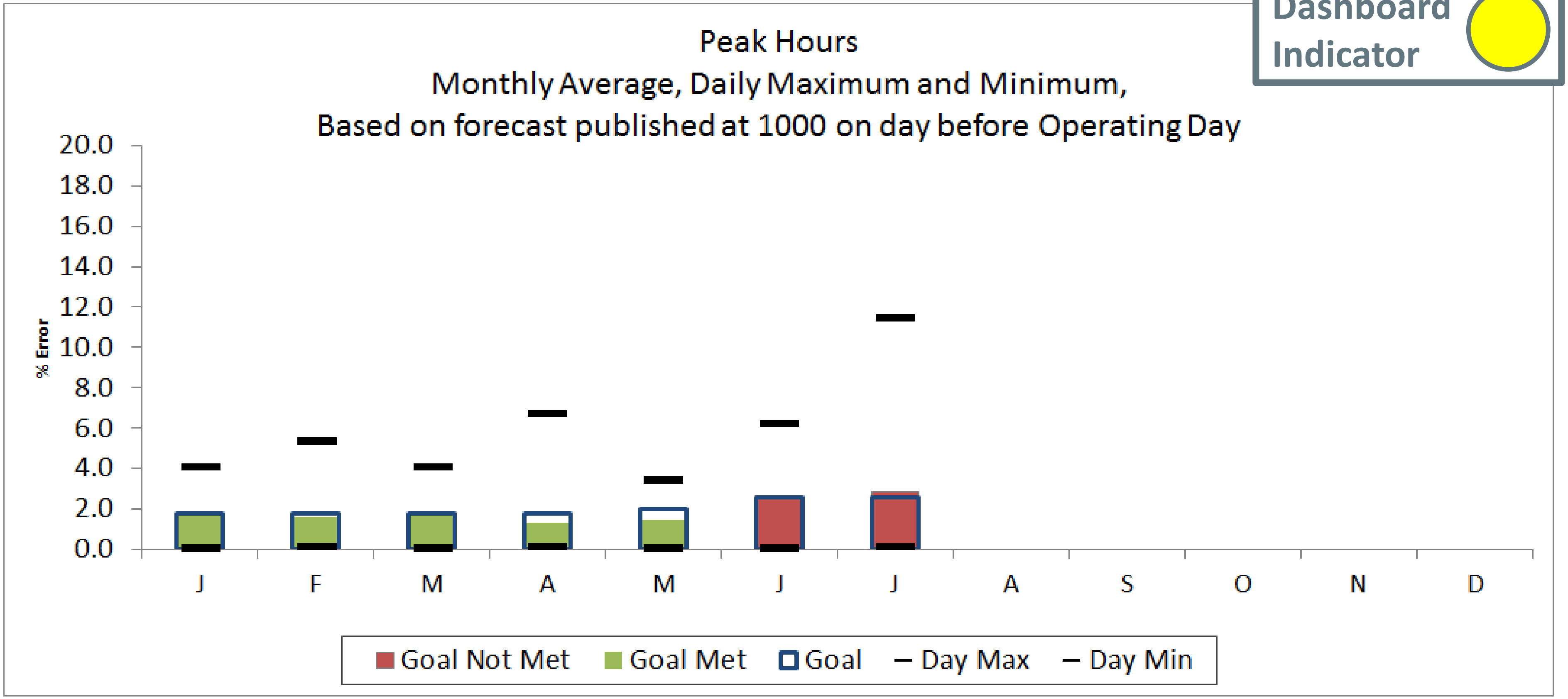
Dashboard Indicator ●



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						7.82
Day Min	0.80	0.74	1.08	1.17	0.96	0.97	0.47						0.47
MAPE	1.91	2.34	2.70	2.52	2.36	2.63	2.64						2.44
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60						

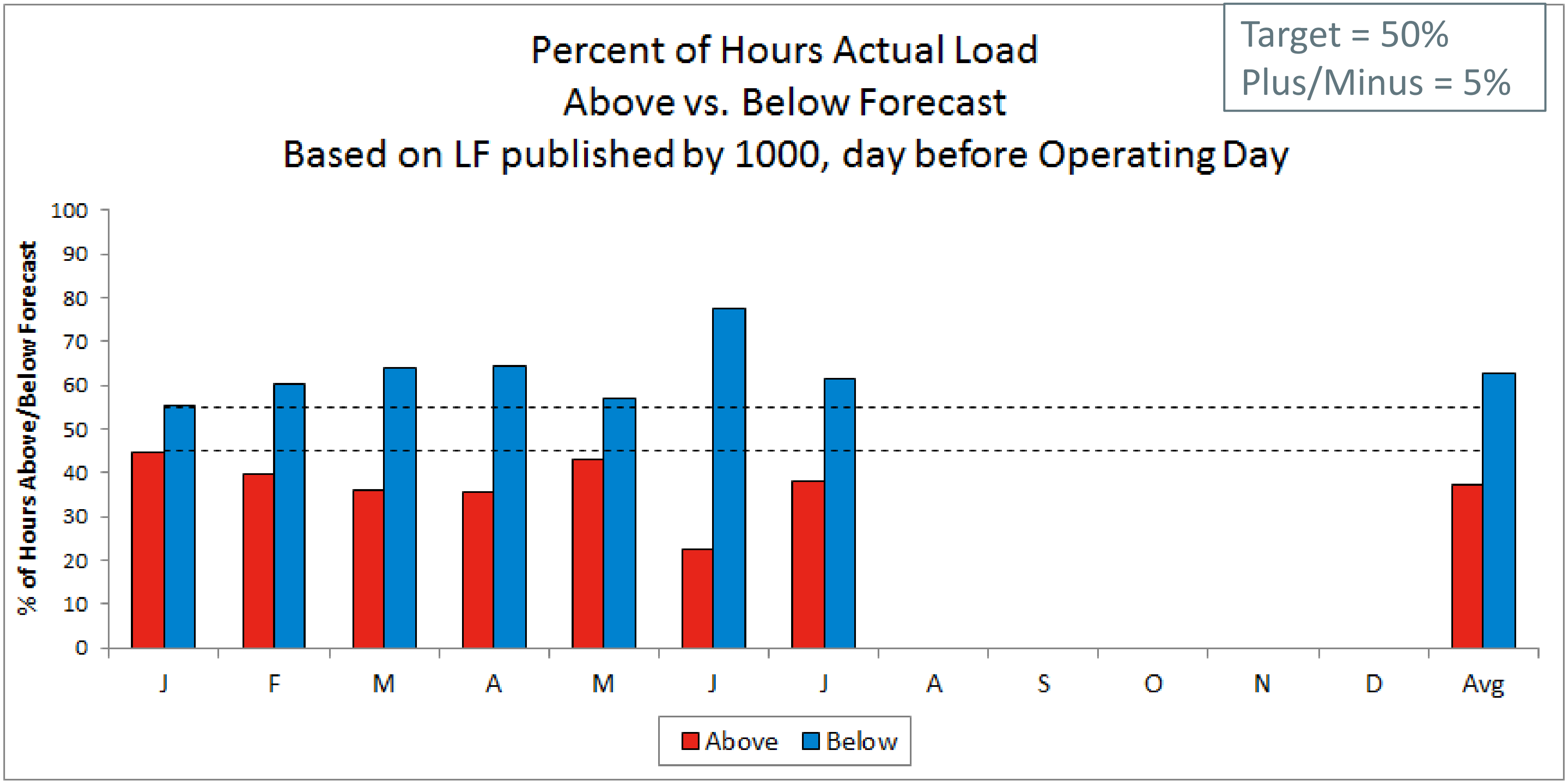
2023 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator 🟡



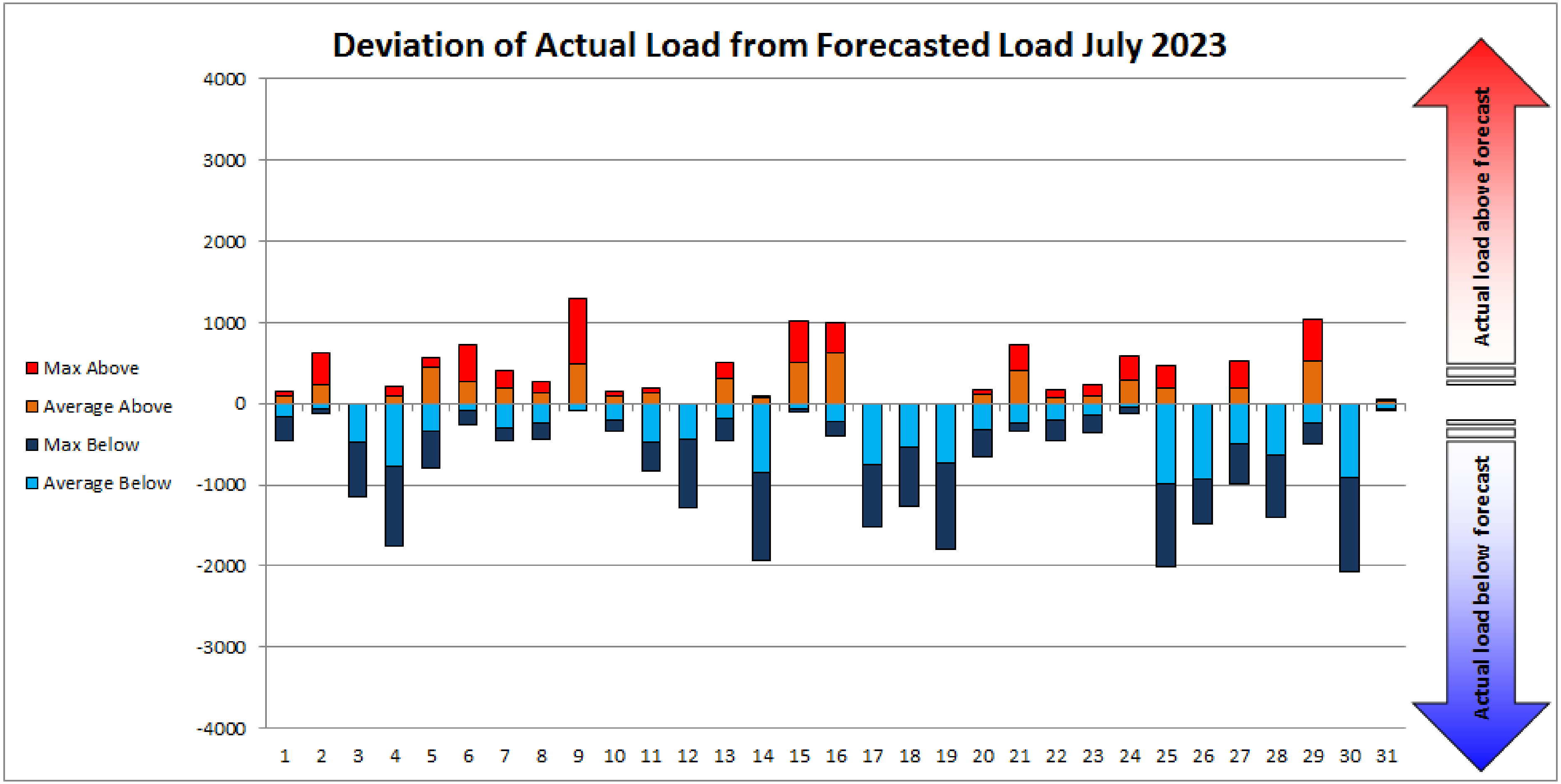
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.05	5.32	4.06	6.68	3.43	6.21	11.40						11.40
Day Min	0.01	0.08	0.06	0.11	0.03	0.04	0.08						0.01
MAPE	1.70	1.64	1.72	1.33	1.47	2.65	2.83						1.91
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60						

2023 System Operations - Load Forecast Accuracy cont.

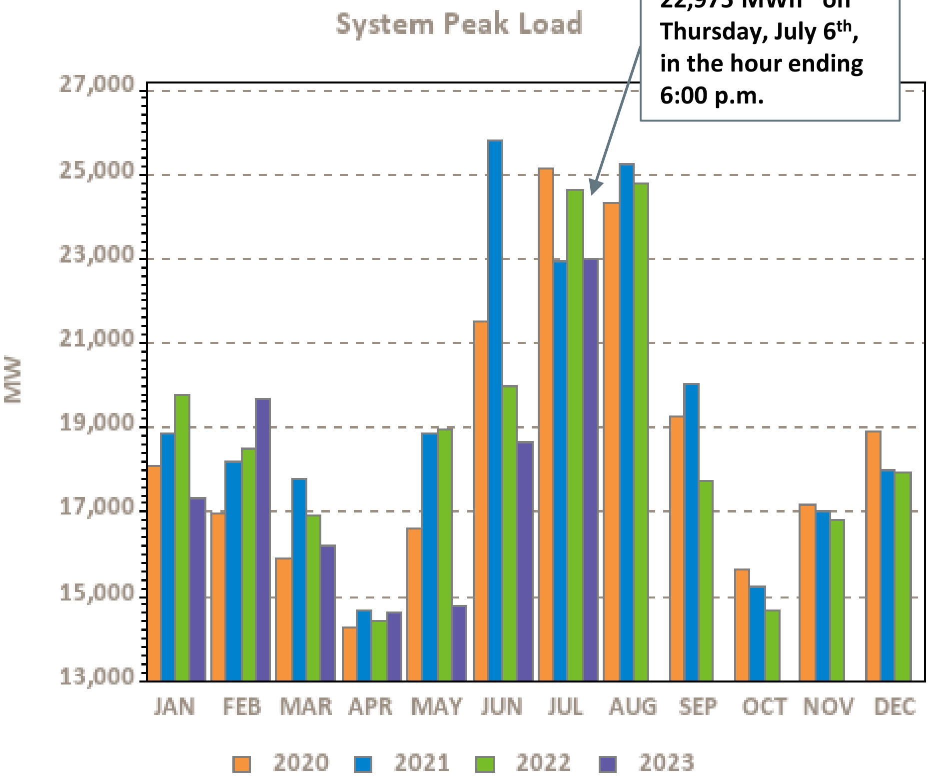


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	44.6	39.7	36.2	35.7	43	22.6	38.3						37
Below %	55.4	60.3	63.8	64.3	57	77.4	61.7						63
Avg Above	235.7	228	172.9	194.5	183.5	120	181.1						236
Avg Below	-197.3	-248.9	-328.3	-245.0	-200.1	-350.3	-393.5						-394
Avg All	-10	-28	-142	-74	-17	-236	-187						-100

2023 System Operations - Load Forecast Accuracy cont.

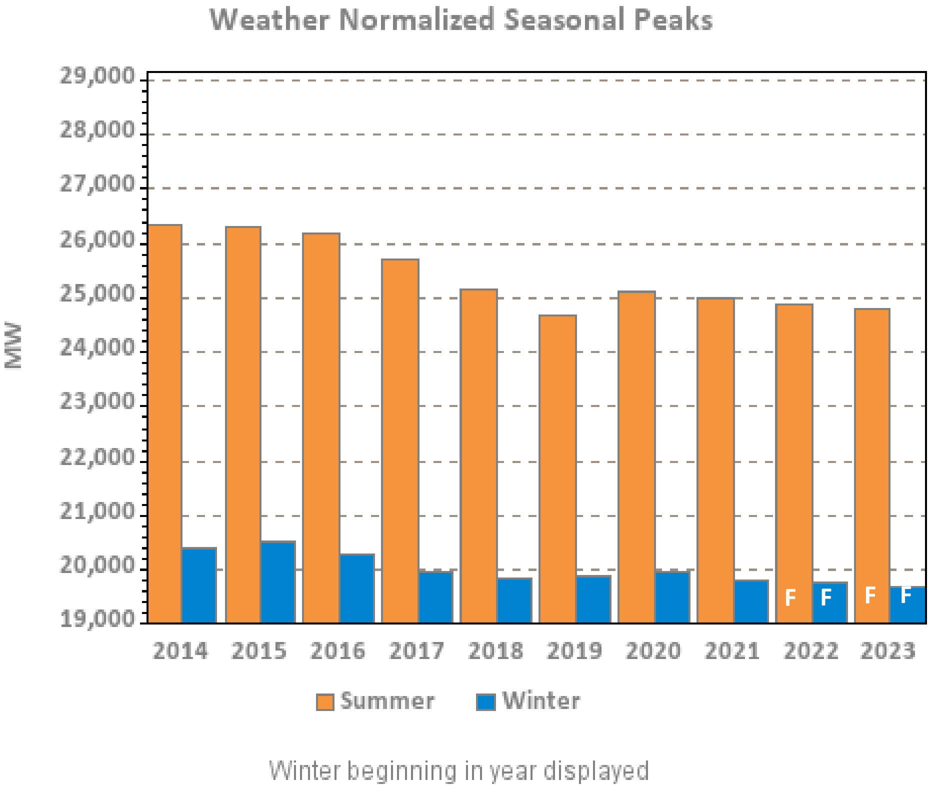


Monthly Peak Loads and Weather Normalized Seasonal Peak History



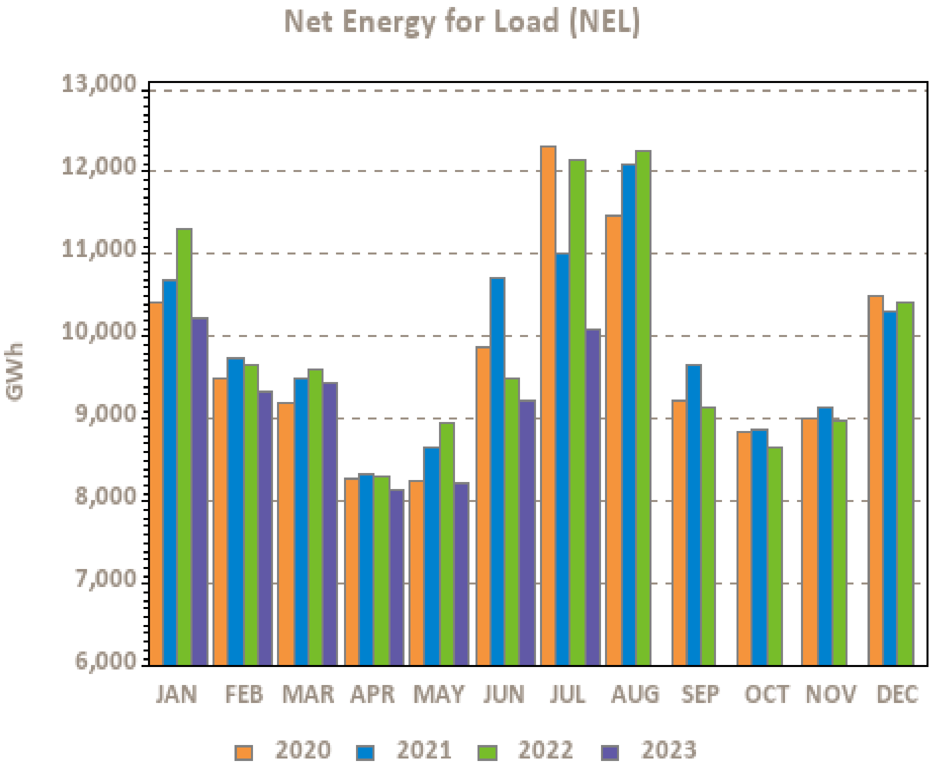
22,975 MWh* on Thursday, July 6th, in the hour ending 6:00 p.m.

***Revenue quality metered value**

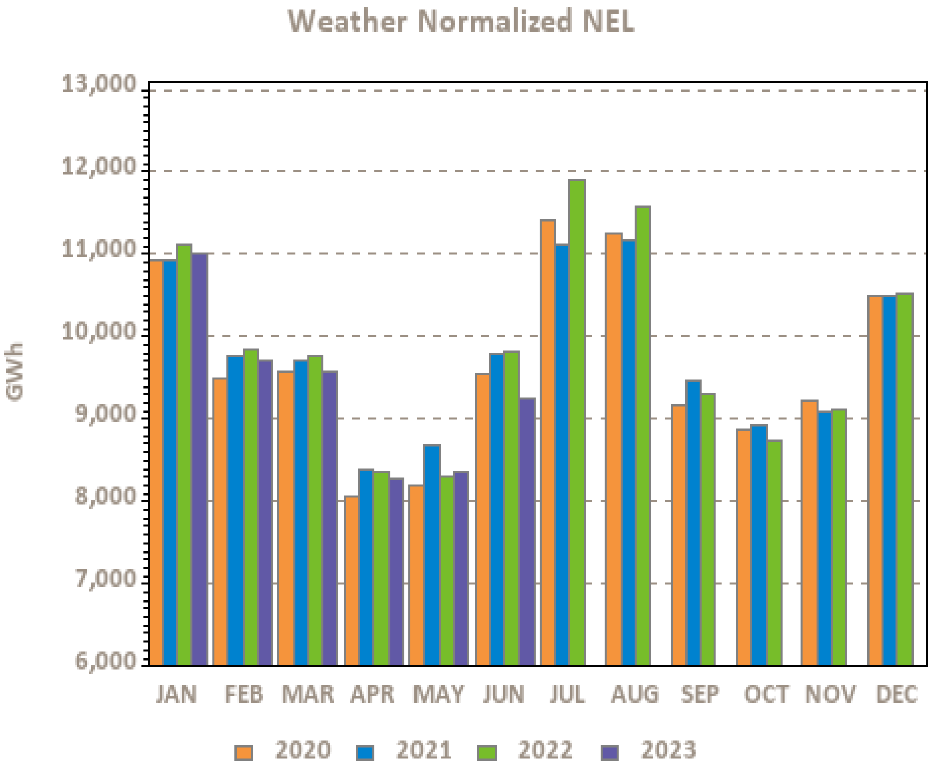


F – designates forecasted values, which are typically updated in April/May of the following year; represents "net forecast" (i.e., the gross forecast net of passive demand response and behind-the-meter solar demand)

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



Ann Tot (TWh): 116.9 118.8 118.9 64.7

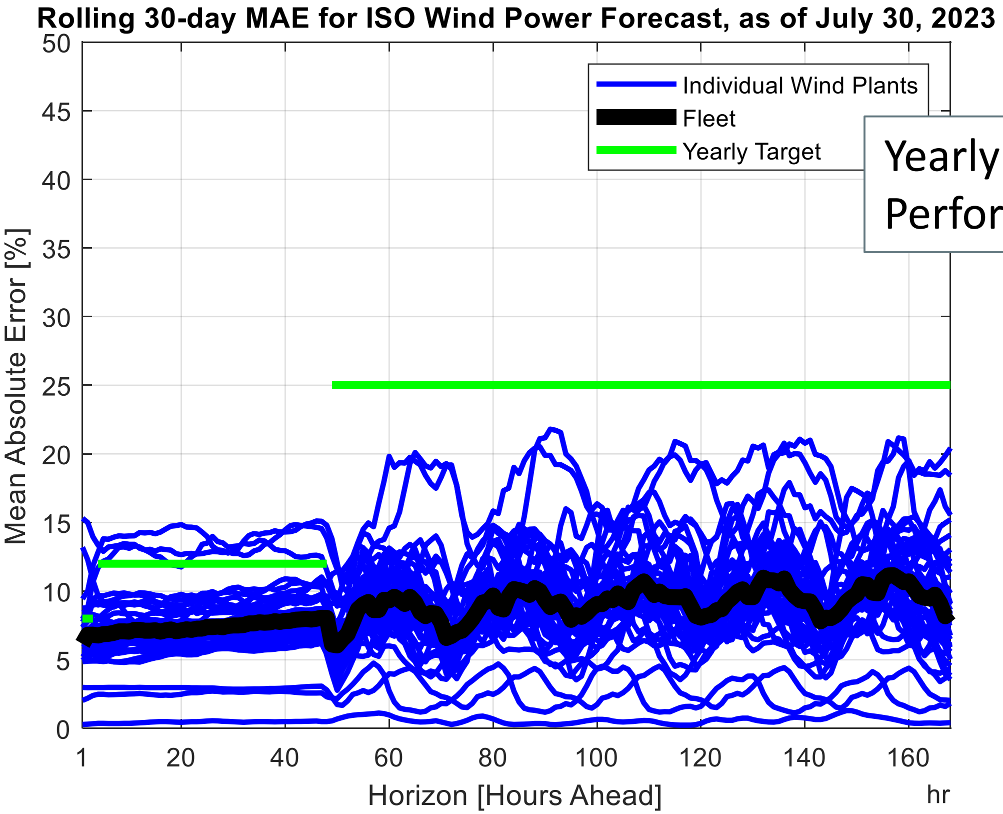


Ann Tot (TWh): 116.3 117.6 118.4 56.2

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 ●

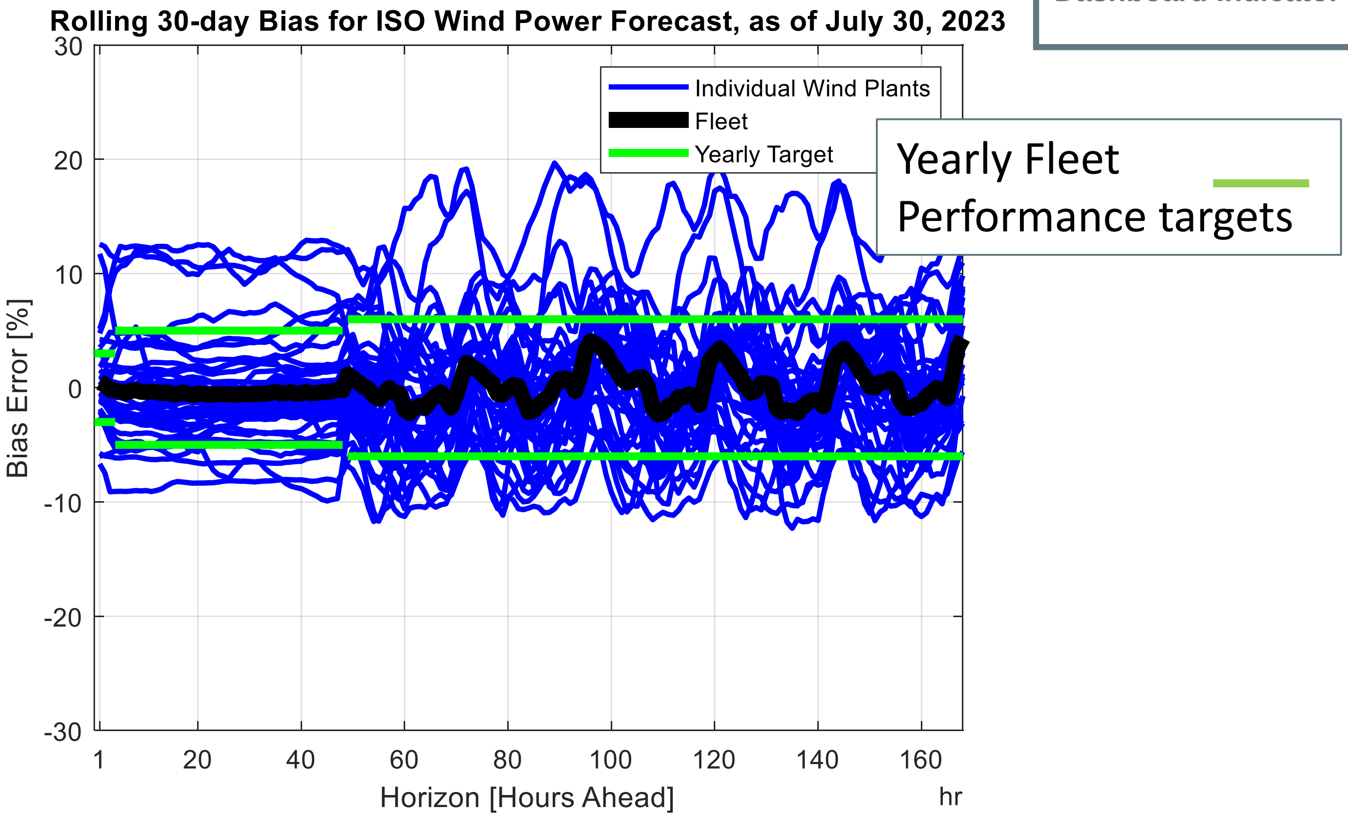


Yearly Fleet Performance targets 🟩

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

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

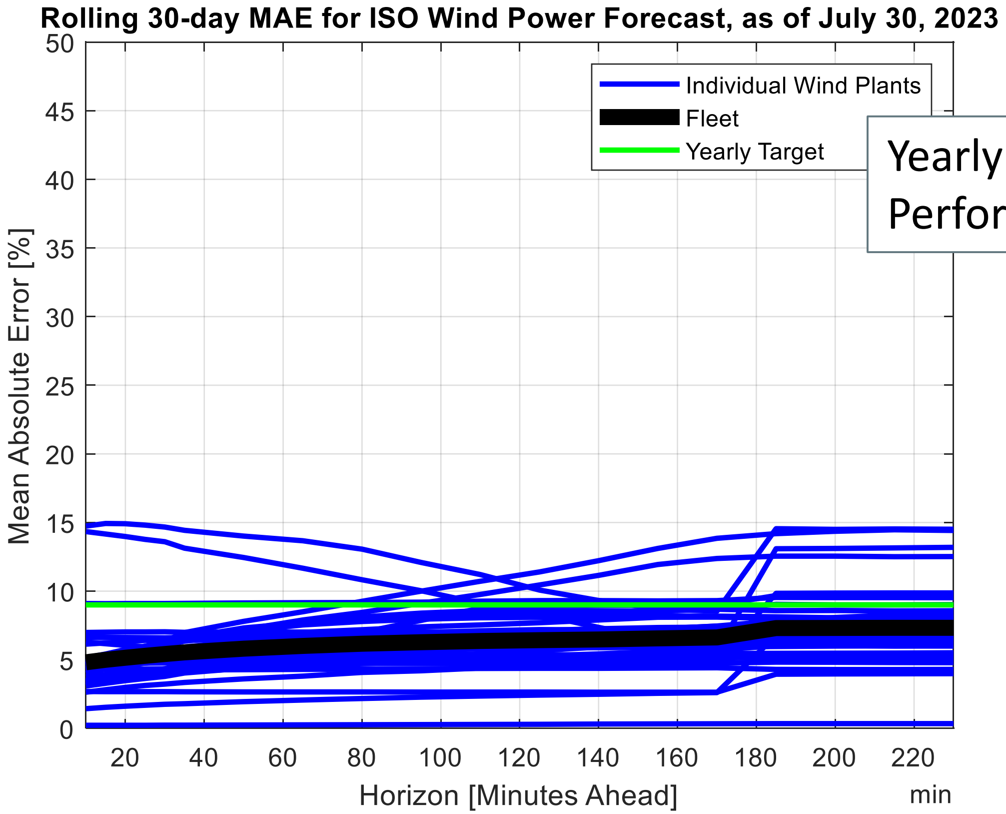
Dashboard Indicator ●



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

Wind Power Forecast Error Statistics: Short Term Forecast MAE

Dashboard Indicator ●



Yearly Fleet Performance targets 🟩

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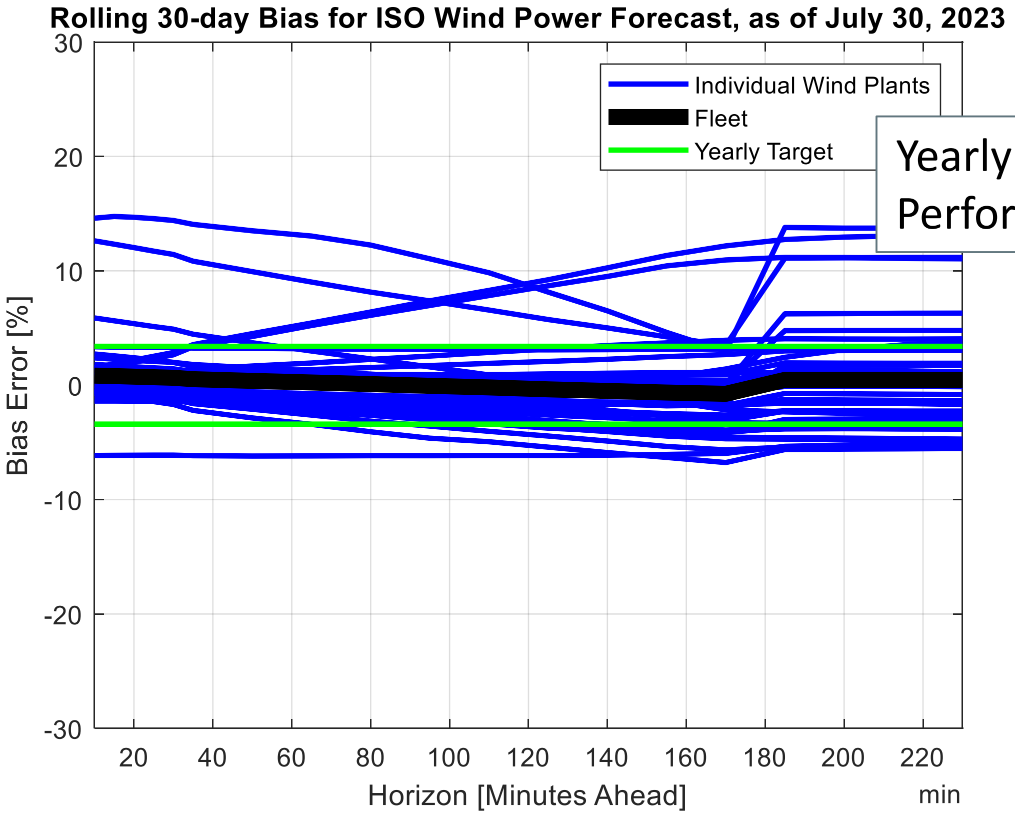
Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator ●

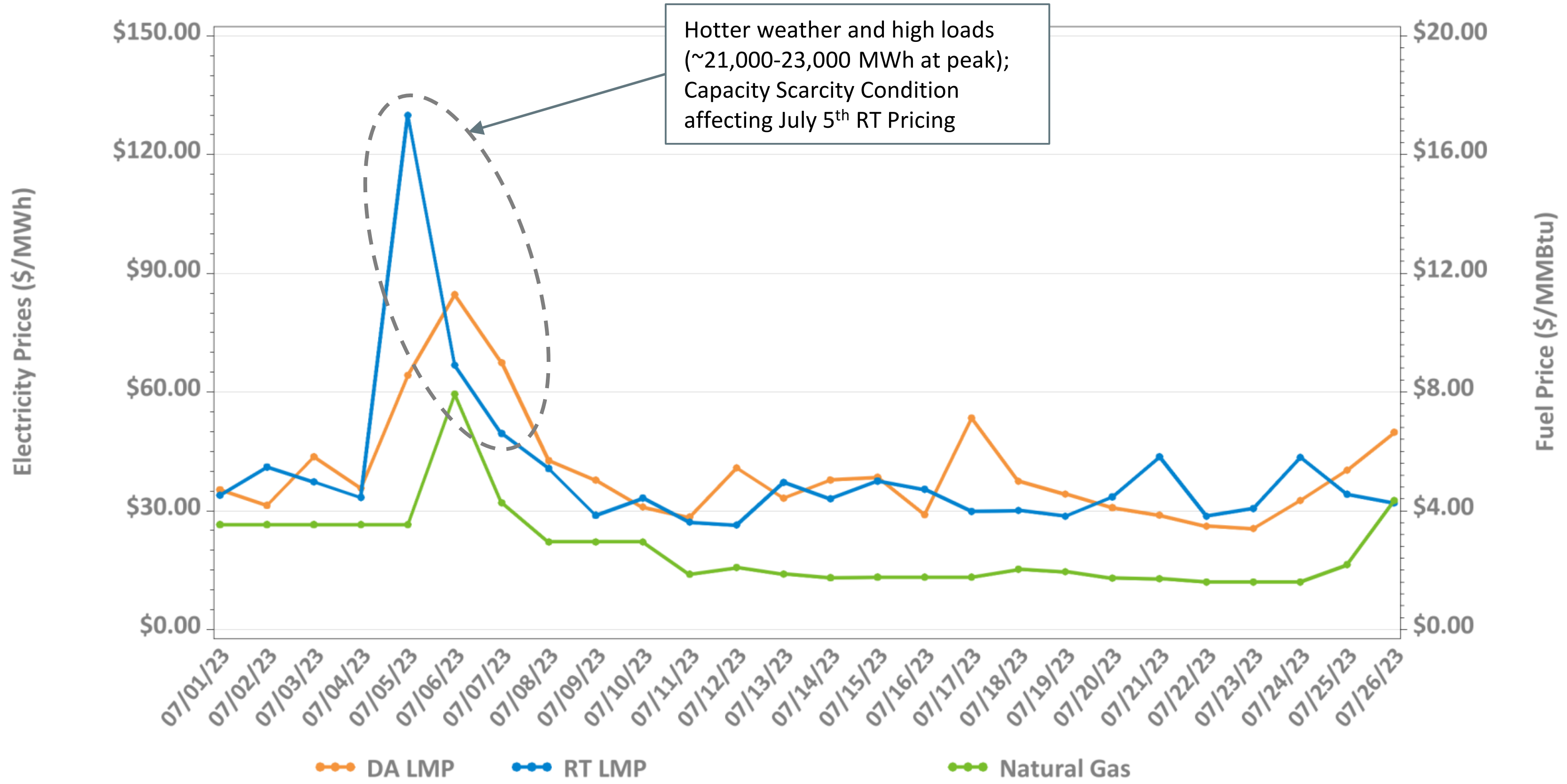


Yearly Fleet Performance targets

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

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: July 1-26, 2023



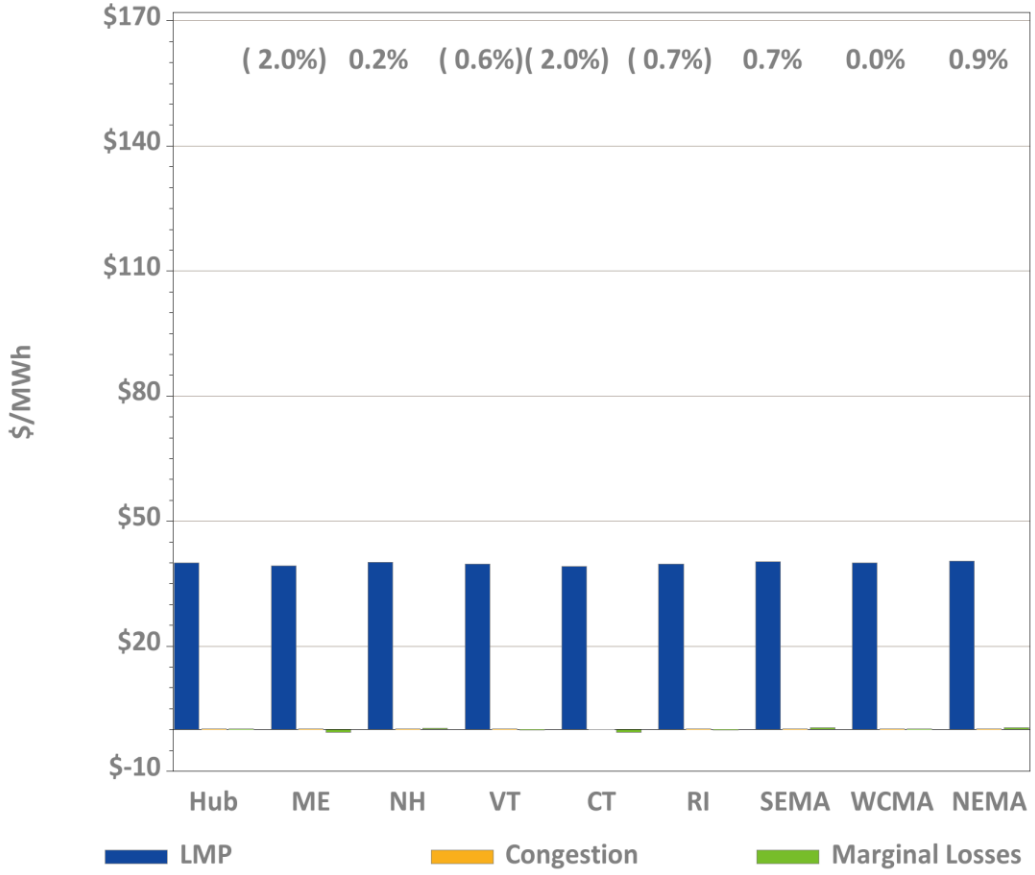
Hotter weather and high loads (~21,000-23,000 MWh at peak); Capacity Scarcity Condition affecting July 5th RT Pricing

Underlying natural gas data furnished by:

***Revenue quality metered values**

Average price difference over this period (DA-RT): $0.56
Average price difference over this period ABS(DA-RT): $10.11
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 26%
Gas price is average of Massachusetts delivery points

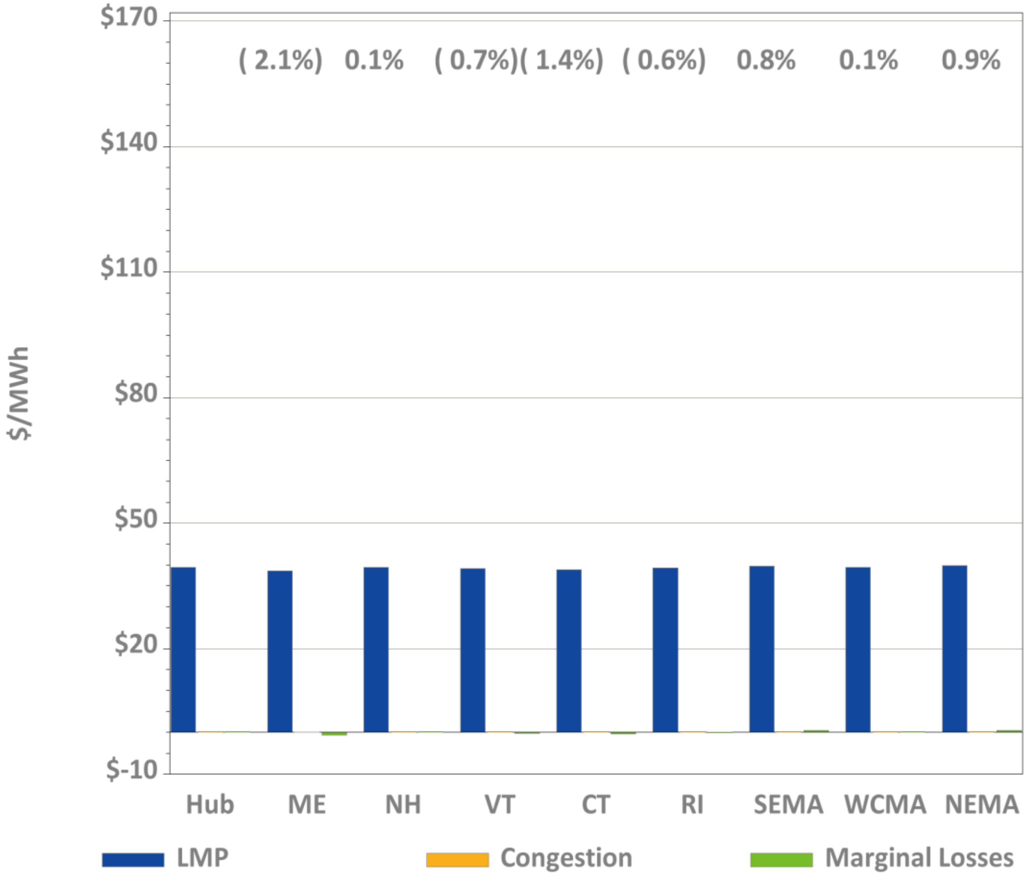
DA LMPs Average by Zone & Hub, July 2023



ME - Maine
NH – New Hampshire
VT – Vermont
CT – Connecticut

RI – Rhode Island
SEMA – Southeastern Massachusetts
WCMA – Western/Central Massachusetts
NEMA – Northeastern Massachusetts

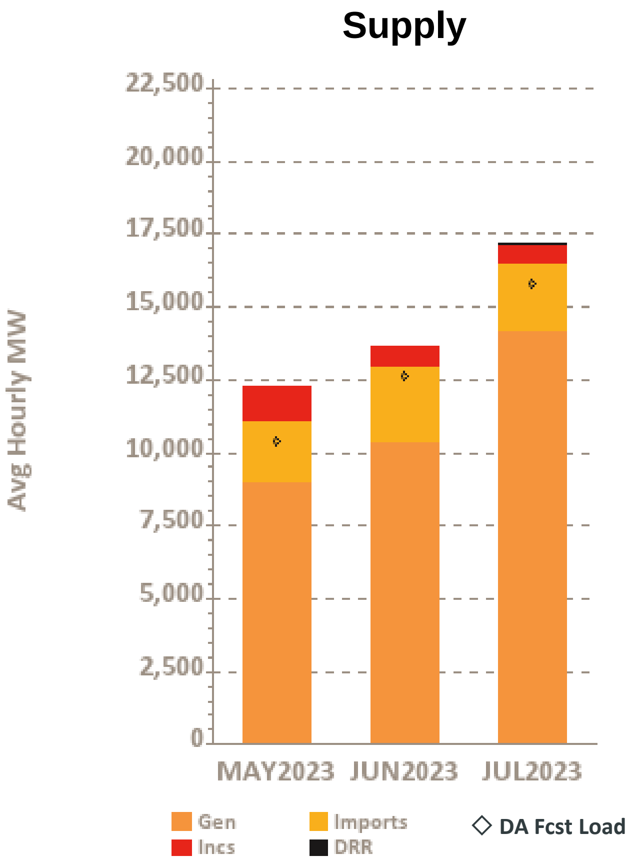
RT LMPs Average by Zone & Hub, July 2023

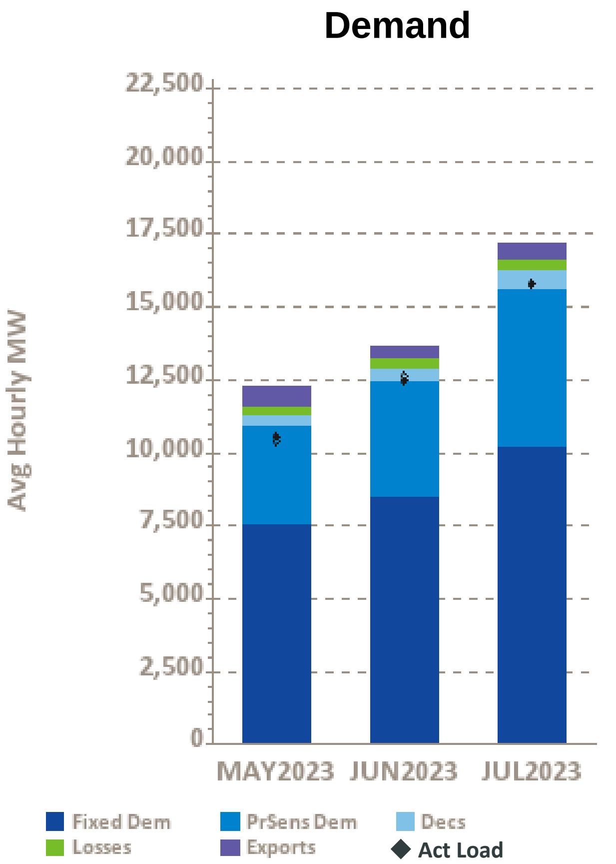


Definitions

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

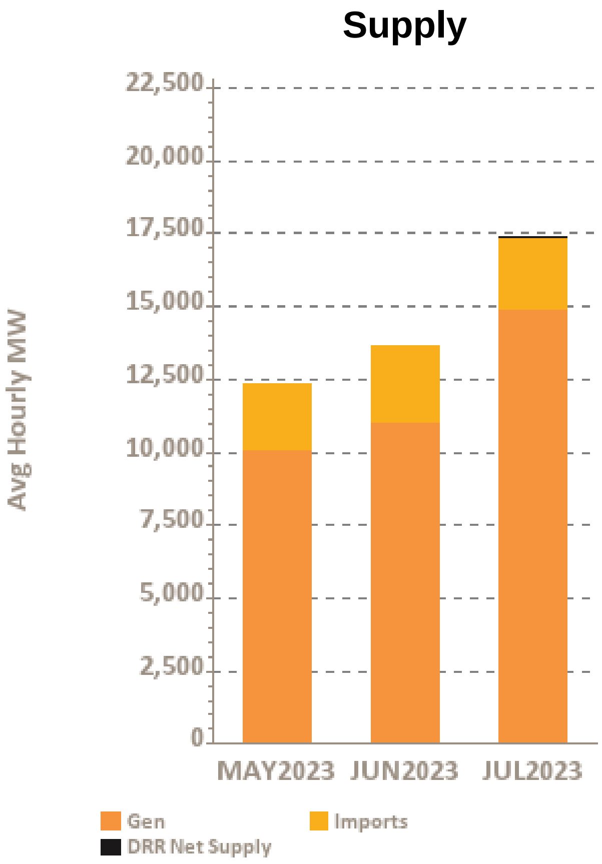


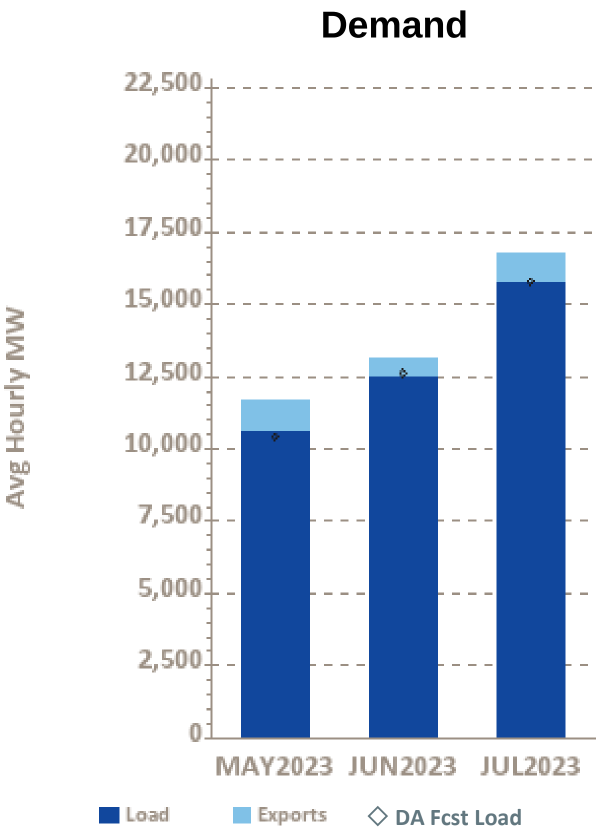


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

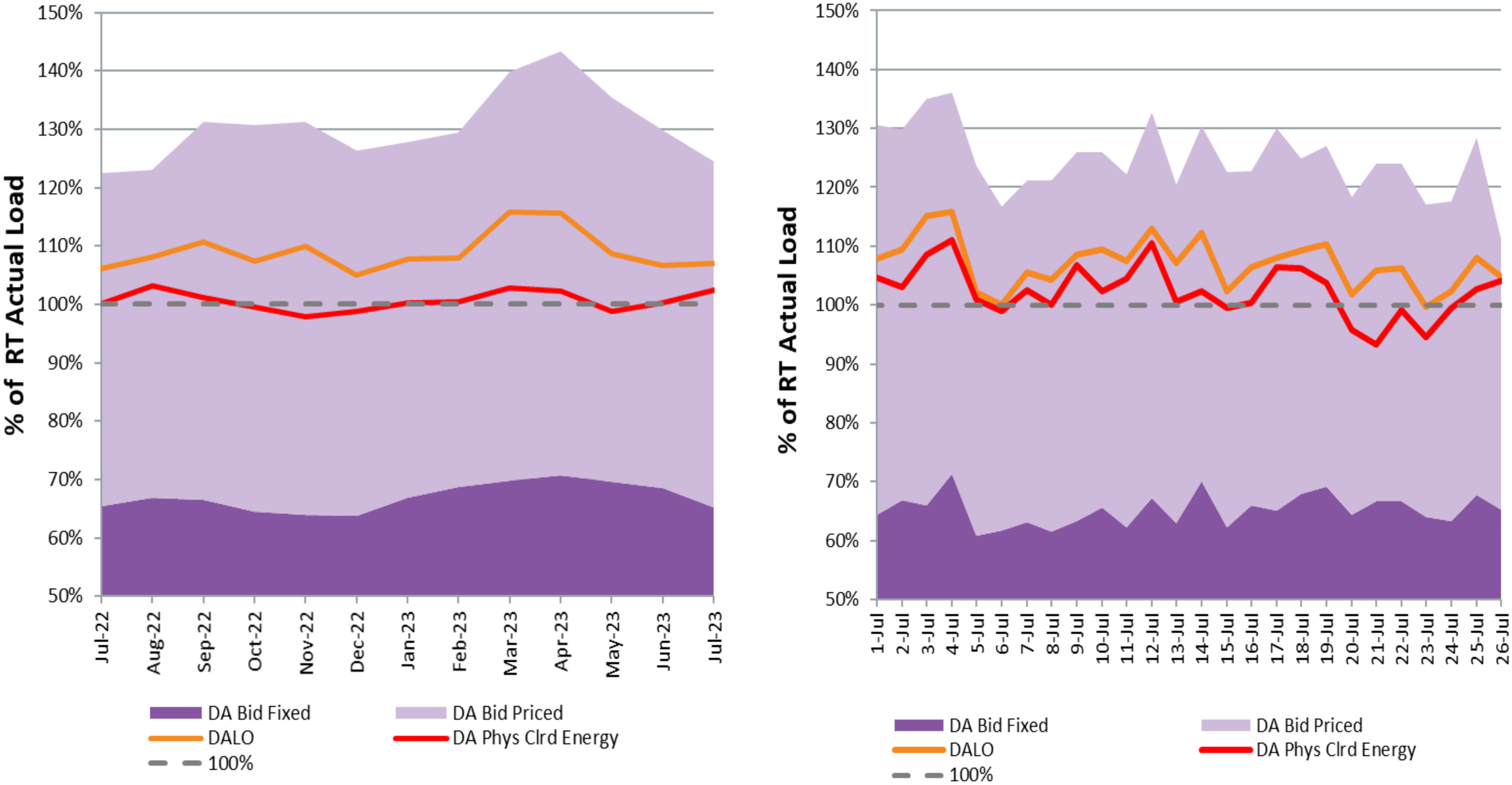
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

Components of RT Supply and Demand – Last Three Months



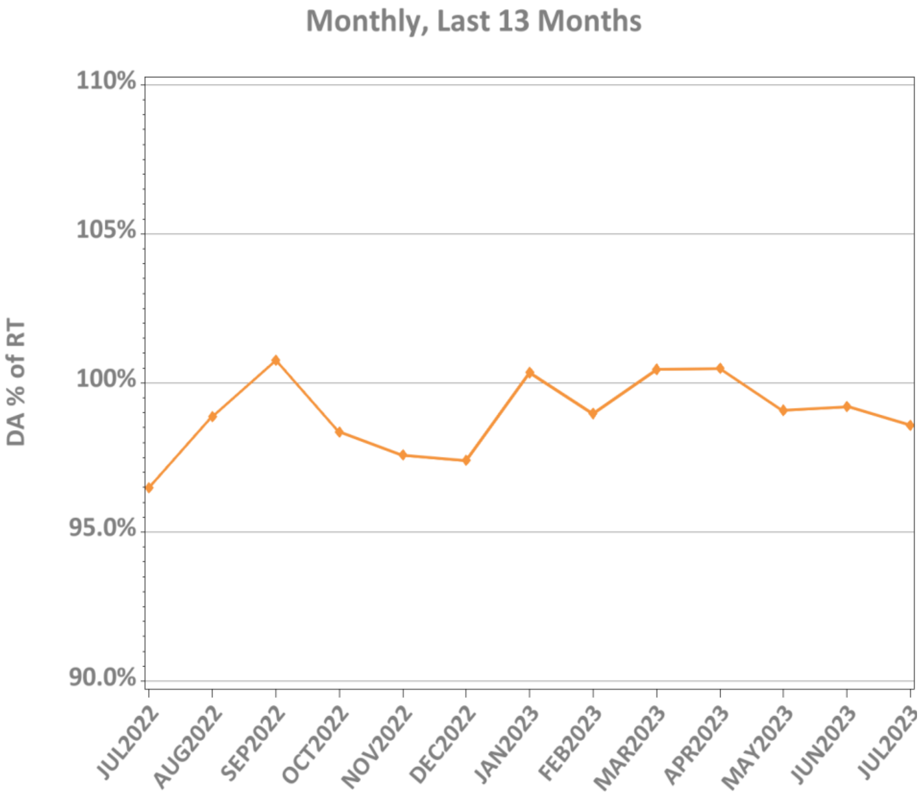


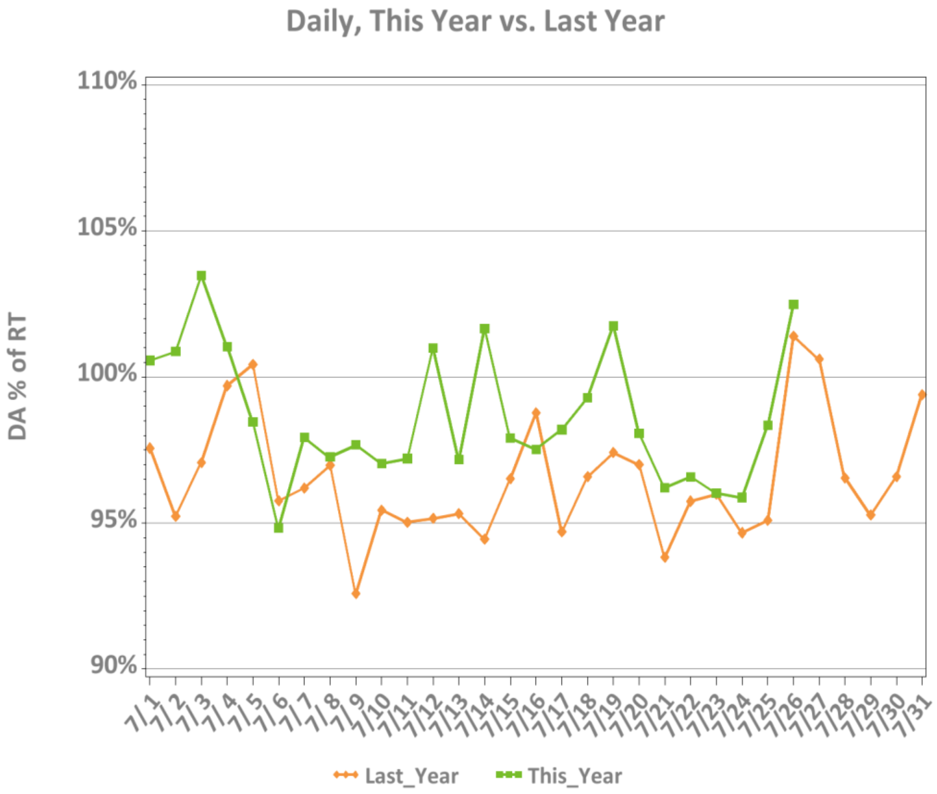
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)



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.)

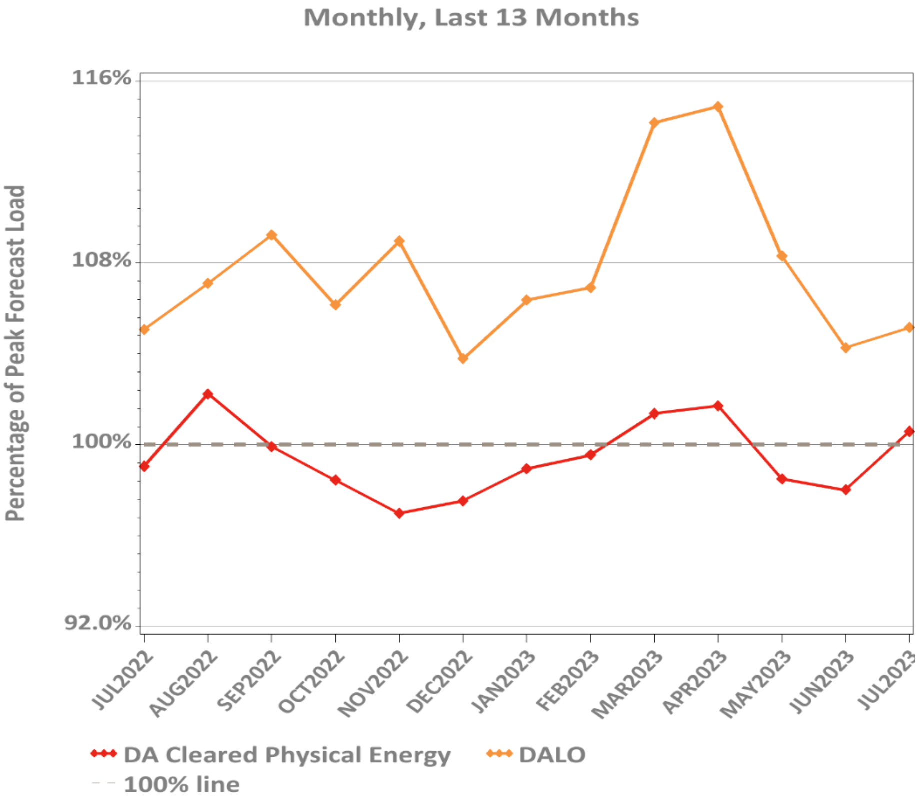
DA vs. RT Load Obligation: July, This Year vs. Last Year

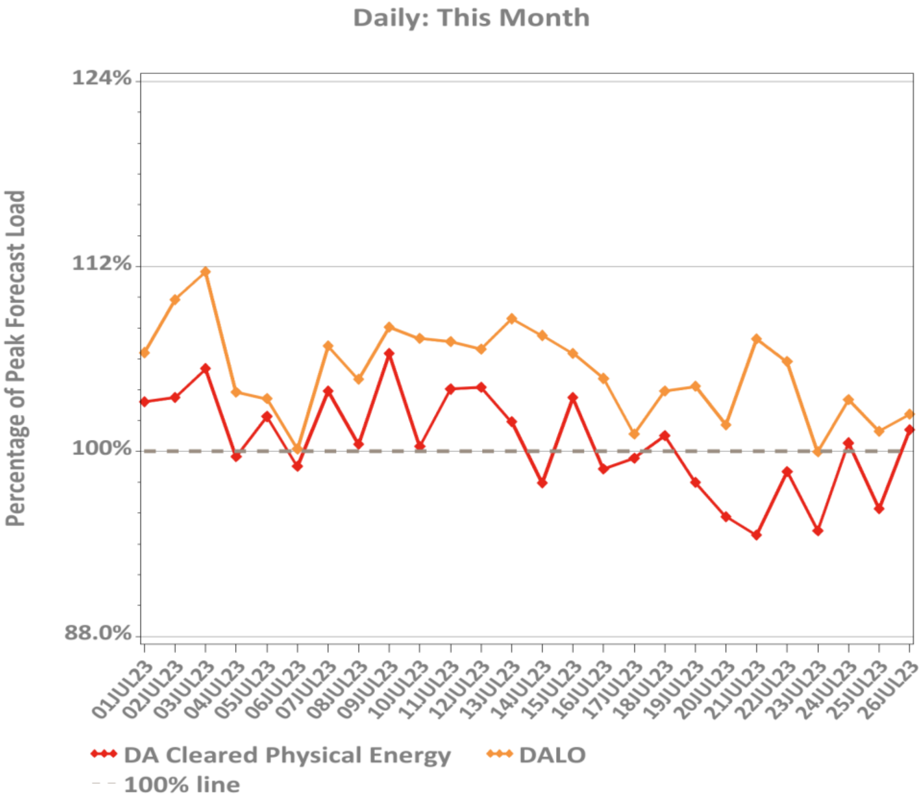




*Hourly average values

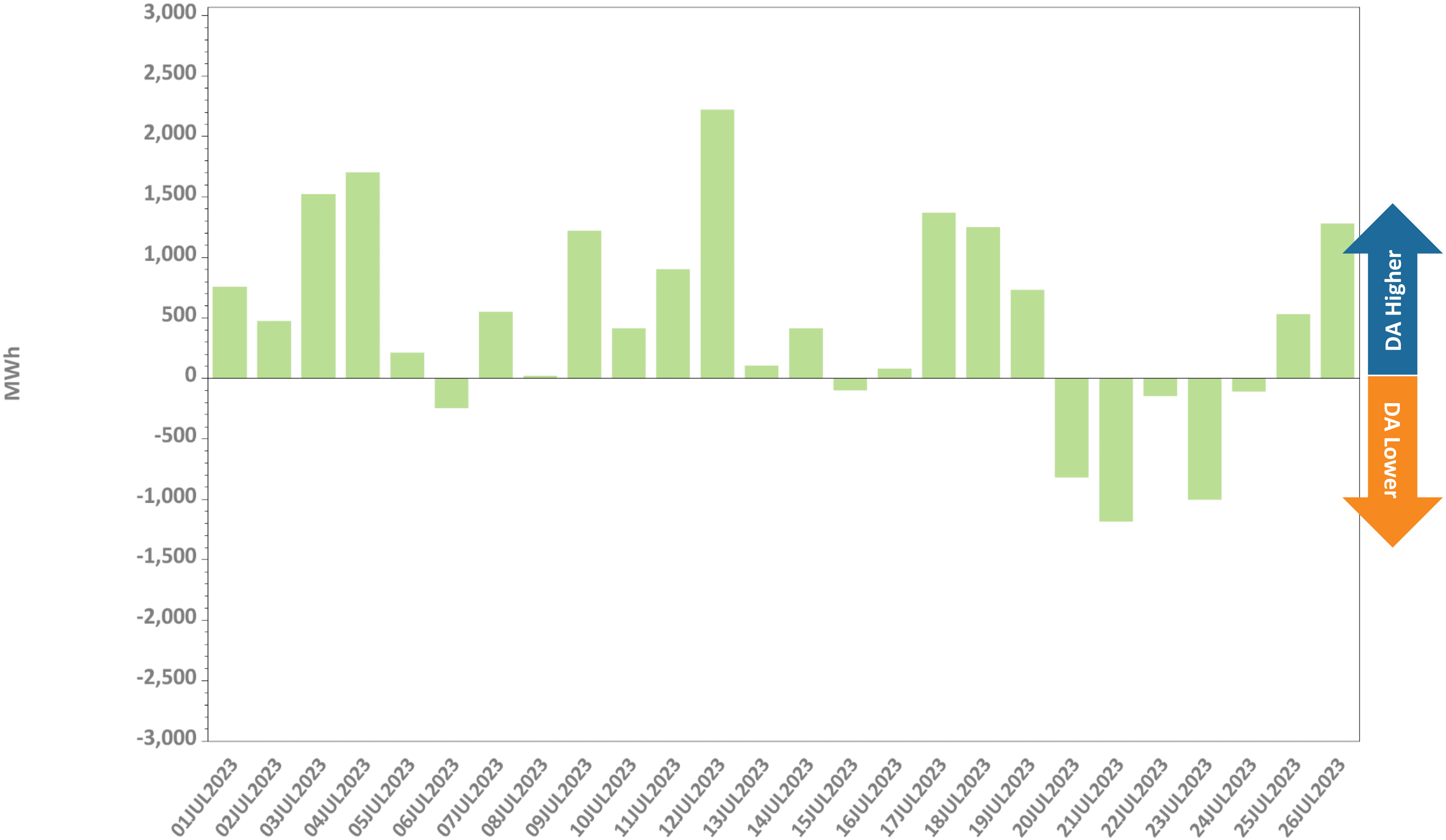
DA Volumes as % of Forecast in Peak Hour


Monthly, Last 13 Months


Daily: This Month

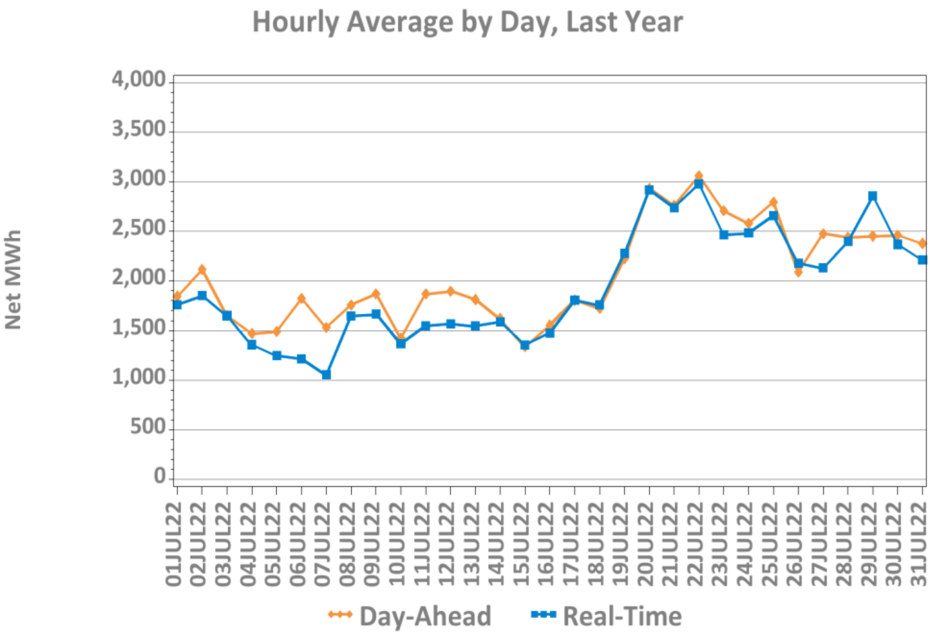
Note: The number of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month was: one (on July 17th).

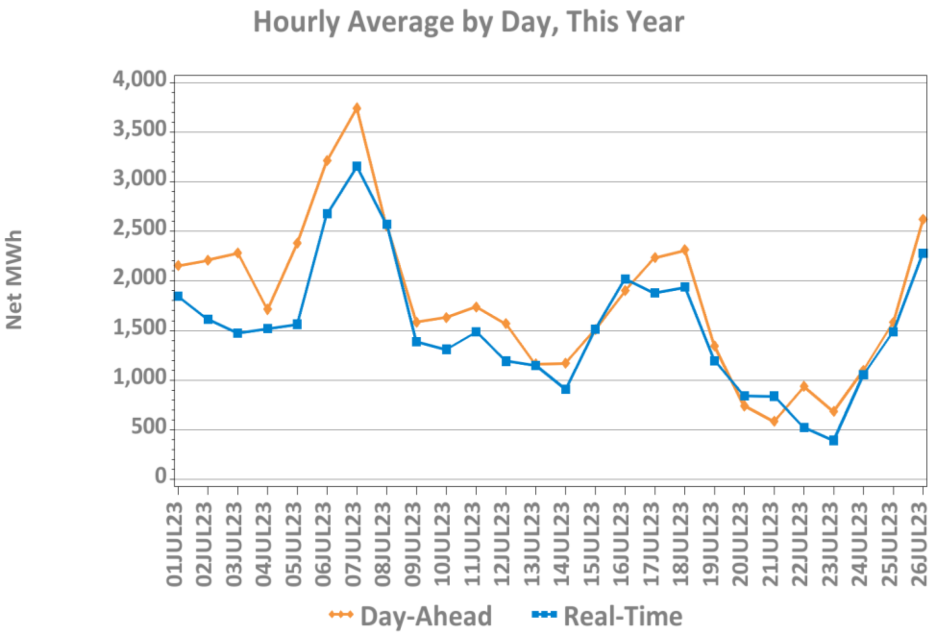
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



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

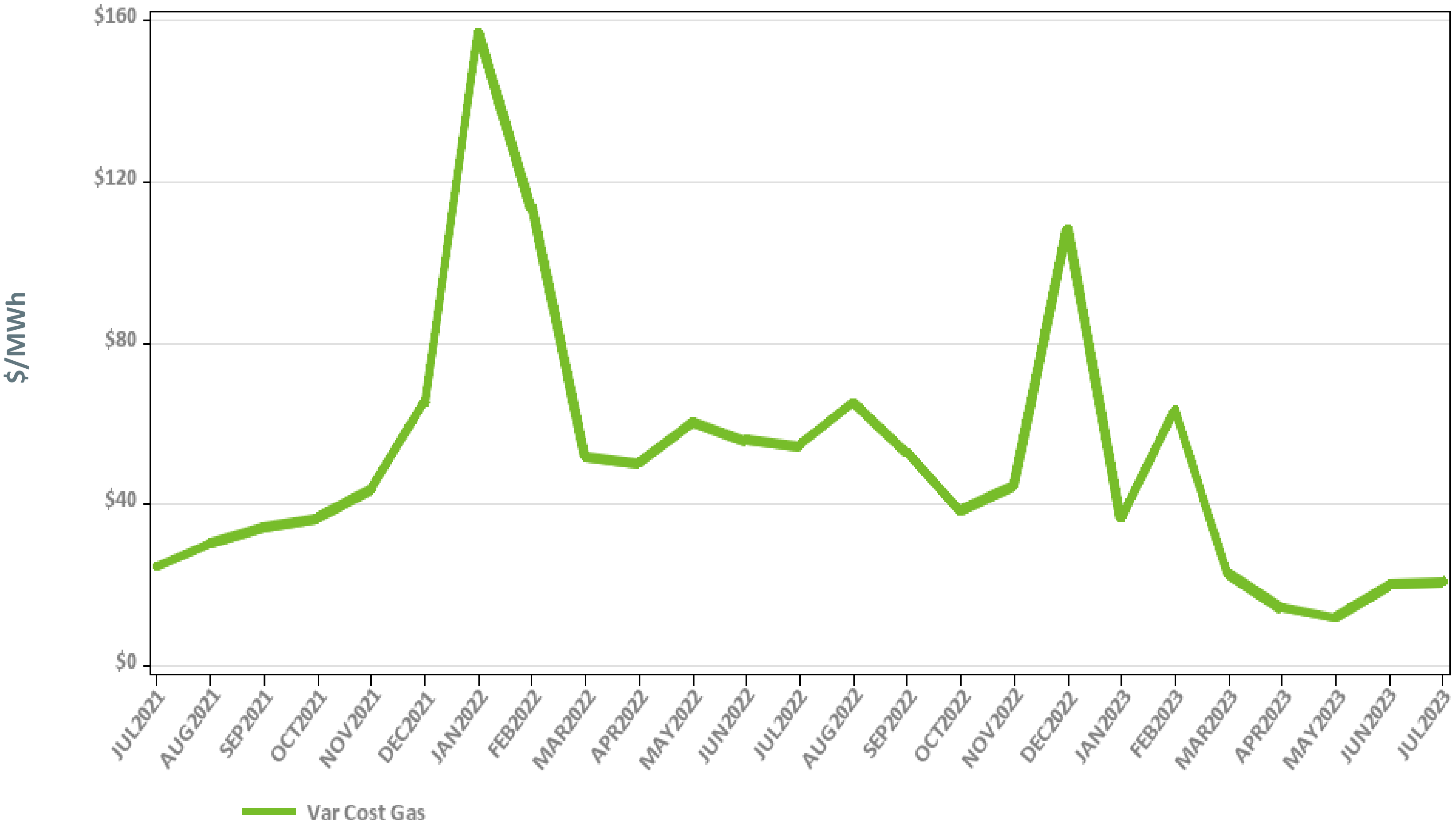
DA vs. RT Net Interchange July 2023 vs. July 2022


Hourly Average by Day, Last Year


Hourly Average by Day, This Year

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

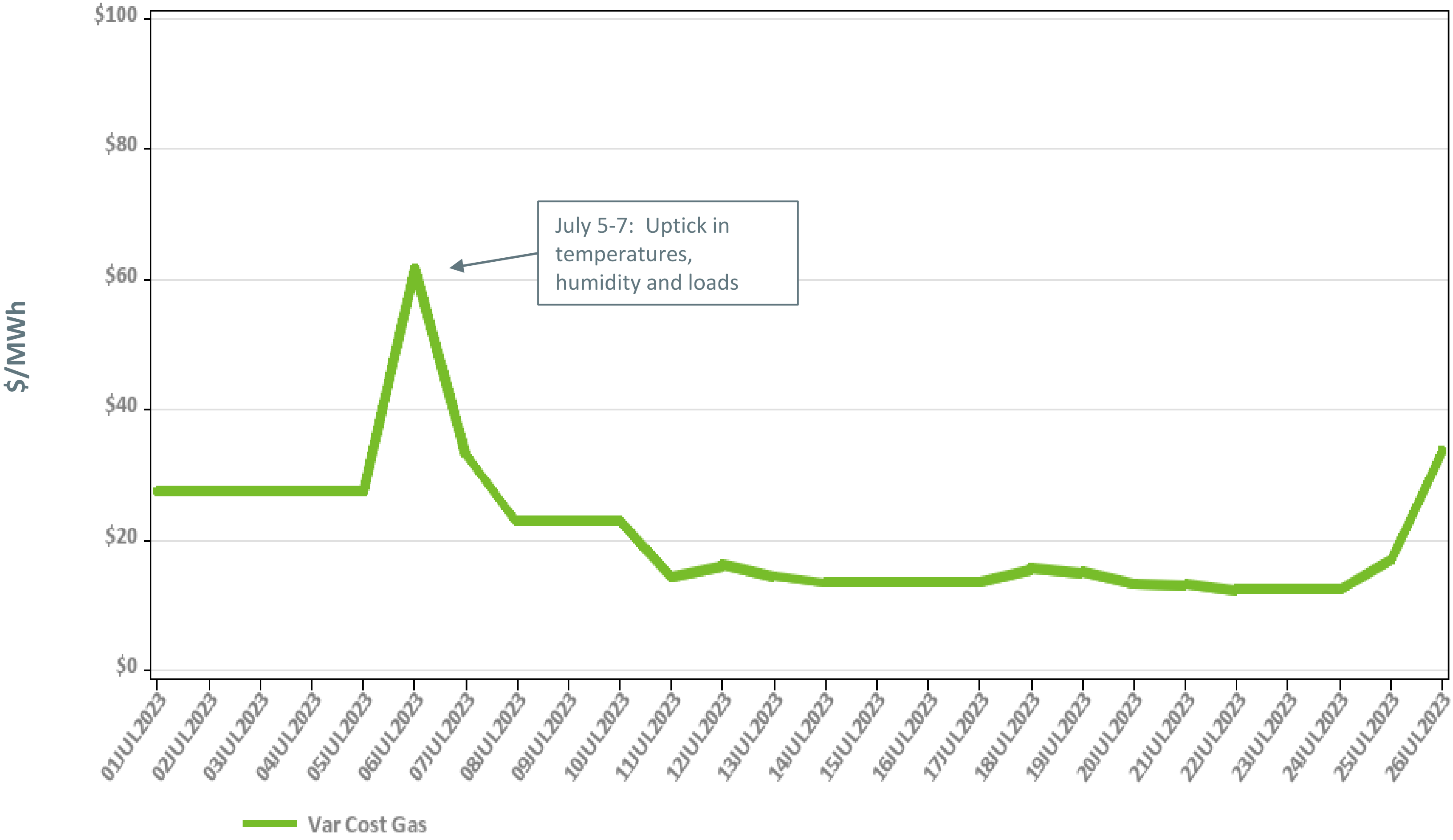


Underlying natural gas data furnished by:

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



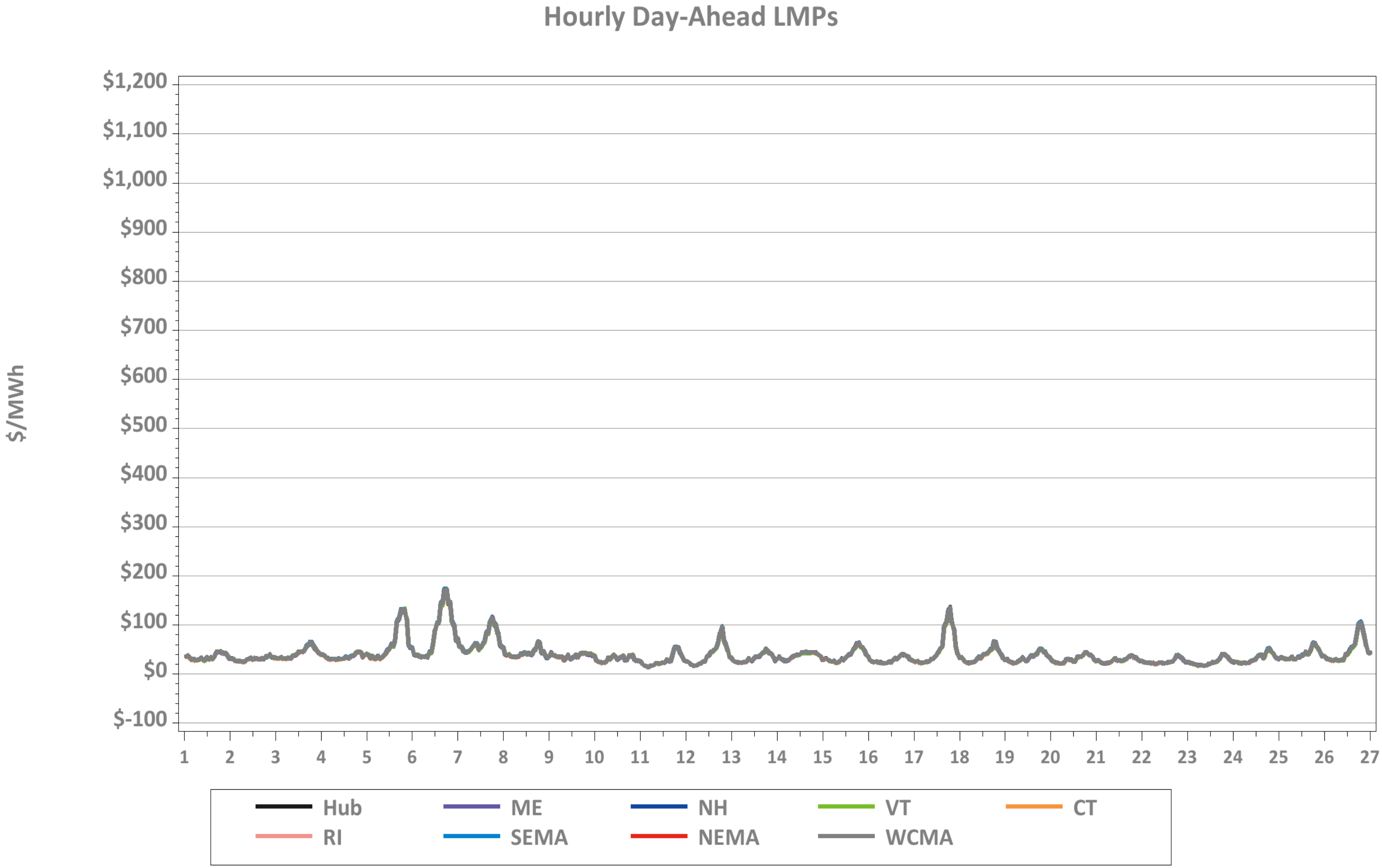
July 5-7: Uptick in temperatures, humidity and loads

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

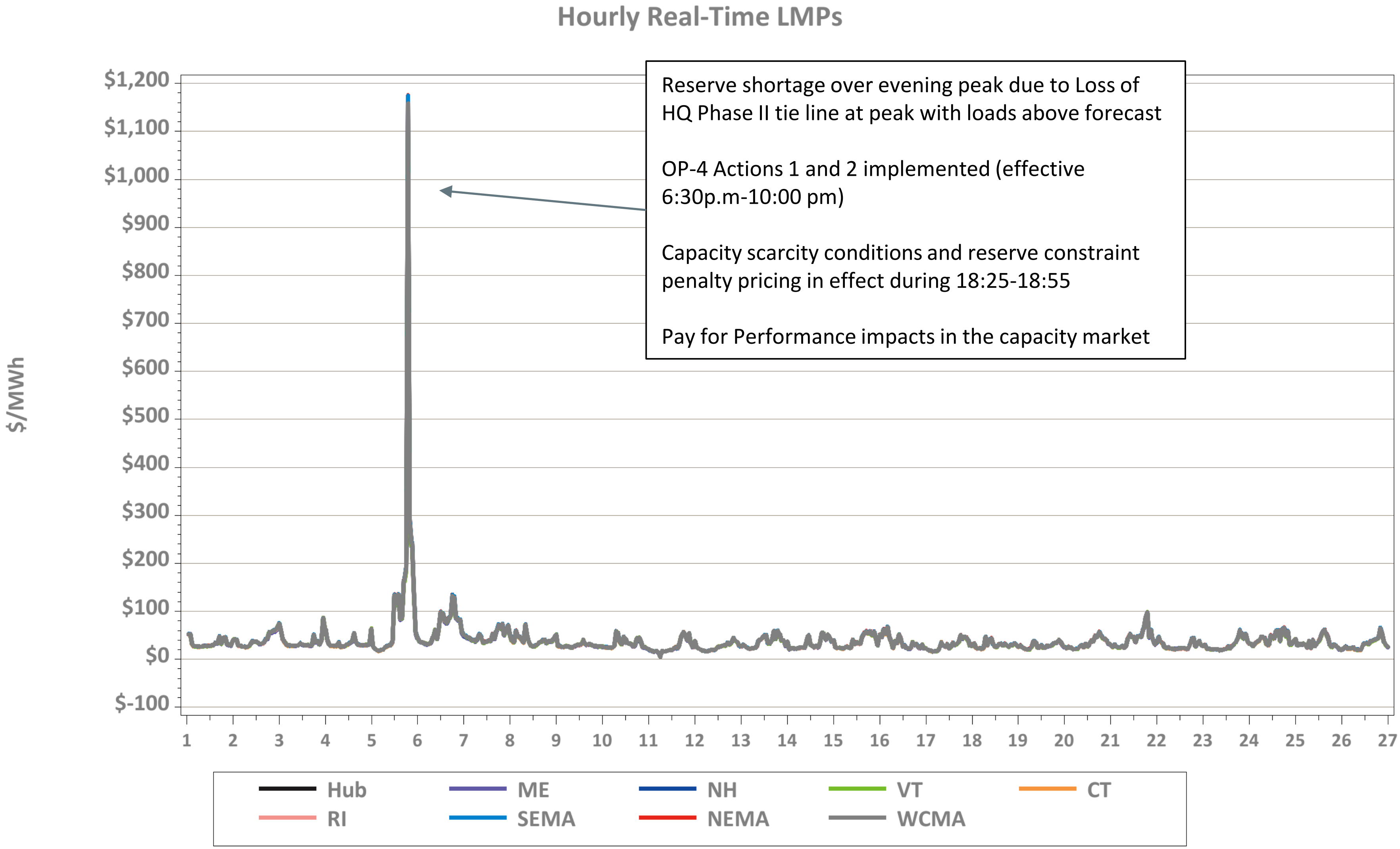
Underlying natural gas data furnished by:

ICE Global markets in clear view

Hourly DA LMPs, July 1-26, 2023



Hourly RT LMPs, July 1-26, 2023



Reserve shortage over evening peak due to Loss of HQ Phase II tie line at peak with loads above forecast

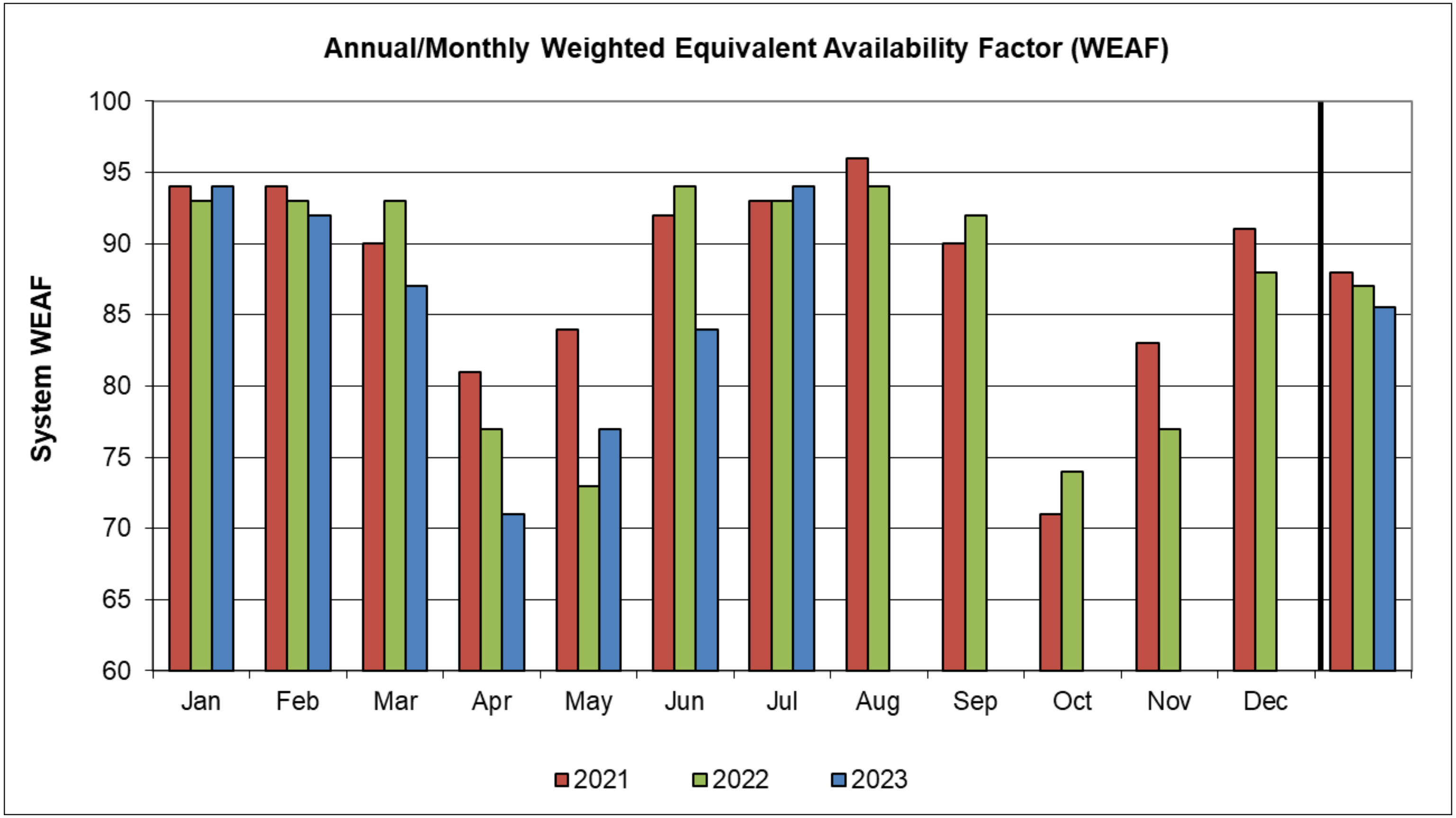
OP-4 Actions 1 and 2 implemented (effective 6:30p.m-10:00 pm)

Capacity scarcity conditions and reserve constraint penalty pricing in effect during 18:25-18:55

Pay for Performance impacts in the capacity market

* BTM (Behind the meter)

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2023	94	92	87	71	77	84	94						86
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 7/23/2023

BACK-UP DETAIL

DEMAND RESPONSE

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

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	48.7	200.2	0.0	248.9
NH	39.6	156.7	0.0	196.3
VT	39.8	134.0	0.0	173.8
CT	117.1	171.0	598.6	886.7
RI	21.0	320.5	0.0	341.4
SEMA	36.3	471.3	0.0	507.7
WCMA	70.4	520.4	26.6	617.4
NEMA	61.1	776.5	0.0	837.6
Total	**433.9**	**2,750.6**	**625.3**	**3,809.9**

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

NEW GENERATION

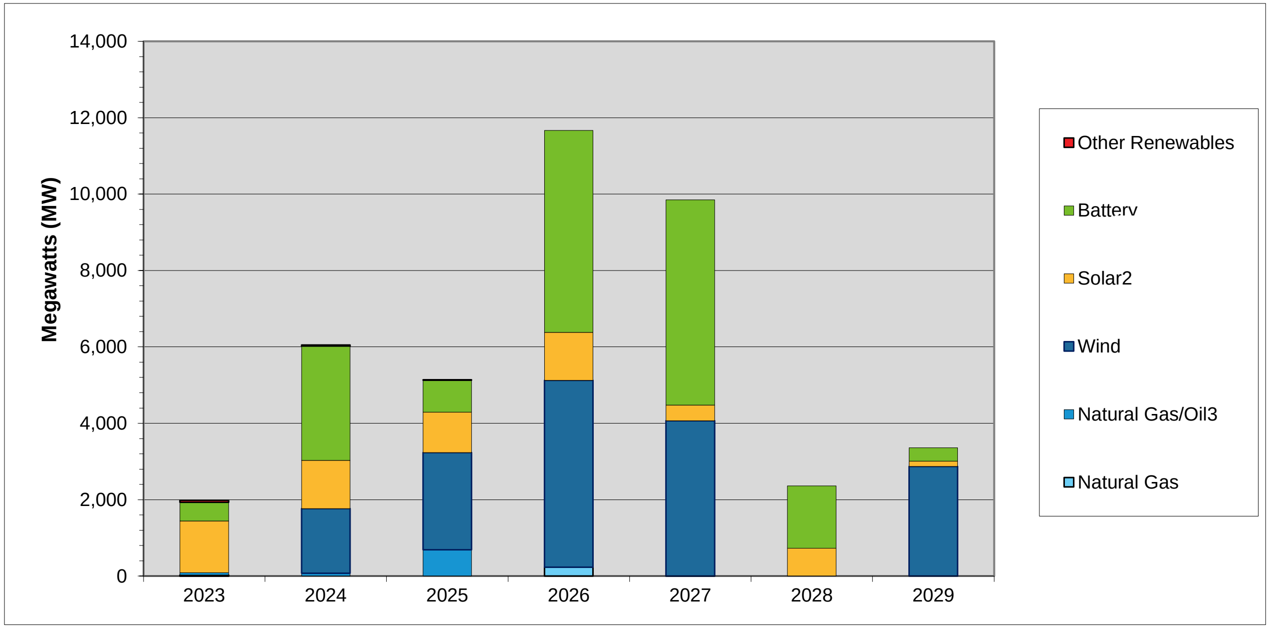
New Generation Update

Based on Queue as of 7/31/23

- Eight projects totaling 1,814 MW were added to the interconnection queue since the last update
  - Six battery projects and two solar projects with in-service dates of 2024 to 2029
- In total, 382 generation projects are currently being tracked by the ISO, totaling approximately 41,287 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	495	2,991	839	5,290	5,377	1,633	351	16,976	42.0
Solar[2]	1,349	1,263	1,060	1,255	408	725	139	6,199	15.3
Wind	0	1,693	2,545	4,893	4,064	0	2,870	16,065	39.8
Natural Gas/Oil[3]	62	73	688	0	0	0	0	823	2.0
Natural Gas	26	0	0	233	4	0	0	263	0.7
Totals	1,979	6,050	5,134	11,671	9,853	2,358	3,360	40,405	100.0

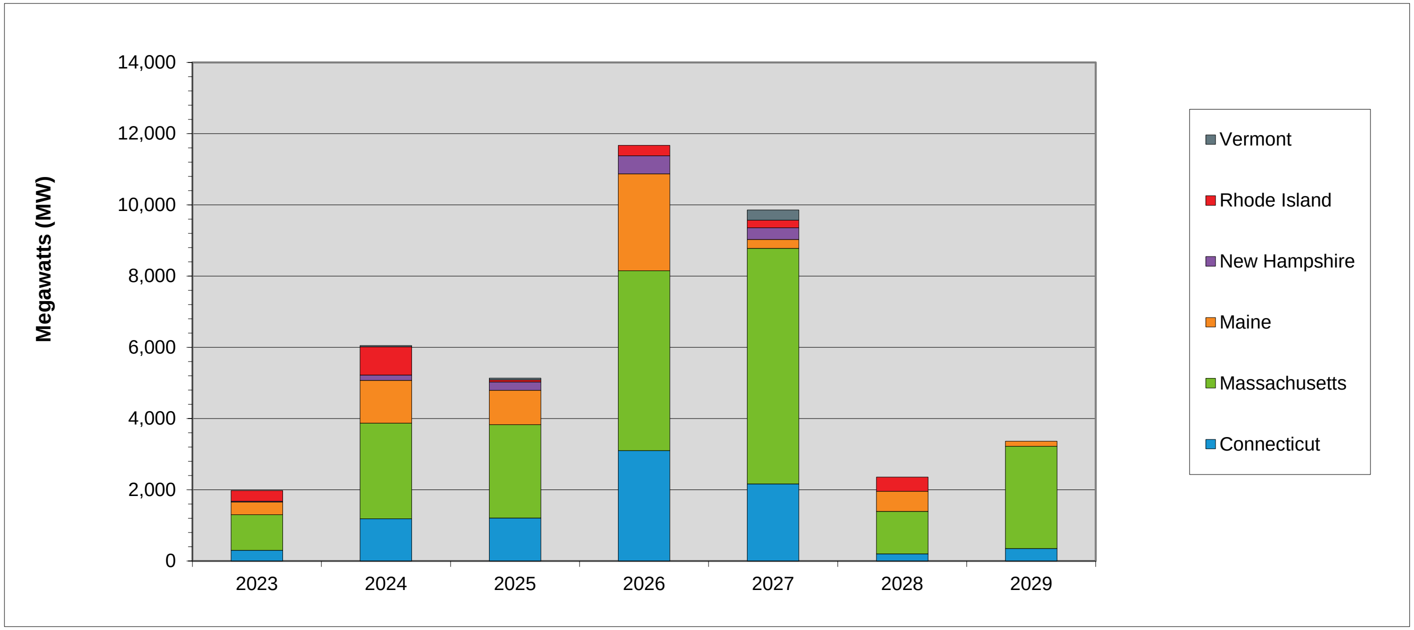
[1] Sum may not equal 100% due to rounding

[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	298	787	54	295	211	400	0	2,045	5.1
New Hampshire	25	154	238	504	328	0	0	1,249	3.1
Maine	360	1,201	966	2,723	254	567	139	6,210	15.4
Massachusetts	996	2,680	2,620	5,048	6,612	1,193	2,870	22,019	54.5
Connecticut	300	1,188	1,206	3,101	2,163	198	351	8,507	21.1
Totals	**1,979**	**6,050**	**5,134**	**11,671**	**9,853**	**2,358**	**3,360**	**40,405**	**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	112	16,976	1	15	111	16,961
Fuel Cell	4	46	0	0	4	46
Hydro	2	33	1	5	1	28
Natural Gas	5	263	0	0	5	263
Natural Gas/Oil	4	823	1	62	3	761
Nuclear	0	0	0	0	0	0
Solar	228	6,199	16	361	212	5,838
Wind	27	16,947	1	800	26	16,147
Total	382	41,287	20	1,243	362	40,044

- 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	3	761	0	0	3	761
Peaker	344	23,487	18	438	326	23,049
Wind Turbine	27	16,947	1	800	26	16,147
Total	382	41,287	20	1,243	362	40,044

- 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	112	16,976	0	0	0	0	112	16,976	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	5	263	2	13	0	0	3	250	0	0
Natural Gas/Oil	4	823	0	0	3	761	1	62	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	228	6,199	0	0	0	0	228	6,199	0	0
Wind	27	16,947	0	0	0	0	0	0	27	16,947
Total	382	41,287	8	92	3	761	344	23,487	27	16,947

- 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				
	Passive Demand	3,212.865	3,211.403	-1.462				
Demand Total		**3,890.538**	**3,884.804**	**-5.734**				
Generator	*Non-Intermittent*	28,154.203	27,714.778	-439.425				
	Intermittent	1,089.265	1,073.794	-15.471				
Generator Total		**29,243.468**	**28,788.572**	**-454.896**				
Import Total		**1,487.059**	**1297.132**	**-189.927**				
Grand Total*		**34,621.065**	**33,970.508**	**-650.557**				
Net ICR (NICR)		**33,270**	**31,775**	**-1,495**				

* 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

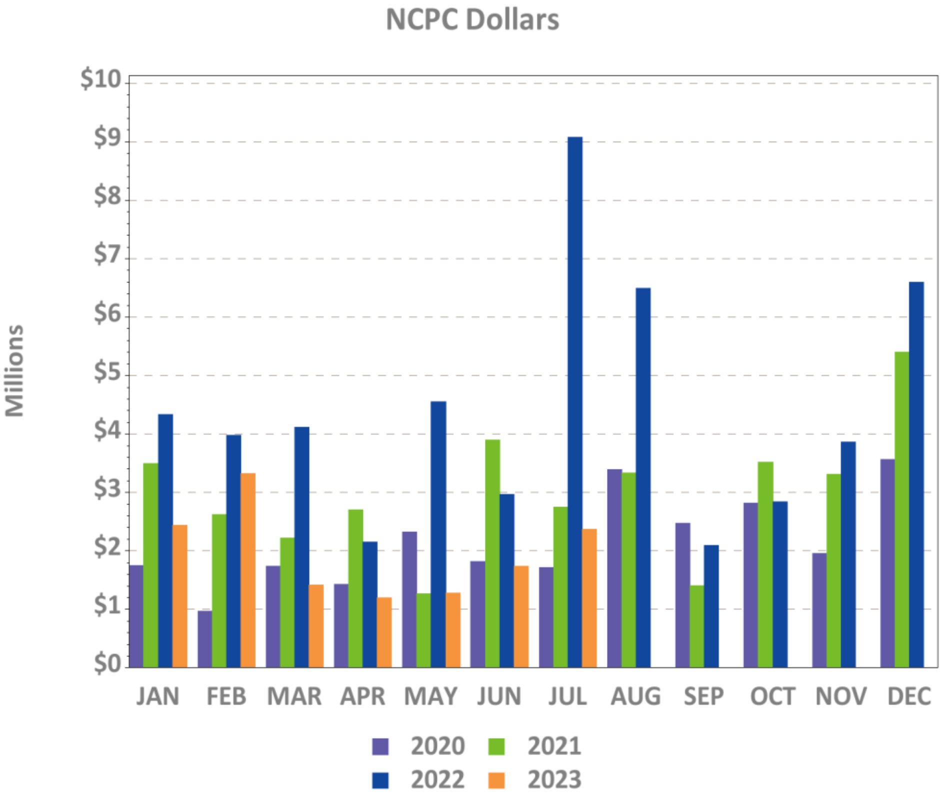
Definitions

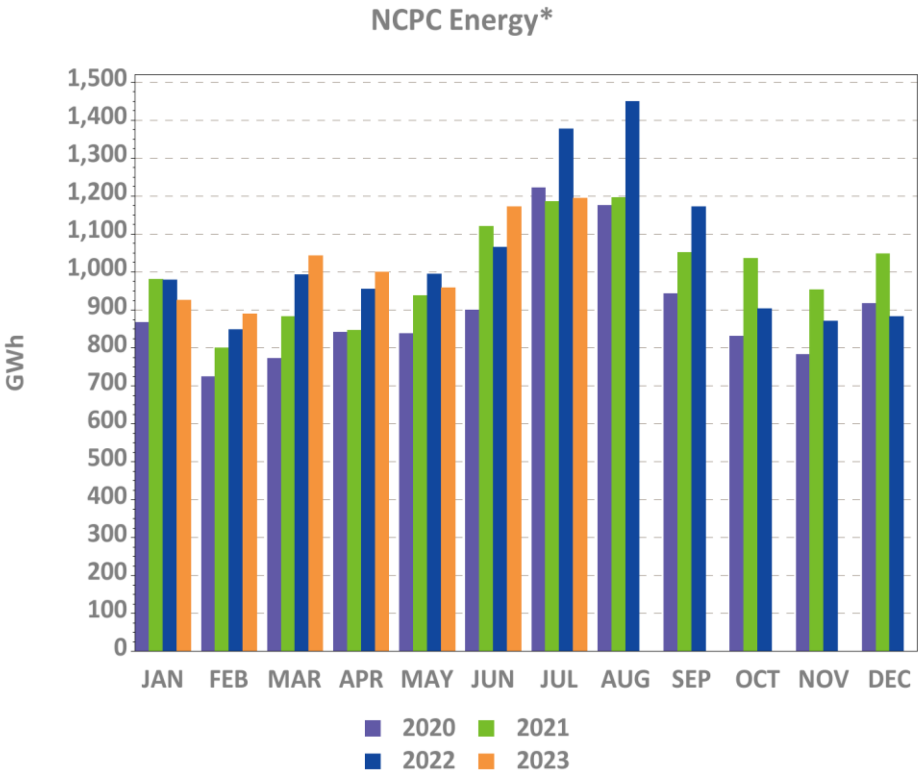
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing 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).

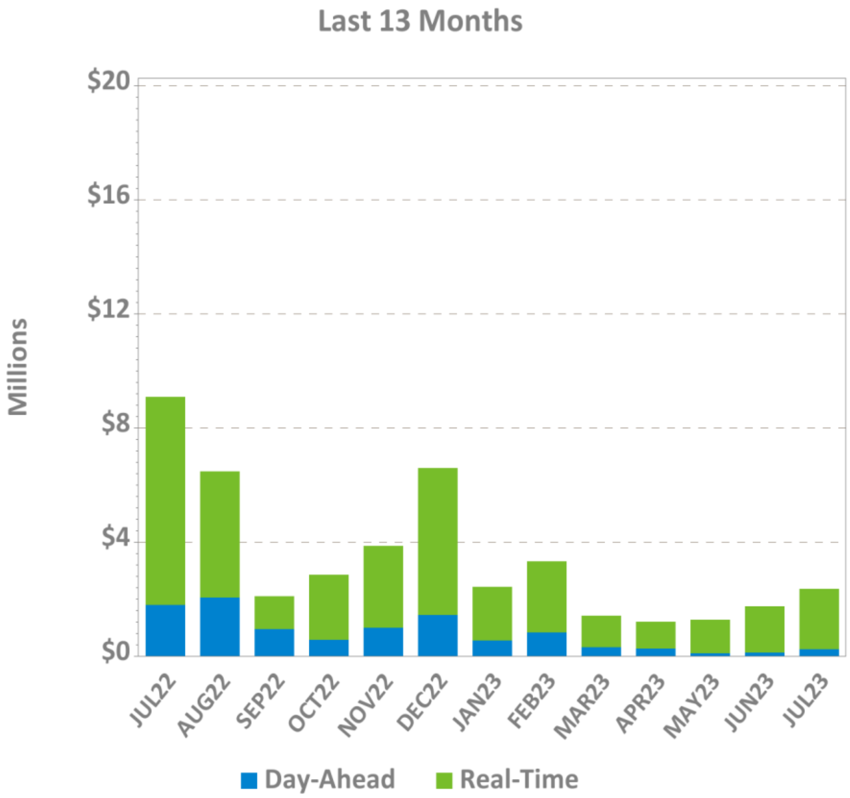
Year-Over-Year Total NCPC Dollars and Energy



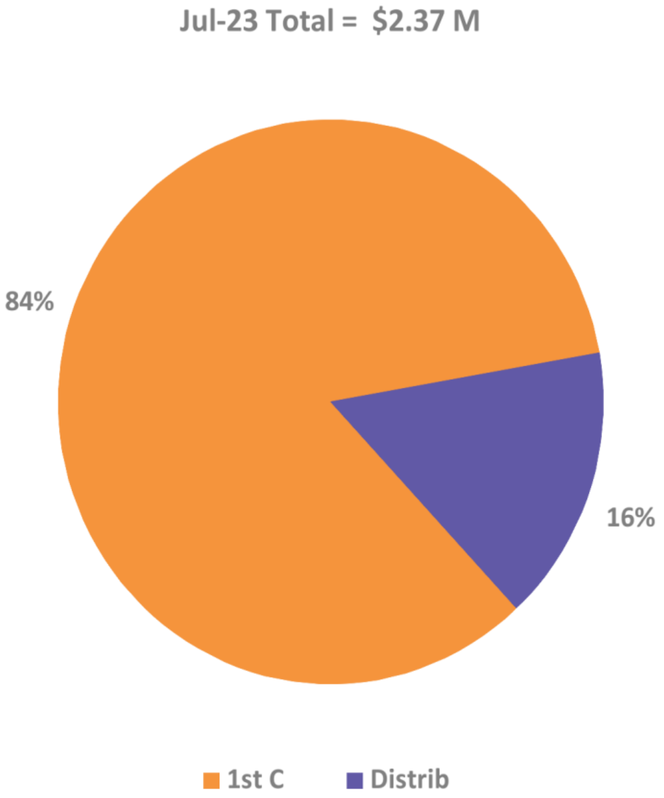


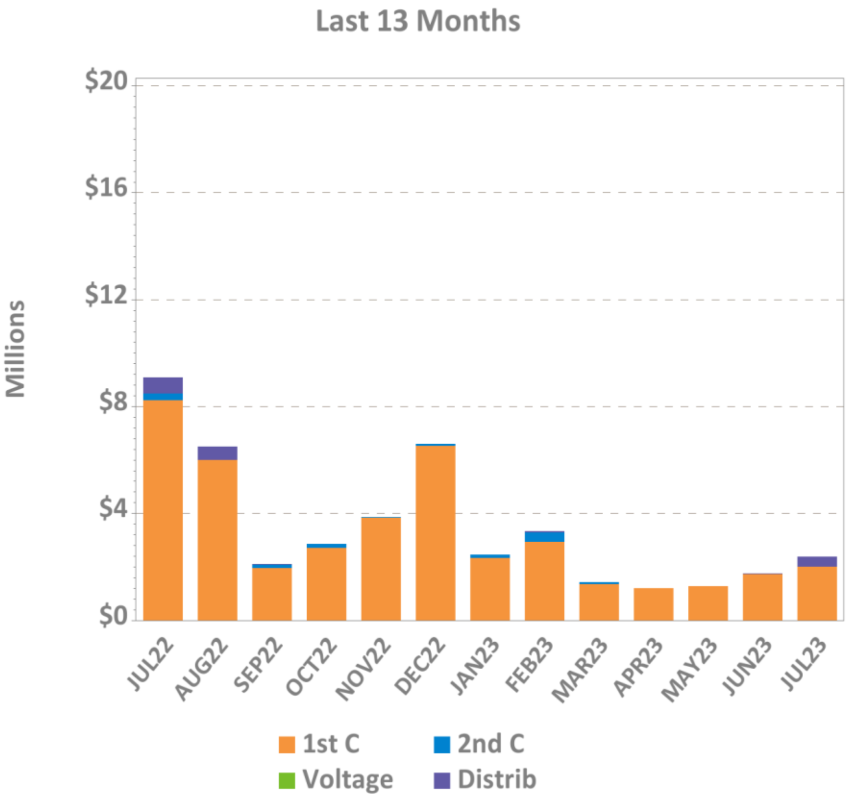
*** NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

DA and RT NCPC Charges



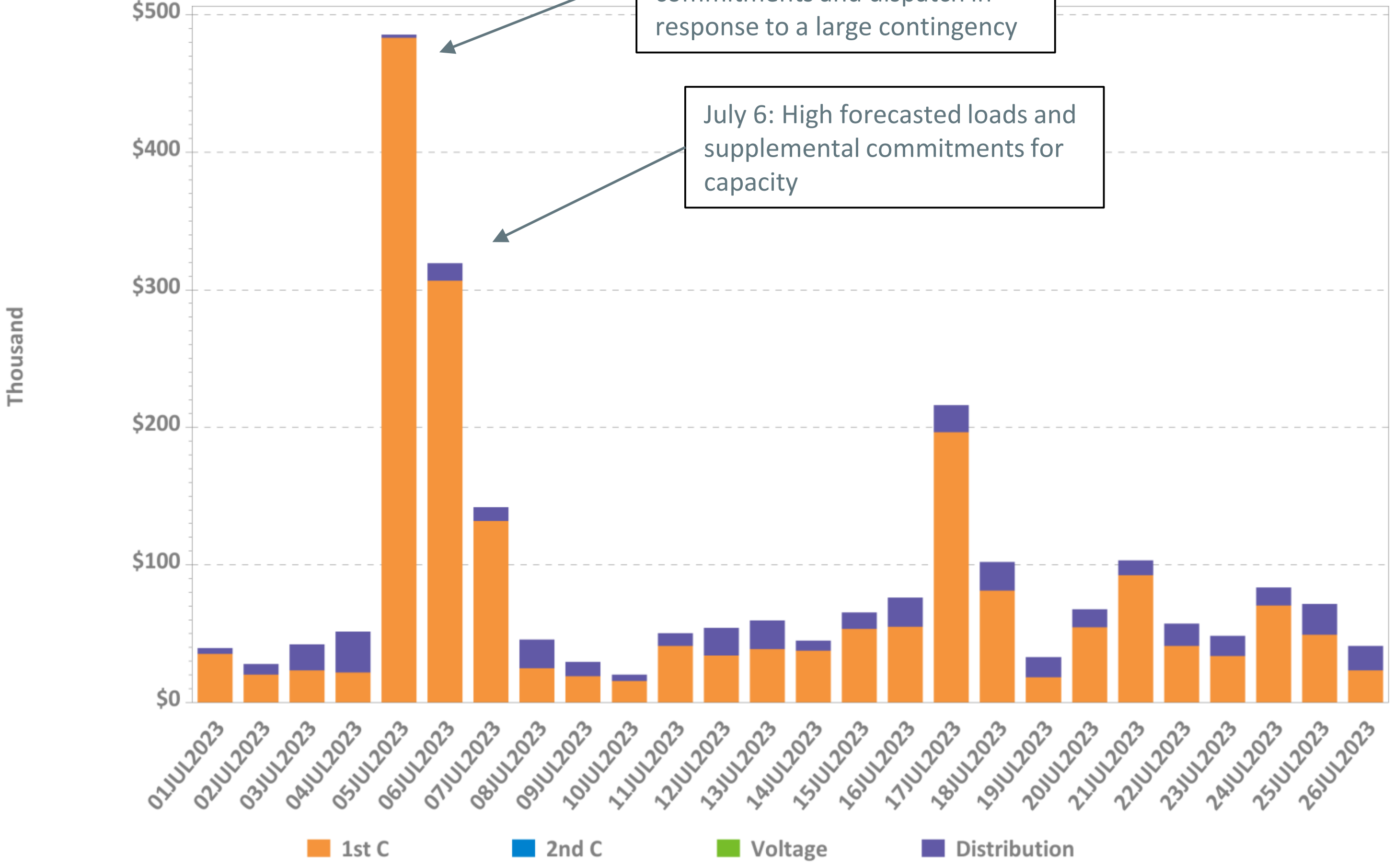
NCPC Charges by Type





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

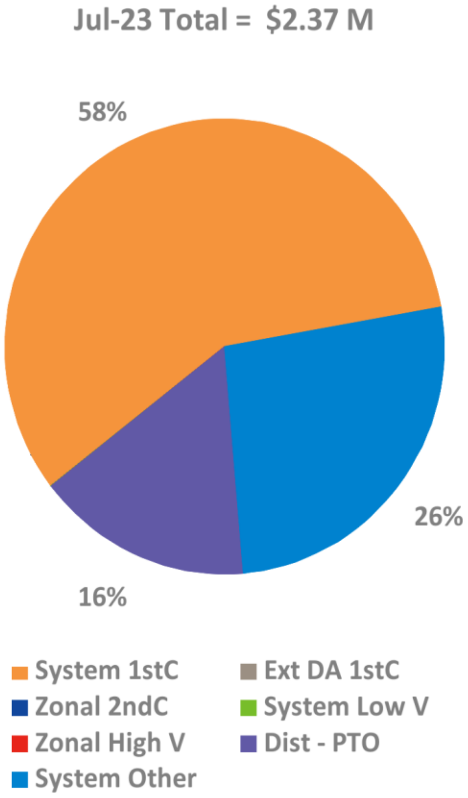
Daily NCPC Charges by Type

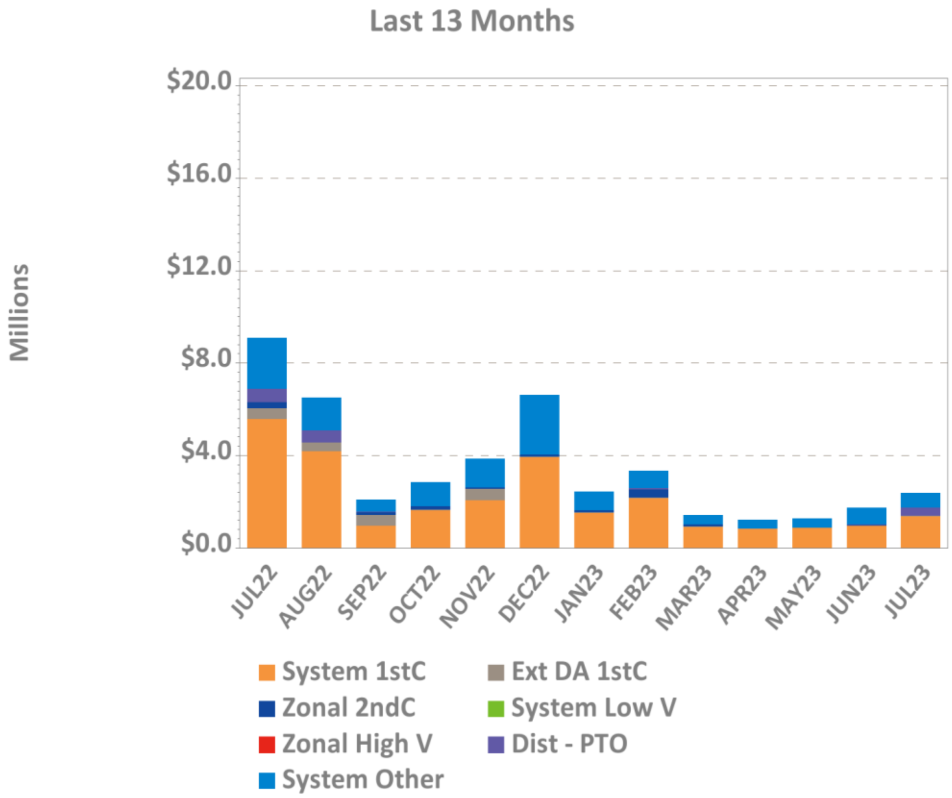


July 5: Compensation primarily associated with unit commitments and dispatch in response to a large contingency

July 6: High forecasted loads and supplemental commitments for capacity

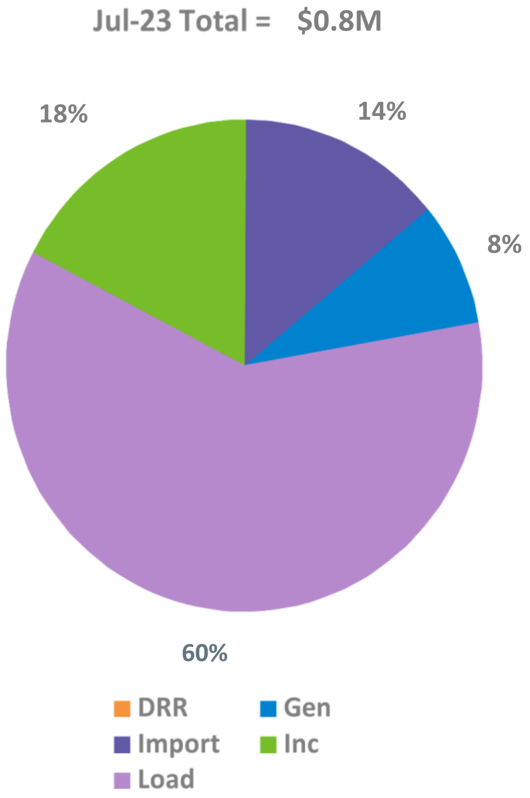
NCPC Charges by Allocation

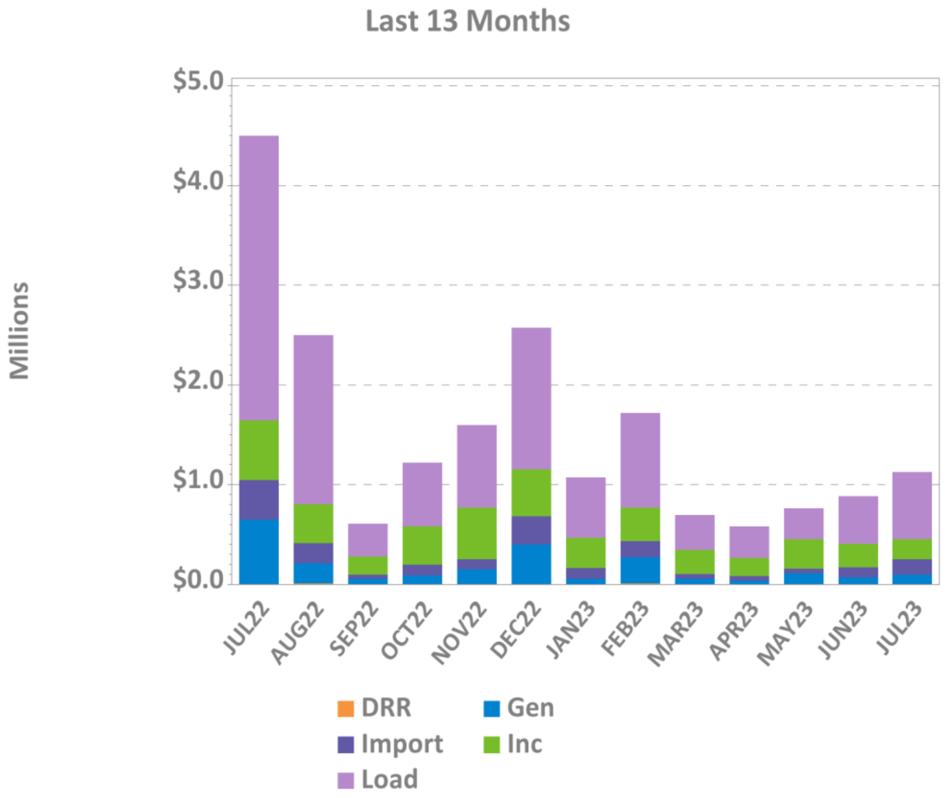




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

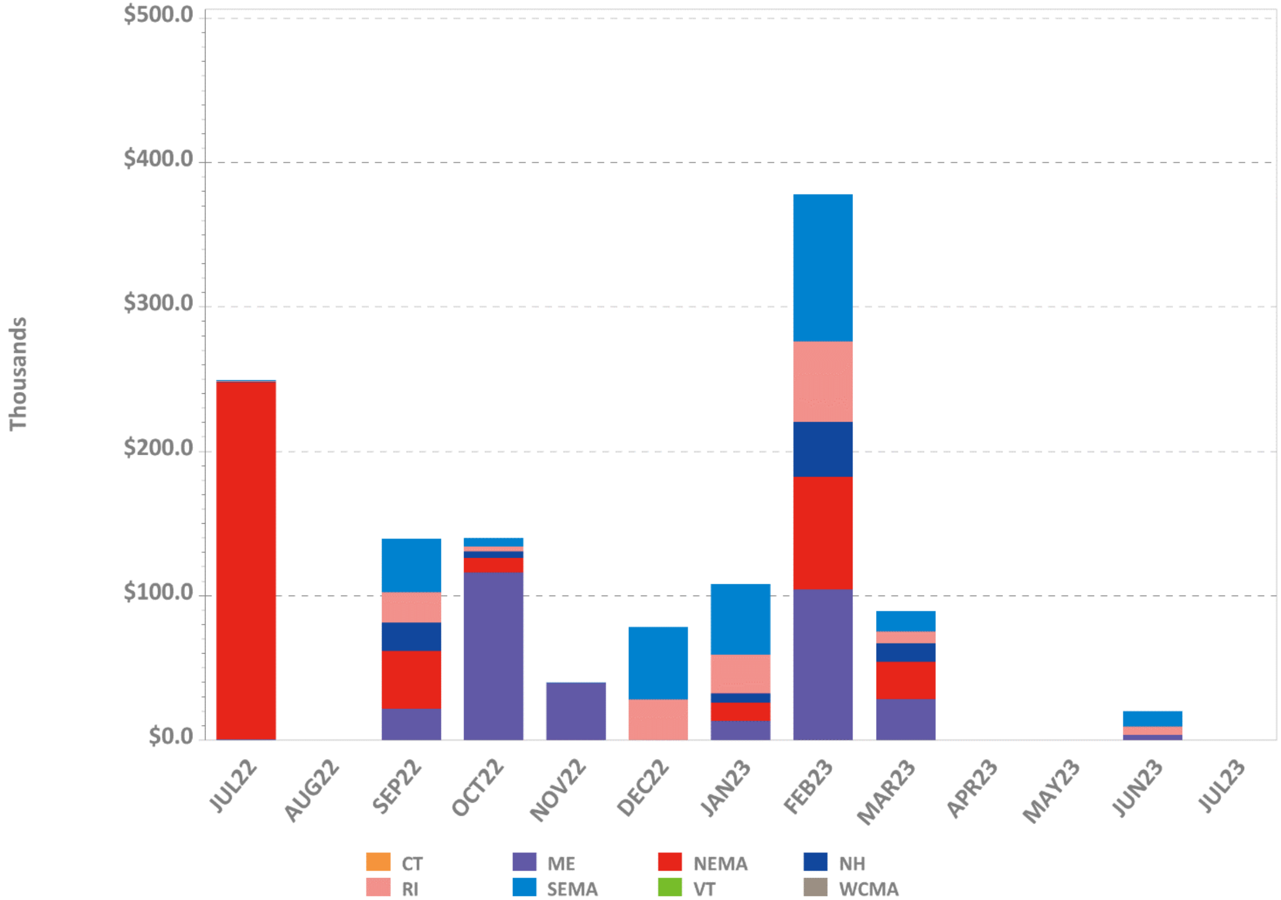
RT First Contingency Charges by Deviation Type





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

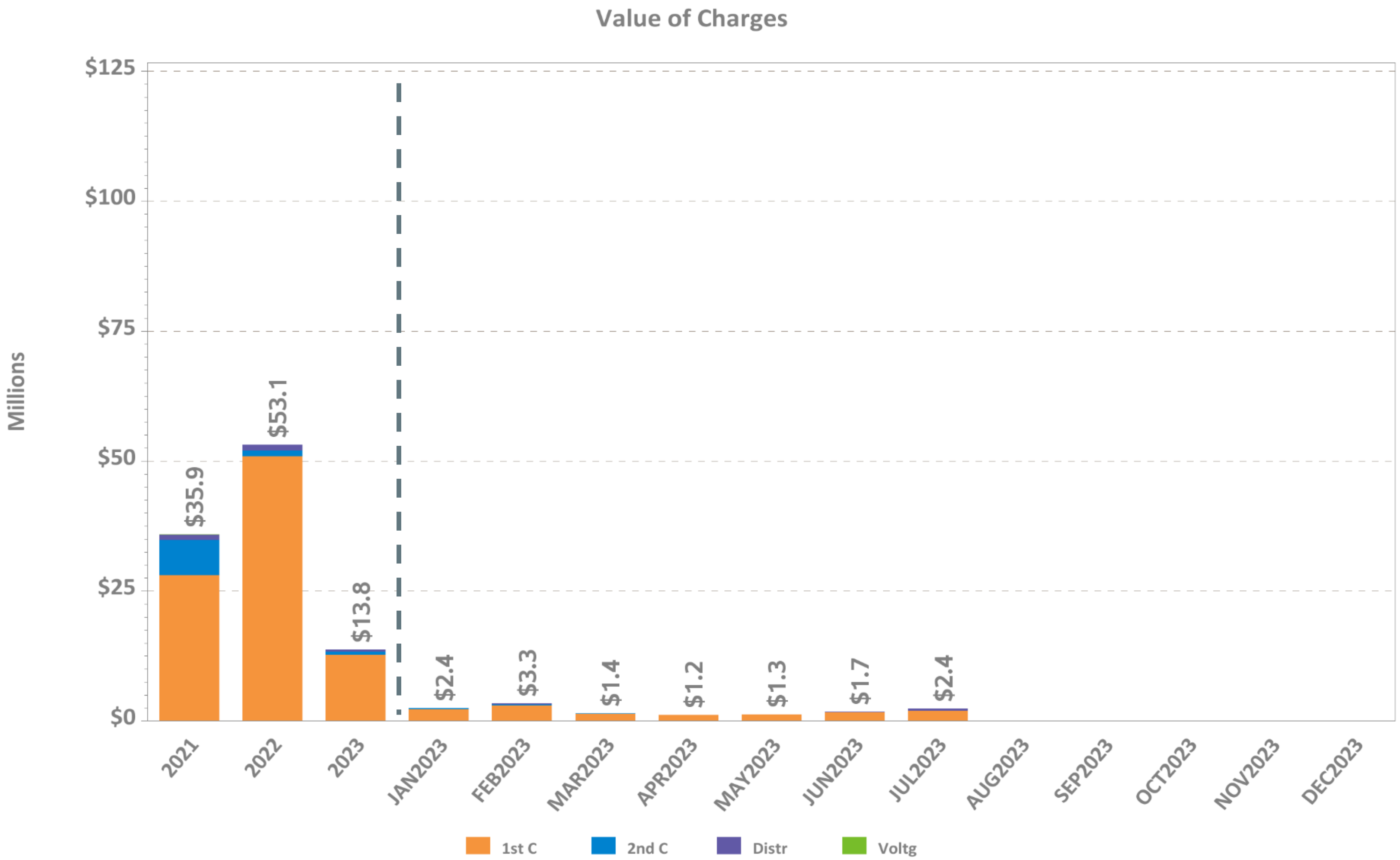
LSCPR Charges by Reliability Region



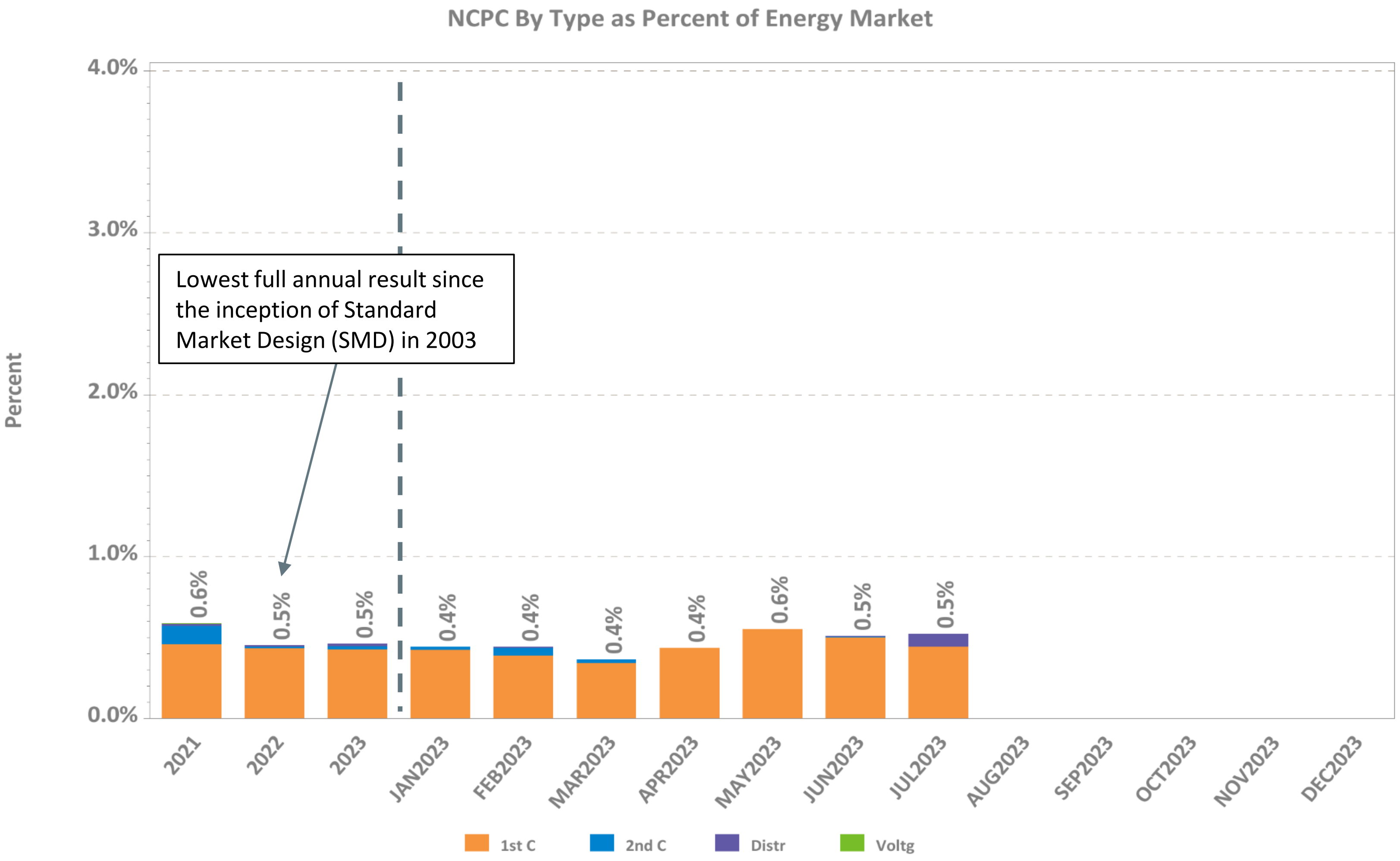
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region

NCPC Charges by Type

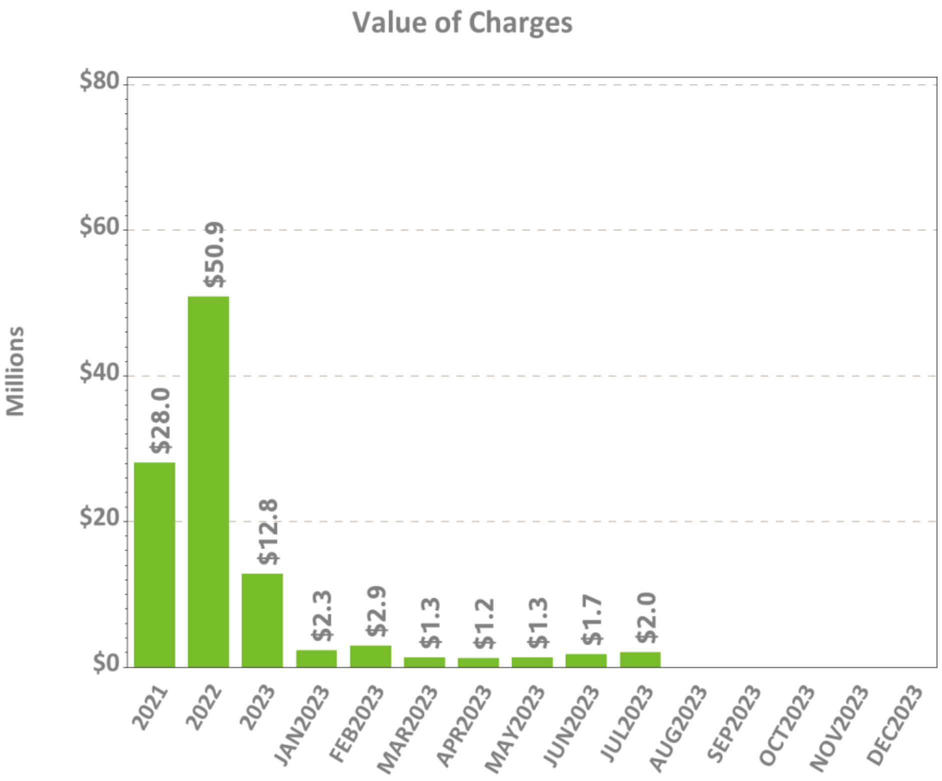


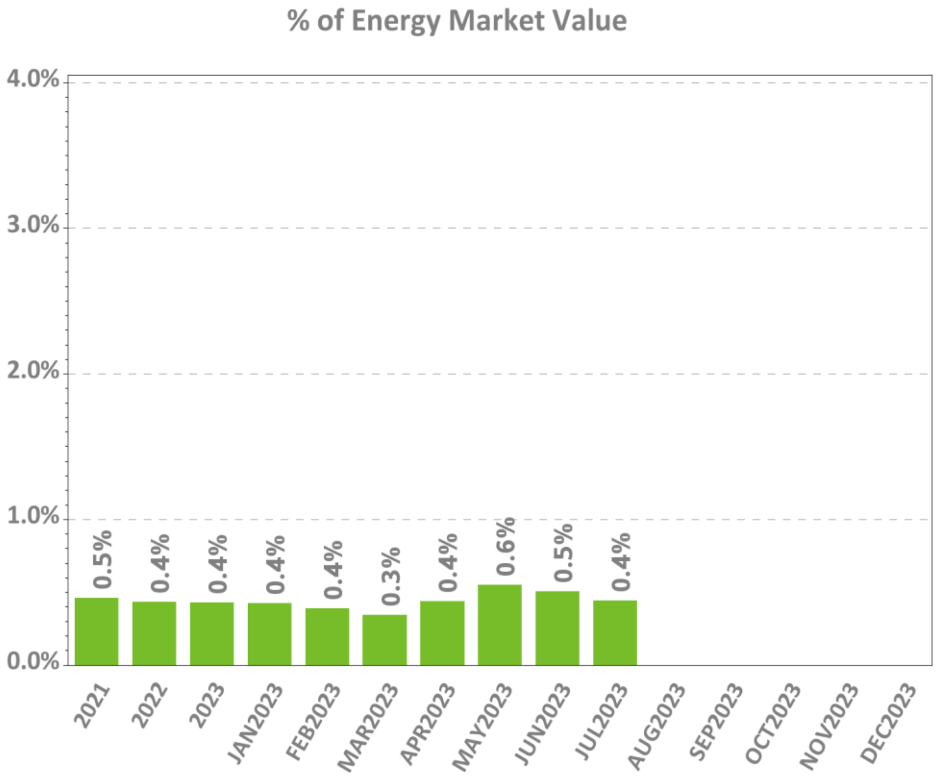
NCPC Charges as Percent of Energy Market



Lowest full annual result since the inception of Standard Market Design (SMD) in 2003

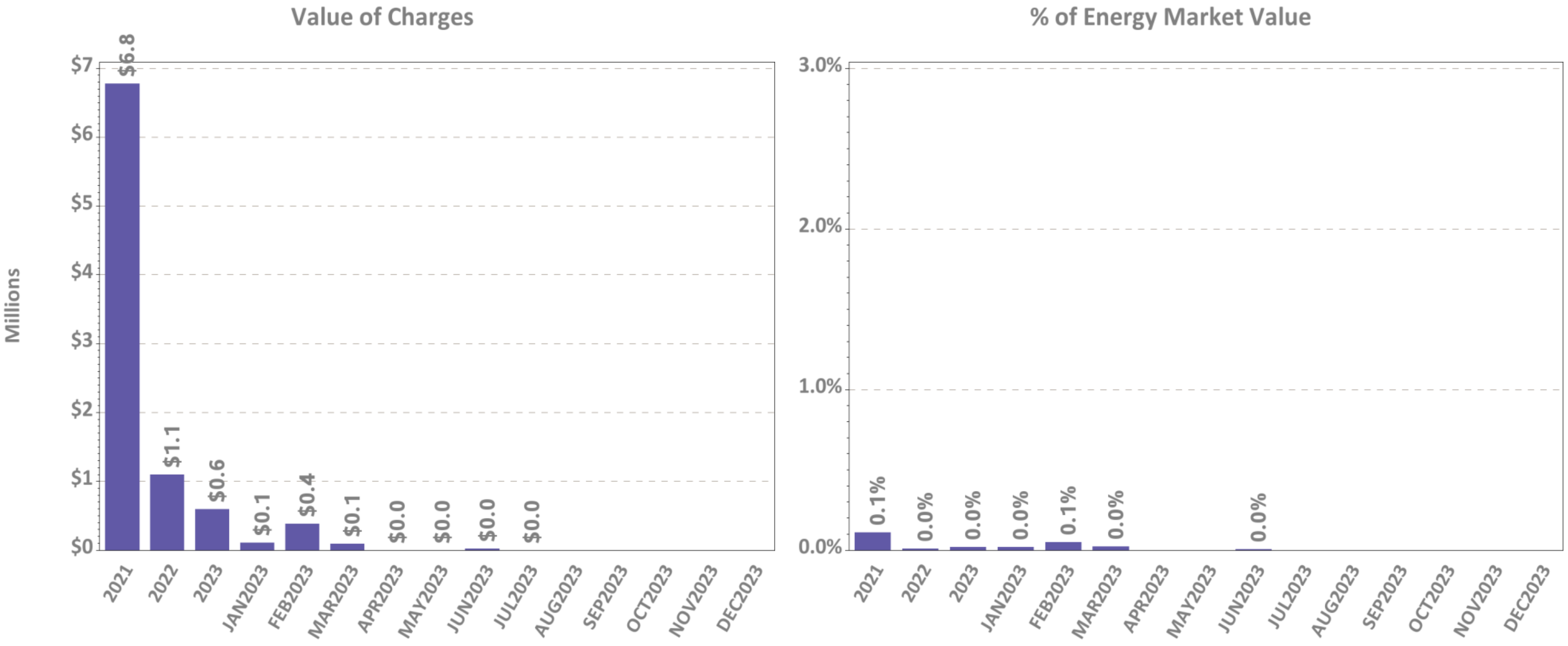
First Contingency NCPC Charges





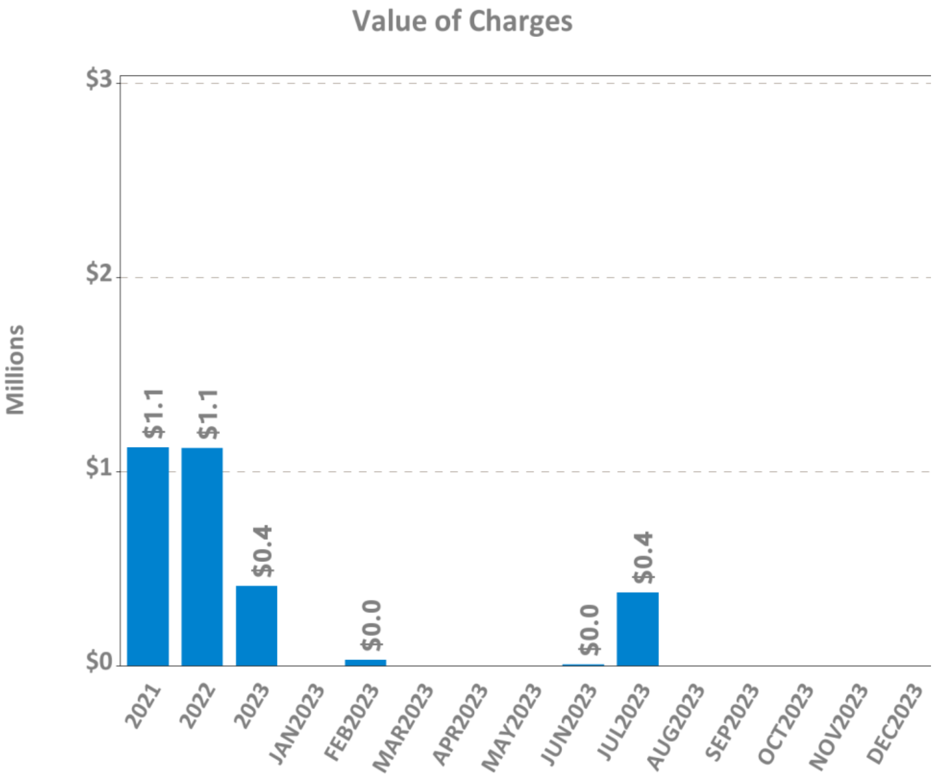
Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

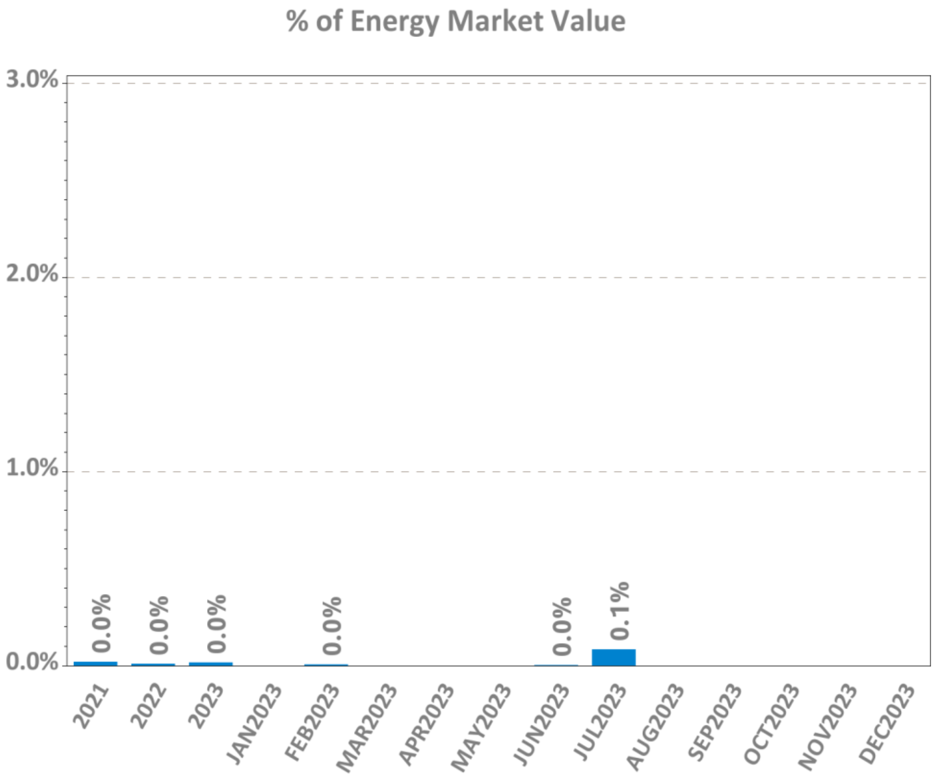
Second Contingency NCPC Charges



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

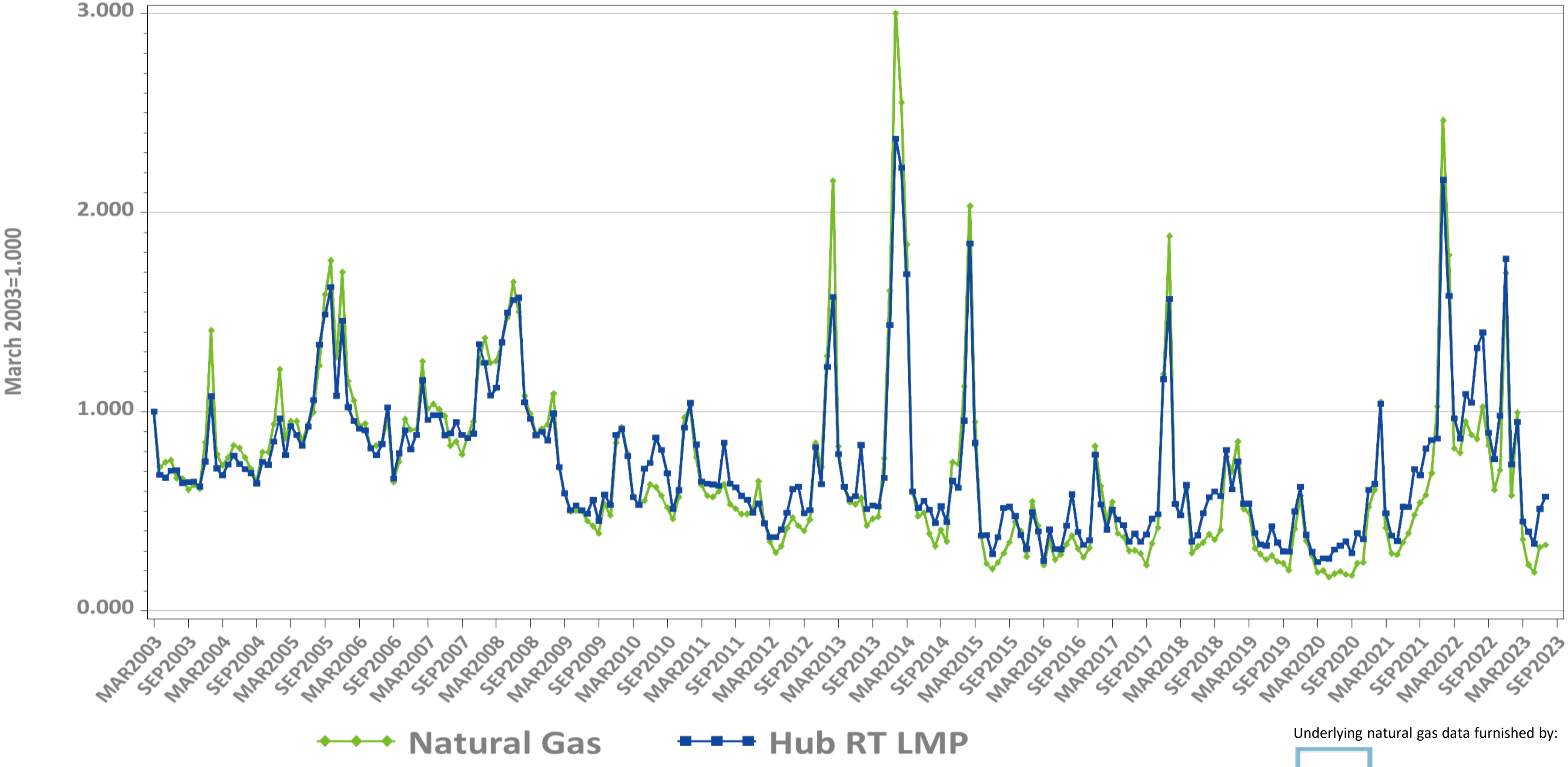
DA vs. RT LMPs ($/MWh)

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%

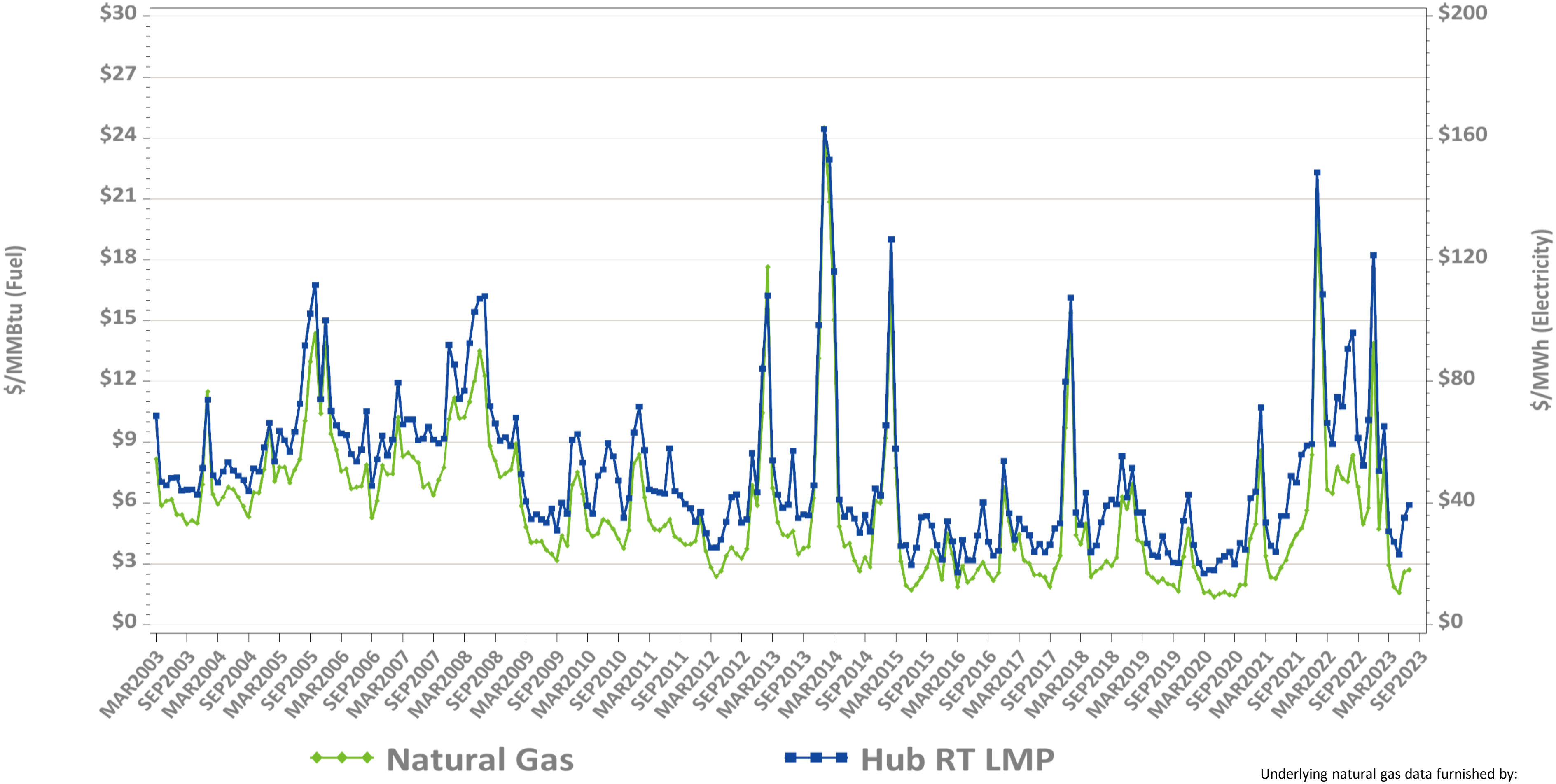
July-22	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$90.61	$88.50	$89.31	$90.87	$89.53	$89.22	$90.23	$90.07	$89.85
Real-Time	$91.55	$89.71	$89.86	$91.72	$89.94	$90.24	$91.36	$90.89	$90.68
RT Delta %	1.0%	1.4%	0.6%	0.9%	0.5%	1.1%	1.3%	0.9%	0.9%
July-23	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$40.36	$39.22	$39.23	$40.11	$39.76	$39.73	$40.29	$40.03	$40.01
Real-Time	$39.83	$38.92	$38.64	$39.50	$39.17	$39.24	$39.78	$39.49	$39.45
RT Delta %	-1.3%	-0.8%	-1.5%	-1.5%	-1.5%	-1.2%	-1.3%	-1.4%	-1.4%
Annual Diff.	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Yr over Yr DA	-55.5%	-55.7%	-56.1%	-55.9%	-55.6%	-55.5%	-55.3%	-55.6%	-55.5%
Yr over Yr RT	-56.5%	-56.6%	-57.0%	-56.9%	-56.4%	-56.5%	-56.5%	-56.6%	-56.5%

Monthly Average Fuel Price and RT Hub LMP Indexes



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

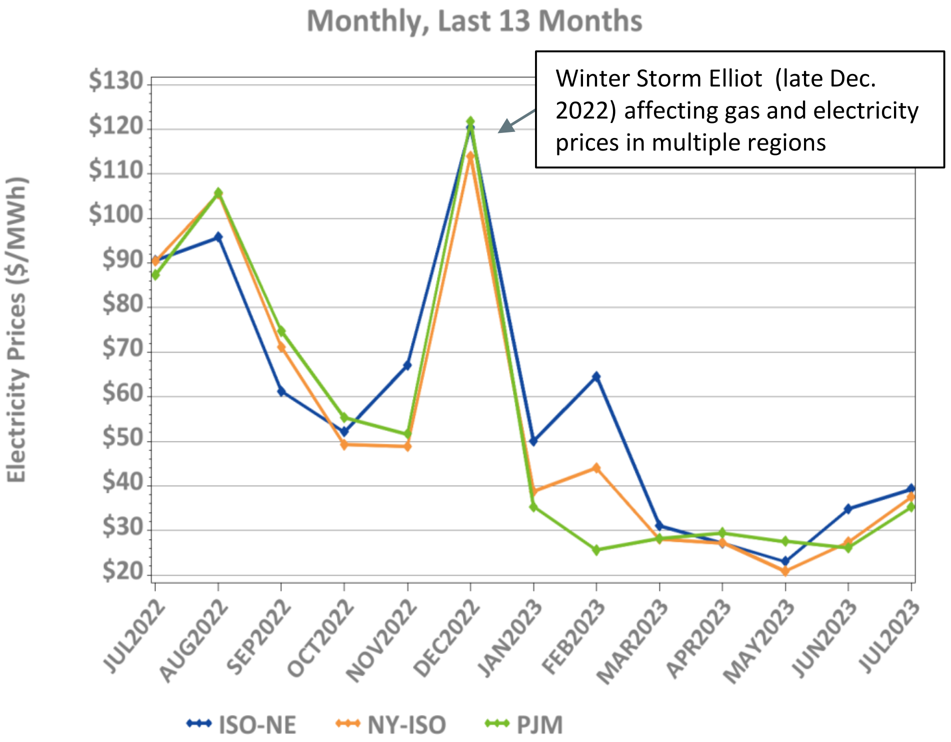
Monthly Average Fuel Price and RT Hub LMP



Underlying natural gas data furnished by:

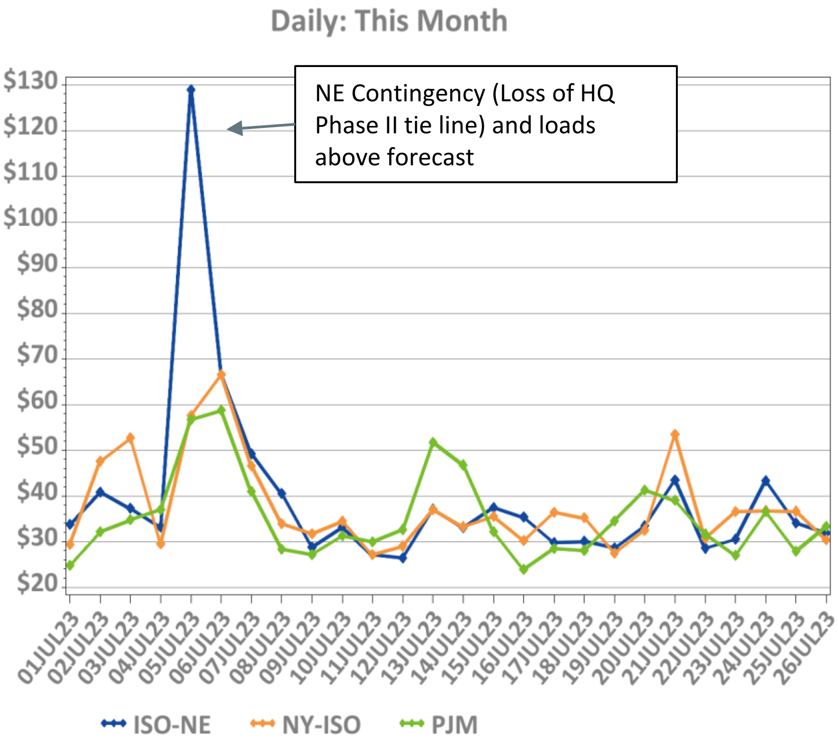
ice Global markets in clear view

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



Winter Storm Elliot (late Dec. 2022) affecting gas and electricity prices in multiple regions

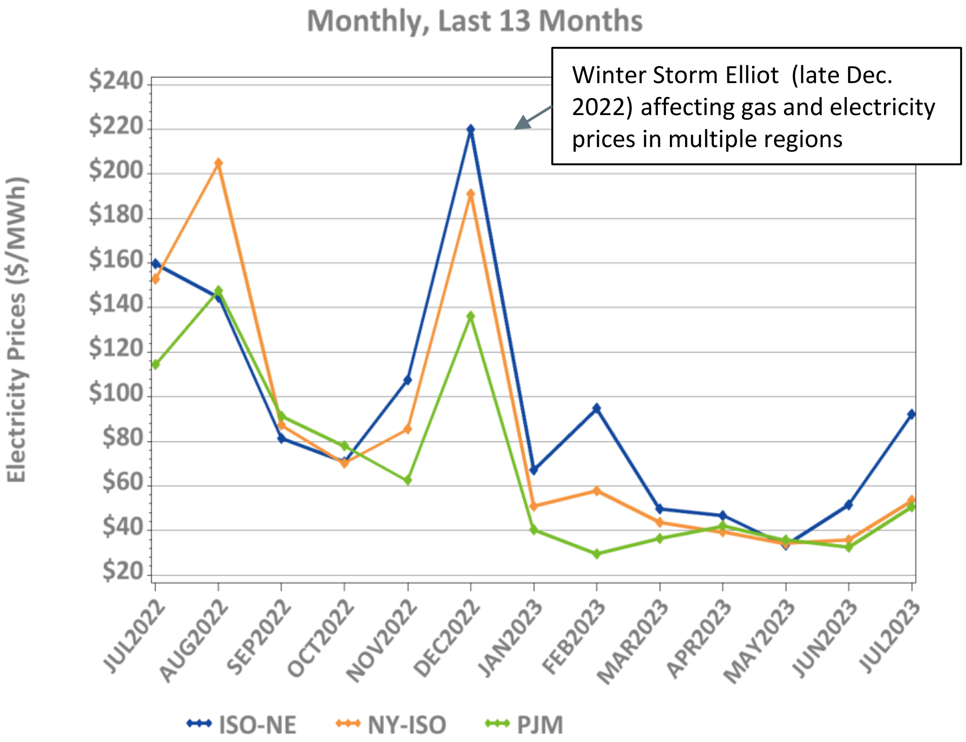
*Note: Hourly average prices are shown.



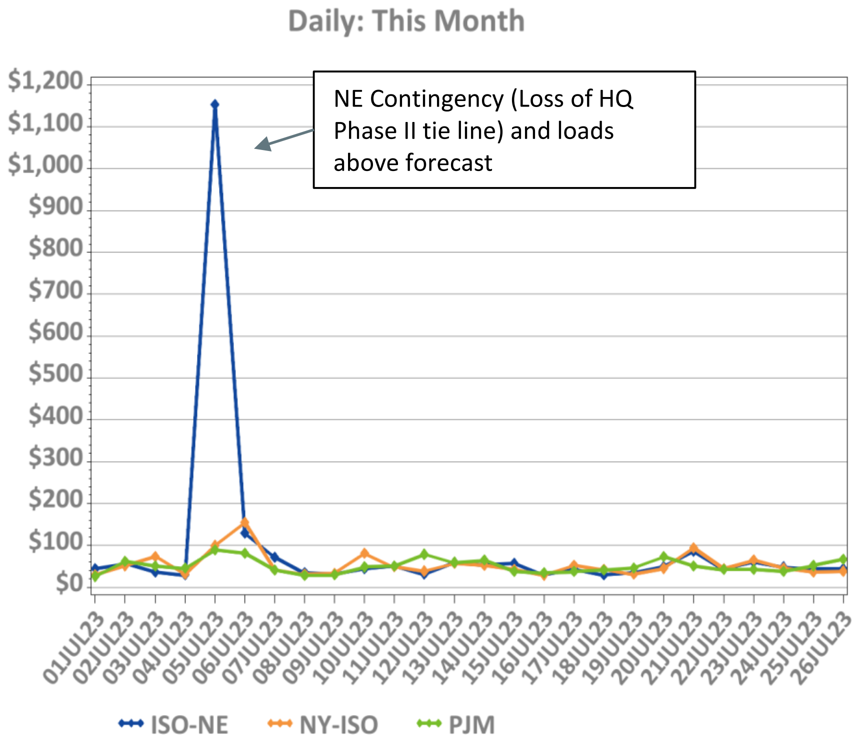
NE Contingency (Loss of HQ Phase II tie line) and loads above forecast

*Note: Hourly average prices are shown.

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



Winter Storm Elliot (late Dec. 2022) affecting gas and electricity prices in multiple regions



NE Contingency (Loss of HQ Phase II tie line) and loads above forecast

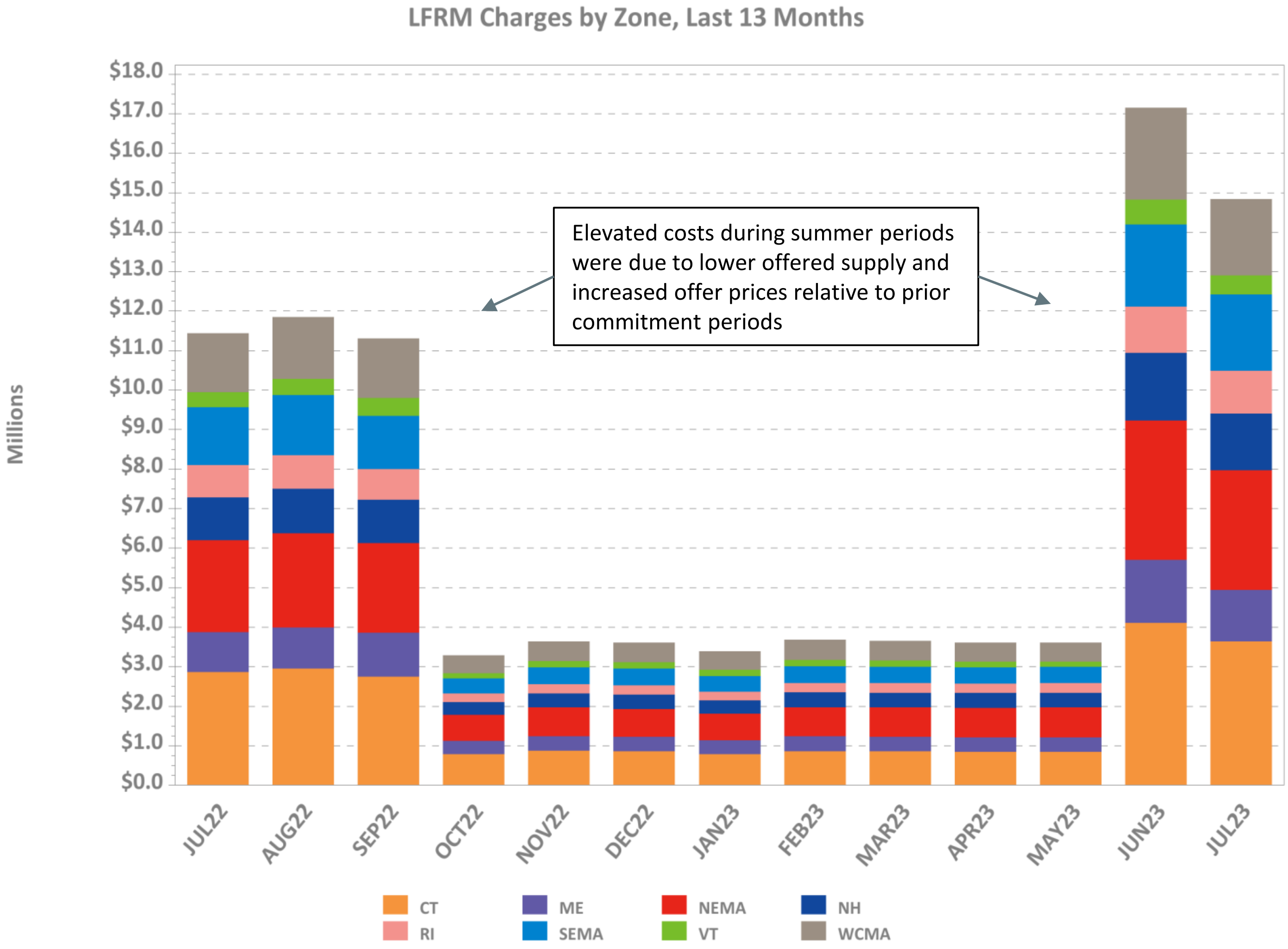
***Forecasted New England daily peak hours reflected**

Reserve Market Results – July 2023

- Maximum potential Forward Reserve Market payments of $16.1M were reduced by credit reductions of $338K, failure-to-reserve penalties of $701K and failure-to-activate penalties of $195K, resulting in a net payout of $14.8M or 92% of maximum
  - Rest of System: $12.33M/13.19M (93%)
  - Southwest Connecticut: $0.32M/0.42M (76%)
  - Connecticut: $2.1M/2.37M (89%)
  - NEMA: $0.91M/0.96M (95%)
- $3.2M total Real-Time credits were reduced by $1.6M in Forward Reserve Energy Obligation Charges for a net of $1.6M in Real-Time Reserve payments
  - Rest of System: 116 hours, $684K
  - Southwest Connecticut: 116 hours, $536K
  - Connecticut: 116 hours, $279K
  - NEMA: 116 hours, $123K

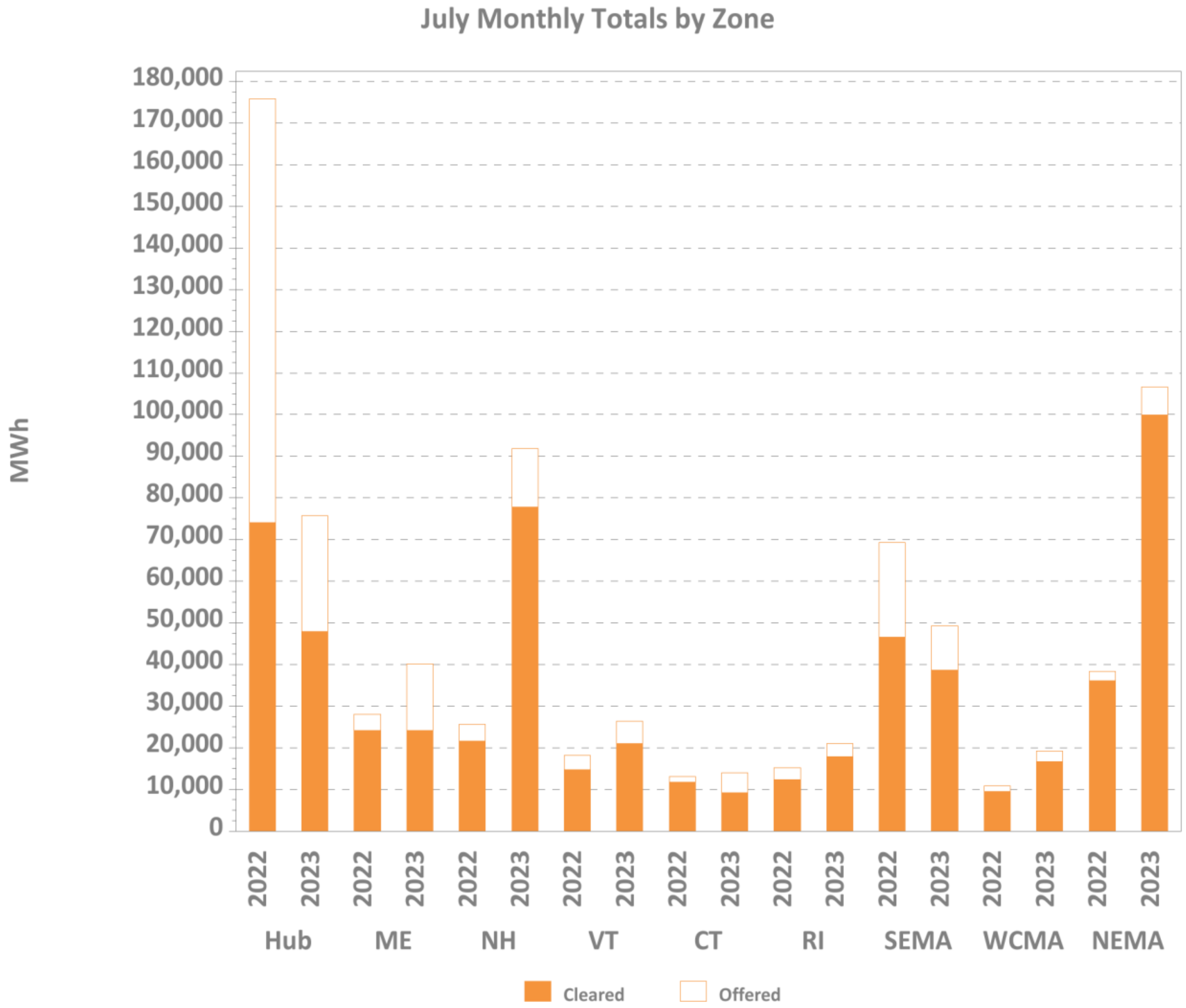
Note: "Failure to reserve" results in both credit reductions and penalties in the Locational Forward Reserve Market. While this summary reports performance by location, there were no locational requirements in effect for the current Forward Reserve auction period.

LFRM Charges to Load by Load Zone ($)

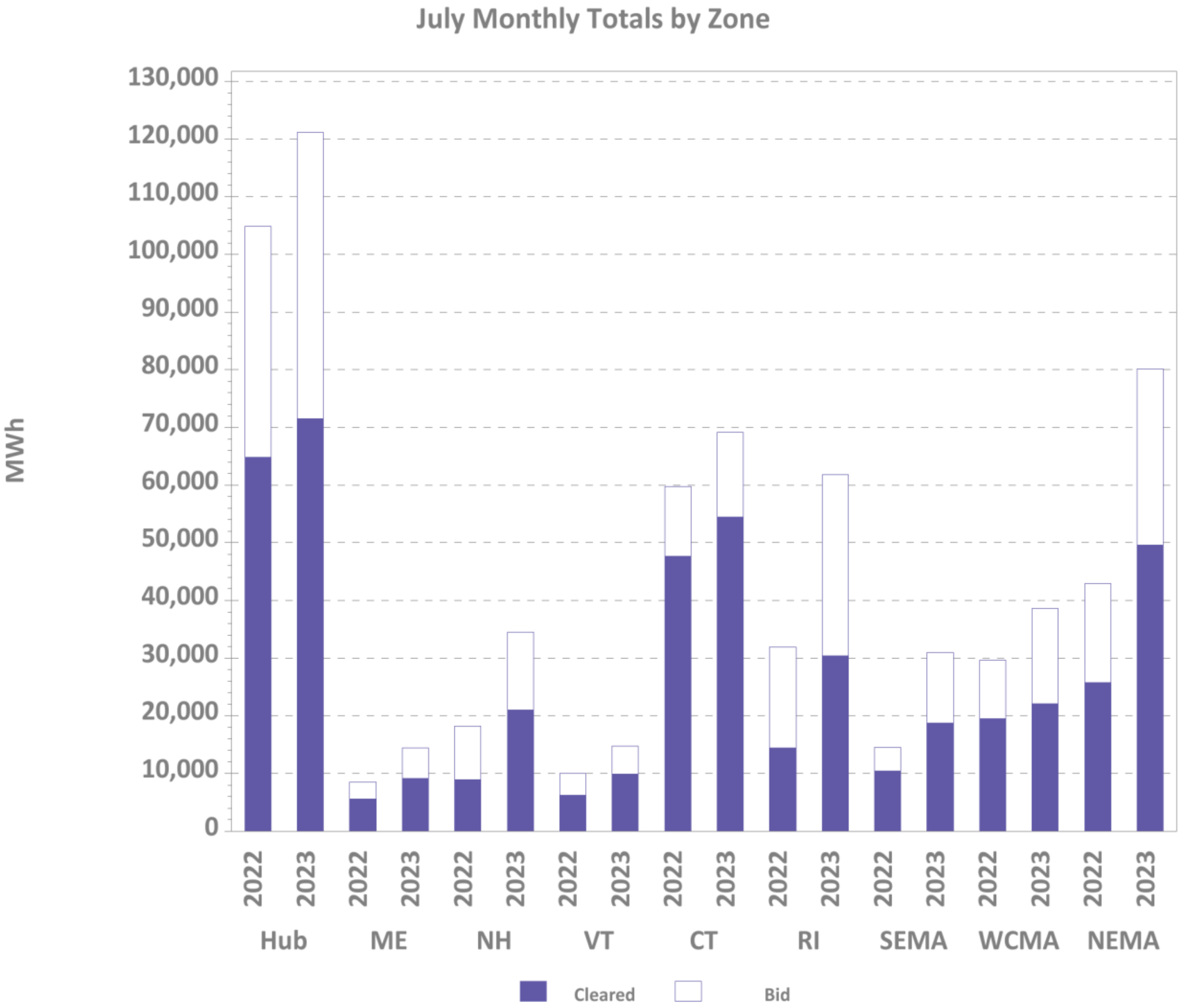


Elevated costs during summer periods were due to lower offered supply and increased offer prices relative to prior commitment periods

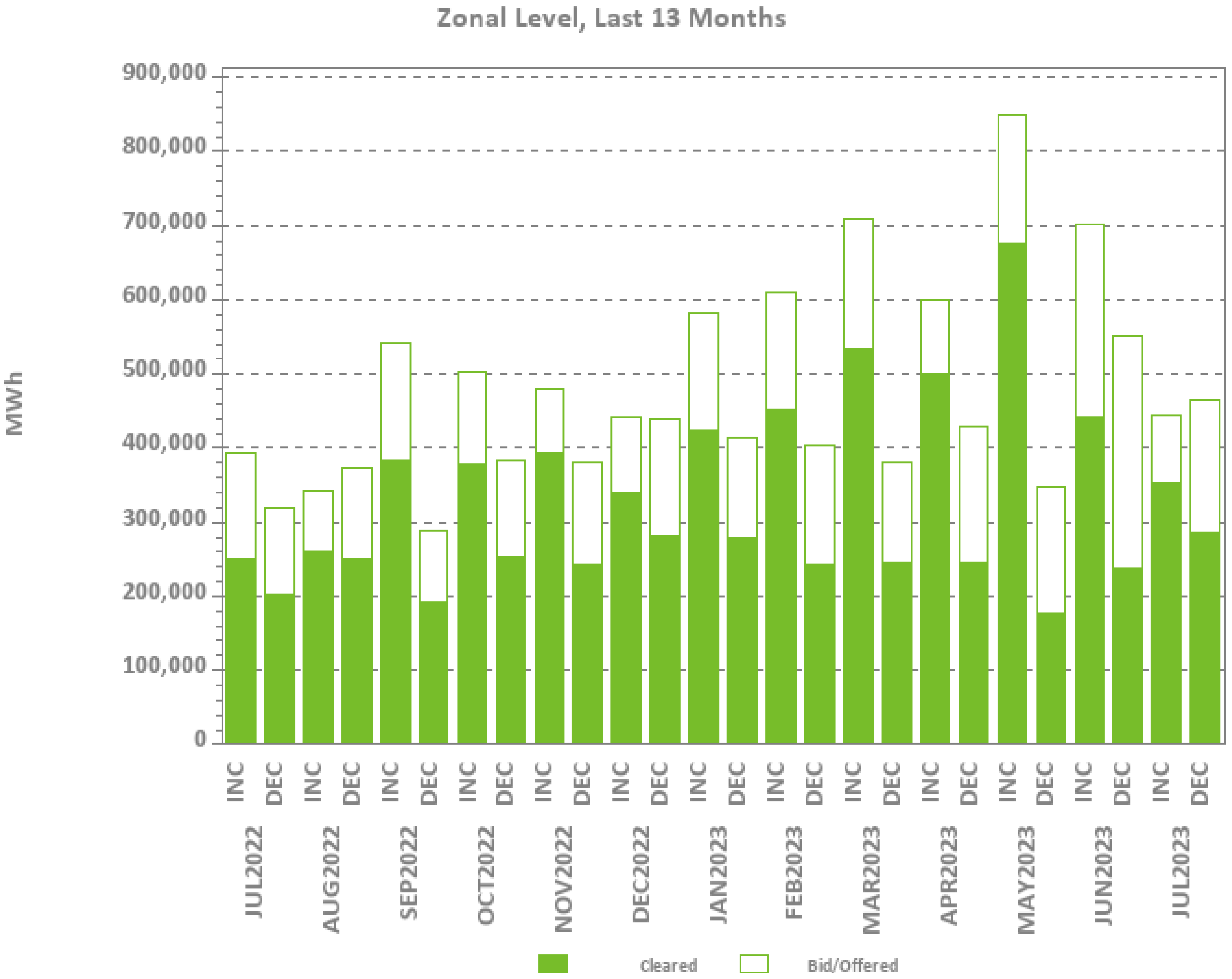
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

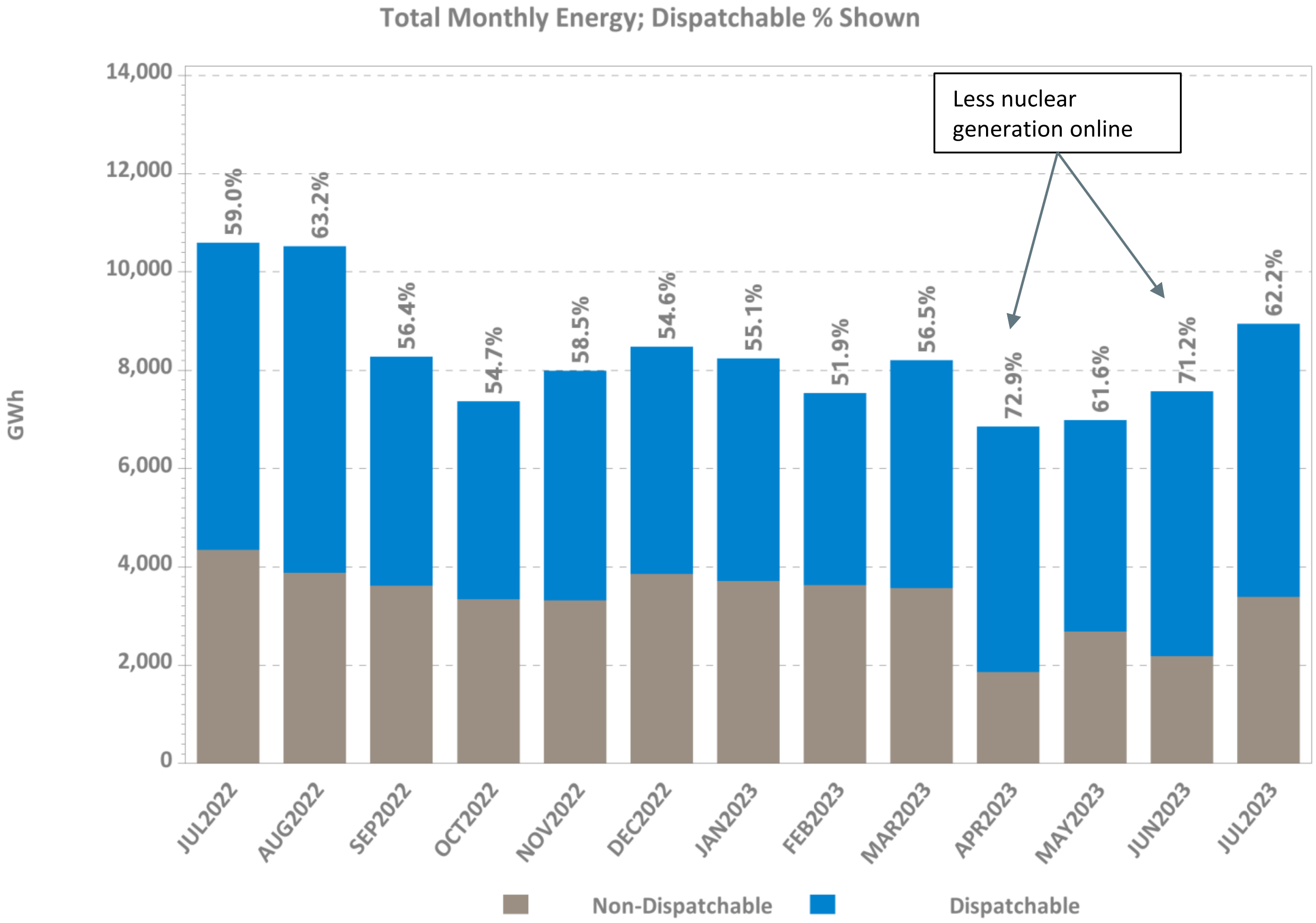


Total Increment Offers and Decrement Bids



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 is an RSP publication year
- 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
- 2023-24 RSP Public Meeting date is set for November 1 and will be held concurrently with the ISO Open Board Meeting
- The draft 2023-24 RSP will be shared with stakeholders in August

Planning Advisory Committee (PAC)

- August 16 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - Southington 115 kV Relay Upgrades (Eversource)
    - Canal Station BPS and Asset Condition Upgrade Re-Presentation (Eversource)
    - Eversource Response to NESCOE Questions on 1704/1722 UG Cable Rebuild Project
    - 308 Asset Condition Refurbishment (National Grid)
  - Economic Planning for the Clean Energy Transition (EPCET) Pilot Study
  - 2023 Draft Regional System Plan

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

2050 Transmission Study

- A 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

Economic Studies

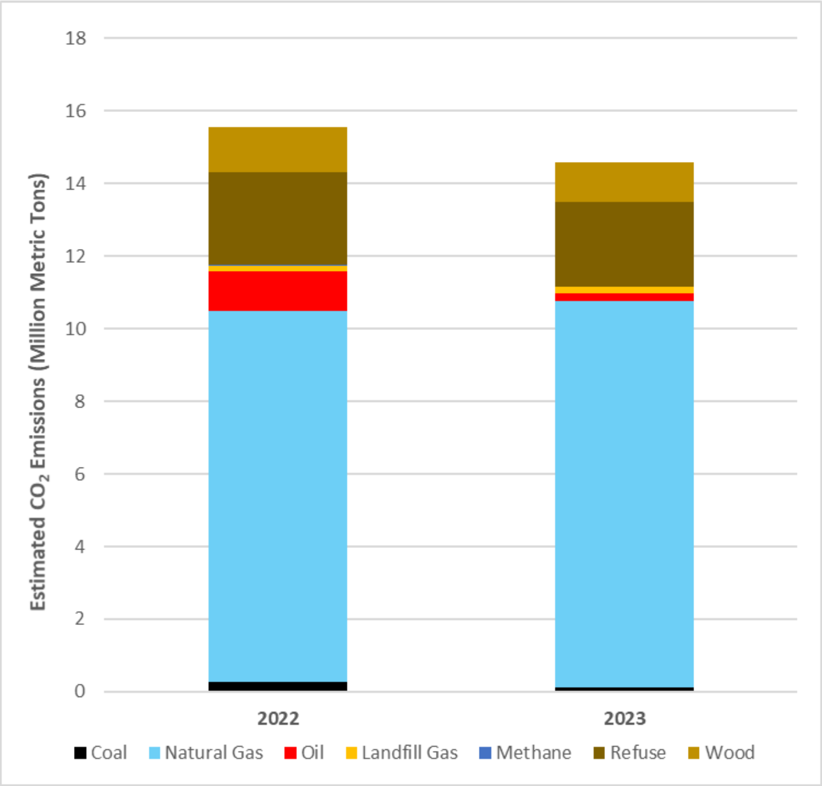
- Economic Planning for the Clean Energy Transition (EPCET) Pilot Study
  - New effort is to review all assumptions in economic planning and perform a test study consistent with the changes to the Tariff
  - PAC presentations began in April 2022. To date, the ISO has presented new modeling features, 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 will be 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

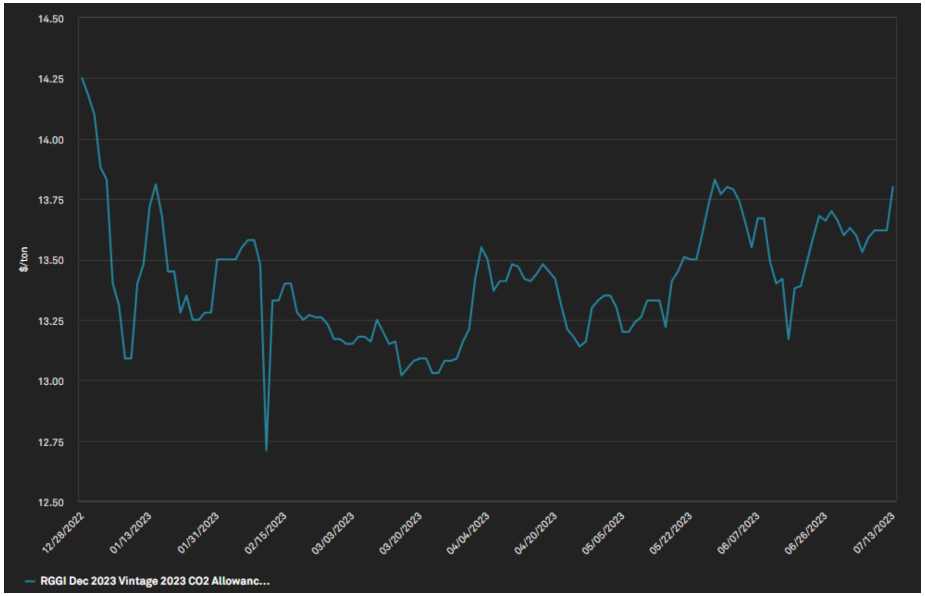
New England Power System Carbon Emissions

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



Data as of 07/09/2023

RGGI Allowance Prices



- 07/13/23: RGGI allowance spot price - $13.80
- 06/07/23 60th RGGI auction cleared at $12.73 per ton
  - 22,026,639 CO_2 allowances sold
  - 11,245,778 Cost Containment Reserve (CCR) allowances available
  - CCR trigger price is $14.88 per ton in 2023; therefore, no CCR allowances were sold

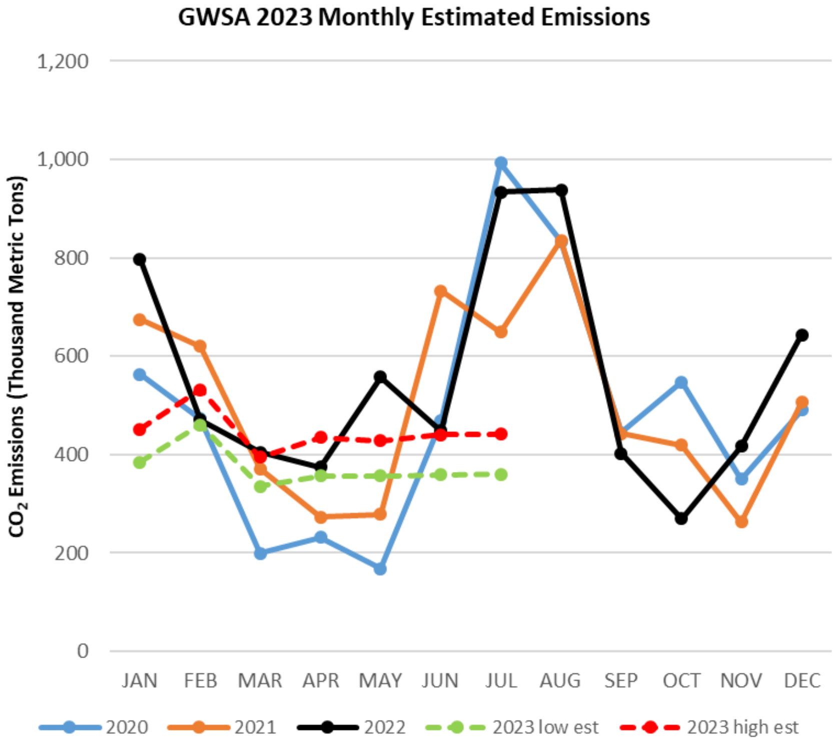
RGGI – Regional Greenhouse Gas Initiative

Massachusetts CO_2 Generator Emissions Cap

2023 Estimated Emissions Under CO_2 Cap

- As of 07/17/23, July 2023 estimated GWSA CO_2 emissions range between **360,000** and **441,988** metric tons
  - Year-to-date 2023 estimated emissions range between **33%** and **40%** 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 7/24/2023

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 7/24/2023

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 7/24/2023

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 7/24/2023

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 7/24/2023

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 7/24/2023

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 7/24/2023

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	3
1722	Extend the Line 114 from the Dartmouth town line (Eversource-National Grid border) to Bell Rock substation	Dec-24	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 7/24/2023

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	Dec-23	3
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Dec-23	3
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-24	1

SEMA/RI Reliability Projects, cont.

Status as of 7/24/2023

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 7/24/2023

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 7/24/2023

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 7/24/2023

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 7/24/2023

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

Boston Area Optimized Solution Projects

Status as of 7/24/2023

Project Benefit: Addresses system needs in the Boston area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1874	Install two 11.9 ohm series reactors at North Cambridge Station on Lines 346 and 365	Dec-21	4
1875	Install a direct transfer trip (DTT) scheme between Ward Hill and West Amesbury Substations for Line 394	Apr-22	4
1876	Install one +/- 167 MVAR STATCOM at Tewksbury 345 kV Substation	Jun-23	4

New Hampshire Solution Projects

Status as of 7/24/2023

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	Dec-23	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	Mar-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 7/24/2023

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	Dec-27	1
1884	Install a 15 MVAR capacitor at Belfast 115 kV substation	Dec-27	1
1885	Install a +50/-25 MVAR synchronous condenser at Highland 115 kV substation	Dec-27	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

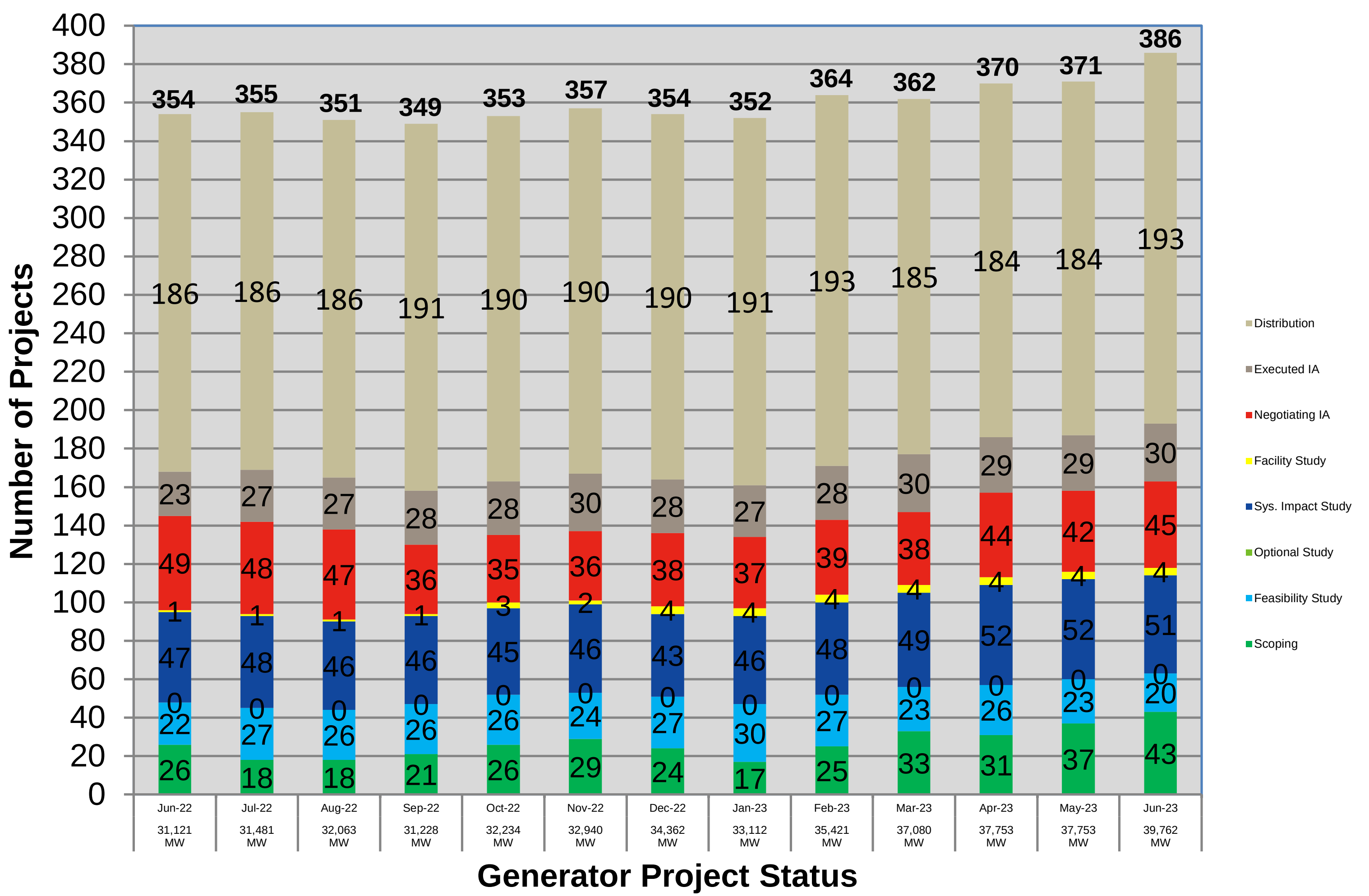
Upper Maine Solution Projects, cont.

Status as of 7/24/2023

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-23	2

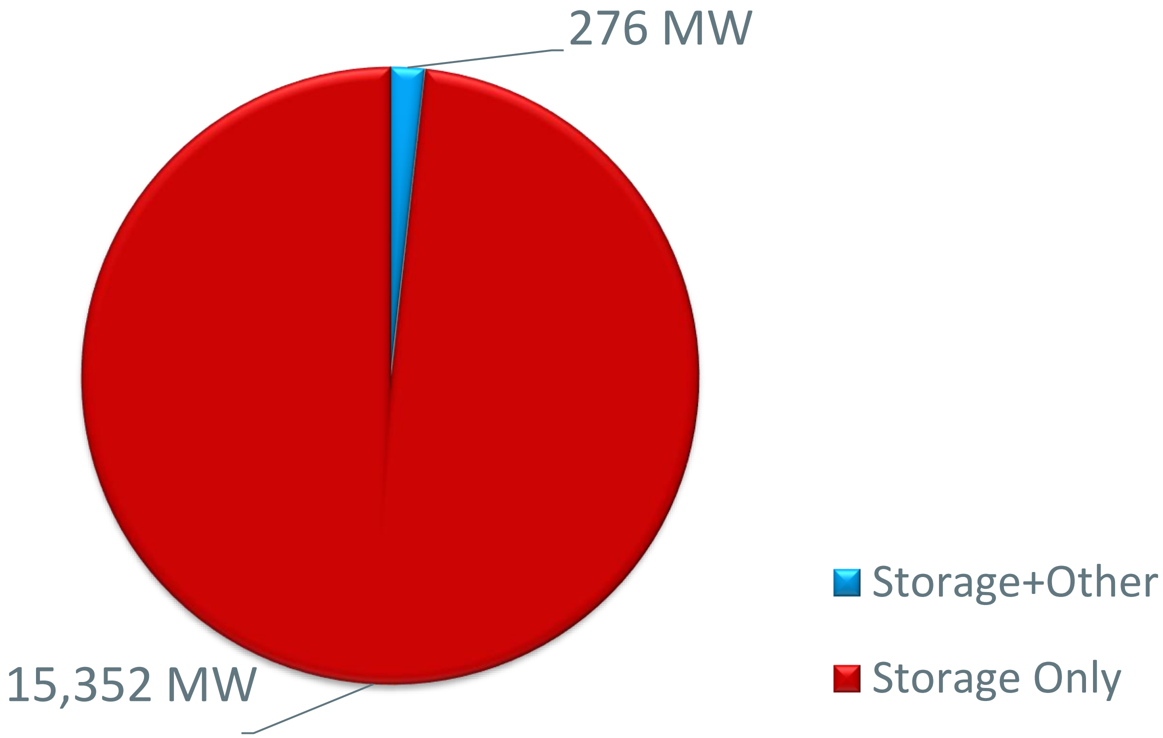
Status of Tariff Studies as of July 1, 2023



11 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: 1 in Scoping and 3 in SIS
https://irtt.iso-ne.com/external.aspx

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

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



OPERABLE CAPACITY ANALYSIS

Summer 2023

Highlights

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

- The lowest 50/50 and 90/10 Preliminary Fall Operable Capacity Margins are projected for week beginning September 23, 2023.

OPERABLE CAPACITY ANALYSIS

Summer 2023 Analysis

Summer 2023 Operable Capacity Analysis

50/50 Load Forecast (Reference)	September - 2023[2] CSO (MW)	September - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,022	29,111
Active Demand Capacity Resource (+) [5]	518	397
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	958	958
Non Commercial Capacity (+)	179	179
Non Gas-fired Planned Outage MW (-)	1,050	1,073
Gas Generator Outages MW (-)	261	394
Allowance for Unplanned Outages (-) [4]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	26,266	27,078
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	24,605	24,605
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	26,910	26,910
Operable Capacity Margin	-644	168

[1] Operable Capacity is based on data as of **July 26, 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 **July 26, 2023.**

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

Summer 2023 Operable Capacity Analysis

90/10 Load Forecast	**September - 2023[2] CSO (MW)**	**September - 2023[2] SCC (MW)**
Operable Capacity MW [1]	28,022	29,111
Active Demand Capacity Resource (+) [5]	518	397
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	958	958
Non Commercial Capacity (+)	179	179
Non Gas-fired Planned Outage MW (-)	1,050	1,073
Gas Generator Outages MW (-)	261	394
Allowance for Unplanned Outages (-) [4]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	26,266	27,078
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	26,421	26,421
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	28,726	28,726
Operable Capacity Margin	-2,460	-1,648

[1] Operable Capacity is based on data as of **July 26, 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 **July 26, 2023.**

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

Summer 2023 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

July 26, 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 August and September.

Report created: 7/26/2023

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
8/12/2023	28075	400	937	15	493	10	2100	0	26824	24605	2305	26910	-86	N	Summer 2023
8/19/2023	28075	400	937	15	515	10	2100	0	26802	24605	2305	26910	-108	N	Summer 2023
8/26/2023	28022	518	958	179	810	0	2100	0	26767	24605	2305	26910	-143	N	Summer 2023
9/2/2023	28022	518	958	179	886	0	2100	0	26691	24605	2305	26910	-219	N	Summer 2023
9/9/2023	**28022**	**518**	**958**	**179**	**1050**	**261**	**2100**	**0**	**26266**	**24605**	**2305**	**26910**	**-644**	**Y**	**Summer 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.

Summer 2023 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

July 26, 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 August and September.

Report created: 7/26/2023

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
8/12/2023	28075	400	937	15	493	10	2100	0	26824	26421	2305	28726	-1902	N	Summer 2023
8/19/2023	28075	400	937	15	515	10	2100	0	26802	26421	2305	28726	-1924	N	Summer 2023
8/26/2023	28022	518	958	179	810	0	2100	0	26767	26421	2305	28726	-1959	N	Summer 2023
9/2/2023	28022	518	958	179	886	0	2100	0	26691	26421	2305	28726	-2035	N	Summer 2023
9/9/2023	**28022**	**518**	**958**	**179**	**1050**	**261**	**2100**	**0**	**26266**	**26421**	**2305**	**28726**	**-2460**	**Y**	**Summer 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)

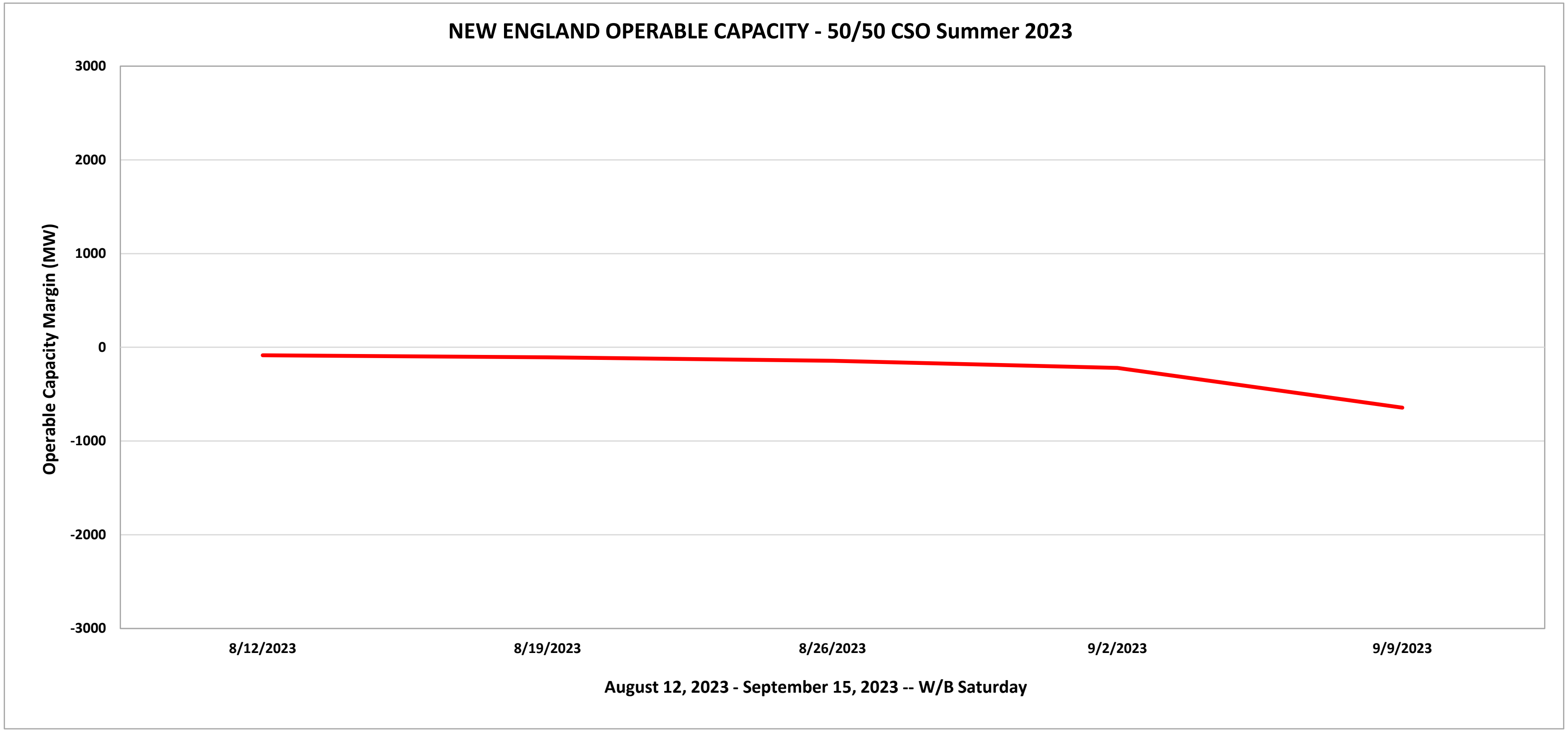
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)

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.

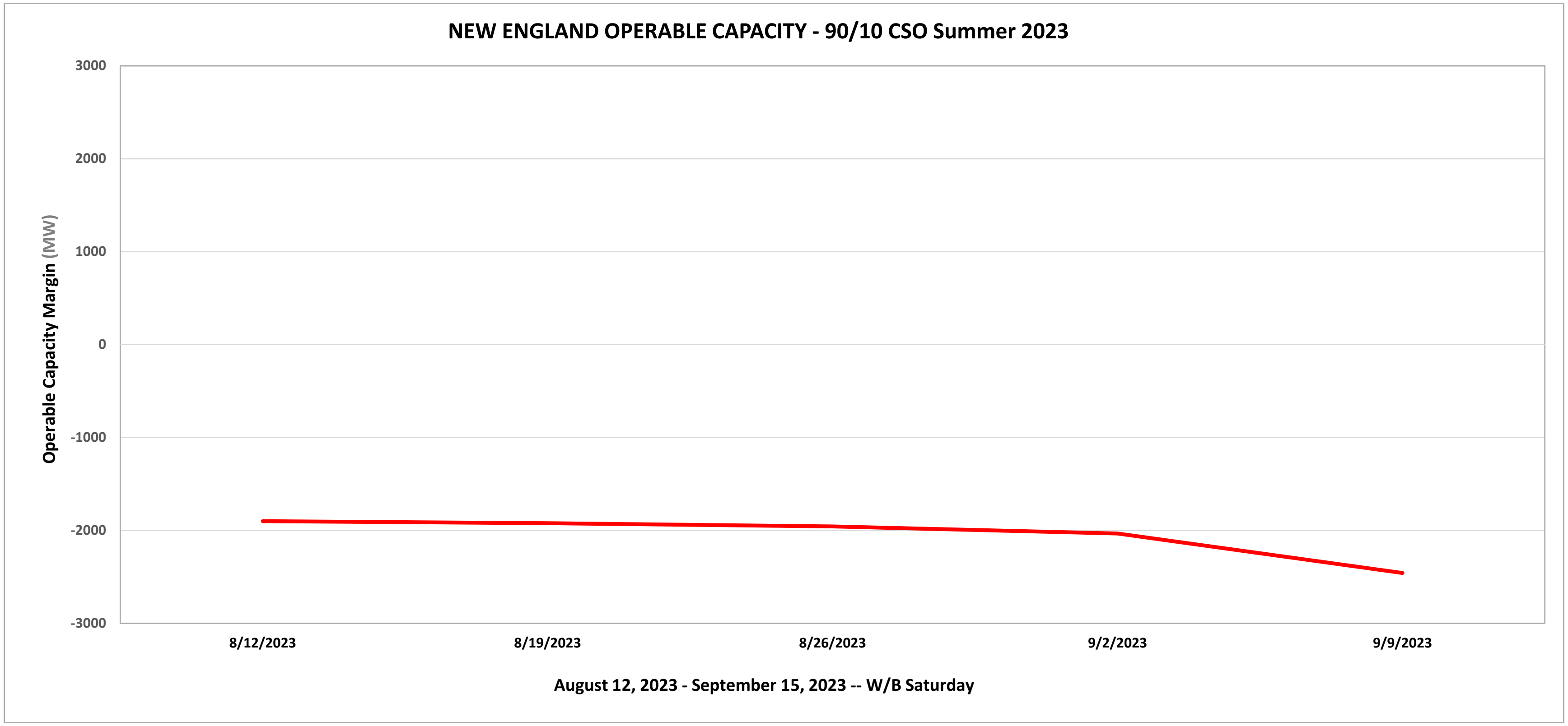
***Highlighted week is based on the week determined by the 50/50 Load Forecast Reference week**

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



Summer 2023 Operable Capacity Analysis

90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Preliminary Fall 2023 Analysis

Preliminary Fall 2023 Operable Capacity Analysis

50/50 Load Forecast (Reference)	**September - 2023[2] CSO (MW)**	**September - 2023[2] SCC (MW)**
Operable Capacity MW [1]	28,022	29,111
Active Demand Capacity Resource (+) [5]	518	397
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	546	546
Non Commercial Capacity (+)	179	179
Non Gas-fired Planned Outage MW (-)	4,359	4,381
Gas Generator Outages MW (-)	371	510
Allowance for Unplanned Outages (-) [4]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	22,435	23,242
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,566	20,566
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,871	22,871
Operable Capacity Margin	-436	371

[1] Operable Capacity is based on data as of **July 26, 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 **July 26, 2023.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **September 23, 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 Fall 2023 Operable Capacity Analysis

90/10 Load Forecast	**September - 2023[2] CSO (MW)**	**September - 2023[2] SCC (MW)**
Operable Capacity MW [1]	28,022	29,111
Active Demand Capacity Resource (+) [5]	518	397
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	546	546
Non Commercial Capacity (+)	179	179
Non Gas-fired Planned Outage MW (-)	4,359	4,381
Gas Generator Outages MW (-)	371	510
Allowance for Unplanned Outages (-) [4]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	22,435	23,242
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	22,115	22,115
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,420	24,420
Operable Capacity Margin	-1,985	-1,178

[1] Operable Capacity is based on data as of **July 26, 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 **July 26, 2023.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **September 23, 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 Fall 2023 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

July 26, 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: 7/26/2023

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
9/16/2023	28022	518	546	179	3698	492	2100	0	22975	20657	2305	22962	13	N	Fall 2023
9/23/2023	**28022**	**518**	**546**	**179**	**4359**	**371**	**2100**	**0**	**22435**	**20566**	**2305**	**22871**	**-436**	**Y**	**Fall 2023**
9/30/2023	28232	518	546	225	4546	2021	2800	0	20154	15371	2305	17676	2478	N	Fall 2023
10/7/2023	28232	518	958	225	3819	4367	2800	0	18947	15406	2305	17711	1236	N	Fall 2023
10/14/2023	28232	518	958	225	5429	2154	2800	0	19550	16324	2305	18629	921	N	Fall 2023
10/21/2023	28232	518	958	225	4808	2696	2800	0	19629	16685	2305	18990	639	N	Fall 2023
10/28/2023	28232	518	958	225	4512	2111	3600	0	19710	16890	2305	19195	515	N	Fall 2023
11/4/2023	28232	518	958	225	4251	2049	3600	0	20033	17005	2305	19310	723	N	Fall 2023
11/11/2023	28232	518	958	225	4192	876	3600	0	21265	17347	2305	19652	1613	N	Fall 2023
11/18/2023	28232	518	958	225	2902	750	3600	620	22061	18079	2305	20384	1677	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.

Preliminary Fall 2023 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

July 26, 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: 7/26/2023

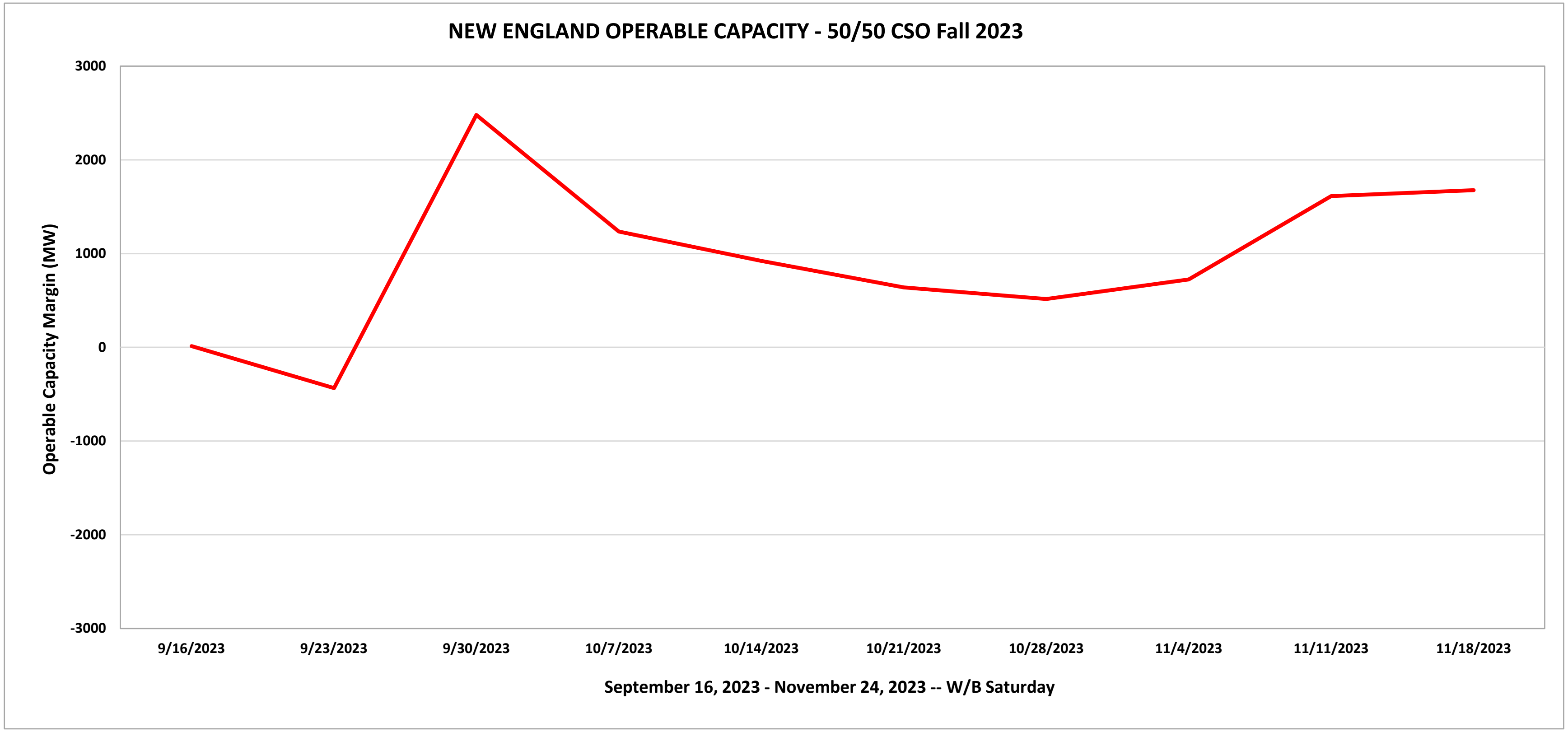
Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due 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
9/16/2023	28022	518	546	179	3698	492	2100	0	22975	22212	2305	24517	-1542	N	Fall 2023
9/23/2023	**28022**	**518**	**546**	**179**	**4359**	**371**	**2100**	**0**	**22435**	**22115**	**2305**	**24420**	**-1985**	**Y**	**Fall 2023**
9/30/2023	28232	518	546	225	4546	2021	2800	0	20154	15971	2305	18276	1878	N	Fall 2023
10/7/2023	28232	518	958	225	3819	4367	2800	0	18947	16007	2305	18312	635	N	Fall 2023
10/14/2023	28232	518	958	225	5429	2154	2800	0	19550	16957	2305	19262	288	N	Fall 2023
10/21/2023	28232	518	958	225	4808	2696	2800	0	19629	17331	2305	19636	-7	N	Fall 2023
10/28/2023	28232	518	958	225	4512	2111	3600	0	19710	17543	2305	19848	-138	N	Fall 2023
11/4/2023	28232	518	958	225	4251	2049	3600	0	20033	17662	2305	19967	66	N	Fall 2023
11/11/2023	28232	518	958	225	4205	750	3600	385	20993	18015	2305	20320	673	N	Fall 2023
11/18/2023	28232	518	958	225	2902	750	3600	785	21896	18773	2305	21078	818	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.

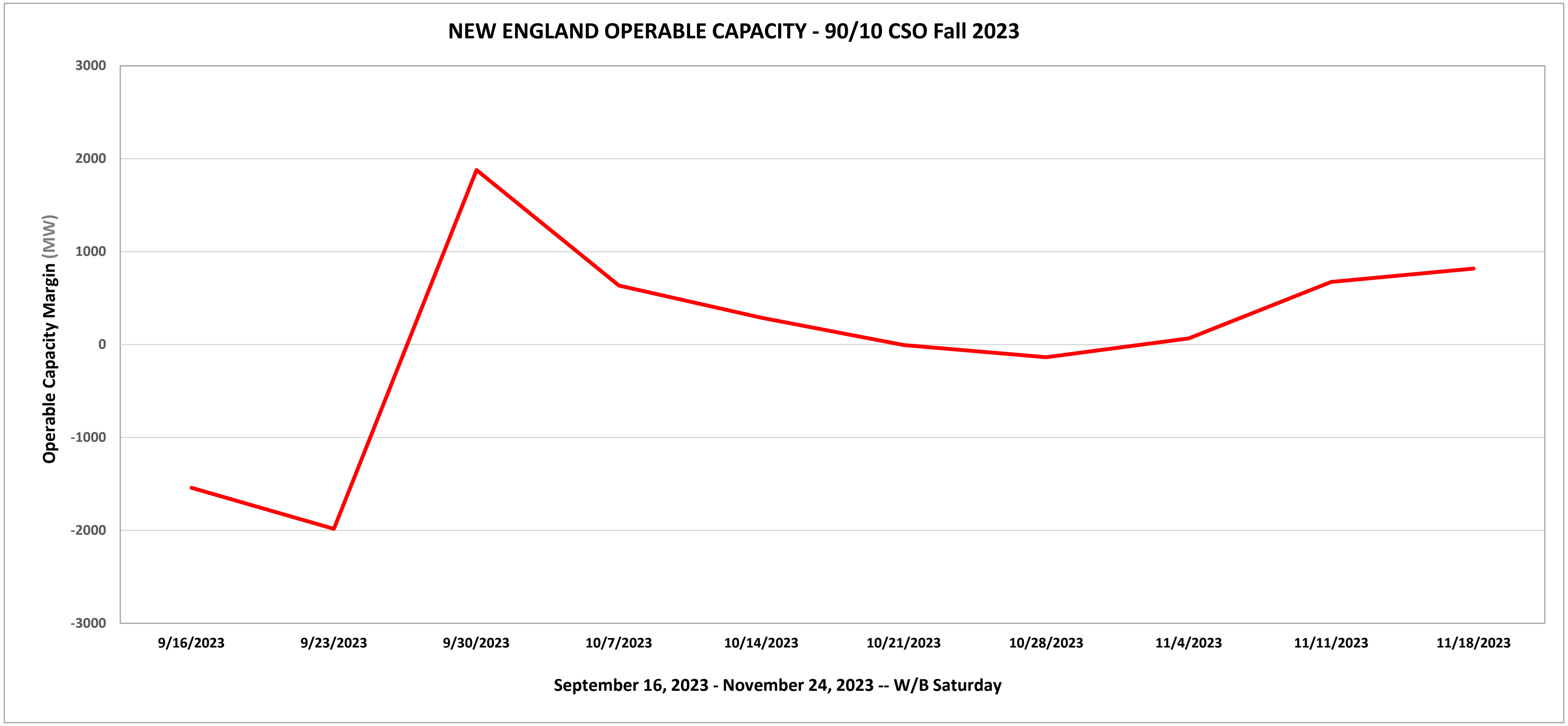
***Highlighted week is based on the week determined by the 50/50 Load Forecast Reference week**

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



Preliminary Fall 2023 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 units <5 MW will be available and respond.
2. The actual load relief obtained is highly dependent on circumstances surrounding the appeals, including timing and the amount of advanced notice that can be given.
3. The MW values are based on a 25,000 MW system load and verified by the most recent voltage reduction test.
4. EEA Levels are described in Attachment 1 to NERC Reliability Standard EOP-011 - Emergency Operations

Possible Relief Under OP4: Appendix A

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

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

MEMORANDUM

TO: NEPOOL Participants Committee

FROM: Pat Gerity, NEPOOL Counsel

DATE: July 27, 2023

RE: Vote on the ISO's Proposed 60-Day Further *Order 881* Compliance Revisions

At next week's August 3, 2023 meeting, you will be asked to support further revisions to Attachment Q to the Open Access Transmission Tariff (Transmission Line Ratings) proposed by the ISO in response to the FERC's June 15, 2023 order[1] conditionally accepting the region's *Order 881* compliance changes ("Further *Order 881* Compliance Changes"). With the exception of the text highlighted in yellow in the attached Tariff redlined sheets, the Further *Order 881* Compliance Changes were reviewed without objection or concern at the July 18-19, 2023 RC/TC Summer Meeting. The package of compliance changes was not voted, however, because that one aspect of the changes (related to how the ISO will maintain local transmission line ratings and exceptions in its database of Transmission Line Ratings and Transmission Line Rating methodologies) had not yet been finalized. Since the RC/TC Summer Meeting, and as further described in the ISO's voting memo included herewith, the ISO has finalized the last changes following consultation with the Transmission Owners.

Given the circumstances, particularly the limited options for further review in light of the FERC's August 14, 2023 deadline for submission of the ISO's 60-day compliance filing, the Participants Committee is being asked to support the Further *Order 881* Compliance Changes without a formal Transmission Committee recommendation. The Further *Order 881* Compliance Changes and related background materials have been included with this memo.

The following resolution can be used for Participants Committee action on this matter:

> RESOLVED, that the Participants Committee supports the Further *Order 881* Compliance Changes, as proposed by the ISO in response to the FERC's June 15, 2023 order in Docket No. ER22-2357, and as circulated to this Committee in advance of this meeting, together with [any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Transmission Committee.

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[1] *ISO New England Inc.*, 183 FERC ¶ 61,180 (June 15, 2023). The order directs the ISO in a 60-day compliance filing (in the absence of an explanation why the ISO should not be so required) to: (i) revise the Tariff to specify that transmission service at the ISO's seams use AARs as the basis for evaluation for near-term transmission service requests; (ii) revise the Tariff to include the examples listed in the FERC's *pro forma* Attachment M; (iii) remove proposed revisions to Schedule 18 excepting the Cross-Sound Cable from the requirements of *Order 881*; and (iv) revise the Tariff to require the ISO in a database that it maintains (rather than dividing responsibility between itself and the transmission owners) to host all transmission line ratings, ratings methodologies, and exceptions or alternate ratings.

ISO new england

memo

To: NEPOOL Participants Committee

From: Graham Jesmer, Regulatory Counsel – Operations and Planning

Date: July 27, 2023

Subject: Order 881 60-Day Further Compliance

The ISO is requesting a vote by the Participants Committee on its proposed revisions to the Open Access Transmission Tariff (OATT) to comply with the Federal Energy Regulatory Commission's (FERC) June 15, 2023 Order on Compliance. Due to the limitations of the 60-day compliance requirement, the time available for the NEPOOL stakeholder process is limited.

The ISO presented its original proposal and OATT revisions to the Transmission Committee (TC) at its July 18-19, 2023 meeting (Agenda Item 5) as an informational item because the ISO had not yet finalized its compliance approach. Since that time, the ISO has developed additional language requiring it to maintain local transmission line ratings and exceptions in its database of Transmission Line Ratings and Transmission Line Rating methodologies, as noted in bold below and as shown in yellow highlighting in the accompanying OATT redlines to reflect the changes made since the July TC meeting.

Overall, to meet the requirements of the Order in its filing for August 14, 2023, the ISO:

- Explains its intent to use ARRs at the ISO's seams between ISO-NE and NYISO and updates Attachment Q of the OATT to clarify that AARs are used on the interface subject to the rating procedures contained in Attachment C "Available Transfer Capability Methodology" of the Open Access Transmission Tariff (OATT).

- Updated Attachment Q of the OATT to include the pro forma examples of circumstance in which transmission equipment may be excepted from AARs.

- Updated Attachment Q of the OATT to specify that ISO-NE will host all required ratings (Seasonal, AARs, and Emergency Ratings) rating methodologies, and exceptions for Day-Ahead Markets, Real-Time Markets, and Real-Time Operations in its database on its OASIS page or on another password-protected website.

- Updated Attachment Q of the OATT to specify that ISO-NE will host all required ratings (Seasonal, AARs, and Emergency Ratings), rating methodologies, **and exceptions for Local Point-To-Point and Local Network Service**, provided by the PTOs under Schedule 21 of the OATT in its database on its OASIS page or on another password-protected website.

- Agrees with the commission determination that the exception to the applicability of AARs for Cross Sound Cable will be removed from Schedule 18 of the OATT.

ATTACHMENT Q

Transmission Line Ratings

General:

Beginning July 12, 2025, the ISO shall implement Transmission Line Ratings as provided below.

Definitions:

The following definitions apply for purposes of this Attachment:

(1) "Transmission Line Rating" means the maximum transfer capability of a transmission line, computed in accordance with a written Transmission Line Rating methodology and consistent with Good Utility Practice, considering the technical limitations on conductors and relevant transmission equipment (such as thermal flow limits), as well as technical limitations of the New England Transmission System (such as system voltage and stability limits). Relevant transmission equipment may include, but is not limited to, circuit breakers, line traps, and transformers.

(2) "Ambient-Adjusted Rating" ("AAR") means a Transmission Line Rating that:

(a) Applies to a time period of not greater than one hour.

(b) Reflects an up-to-date forecast of ambient air temperature across the time period to which the rating applies.

(c) Reflects the absence of solar heating during nighttime periods, where the local sunrise/sunset times used to determine daytime and nighttime periods are updated at least monthly, if not more frequently.

(d) Is calculated at least each hour, if not more frequently.

(3) "Seasonal Line Rating", as further defined in ISO Operating Documents, means a Transmission Line Rating that:

(a) Applies to a specified season, to include not fewer than four seasons in each year, and to reasonably reflect portions of the year where expected high temperatures are relatively consistent.

(b) Reflects up-to-date historical ambient air temperatures across the relevant season over which the rating applies.

(c) Is calculated annually, if not more frequently, for each season in the future.

(4) "Emergency Rating," as further defined in ISO Operating Documents, means a Transmission Line Rating that reflects operation for a specified, finite period, rather than reflecting continuous operation. An Emergency Rating may assume an acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

System Reliability:

If ISO or Transmission Owner reasonably determines, consistent with Good Utility Practice, that the temporary use of a Transmission Line Rating different than would otherwise be required by this Attachment is necessary to ensure the safety and reliability of the New England Transmission System, then the ISO may use such an alternate rating. The ISO and Transmission Owners shall confirm the use of such an alternate rating consistent with each respective operating agreement, and the procedures established in ISO Operating Documents. The ISO and Transmission Owner shall document in their databases of Transmission Line Ratings on OASIS or another password-protected website, as required by this Attachment, the use of an alternate Transmission Line Rating under this paragraph, including the nature of and basis for the alternate rating, the date and time that the alternate rating was initiated, and (if applicable) the date and time that the alternate rating was withdrawn and the standard rating became effective again.

Obligations of the ISO and Transmission Owners:

The obligations of the ISO and Transmission Owners under this Attachment are as follows:

ISO shall use AARs in the security-constrained unit commitment, security constrained economic dispatch, and related models, as well as for Day-Ahead Energy Market and Real-Time Energy Market operations and clearing (including at the seams with neighboring Balancing Authority Areas, at which ISO provides transmission service, subject to the procedures in Attachment C of Section II of the Tariff). ISO shall use Seasonal Line Ratings as a recourse rating in the event that an AAR otherwise required to be used under this Attachment is unavailable.

The ISO shall use uniquely determined Emergency Ratings, as specified in the ISO New England Operating Documents and as determined consistent with the rights and obligations of the parties under each respective operating agreement and provided by the Transmission Owners, for contingency analysis and in post-contingency simulations of constraints in the Day-Ahead and Real-Time Energy Markets. Such uniquely determined Emergency Ratings shall also include separate AAR calculations for each Emergency Rating duration used.

Transmission Owners shall, consistent with this Attachment, and their respective operating agreements, and the ISO New England Operating Documents, calculate and electronically transmit AARs and Emergency Ratings to ISO, for use in the Day-Ahead and Real-Time Energy Markets, as well as calculate and provide Seasonal Line Ratings to the ISO.

In utilizing forecasts of ambient air temperature for AARs and evaluating historical temperatures for Seasonal Line Ratings, the Transmission Owners shall utilize such forecasts and historical temperatures consistent with Good Utility Practice and on a non-discriminatory basis.

Postings to OASIS or another password-protected website: The ISO ~~and Transmission Owners~~ shall maintain on the~~ir respective~~ password-protected sections of its ~~their respective~~ OASIS pages or on another password-protected website a database of Transmission Line Ratings and Transmission Line Rating methodologies consistent with this Attachment.

The ISO’s database shall include a full record of all Transmission Line Ratings (Seasonal, AARs and Emergency Ratings), as used in Day-Ahead and Real-Time Energy Markets and Real-Time operations. Any postings of temporary alternate Transmission Line Ratings or exceptions, including the nature and basis for each exception or alternate rating, used under the System Reliability section above or the Exceptions section below, respectively, are considered part of the database. The database shall include ~~records that cover the previous five years~~which Transmission Line Ratings and Transmission Line Rating methodologies were in effect at which times over at least the previous five years and records of which temporary alternate Transmission Line Ratings or exceptions were in effect at which times during the previous five years.

The database shall include a full record of all Local Transmission Line Ratings, both as used in real-time operations, and as used for all future periods for which Local Point-to-Point Service or Local Network Service is offered. Any postings of temporary alternate Local Transmission Line Ratings or exceptions used under the System Reliability section above or the Exceptions section below, respectively, are considered part of the database. The database must include records of which Local Transmission Line Ratings and Local Transmission Line Rating methodologies were in effect at which times over at least the previous five years, including records of which temporary alternate Local Transmission Line Ratings or exceptions were in effect at which times during the previous five years. The Local Transmission Line Ratings and Local Transmission Line Ratings methodologies, as described in Schedule 21, shall be provided to the ISO by the Transmission Owners and ISO shall incorporate that data into its database.

Each record in the database shall indicate which transmission line the record applies to, and the date and time the record was entered into the database. The database shall be maintained such that users can view, download, and query data in standard formats, using standard protocols.

~~The Transmission Owners' databases shall contain a record of their respective Transmission Line Rating (Seasonal, AAR and Emergency Ratings) methodologies, as well as the resulting Transmission Seasonal Line Ratings (AARs, Seasonal Line Ratings, and Emergency Ratings) for each line provided to the ISO. Aany postings of temporary alternate Transmission Line Ratings used in the Day-Ahead and Real-Time Energy Markets and Real-Time operations or exceptions, including the nature and basis for each exception or alternate rating, used under the System Reliability section above or the Exceptions section below, respectively, are considered part of the database. (including any Eexceptions to the use of AARs discussed below and any temporary rating(s) transmitted to the ISO), and their respective Transmission Line Rating methodologies . Each record in the database shall indicate to which transmission line the record applies to, and the date and time the record was entered into the database. The database shall be maintained such that users can view, download, and query data in standard formats, using standard protocols.~~

Sharing with Transmission Providers: The ISO and Transmission Owners shall provide, upon request by any transmission provider and in a timely manner, the following information:

(1) Transmission Line Ratings for each period for which Transmission Line Ratings are calculated, with updated ratings shared each time Transmission Line Ratings are calculated, and

(2) Written Transmission Line Rating methodologies used to calculate the Transmission Line Ratings in (1) above.

Exceptions: Where the Transmission Owner determines, consistent with Good Utility Practice, that the Transmission Line Rating of a transmission line is not affected by ambient air temperature or solar heating, the Transmission Owner may, consistent with the rights and obligations of the parties under each respective operating agreement, provide a Transmission Line Rating for that transmission line that is not an AAR or Seasonal Line Rating. Examples of such a transmission line -may include (but are not limited to): (1) a transmission line for which the technical transfer capability of the limiting conductors and/or limiting transmission equipment is not dependent on ambient air temperature or solar heating; or (2) a transmission line whose transfer capability is limited by a Transmission System limit (such as a system voltage or stability limit) which is not dependent on ambient air temperature or solar heating. The criteria for determining whether a given transmission line may be excepted are contained in ISO-NE Operating Documents. The Transmission Owner shall document in its database of Transmission Line Ratings and Transmission Line Rating methodologies on OASIS or another password-protected website any exceptions to the requirements contained in this Attachment initiated under this paragraph, including the nature of and basis for each exception, the date(s) and time(s) that the exception was initiated, and (if applicable) the date(s) and time(s) that each exception was withdrawn and the standard rating became effective again. If the technical basis for an exception under this paragraph changes, then the Transmission Owner shall update the relevant Transmission Line Rating(s) in a timely manner. The Transmission Owner shall reevaluate any exceptions taken under this paragraph at least every five years.

JULY 18-19, 2023 | NEWPORT, RHODE ISLAND |
NEPOOL RELIABILITY AND TRANSMISSION COMMITTEES SUMMER MEETING

FERC Order No. 881 Further Compliance

Incorporation of Ambient Adjusted Line Ratings

Graham Jesmer

REGULATORY COUNSEL – OPERATIONS AND PLANNING

FERC Order No. 881 Further Compliance

Current Effective Date: July 12, 2025

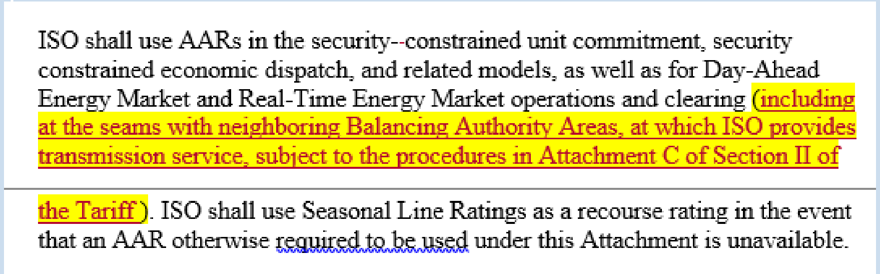
- On December 16, 2021, the Federal Energy Regulatory Commission ("Commission") issued Order No. 881, its Final Rule on Managing Transmission Line Ratings
- The ISO submitted the first compliance filing on July 12, 2022; changes included:
  - Incorporating new OATT Attachment Q (based on language in the Commission's new *pro forma* "Attachment M") for the calculation and use of AARs for all transmission lines (minus certain exceptions)
  - Enabling acceptance of electronic updates to line ratings at least hourly
  - Adding transparency requirements
- On June 15, 2023, the Commission issued the Order on Compliance,* requiring either modifications to the submitted Tariff language, or an explanation of why the current submittal meets the original Order No. 881 requirements, within 60 days (August 14, 2023), with respect to:
  1. Use of AARs at the ISO's seams
  2. Inclusion of a list of exceptions to Attachment Q
  3. Posting requirements for line ratings
  4. Inclusion of language in Schedule 18 excepting Cross Sound Cable ("CSC") from Attachment Q
- At this meeting, ISO-NE will present modifications to proposed Attachment Q, and ISO-NE and Cross Sound Cable will address the revisions to Schedule 18

*Note that a further compliance filing explaining the method and timeframe for calculation of AARs is required to be submitted in 2024

Compliance Order Requirements

1) Revise the Tariff to specify that transmission service at ISO-NE's seams use AARs as the basis for near-term service requests or explain why it should not be required to do so

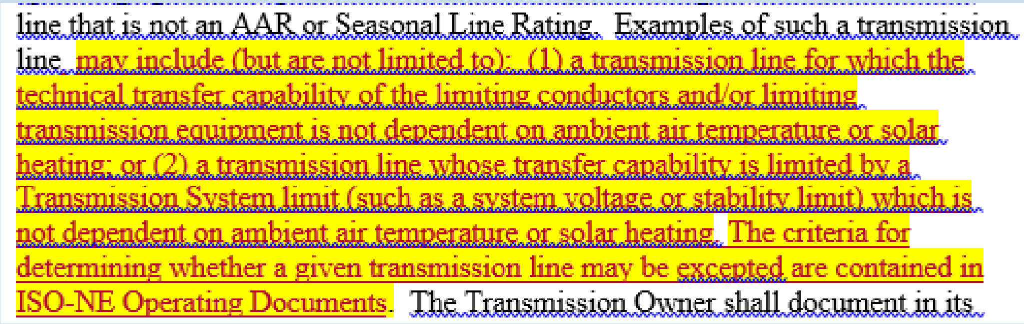
- Response: Transmission lines that comprise the interface between ISO-NE and NYISO will utilize AARs in the DAM and RTM. Because the transfer limit on the NY-NE interfaces is heavily dependent upon generation dispatch in both areas and that dispatch is not known to either market in the DAM or RTM the interface TTC is calculated using Attachment C of the Tariff.
  - This is consistent with NYISO's FERC 881 Order Filing (Docket No. ER22-2350)
- Compliance revisions: Update Attachment Q to state that AARs are used on the interface subject to Attachment C of the Tariff

Where	Example	Why?
Obligations of the ISO and Transmission Owners	 ISO shall use AARs in the security--constrained unit commitment, security constrained economic dispatch, and related models, as well as for Day-Ahead Energy Market and Real-Time Energy Market operations and clearing (including at the seams with neighboring Balancing Authority Areas, at which ISO provides transmission service, subject to the procedures in Attachment C of Section II of the Tariff). ISO shall use Seasonal Line Ratings as a recourse rating in the event that an AAR otherwise required to be used under this Attachment is unavailable.	State that AARs will be used at ISO-NE's seams

Compliance Order Requirements (cont.)

2) Revise the Tariff to include the pro forma exceptions and alternate rating example criteria or explain why it should not be required to do so

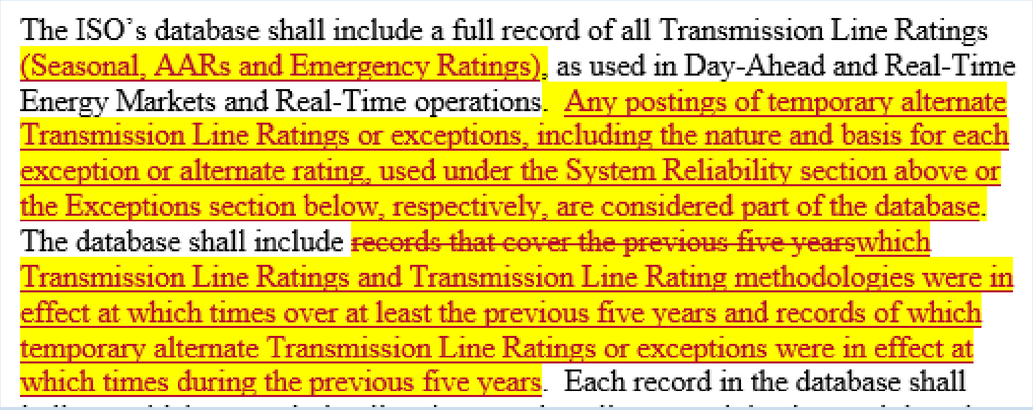
- Response: Proposed Attachment Q has been updated to include the pro forma examples

Where	Example	Why?
Exceptions	 line that is not an AAR or Seasonal Line Rating. Examples of such a transmission line may include (but are not limited to): (1) a transmission line for which the technical transfer capability of the limiting conductors and/or limiting transmission equipment is not dependent on ambient air temperature or solar heating; or (2) a transmission line whose transfer capability is limited by a Transmission System limit (such as a system voltage or stability limit) which is not dependent on ambient air temperature or solar heating. The criteria for determining whether a given transmission line may be excepted are contained in ISO-NE Operating Documents. The Transmission Owner shall document in its	Use pro forma example language

Compliance Order Requirements (cont.)

3) Revise the Tariff to state that ISO-NE will host all transmission line ratings, ratings methodologies, and exceptions or alternate ratings

- Response: Proposed Attachment Q has been updated to state the ISO-NE will host all required ratings

Where	Example	Why?
Exceptions	 The ISO's database shall include a full record of all Transmission Line Ratings (Seasonal, AARs and Emergency Ratings), as used in Day-Ahead and Real-Time Energy Markets and Real-Time operations. Any postings of temporary alternate Transmission Line Ratings or exceptions, including the nature and basis for each exception or alternate rating, used under the System Reliability section above or the Exceptions section below, respectively, are considered part of the database. The database shall include ~~records that cover the previous five years~~which Transmission Line Ratings and Transmission Line Rating methodologies were in effect at which times over at least the previous five years and records of which temporary alternate Transmission Line Ratings or exceptions were in effect at which times during the previous five years. Each record in the database shall	Update language to state that ISO-NE will host all ratings for Day-Ahead Markets, Real-Time Markets and Real-Time Operations in its database

Compliance Order Requirements (cont.)

4) Revise Schedule 18 to remove exception to applicability of AARs for Cross Sound Cable ("CSC")

- Response: ISO and CSC agree to remove the language from Schedule 18
  - CSC is not ambient limited and will likely be subject to an exception during implementation consistent with Attachment Q

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Transmission Committee July 18-19, 2023	Vote
Participants Committee August 3, 2023	Vote

Questions

Graham Jesmer

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EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of August 2, 2023

The following activity, as more fully described in the attached litigation report, has occurred since the report dated June 24, 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)	Aug 2	Brookfield seeks a FERC order directing ISO-NE to revise the Tariff to allow Pumped Storage ESFs to participate in the IEP; comment deadline ***Aug 22, 2023***
	1	206 Proceeding: ISO-NE Market Power Mitigation Rules (EL23-62)	Jun 28	ISO-NE files motion to hold proceeding in abeyance
			Jul 5	NEPOOL files comments supporting ISO-NE motion for abeyance
			Jul 14	FERC grants ISO-NE Jun 28 motion; no FERC action to be taken until after ***Feb 1, 2024***

II. Rate, ICR, FCA, Cost Recovery Filings

*	6	Stonepeake Kestrel CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER23-2429)	Jul 18	Stonepeake Kestrel requests recovery of ***$1.6 million*** in incremental medium impact CIP-IROL Costs incurred between Mar 29, 2021 and Mar 31, 2023; comment deadline ***Aug 8, 2023***
			Jul 20-21	NEPOOL, NESCOE file doc-less motions to intervene
*	6	Bucksport Generation (Schedule 17) Section 205 Cost Recovery Filing (ER23-2428)	Jul 18	Bucksport Generation requests recovery of ***$277,874*** in incremental medium impact CIP-IROL Costs incurred between Mar 29, 2021 and Mar 31, 2023; comment deadline ***Aug 8, 2023***
			Jul 20-21	NEPOOL, NESCOE file doc-less motions to intervene
*	7	FCA18 De-List Bids Filing (ER23-2379)	Jul 12	ISO-NE submits filing describing Permanent and Retirement De-List Bids submitted on or prior to the FCA18 Existing Capacity Retirement Deadline
			Jul 13-28	NEPOOL, Calpine, National Grid intervene
	7	CSC CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER23-1826)	Jun 29	FERC issues deficiency letter requesting additional information
			Jul 28	CSC files deficiency letter response; comment deadline ***Aug 18, 2023***
	7	BHD Regulatory Asset-Establishment & Recovery Through Rates (ER23-1598)	Jul 5	Versant submits response to deficiency letter
			Jul 19	MPUC intervenes (out-of-time)
	8	FCA17 Results Filing (ER23-1435)	Jul 18	FERC accepts FCA17 Results filing, eff. *Jul 19, 2023*
			Jul 25	NEPGA intervenes (out-of-time)
	8	Add'l Cost Recovery Due to Dec 24 General Threshold Energy Mitigation: Dynegy (ER23-1261)	Aug 1	FERC accepts compliance filing identifying full amount of regulatory costs ($116,000) to be recovered
	9	**Mystic 8/9 COSA (ER18-1639)**		
	9	(-000) Public Systems' Request for Disclosure of Audit Information	Jul 5	Public Systems answer Mystic's and ISO-NE's Jun 9 answers
			Jul 14	Mystic answers Public System's Jul 5 answer
	10	(-021) First CapEx Info. Filing Settlement Agreement	Jun 28	Mystic clarifies uncontested nature of Settlement and requests expedited action; ENECOS confirm they will not contest Settlement
			Jul 10, 11	NESCOE, National Grid support Mystic's request for expedited action
			Aug 1	FERC approves Settlement Agreement, subject to 30-day eTariff filing

	12	30-Day Compliance Filing per *Order on ENECOS Mystic COSA Complaint* (ER23-1735)	Jul 10	ENECOS protest compliance filing (out-of-time)
			Jul 20	Mystic answers ENECOS' Jul 10 protest
*	12	Transmission Rate Annual (2024) Update/Informational Filing (ER20-2054)	Jul 29	PTO AC submits informational filing identifying adjustments to Regional Transmission Service charges, Local Service, and Schedule 12C Costs under Section II of the Tariff for 2023, and a Schedule 1 formula rate for Jun 1, 2022 to May 31, 2023 (a 2023 RNS Rate of $140.94/kW-year and a Schedule 1 formula rate of $1.75 kW-year, decreases of $1.84/kW-year and $0.12/kW-year, respectively); this filing will not be noticed for public comment

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

*	14	Waiver Request: FCA18 Summer Qualified Capacity (Yarmouth 4) (ER23-2356)	Jul 6	Wyman IV requests one-time Tariff waiver to allow an incremental increase in Yarmouth 4's summer Qualified Capacity
			Jul 14, 19	NEPOOL, National Grid intervene
	14	IEP Parameter Updates (ER23-1588)	Jun 30	Indicated Suppliers file comments supporting the IEP Parameter Updates
	15	SATOA Revisions (ER23-739; ER23-743)	Jul 5	Elevate Renewables files comments
			Jul 12	National Grid urges FERC to reject Elevate Renewables' comments
			Jul 27	Elevate Renewables answers National Grid's motion to reject
	16	New England's *Order 2222* Compliance Filing (ER22-983)	Jun 28	AEU/PowerOptions/SEIA files answer to ISO-NE's Jun 14 answer
			Jun 30	ISO-NE, CMP/UI, Eversource, National Grid appeal to DC Circuit *Order 2222 Compliance Order* and *Order 2222 Compliance Allegheny Notice*

IV. OATT Amendments / TOAs / Coordination Agreements

*	18	Versant Power Att. F App. D Depreciation Rate Change (ER23-2483)	Jul 26	Versant Power proposes updated depreciation rates for Versant Power's local transmission facilities in the Bangor Hydro District as set forth in Appendix D to Attachment F of the ISO-NE OATT; comment date ***Aug 16, 2023***
*	18	CMP Att. F App. D Depreciation Rate Change (ER23-2477)	Jul 26	CMP proposes updated depreciation rates for its transmission facilities as set forth in Appendix D to Attachment F of the ISO-NE OATT; comment date ***Aug 16, 2023***

V. Financial Assurance/Billing Policy Amendments

*	19	FAP Eligible LOC Issuer Changes (ER23-2277)	Jun 28	ISO-NE and NEPOOL file changes to FAP
			Jul 19	National Grid intervenes

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

	19	Schedule 21-VP: Versant/Black Bear LSAs (ER23-2035)	Jul 26	ISO-NE and Versant clarify that discounted trans. rate will be as provided in the LSAs - $1,151.67/MW-mo.
			Jul 28	FERC accepts 7 fully executed, non-conforming LSAs by and among Versant, ISO-NE and Black Bear, eff. *Aug 1, 2023*; refunds ordered and to be made on or before ***Aug 28, 2023***

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activities to Report

VIII. Regional Reports

*	20	LFTR Implementation Quarterly Status Reports (ER07-476)	Jul 14	ISO-NE files its 59th quarterly report
*	20	IMM Quarterly Markets Reports - 2023 Spring (ZZ23-4)	Aug 1	IMM files Spring 2023 Report; to be reviewed at Markets Committee Summer Meeting

IX. Membership Filings

*	22	Aug 2023 Membership Filing (ER23-2514)	Jul 31	***New Member:*** Clover Energy LLC; comments deadline ***Aug 21, 2023***
*	22	Membership – Manchester Methane Involuntary Termination (ER23-2390)	Jul 13	NEPOOL and ISO-NE request the involuntary termination of the Participant status of Manchester Methane, LLC, eff. *Sep 11, 2023*; comment deadline ***Aug 3, 2023***
*	22	July 2023 Membership Filing (ER23-2319)	Jun 30	***New Members:*** Hecate Energy Albany 2; Erie Wind, LLC; and SCEF1 FUEL CELL, LLC ***Terminations:*** Concurrent LLC; and Brookfield Energy Marketing LP ***Name changes:*** CPV Spruce Mountain Wind, LLC (f/k/a Spruce Mountain Wind, LLC)
	22	June 2023 Membership Filing (ER23-2025)	Jul 27	FERC accepts (i) ***the memberships of*** Con Edison Transmission; Generate NB Fuel Cells; Jonathan Lamson; and Tomorrow Energy Corp; and (ii) **the termination of the Participant status** of Northern States Power and Granite Reliable Power
	23	May 2023 Membership Filing (ER23-1768)	Jun 27	FERC accepts (i) **the memberships** of Carbon Solutions Group, PPL TransLink, Inc. and Second Foundation US Trading, LLC; (ii) **the termination of the Participant status** of EnPowered USA LLC, Invenia Technical Computing Corp., Uniper Global Commodities NA LLC, and WATTIFI INC.; and (iii) **the name changes** of RWE Clean Energy Wholesale Services, Inc. (f/k/a Consolidated Edison Energy, Inc.); RWE Clean Energy Asset Holdings, Inc. (f/k/a Consolidated Edison Development, Inc.); RWE Clean Energy Solutions, Inc. (f/k/a Consolidated Edison Solutions, Inc.); and SYSO Inc. (f/k/a SYSO LLC).

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

	23	NERC Report on Evaluation of Physical Reliability Standard (CIP-014) (RD23-2)	Jun 29, Jul 27	FERC issues supplemental notices of Joint FERC/NERC tech. conf. to be held ***Aug 10, 2023***, to discuss physical security of the BPS
	23	Revised Reliability Standards: EOP-011-3 and EOP-012-1 (RD23-1)	Jun 29	FERC issues “Allegheny Order”, addressing arguments raised on reh’g, modifying the discussion in the *Cold Weather Standards Order* and continuing to reach the same result; federal court appeals, if any, due on or before ***Aug 28, 2023***
	26	2023 NERC/NPCC Business Plans and Budgets (RR22-4)	Jul 3	FERC accepts Jan 3, 2023 compliance filing

XI. Misc. - of Regional Interest

	26	203 Application: Three Corners Solar/Three Corners Prime Tenant (EC23-90)	Jul 28	FERC authorizes disposition and consolidation of jurisdictional facilities and the lease of an existing 112 MWac solar PV generation facility in Kennebec County, Maine
	27	203 Application: Energy Harbor / Vistra (EC23-74)	Jul 10 Jul 25	Vistra/Energy Harbor Public Utilities file answer to protests/comments Office of the Ohio Consumers’ Counsel, NOPEC answer Jul 10 answer

*	27	PURPA Enforcement Petition: Allco Finance Limited (EL23-84)	Jul 24	Allco petitions the FERC to initiate an enforcement action against Massachusetts Agencies (MA DPU and MA DOER); comment deadline ***Aug 14, 2023***
			Jul 25-Aug 2	MA DOER, MA DPU, HQUS, MOPA, NEPGA, Public Citizen intervene
*	27	LGIAs: RIE/ISO-NE/RISEC & Tiverton (ER23-2494 and ER23-2491)	Jul 26	ISO-NE and RIE file two revised LGIAs to reflect RIE as the new Interconnecting TO; comment deadline ***Aug 16, 2023***
*	28	LGIA Termination: CL&P/ISO-NE/NTE CT (ER23-2378)	Jul 11	CL&P and ISO-NE file LGIA notice of termination
*	28	Engineering & Test Agreement: CL&P/BPUS (ER23-2335)	Jul 5	CL&P files Engineering and Test Agreement with BPUS
			Jul 10	BPUS intervenes
	28	Changes to Depreciation Rates in MPD OATT Formula Rate (ER23-2085)	Jun 28	Maine PUC files comments
			Jul 13	Versant answers Maine PUC comments
			Jul 18	Maine PUC answers Versant's Jul 13 comments
	29	LGIA: National Grid/Millennium Power (ER23-2065)	Jul 31	FERC accepts LGIA, eff. *May 3, 2023*
	29	Revised LSAs: NEP/ISO-NE/RIE (ER23-1831; ER23-1830)	Jun 30	FERC accepts the revised LSAs, eff. *May 5, 2023*
	29	FOA: Generate NB Fuel Cells/FRPC, SBD, EIP (ER23-1979)	Jul 24	FERC accepts FOA, eff. *May 27, 2023*
	29	LGIA: RIE/ISO-NE/Various Entities (ER23-1741)	Jul 5	FERC accepts LGIA filed in ER23-1741, eff. *Jan 1, 2023*
	30	LSAs: RI Energy/ISO-NE/BIPCO (ER23-1000; ER23-1003)	Jun 27	ISO-NE and RIE file joint motion to hold proceedings in abeyance
	31	VEC-HQUS Use Rights Transfer Agreement (NJ23-12)	Jun 30	VEC files amended Agreement with HQUS for the Transfer of Use Rights on the Phase I/II HVDC Transmission Facilities

XII. Misc. - Administrative & Rulemaking Proceedings

31	Interregional Transfer Capability Transmission Planning & Cost Allocation Requirements (AD23-3)	Jun 28	Reply comments filed by, among others: June 28, 2023 and were filed by, among others: AEP, AEU, Clean Energy Buyers Assoc., EEI, EPSA, ITC, MISO, NRDC, Vistra/NRG
32	Second New England Winter Gas-Electric Forum (AD22-9)	Jul 10	FERC issues notice inviting post-forum comments; comments due by ***Aug 24, 2023***
		Jul 21	FERC posts Forum's final transcript to eLibrary
32	Transmission Planning & Cost Management Tech. Conf. (AD22-8)	Jul 19	CA PUC supports inclusion of CA PUC Final Resolution E-5252 in this proceeding's record
33	Joint Federal-State Task Force on Electric Transmission (AD21-15)	Jun 29	NARUC nominates state commissioners for the Aug 2023 to July 2024 term, including Commissioner Riley Allen (VT PUC) and Chair Marissa Gillett (CT PURA) from the NECPUC region
		Jul 16	JFSTF holds seventh meeting
35	*Order 893*: Incentives for Advanced Cybersecurity Investment (RM22-19)	Jul 27	FERC issues *Order 893-A* granting clarifications requested by NRECA, and thus denying reh'g of *Order 893*
36	*Order 2023*: Interconnection Reforms (RM22-14)	Jul 28	FERC issues *Order 2023*
40	*Order 898*: Accounting and Reporting Treatment of Certain Renewable Energy Assets (RM21-11)	Jun 29	FERC issues *Order 898*, eff. Jan 1, 2025

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

*	40	NRG Energy (IN23-3)	Jul 20	FERC approves Stipulation and Consent Agreement that resolves OE's investigation into NRG's compliance with the PJM Tariff Parameter Limited Schedule requirements at its Fisk Facility in Chicago for the 2018-2020 delivery years; NRG must ***disgorge $32,658***, pay a ***$37,342 civil penalty***, and submit at least one annual compliance monitoring report

Natural Gas-Related Enforcement Actions

*	41	Pacific Summit Energy LLC (IN23-9)	Jun 30	FERC approves Stipulation and Consent Agreement that resolved OE's investigation into whether Pacific Summit engaged in a related-positions fraudulent scheme involving physical trading at Transco Zone 6 for the purpose of benefiting related financial positions during the Oct 2017 Bidweek (Sep 25-29, 2017), in violation of section 4A of the NGA and the FERC's Anti-Manipulation Rule; Pacific Summit must ***disgorge $154,623*** and pay a ***$360,000 civil penalty***
	42	BP (IN13-15)	Jul 7	FERC approves Stipulation and Consent Agreement that resolves OE's investigation into BP's violations of the FERC's Anti-Manipulation Rules; BP will not seek return of ***$250,295 in disgorgement*** already paid and will ultimately pay a ***civil penalty of $10.75 million***.
	42	Total Gas & Power North America, Inc. et al. (IN12-17)	Jul 18	ALJ Patricia M. French substituted in as Presiding Judge

XIV. Natural Gas Proceedings

No Activity to Report

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

*	45	*Order 2222* Compliance Orders (23-1167 *et al.*) (consolidated)	Jun 30 Jul 3 Jul 19	Petitions for review docketed Cases consolidated Versant intervenes FERC moves to hold case in abeyance Court grants abeyance; parties directed to file motions to govern future proceedings by ***Oct 10, 2023***
	46	Seabrook Dispute Order (23-1094)	Jul 21 Jul 28	FERC files Certified Index to the Record NextEra files Petitioners' Brief
	46	2nd Revised Narragansett LSA Orders (22-1161, 22-1108) (consolidated)	Jul 28	Court denies petitions for review
	47	Mystic II (ROE & True-Up) (21-1198 *et al.*) (consolidated)	Jul 24 Jul 27	Constellation proposes continued abeyance for an additional 90 days Court orders cases to remain in abeyance; parties directed to file motions to govern future proceedings by ***Oct 25, 2023***
	49	Northern Access Project (22-1233)		Oral argument scheduled for ***Sep 18, 2023***
	49	Algonquin Atlantic Bridge Project Orders (22-1146, 22-1147) (consol.)	Jul 21	Court dismisses petitions as moot

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: August 3, 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 August 2, 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 August 2, 2023, Brookfield Renewable Trading and Marketing LP ("Brookfield") filed a complaint pursuant to Section 206 of the FPA regarding the exclusion of pumped storage hydroelectric facilities that are Electric Storage Facilities ("ESFs") from the Inventoried Energy Program ("IEP"). Consistent with its proposed amendment to the IEP that was supported by the Participants Committee at the November 2, 2022 meeting, but ultimately rejected by the FERC in its April 24, 2023 order in the IEP Remand Proceeding, Brookfield asked the FERC to direct ISO-NE to revise the Tariff, effective August 2, 2023, to allow Pumped Storage ESFs to participate in the IEP. Brookfield asked that the FERC act on its Complaint expeditiously, noting that ISO-NE has informed Brookfield that any order from the FERC directing ISO-NE to include Pumped Storage ESFs in the IEP cannot be implemented for Winter 2023/24 unless it is received on or before September 22, 2023. Comments on the Brookfield IEP Complaint are due on or before ***August 22, 2023***. 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 previously reported, the FERC instituted a Section 206 proceeding, on May 5, 2023, 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.[2] Accordingly, ISO-NE was directed, on or before July 5, 2023, 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.[3] The refund effective date for this proceeding will be May 12, 2023.[4] Interventions were due on or before May 26 and were filed by: NEPOOL, Calpine, Connecticut office of Consumer Counsel ("CT OCC"), Massachusetts ("MA") Attorney General ("MA AG"), New England Power Generators Association ("NEPGA"), New

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

[2] *Dynegy Marketing and Trade, LLC and ISO New England, Inc.*, 183 FERC ¶ 61,091 (May 5, 2023) ("*Dynegy Mitigation Order*").

[3] *Id.* at P 39.

[4] Notice of the 206 proceeding was published in the *Fed. Reg.* on May 12, 2023 (Vol. 88, No. 92) at pp. 30,738-30, 739.

England States Committee On Electricity (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 June 28, 2023, ISO-NE filed a motion requesting that the FERC hold this proceeding in abeyance to allow potential ISO-NE Tariff design changes to be vetted through the Participant Processes, with a filing expected on or before February 1, 2024. On July 5, NEPOOL submitted limited comments supporting ISO-NE's motion. On July 14, 2023, the FERC granted ISO-NE's motion, stating 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 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)**

Also still pending before the FERC is the Section 206 proceeding, instituted on July 28, 2022, in which the FERC found that the existing tariffs of certain ISO/RTOs, including the ISO-NE Tariff, appear to be unjust and unreasonable.[7] The FERC found that ISO-NE's Tariff appears to be unjust and unreasonable in the absence of volumetric minimum collateral requirements for FTR Market Participants ("volumetric FTR collateral requirements"). Accordingly, ISO-NE was directed, on or before October 26, 2022, 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

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

Tariff has in fact become unjust and unreasonable or unduly discriminatory or preferential.[8] As noted below, ISO-NE answered by explaining why it believes its existing Tariff provisions to be just and reasonable and changes not necessary.

By way of background, the *FTR Collateral Show Cause Order* follows PJM's *Green Hat* experience,[9] a 2019 request by the Energy Trading Institute requesting a FERC-convened technical conference to consider a potential rulemaking to improve ISO/RTO credit practices,[10] and a two-day technical conference in February 2021 that discussed principles and best practices for credit risk management in organized wholesale electric markets.[11] In the *FTR Collateral Show Cause Order*, the FERC stated that, although the record developed through the technical conference highlighted numerous different approaches to managing credit risk, "we believe that two specific practices may be particularly critical to effectively managing credit risk for FTRs: the use of a mark-to-auction mechanism and a volumetric minimum collateral requirement for FTRs."[12] ISO-NE currently employs a mark-to-auction mechanism but not volumetric FTR collateral requirements.

The FERC issued on July 28, 2022, a notice of this proceeding and of the refund effective date, August 3, 2022.[13] Those interested in participating in this proceeding were required to intervene on or before August 18, 2022. Doc-less interventions were filed by NEPOOL, Calpine, DC Energy, NRG, MPUC, EPSA, PJM, SPP, Public Citizen, and Financial Marketers Coalition[14] (out-of-time).

ISO-NE October 26, 2022 Response. In its Answer in response to the *FTR Collateral Show Cause Order*, ISO-NE explained how the FTR financial assurance calculations contained in the Financial Assurance Policy ("FAP") remain just and reasonable, adequately accounting for FTR risk in the absence of a more sophisticated risk management solution such as a clearing solution. ISO-NE asked that, should the FERC not agree and proceed to require volumetric FTR collateral requirements, that it be permitted to follow the Participant Processes to propose revisions to the FAP consistent with any such order. Comments on ISO-NE's response were due on or before November 25, 2022; none were filed. As noted, this matter remains pending before the FERC.

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[8] *Id.* at P 31.

[9] *See GreenHat Energy, LLC*, 175 FERC ¶ 61,138 (2021) (order to show cause) (GreenHat Show Cause Order); *GreenHat Energy, LLC*, 177 FERC ¶ 61,073 (2021) (order assessing civil penalties). In June 2018, GreenHat Energy LLC ("GreenHat") defaulted on its obligations to PJM after amassing one of the largest FTR portfolios in the PJM region. At the time of its default, GreenHat had only $559,447 on deposit as collateral with PJM and no other material assets. However, over the subsequent three-year period ending in May 2021, this FTR portfolio incurred approximately $179 million in losses, which were borne by non-defaulting market participants in PJM.

[10] Energy Trading Institute Request for Technical Conference and Petition for Rulemaking to Update Credit and Risk Management Rules and Procedures in the Organized Markets, *Credit Reforms in Organized Wholesale Elec. Mkts.*, Docket No. AD20-6-000 (Dec. 16, 2019).

[11] *See* Supp. Notice of Tech. Conf., *RTO/ISO Credit Principles and Practices*, Docket No. AD21-6, et al. (Feb. 10, 2021).

[12] The FERC explained that (i) the mark-to-auction mechanism mitigates the risk of default by updating collateral requirements to reflect the most recent valuation of the FTR position and (ii) volumetric FTR collateral requirements ensure that a market participant is required to post a minimum amount of collateral to cover potential defaults, even when the market participant has offsetting positions. With respect to volumetric FTR collateral requirements, the FERC expressed a concern that netting of FTRs with negative collateral requirements against FTRs with positive collateral requirements can lead to insufficient collateral for a portfolio's risk should future congestion be significantly different than historical congestion. Without explicit $/MWh volumetric FTR collateral requirements, the FERC is "concerned that market participants may be able to minimize their collateral requirements without a corresponding reduction in risk". The ISO-NE Financial Assurance Policy allows for some limited offsetting. *See* FAP § VI (allowing for netting of FTRs with the same or opposite path, same contract month and type). *FTR Collateral Show Cause Order* at PP 28-29.

[13] The *Notice* was published in the *Fed. Reg.* on Aug 3, 2022 (Vol. 87, No. 148) p. 47,409.

[14] "Financial Marketers Coalition" identified themselves in their doc-less intervention as "financial market participants participating in the various ISO/RTO markets, including those operated by CAISO, SPP, NYISO and ISO-NE. Many of the Coalition members participate in these ISO/RTOs' FTR markets."

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

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

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

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

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

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

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

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

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

[21] The 4th ROE Complaint asked the FERC to reduce the TOs' current 10.57% return on equity ("Base ROE") to 8.93% and to determine that the upper end of the zone of reasonableness (which sets the incentives cap) is no higher than 11.24%. The FERC established hearing and settlement judge procedures (and set a refund effective date of April 29, 2016) for the 4th ROE Complaint on September 20, 2016. Settlement procedures did not lead to a settlement, were terminated, and hearings were held subsequently held December 11-15,

27, 2017.[22] 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.[23] Parties in this proceeding filed briefs on exception to the FERC, which has not yet issued an opinion on the *Base ROE IV Initial Decision*.

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

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

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

The FERC provided preliminary analysis of how it would apply the proposed methodology in the Base ROE I Complaint, suggesting that it would affirm its holding that an 11.14% Base ROE is unjust and

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

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

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

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

[25] *Ass’n of 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*.

[26] *Id.* at P 19.

unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[27] The new ROE would be effective as of the date of *Opinion 531-A*, or October 16, 2014. Accordingly, the issue to be addressed in the Base ROE Complaint II proceeding is whether the ROE established on remand in the first complaint proceeding remained just and reasonable based on financial data for the six-month period September 2013 through February 2014 addressed by the evidence presented by the participants in the second proceeding. Similarly, briefing in the third and fourth complaints will have to address whether whatever ROE is in effect as a result of the immediately preceding complaint proceeding continues to be just and reasonable.

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

TOs Request to Re-Open Record and file Supplemental Paper Hearing Brief. On December 26, 2019, the TOs filed a Supplemental Brief that addresses the consequences of the November 21 *MISO ROE Order*[29] and requested that the FERC re-open the record to permit that additional testimony on the impacts of the *MISO ROE Order*'s changes. On January 21, 2020, EMCOS and 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)**

On July 18, 2023, Stonepeake Kestrel Energy Marketing LLC ("Stonepeake Kestrel") requested FERC acceptance of its revised rate schedule to allow recovery of eligible medium-impact Interconnection Reliability Operating Limits ("IROL") critical infrastructure protection ("CIP") costs ("IROL-CIP Costs") under Schedule 17 of the ISO-NE Tariff, effective *September 16, 2023*. Stonepeake Kestrel seeks to recover ***$1,605,854*** in incremental medium impact CIP-IROL Costs incurred between March 29, 2021 and March 31, 2023. Comments on Stonepeake Kestrel's request are due on or before ***August 8, 2023***. Thus far, doc-less interventions have been filed by NEPOOL and NESCOE. 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)**

Also on July 18, 2023, Bucksport Generation LLC ("Bucksport Generation") requested FERC acceptance of its revised rate schedule to allow recovery of eligible medium-impact IROL-CIP Costs under Schedule 17 of the ISO-

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[27] *Id.* at P 59.

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

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

NE Tariff, effective September 16, 2023. Bucksport Generation seeks to recover ***$277,874*** in incremental medium impact CIP-IROL Costs incurred between March 29, 2021 and March 31, 2023. Comments on Bucksport Generation's request are due on or before ***August 8, 2023***. Thus far, doc-less interventions have been filed by NEPOOL and NESCOE. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **FCA18 De-List Bids Filing (ER23-2379)**

Pursuant to Market Rule 1 § 13.8.1(a), ISO-NE submitted on July 12, 2023 a filing describing the Permanent De-List Bids and Retirement De-List Bids that were submitted on or prior to the April 6, 2023 FCA18 Existing Capacity Retirement Deadline. ISO-NE reported that it received 14 Retirement De-List Bids. The bids were for resources located in the Connecticut, Northeastern Massachusetts, RI, Southeastern Massachusetts, and Western/ Central MA Load Zones, with 870.718 MWs of aggregate capacity. 10 of the Bids (totaling 15.916 MWs) were for resources under 20 MW or that did not meet the affiliation requirements that would have required Internal Market Monitor ("IMM") review. The IMM's determination regarding the remaining bids is described in the version of the filing that was filed confidentially as required under §13.8.1(a) of Market Rule 1. Comments on the FCA18 De-List Bids Filing were due on or before August 2; none were filed. Doc-less interventions were filed by NEPOOL, Calpine and National Grid. 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).

- **CSC CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER23-1826)**

On May 4, 2023, Cross-Sound Cable ("CSC") requested FERC acceptance of its revised rate schedule to allow recovery of eligible medium-impact IROL-CIP Costs under Schedule 17 of the ISO-NE Tariff, effective July 4, 2023. CSC seeks to recover ***$723,601*** of CIP-IROL Costs incurred between June 1, 2021 and December 31, 2022. Comments on CSC's request were due on May 25; none were filed. Doc-less interventions were filed by NEPOOL, National Grid and NESCOE.

Deficiency Letter and Deficiency Letter Response. On June 29, 2023, the FERC issued a deficiency letter requesting additional information/clarification from CSC. CSC filed its response on July 28, 2023. Comments on CSC's deficiency letter response are due on or before ***August 18, 2023***.

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 which, barring further developments, must happen on or before September 4, 2023). 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). This matter is again pending before the FERC.

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

- **FCA17 Results Filing (ER23-1435)**

On July 18, 2023, the FERC accepted the results of the seventeenth FCA ("FCA17") for the June 1, 2026 - May 31, 2027 Capacity Commitment Period ("CCP").[30] In accepting the FCA17 results, the FERC found that ISO-NE conducted FCA17 in accordance with its Tariff. The FERC found the protests of No Coal No Gas, other organizations and pro se commenters raised issues "outside the scope of this proceeding because they do not bear on the sole question … namely, whether ISO-NE conducted [FCA17] in accordance with its own Tariff rules."[31] The FERC accepted the FCA17 rates and results, effective *July 19, 2023*, as requested. Unless the *FCA17 Results Order* is challenged, with any challenges due on or before August 17, 2023, this proceeding will be concluded. 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).

- **Add'l Cost Recovery Due to Dec 24 General Threshold Energy Mitigation: Dynegy (ER23-1261)**

As previously reported, the FERC, on May 5, 2023, granted in part, and denied in part, the March 6, 2023 request by Dynegy Marketing and Trade, LLC ("Dynegy"), pursuant to § 15 of Appendix A to Market Rule 1, for recovery of unrecovered costs (upward price mitigation and downward price mitigation) incurred because Dynegy's Resources were subject to General Threshold Energy Mitigation on December 24, 2022 during Winter Storm Elliott.[32] Specifically, the FERC granted Dynegy recovery of its costs related to *downward* price mitigation and to the regulatory costs incurred in connection with the cost recovery filing, subject to a compliance filing detailing the actual regulatory costs (which was submitted on June 22, 2023 and accepted on August 1, 2023).[33] However, the FERC, while sympathetic to the arguments made by Dynegy and NEPGA related, denied *upward* price mitigation-related cost recovery, concluding that interpreting the Tariff to allow recovery of costs due to upward mitigation would read out the requirement that the section 205 cost recovery filing state why "actual costs exceeded Reference Levels."[34]

As summarized in Section I above, the FERC found in the *Dynegy Mitigation Order* that ISO-NE's existing 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, and initiated a section 206 proceeding (Docket No. EL23-62), directing ISO-NE to show cause as to why its Tariff is remains just and reasonable and not unduly discriminatory or preferential or propose revisions to its Tariff.

The *Dynegy Mitigation Order* was not challenged and is final and unappealable. With Dynegy's June 22 compliance filing accepted, this proceeding is now concluded. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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[30] *ISO New England Inc.*, 184 FERC ¶ 61,041 (July 25, 2023) ("*FCA17 Results Order*").

[31] *Id.* at P 11.

[32] *Dynegy Mitigation Order (see note 2 supra).*

[33] In its June 22 compliance filing, Dynegy stated that its actual regulatory costs incurred in connection with the Cost Recovery Filing totaled ***$116,100***. The June 22 compliance filing was accepted in *Dynegy Marketing and Trade, LLC*, Docket No. ER23-1261-001 (Aug. 1, 2023) (unpublished letter order).

[34] *Id.* at P 31.

- **Mystic COS Agreement Updates to Reflect Constellation Spin Transaction[35] (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.[36] 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,[37] 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[38] 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[39] 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.

(-024) Mystic Request for Rehearing of Mystic I Order on Remand. On April 27, 2023, Mystic requested rehearing and/or clarification of the March 28, 2023 *Mystic I Order on Remand*.[40] Mystic asserted that (a) the

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[35] 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.

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

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

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

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

[40] *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

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.

Request for Rehearing Denied by Operation of Law. On May 30, 2023, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[41] 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."

(-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 is pending before the FERC.

(-022) First CapEx Info. Filing Settlement Agreement Interim Rate Implementation. As previously reported, on March 27, 2023, Acting Chief ALJ Satten granted Mystic's request to implement the settlement rates on an interim basis, effective as of June 1, 2022. The interim rates will remain in effect pending FERC action on the First CapEx Settlement Agreement (*see* -021).[42]

(-021) First CapEx Info. Filing Settlement Agreement. On March 15, 2023, Mystic filed a Settlement Agreement to resolve all issues raised by the formal challenges to its First CapEx Info. Filing[43] and set for hearing in the April 28, 2023 Mystic *First CapEx Info. Filing Order* ("Settlement Agreement").[44] The Settling Parties asked that the FERC act on the Settlement Agreement as soon as possible, but no later than September 1, 2023. Initial

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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).

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

[42] *Constellation Mystic Power, LLC*, 182 FERC ¶ 63,026 (Mar. 27, 2023) (Chief ALJ order granting motion to implement settlement rate on an interim basis).

[43] As previously reported, Mystic submitted, on Sep. 15, 2021, as required by orders in this proceeding and Sections I.B.1.i. and II.6. of Schedule 3A of the COSA ("Protocols"), its informational filing to provide support for the capital expenditures and related costs that Mystic projected would be collected as an expense between June 1, 2022 and Dec. 31, 2022 ("First CapEx Projects Info. Filing"). Formal challenges to the First CapEx Projects Info. Filing were submitted by the Eastern New England Customer-Owned Systems ("ENECOS") and NESCOE.

[44] *Constellation Mystic Power, LLC*, 179 FERC ¶ 61,011 (Apr. 28, 2022) ("*Mystic First CapEx Info. Filing Order*") (granting in part, and denying in part, ENECOS' and NESCOE's formal challenges, subject to refund, and establishing hearing and settlement judge procedures).

comments on the Settlement Agreement were due by April 4, 2023 and filed by ENECOS, CT PURA, FERC Trial Staff, MA AG, NESCOE, and National Grid. Reply comments were filed on April 14, 2023 by Mystic and State Settling Parties.[45] Settlement Judge McBarnette issued her Settlement Report on June 2, 2023,[46] and Acting Chief ALJ Satten terminated settlement judge procedures on June 5, 2023, subject to final action by the Commission. Since the last Report, Mystic clarified the uncontested nature of Settlement and requested expedited action. ENECOS confirmed they will not contest Settlement, and joined in Mystic's request for expedited Commission action. On July 10 and 11, NESCOE and National Grid, respectively, supported Mystic's request for expedited action. The FERC conditionally approved the Settlement Agreement on August 1, 2023,[47] subject to a compliance filing on or before ***August 31, 2023*** with revised tariff records in eTariff format to reflect the FERC's action.[48]

(-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 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 February 17, 2023, reporting that it intends to file a settlement agreement in the *First CapEx Info. Filing* proceeding that would also impact certain pending Formal Challenges filed in response to the *Second CapEx Info. Filing*, Mystic requested that the FERC hold off on acting on the pending Formal Challenges in this proceeding until after the FERC acts on the Settlement Agreement (summarized in (-021) above) ("Motion for Abeyance"). On March 6, 2023, ENECOS filed a protest to Mystic's Motion for Abeyance. That request is pending before the FERC.

(-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*.[49] 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.

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[45] The "State Settling Parties" are, collectively, the Connecticut Department of Energy and Environmental Protection ("CT DEEP"), the Connecticut Public Utilities Regulatory Authority ("CT PURA"), and CT OCC (the "CT Parties"); the Attorney General of the Commonwealth of Massachusetts ("MA AG"); and the New England States Committee on Electricity ("NESCOE").

[46] *Constellation Mystic Power, LLC*, 183 FERC ¶ 63,026 (June 2, 2023). The Settlement Report included the Mar. 15 Settlement, Initial Comments, and all pleadings, orders, and other documents of record in this proceeding.

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

[48] *Id.* at P 7.

[49] 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.

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*,[50] 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.

Since the last Report, 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).

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

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.

While this filing will not be noticed for public comment, this filing triggers the commencement of an Information Exchange Period and a Review Period under the Protocols. Interested Parties have 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.

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[50] *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 (2022-23) Update/Informational Filing (ER09-1532)**

About this time last year, the PTO AC submitted its 2023 annual filing identifying adjustments to Regional Transmission Service charges, Local Service charges, and Schedule 12C Costs under Section II of the Tariff. The 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. As prescribed in the Interim Protocols,[51] the formula rates that will be in effect for 2023 include a billing true up of seven months of 2021 (June-December). The PTO AC stated that the annual updates result in a Pool "postage stamp" RNS Rate of $140.94 /kW-year effective January 1, 2023, a decrease of $1.84 /kW-year from the charges that went into effect on January 1, 2022. In addition, the filing included updates to the revenue requirements for Scheduling, System Control and Dispatch Services (the Schedule 1 formula rate), which result in a Schedule 1 charge of $1.75 kW-year (effective 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. This filing was not noticed for public comment.

The July 29 filing was reviewed with the Transmission Committee at its August 16, 2022 summer meeting and at an August 22, 2022 technical session for Interested Parties. The July 29 filing triggered the commencement of the Information Exchange Period and a Review Period under the Interim Protocols. Interested Parties had until September 15, 2022 to submit information and document requests, and the PTOs were required to make a good faith effort to respond to all requests within 15 days, but by no later than October 15, 2022. During the Review Period, Interested Parties had until November 15, 2022 to submit Informal Challenges to the PTOs, and the PTOs were required to make a good faith effort to respond to any Informal Challenges by no later than December 15, 2022. Interested Parties had until January 31, 2023 to file a Formal Challenge with the FERC.

RENEW Formal Challenge. On January 31, 2023, RENEW filed a formal challenge ("Challenge"). RENEW asserted that (i) the TOs failed to provide adequate rate input information in the Annual Informational Filing and in the Information Exchange Period under the Interim Formula Rate Protocols regarding inclusion or exclusion of "O&M costs" on Network Upgrades that the TOs directly assign to Interconnection Customers (and thereby failing to demonstrate that such O&M costs are not being double counted in transmission rates); and (ii) the TO's Interpretation of "Interested Party" to exclude RENEW violated the Interim Formula Rate Protocols. RENEW thus asked that the FERC (a) require the TOs to show the calculation of the annual O&M charges with sources of data inputs and show how such O&M charges are not being double recovered in transmission rates, and (b) determine that an entity such as RENEW is an Interested Party under the Interim Formula Rate Protocols and that its Information Requests seeking rate inputs and support for the O&M charges on Network Upgrades are within the scope of the Interim Formula Rate Protocols process. Comments on RENEW's Challenge were due on or before March 16, 2023. Comments and protests were filed by: Avangrid, Eversource, National Grid, Public Systems, RI Energy, Unitil, Versant Power, VTransco/GMP. On March 31, 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).

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[51] The Interim Formula Rate Protocols ("Interim Protocols") became effective June 15, 2021, and will be replaced by permanent Formula Rate Protocols that will become effective June 15, 2023. *See* Settlement Agreement resolving all issues in Docket No. EL16-19 ("Settlement") approved by the FERC on Dec. 28, 2020, in *ISO New England et al.*, 173 FERC ¶ 61,270 (2020) ("Settlement Order").

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

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

On July 6, 2023, FPL Energy Wyman IV LLC ("Wyman IV") requested 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"). In its Waiver Request, Wyman IV explained 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,[52] 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. Wyman IV seeks a one-time waiver of the Tariff to allow ISO-NE to revise Yarmouth 4's Summer Qualified Capacity to reflect its higher capability consistent with the Tariff. ISO-NE, Wyman IV stated, does not oppose the waiver request. Comments on Wyman IV's waiver request were due on or before July 27, 2023; none were filed. NEPOOL and National Grid each 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 (860-275-0533; pmgerity@daypitney.com).

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

On April 7, 2023, ISO-NE and NEPOOL filed proposed revisions to Appendix K to Market Rule 1 to update certain parameters within the Inventoried Energy Program ("IEP Parameter Updates"). Specifically, the IEP Parameter Updates (i) move from a fixed rate to an indexed rate, which provides for automatic adjustments to account for changes in gas markets prior to each winter period, (ii) include modifications to 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) included changes to provide clarity and improve the administration of the IEP. A June 6, 2023 effective date was requested. The IEP Parameter Updates were supported by the Participants Committee at its April 6, 2023 meeting. Comments on the IEP Parameter Updates were due by April 28, 2023. Comments supporting the Updates were filed by Indicated Suppliers.[53] Consumer Advocates[54] and Sierra Club/CLF/UCS protested the Updates (challenging the costs and basis for the IEP as updated). Doc-less motions to intervene only were filed by Calpine, Constellation, Eversource, National Grid, Public Systems,[55] the MA DPU, and Public Citizen (following the Deficiency Letter response). On May 12, Senator Blumenthal (D-CT) filed a response to the IEP Parameter Updates encouraging the FERC to thoroughly review the justification and indexing formulas when assessing if the proposal is just and reasonable. On May 15, both NEPOOL and ISO-NE filed answers to the protests, noting that the costs and basis for updates are reasonable and were supported by NEPOOL Participants through the stakeholder process. On May 26, Consumer Advocates and Sierra Club/CLF/UCS filed answers to ISO-NE and NEPOOL's May 15 answers.

Deficiency Letter; ***Response (-001)***. On May 25, 2023, the FERC issued a deficiency letter requesting ISO-NE provide "any quantitative studies, liquidity analysis, work papers, and any other information used to support the choice of financial product and July 17 to July 31 measurement period." ISO-NE filed its response to the Deficiency Letter on June 9, 2023, re-setting the filing date (to June 9, 2023) and deadline for FERC action (to ***August 8, 2023***). Comments on the Deficiency Letter response were due on or before June 30, 2023. Indicated Suppliers filed comments in support of ISO-NE's Deficiency Letter response, urging the FERC to promptly accept

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[52] 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.

[53] "Indicated Suppliers" are CPV Towantic LLC, Eastern Generation LLC, JERA Americas Inc., and Vistra Corp.

[54] "Consumer Advocates" are the MA AG, CT OCC, NH OCA, and the Maine OPA.

[55] "Public Systems" for purposes of this proceeding are CMEEC, MMWEC, NHEC, and VPPSA.

the IEP Parameter Updates as of August 4, 2023, so that the Updates can be included in the index rate for Winter 2023/24 (which will be posted August 8, 2023).

If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

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).

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

In a lengthy compliance Order[56] 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[57] ("*Order 2222 Compliance Order*").[58]

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

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[56] 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."

[57] 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.

[58] *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***. 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.

Requests for Rehearing and/or Clarification (-002). On March 31, 2023, ISO-NE and New England Public Utilities[59] 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 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".[60] 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."

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[59] "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").

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

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

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

On July 26, 2023, Versant Power ("VP") proposed updated depreciation rates for Versant Power's local transmission facilities in eastern and coastal Maine (the "Bangor Hydro District" or "BHD") that are set forth in Appendix D to Attachment F of the ISO-NE OATT. A January 1, 2025 effective was proposed. Comments on this filing are due on or before ***August 16, 2023***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **CMP Att. F App. D Depreciation Rate Change (ER23-2477)**

Also on July 26, 2023, CMP proposed updated depreciation rates for its transmission facilities that are set forth in Appendix D to Attachment F of the ISO-NE OATT. CMP requested a July 1, 2023 effective. Comments on this filing are also due on or before ***August 16, 2023***. 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,[61] 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
  - 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 are 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*[62] ("OATT *Order 881* Compliance Changes").[63] As previously reported, the Filing Parties[64] proposed the addition of a new Attachment Q to the OATT, and to revise OATT Schedules 18 (MTF; MTF Service) and 21 (Local Service - Common). 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

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

[62] *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*").

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

[64] As previously reported, the "Filing Parties" were ISO-NE, NEPOOL, the PTO AC, and CSC.

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. Challenges, if any, to the *OATT Order 881 Compliance Order* were due on or before July 17, 2023; none were filed and Order 881 is final and unappealable.

60-Day Compliance Changes. The 60-Day Compliance Changes, due August 14, 2023, will be considered by the Participants Committee at its August 3 meeting (Agenda Item #5).

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

- **FAP Eligible LOC Issuer Changes (ER23-2277)**

On June 28, 2023, ISO-NE and NEPOOL jointly filed revisions to the ISO-NE Financial Assurance Policy ("FAP") to allow ISO-NE to remove banks from the List of Eligible Letter of Credit ("LOC") Issuers (the "Eligible LOC List") ("Eligible LOC Issuer Changes"). Specifically, the Eligible LOC Issuer Changes (i) allow the ISO to remove a bank from the Eligible LOC List if ISO-NE determines that despite satisfying the eligibility criteria, accepting a LOC from a bank on the list presents an unreasonable risk that the bank may fail to honor the terms of such letter of credit; (ii) provides Market Participants five Business Days from the date of notice by ISO-NE that a bank is removed from the Eligible LOC List to replace the LOC (and ISO-NE has discretion to extend this cure period to 20 Business Days); and (iii) add language to clarify that when a bank is removed from the Eligible LOC List, ISO-NE will provide a notice to the Budget & Finance Subcommittee. An August 27, 2023 effective date was requested. The Eligible LOC Issuer Changes were supported by the Participants Committee at its June 27, 2023 meeting. Comments on the Eligible LOC Issuer Changes were due on or before July 19, 2023; none were filed. National Grid intervened doc-lessly. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

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

- **Schedule 21-VP: Real Power Loss Factor Charge (ER23-2142)**

On June 15, 2023, Versant Power filed a revised Schedule 21-VP to reflect a change in the Real Power Loss factor for Local Point-to-Point Service from 1.99 % to 1.764 %, as reflected in a recently-completed study of real power losses on its transmission and distribution systems included with this filing. The study found that, for the study period, real power losses on Versant Power's BHD transmission system were 1.764%, and Versant proposes to change that factor set forth in Section 11.2 accordingly. Versant requested that the revised Schedule 21-VP reflecting this change be accepted for filing effective *September 1, 2023*. Comments on the revised Schedule 21-VP were due on or before July 6, 2023; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On July 28, 2023, the FERC accepted seven fully executed, non-conforming Local Service Agreements ("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").[65] 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.[66] Challenges to the *Versant Black Bear LSAs Order*, and the refunds ordered, are due on or before ***August 28, 2023***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activities to Report

VIII. Regional Reports

- ***Opinion* 531 Refund Reports (EL11-66)**

The following refund reports filed in response to *Opinions No. 531-A*[67] *and 531-B*[68] remain pending:

- The TOs' November 2, 2015 regional refund report;
- The TOs'[69] local refund reports; and
- Fitchburg Gas & Electric's ("FG&E") June 29, 2015 local refund report.

If there are questions on these reports, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **LFTR Implementation Quarterly Status Report (ER07-476)**

On July 14, 2023, ISO-NE filed its 59th quarterly status report regarding LFTR implementation. ISO-NE reported that it implemented monthly reconfiguration auctions (accepted in ER12-2122) beginning October 2019. ISO-NE further reported that, while it will continue to evaluate its as-filed LFTR design and financial assurance issues, including an ongoing evaluation of the FTR market and risk associated with FTRs and LFTRs, it is currently focused on higher priority market-design initiatives. ISO-NE concluded its report by describing the 18-month implementation that would be required once the LFTR financial assurance issues are resolved. These status reports are not noticed for public comment.

- **IMM Quarterly Markets Reports – Spring 2023 (ZZ23-4)**

On August 1, 2023, the IMM filed with the FERC its Spring 2022 report of "market data regularly collected by [the IMM] in the course of carrying out its functions under … Appendix A and analysis of such market data," as required pursuant to Section 12.2.2 of Appendix A to Market Rule 1. These filings are not noticed for public comment by the FERC. The Spring 2023 Report will be discussed with the Markets Committee at its August 8-10, 2023 Summer Meeting.

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

[66] 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, the Filing Parties must, on or before ***Aug. 28, 2023***, refund the time value of revenues collected for the time period the rate was collected without FERC authorization (with refunds limited so as not to cause Filing Parties to operate at a loss) and file a refund report with the FERC, including information supporting calculation of the time value of revenues collected without FERC authorization and any limit on the refunds due, on or before ***Sep. 27, 2023***.

[67] *Martha Coakley, Mass. Att'y Gen.*, 149 FERC ¶ 61,032 (Oct. 16, 2014) ("*Opinion 531-A*").

[68] *Martha Coakley, Mass. Att'y Gen.*, Opinion No. 531-B, 150 FERC ¶ 61,165 (Mar. 3, 2015) ("*Opinion 531-B*").

[69] TOs filing local refund reports include: CMP, National Grid, UI, Versant Power (f/k/a Emera Maine), NHT, VTransco, Eversource, and NSTAR.

- **IMM 2022 Annual Markets Report (ZZ23-4)**

On June 5, 2023, the IMM filed its 2022 Annual Markets Report, which covers the 2022 calendar year period.[70] The report addresses the development, operation, and performance of the New England Markets and presents an assessment of each market based on market data, performance criteria, and independent studies, providing the information required under Section 17.2.4 of Appendix A to Market Rule 1. On the basis of its review of market outcomes and related information, the IMM concluded, as it has for many years in a row, that the New England Market operated competitively in 2022. The IMM reported that Day-Ahead and Real-Time Energy prices reflected changes in underlying primary fuel prices, electricity demand and the region's supply mix. The region saw record high energy prices in 2022 -- the annual average day-ahead price of $86/MWh was almost 90% higher than 2021, and was the highest since the inception of Standard Market Design in 2003. Energy prices continued to be driven by the market price of natural gas, which at $9.32/MMBtu was more than double 2021's price, and was the highest average price since 2008.

While there were no major reliability issues in 2022, New England experienced its second capacity scarcity condition in five years (due to lower imported energy and generator outages at the tail end of Winter Storm Elliott). December 2022 saw the first Pay-for-Performance ("PFP") event since 2018. The December 2022 event lasted 17 five-minute intervals (1 hour 25 minutes) and resulted in the transfer of $35.9 million from under-performing resources to over-performing resources. Import and nuclear resources received the most over-performance payments, while gas resources were charged the most for under-performance. A significant amount of gas generation was out of economic merit order in the Day-Ahead Energy Market due to very high natural gas costs, and in Real-Time could not respond to high prices during the emerging event due to start time constraints.

For the eighth consecutive year, the forward capacity auction procured surplus capacity. Other highlights included:

- 2022 total wholesale costs ($16.7 billion) were $5.5 billion higher than 2021, driven by higher energy costs; with the exception of capacity costs (down $0.22 billion), each component of the wholesale cost of electricity again increased in 2022.
- 2022 Energy costs, 70% of wholesale costs (up from 55% in 2012), totaled $11.7 billion, up 92% from 2021 (Day-Ahead LMPs averaged $85.56/MWh; Real-Time LMPs, $115.23/MW).
- Capacity costs ($2 billion) decreased 10%. When compared against 2021 capacity costs, lower auction clearing prices more than offset supplemental payments under the Mystic COSA ($166 million in 2022) that began in summer 2022.
- The trend of decreasing load may have reached an inflection point. In 2022, Energy Efficiency ("EE") reduced weather-normalized annual average load by an estimated 2,538 MW (by 16%), which was a 2% decrease (40 MW) compared to 2021. BTM solar generation reduced weather-normalized load by 426 MW (by approx. 3%) which was a 15% increase (57 MW) compared to 2021, and is expected to continue this upward trend in future years.
- In 2022, net interchange (or net imports) averaged 1,914 MWs per hour, an 11% (or 231 MW) decrease compared to 2021, and the lowest amount over the past five years. Net imports met just 14% of New England's electric demand, compared to up to 19% during the 2018-2020 period.

In light of its review, the IMM, on pp. 13-17 of the Report, made a number of recommendations for Market Rule changes and identified areas for additional analysis in 2023. These recommendations will be discussed in more detail at a future Participants Committee meeting.

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

- **ISO-NE FERC Form 3Q (2023/Q1) (not docketed)**

On May 26, 2023, ISO-NE submitted its 2023/Q1 FERC Form 3Q (quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is a quarterly regulatory requirement which supplements the annual FERC Form 1 financial reporting requirement. These filings are not noticed for comment.

- **ISO-NE 2022 FERC Form 714 (not docketed)**

On June 14, 2023, ISO-NE submitted its Annual Electric Balancing Authority Area and Planning Area Report for calendar year 2022. Through its Form 714 filing, ISO-NE reports, among other things, generation in the New England Control Area, actual and scheduled inter-balancing authority area power transfers, and net energy for load, summer-winter generation peaks and system lambda. The FERC uses the data to obtain a broad picture of interconnected balancing authority area operations including comprehensive information of balancing authority area generation, actual and scheduled inter-balancing authority area power transfers, and load; and to prepare status reports on the electric utility industry including review of inter-balancing authority area bulk power trade information. Planning area data will be used to monitor forecasted demands by electric utility entities with fundamental demand responsibility, and to develop hourly demand characteristics. These filings are not noticed for public comment.

IX. Membership Filings

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

On July 31, 2023, NEPOOL requested that the FERC accept the membership of Clover Energy LLC (Supplier Sector). Comments on the August membership filing are due on or before ***August 21, 2023***.

- **Involuntary Termination of Membership of Manchester Methane, LLC (ER23-2390)**

On July 13, 2023, NEPOOL and ISO-NE jointly requested that the FERC terminate (i) the NEPOOL Participant status of Manchester Methane, LLC ("Manchester Methane") and (ii) the Market Participant Service Agreement between ISO-NE and Manchester Methane, each as a result of the failure by Manchester Methane to pay when and as due the amounts invoiced to it under the Billing Policy. NEPOOL and ISO-NE requested that the termination of Manchester Methane's NEPOOL and Market Participant status become effective as of September 11, 2023. Comments on this filing are due on or before ***August 3, 2023***.

- **July 2023 Membership Filing (ER23-2319)**

On June 30, 2023, NEPOOL requested that the FERC accept: (i) the memberships of Hecate Energy Albany 2 LLC [Related Person to Howard Wind and RoxWind (Supplier Sector)]; Erie Wind, LLC [Related Person to Brookfield Renewable Trading and Marketing (Supplier Sector)]; and SCEF1 FUEL CELL, LLC [Related Person to Bridgeport Fuel Cell and Derby Fuel Cell (AR Sector, RG Sub-Sector)]; (i) termination of Concurrent LLC (Supplier Sector); and Brookfield Energy Marketing LP [Related Person to Brookfield (Supplier Sector)]; and (iii) the name change of: CPV Spruce Mountain Wind, LLC (f/k/a Spruce Mountain Wind, LLC). The July membership filing is pending before the FERC.

- **June 2023 Membership Filing (ER23-2025)**

On July 27, 2023, the FERC accepted: (i) the memberships of Con Edison Transmission Inc. [Related Person to Consolidated Edison Company of New York, Inc. (Supplier Sector)]; Generate NB Fuel Cells, LLC (Related Person to Generate Colchester Fuel Cells, LLC (AR Sector, RG Sub-Sector); Jonathan Lamson (Governance Only End User); and Tomorrow Energy Corp (Supplier Sector); and (ii) termination of the Participant status of: Northern States Power Company (Supplier Sector); and Granite Reliable Power, LLC [Related Person to NextEra Energy Resources (Generation Sector)].

- **May 2023 Membership Filing (ER23-1768)**

On June 27, 2023, the FERC accepted[71]: (i) the memberships of Carbon Solutions Group (GIS-Only Participant); PPL TransLink Inc. [Related Person to RI Energy (Transmission Sector)]; and Second Foundation US Trading, LLC (Supplier Sector); (ii) the termination of the Participant status of EnPowered USA LLC; Invenia Technical Computing Corp.; Uniper Global Commodities NA LLC; and WATTIFI INC.; and (iii) the name changes of RWE Clean Energy Wholesale Services, Inc. (f/k/a Consolidated Edison Energy, Inc.); RWE Clean Energy Asset Holdings, Inc. (f/k/a Consolidated Edison Development, Inc.); RWE Clean Energy Solutions, Inc. (f/k/a Consolidated Edison Solutions, Inc.); and SYSO Inc. (f/k/a SYSO LLC).

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,[72] 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 May 30, 2023, the FERC issued a notice that FERC and NERC staff will convene an in-person technical conference on ***August 10, 2023*** at NERC's headquarters in Atlanta, GA. The purpose of this conference is to discuss physical security of the Bulk-Power System ("BPS"), including the adequacy of existing physical security controls, challenges, and solutions. The conference will be open for the public to attend, and there is no fee for attendance. Attached to its most recent supplemental notice issued July 27, 2023 is an agenda for the technical conference, which includes more detail for each panel.[73] Only invited panelists and staff from the FERC and NERC will participate in the panel discussions. Interested parties may listen and observe, and written comments may be submitted after the conference in Docket No. RD23-2. Information on this technical conference is also posted on the Calendar of Events on the FERC's website (www.ferc.gov).

- **Revised Reliability Standards: EOP-011-3 and EOP-012-1 (RD23-1)**

On February 16, 2023, the FERC approved NERC's changes to Reliability Standards EOP-011-3 (Emergency Operations) and EOP-012-1 (Extreme Cold Weather Preparedness and Operations) (the "*Cold Weather Standards*").[74] As previously reported, the changes to the *Cold Weather Standards*, which address certain key

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[71] *New England Power Pool Participants Comm*., Docket No. ER23-1768-000 (June 27, 2023) (unpublished letter order).

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

[73] Panels will discuss (i) the effectiveness of CIP-014-3 -- applicability and minimum level of physical protection; and (ii) solutions beyond CIP-014-3 – best practices and operational preparedness and grid planning to respond to and recover from physical and cyber security threats and potential obstacles.

[74] *N. Amer. Elec. Rel. Corp.*, 182 FERC ¶ 61,094 (Feb. 16, 2023), *reh'g denied by operation of law* ("*Cold Weather Standards Order*").

recommendations from the *Feb 2021 Cold Weather Outages Joint Report,*[75] establish a more comprehensive framework of requirements addressing generator preparedness for cold weather operations. The *Cold Weather Standards* also address the use of manual load shed during Emergency conditions, requiring Transmission Operators to take steps to minimize the use of manual load shed that could further exacerbate Emergency conditions and threaten system reliability.

In accepting the *Cold Weather Standards*, the FERC directed a number of changes and follow-up items. For example, the FERC directed NERC to modify EOP-012-1:

- to ensure that it captures all bulk electric system generation resources needed for reliable operation and excludes only those generation resources not relied upon during freezing conditions by clarifying "the language of the applicability section to align with NERC's explanation of the entities that should already be preparing to comply with the Standard, and should not need additional implementation time";[76]
- Requirements R1 and R7, to address concerns related to the ambiguity of generator-defined declarations of technical, commercial, or operational constraints that exempt a generator owner from implementing the appropriate freeze protection measures by including "objective criteria on permissible technical, commercial, and operational constraints, to identify the appropriate entity that would receive the generator owners' constraint declarations under [] Requirements R1 and R7, to describe how that entity would confirm that the generator owners comply with the objective criteria, and to describe the consequences of providing a constraint declaration," ensuring that "declarations cannot be used to opt out of mandatory compliance with the Standard or obligations set forth in a corrective action plan";[77]
- to clarify R1 to ensure that generators that are technically incapable of operating for 12 continuous hours (e.g., solar facilities during winter months with less than 12 hours of sunlight) are not excluded from complying with the Standard;[78]
- to increase the length of R2's continuous operations requirement (one hour being too short);[79]
- to include in R7 deadlines for implementation completion of corrective action plans, as recommended in the *November 2021 Report*;[80]
- to shorten the implementation plan for existing generating units, staggering the implementation for existing unit(s) in a generator owner's fleet;[81] and
- to work with FERC staff to submit a plan no later than February 16, 2024 explaining how it will collect and assess data prior to and after the implementation of the following elements of EOP-012-1: (1) generator owner declared constraints and explanations thereof; and (2) the adequacy of the Extreme Cold Weather Temperature definition.[82]

The FERC deferred its decision on whether to approve or modify NERC's proposed implementation date for EOP-011-3 (and proposed retirement of EOP-011-2) until NERC submits its revised applicability section for EOP-012. The FERC stated that "allowing EOP-011-2 requirements to remain mandatory and enforceable until such

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[75] FERC, NERC, Regional Entity Staff Report: The February 2021 Cold Weather Outages in Texas and the South Central United States (Nov. 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texasand-south-central-united-states-ferc-nerc-and ("*Feb 2021 Cold Weather Outages Joint Report*").

[76] *Id.* at P 4.

[77] *Id.* at P 6.

[78] *Id.* at P 7.

[79] *Id.* at P 8.

[80] *Id.* at P 9.

[81] *Id.* at P 10.

[82] *Id.* at P 11.

time as the revised applicability is effective for EOP-012 will ensure all bulk electric system generating units are required to maintain cold weather preparedness plans."[83]

Request for Rehearing Denied by Operation of Law. On March 20, 2023, EPSA, NEPGA and the PJM Power Providers Group ("P3") filed a joint request for rehearing. The petitioners allege that, by approving the *Cold Weather Standards* without addressing how generators can recover the costs associated with complying with EOP-012-1, the FERC "breached its duty to ensure that proposed reliability standards are 'just' and 'reasonable' … and failed to engage in reasoned decision-making." On April 20, 2023, the FERC issued a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration".[84] That Notice confirmed that the 60-day period during which a petition for review of the *Cold Weather Standards 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 *Cold Weather Standards 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."

Cold Weather Standards Allegheny Order. As was its right under section 313(a) of the FPA, the FERC issued an order, on June 29, 2023, modifying the discussion in the *Cold Weather Standards Order* but reaching the same result.[85] Challenges, if any, to the Cold Weather Standards Allegheny Order must be filed in Federal Court on or before ***August 28, 2023***. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **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"))[86] on June 15, 2023. Project 2016-02 focuses on modifications to the CIP Reliability Standards to incorporate applicable protections for virtualized environments. In the June 15 report, NERC reported that, because ballot body 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 October 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[87] proposing to direct NERC (i) to develop new or modified Reliability Standards that address the following reliability gaps related to inverter-based resources ("IBR"): 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[88] and were filed by nearly 20 parties, including, among others, ISO-

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[83] *Id.* at P 5.

[84] *N. Am. Elec. Rel. Corp.*, 183 FERC ¶ 62,034 (Apr. 20, 2023) ("*Cold Weather Standards Allegheny Notice*").

[85] *N. Am. Elec. Rel. Corp.*, 183 FERC ¶ 61,222 (June 29, 2023) ("*Cold Weather Standards Allegheny Order*").

[86] 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.

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

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

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.

- **Order 896: Transmission System Planning Performance Requirements for Extreme Weather (RM22-10)**

On June 15, 2023, the FERC issued a final rule[89] directing NERC to develop a new or modified Reliability Standard no later than ***December 15, 2024***[90] to address reliability concerns pertaining to transmission system planning for extreme heat and cold weather events that impact the Reliable Operation of the BPS. Specifically, FERC directed NERC to develop a new or modified Reliability Standard that requires the following: (i) development of benchmark planning cases based on prior extreme heat and cold weather events and/or future meteorological projections; (ii) planning for extreme heat and cold events using steady state and transient stability analyses that cover a range of extreme weather scenarios, including the expected resource mix's availability during extreme weather conditions and the broad area impacts of extreme weather; and (iii) corrective action plans that include mitigation activities for specified instances where performance requirements during extreme heat and cold events are not met. *Order 896* will become effective *September 21, 2023*.

- **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,[91] 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 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.

- **2023 NERC/NPCC Business Plans and Budgets (RR22-4)**

As previously reported, the FERC accepted, subject to a 60-day compliance filing, NERC's proposed Business Plan and Budget, as well as the Business Plans and Budgets for the Regional Entities, including NPCC, for 2023.[92] In accepting NERC's Business Plan/Budget Filing, the FERC agreed with EEI that additional transparency into certain Electricity Information Sharing and Analysis Center ("E-ISAC") costs would better allow the FERC to fulfill its oversight duties, and thus directed NERC to submit a compliance filing providing additional information related to E-ISAC costs, the E-ISAC vendor affiliate program, and the E-ISAC and natural gas stakeholder partnership. That compliance filing was due, and was filed, on January 3, 2023. Comments on the January 3 compliance filing were due on or before January 24, 2023; none were filed. The 60-day compliance filing was accepted on July 3, 2023.[93]

XI. Misc. - of Regional Interest

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

On July 28, 2023, the FERC authorized[94] the disposition and consolidation of jurisdictional facilities and the lease of an existing generation facility that will result from the commencement of a master lease agreement ("Lease") between Three Corners Solar, LLC ("Lessor") and Three Corners Prime Tenant, LLC ("Lessee") pursuant to

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[89] *Transmission System Planning Performance Requirements for Extreme Weather*, Order No. 896, 183 FERC ¶ 61,191 (June 15, 2023) ("*Order 896*").

[90] *Order 896* was published in the *Fed. Reg.* on June 23, 2023 (Vol. 88, No. 120) pp. 41,262-41,287.

[91] 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").

[92] *N. Am. Elec. Rel. Corp.*, 181 FERC ¶ 61,095 (Nov. 2, 2022) ("*2023 Budgets Order*").

[93] *N. Am. Elec. Rel. Corp.*, 184 FERC ¶ 61,002 (July 3, 2023).

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

which Lessee will lease, operate, and control an approximately 112 MWac solar photovoltaic ("PV") electric generation facility owned by Lessor in Kennebec County, Maine (the "Transaction"). Pursuant to the July 28 order, Lessor and Lessee must file a notice within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **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, and Monitoring Analytics, LLC (the PJM Independent Market Monitor). Public Citizen filed a doc-less intervention. Since the last Report, Vistra and the Energy Harbor Public Utilities responded to the protests and comments. Answers to that answer were filed by NOPEC and the Ohio Consumers' Council. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Weaver Wind / Greenbacker (EC23-68)**
  On May 12, 2023, the FERC issued an order authorizing the proposed transaction pursuant to which Jade Energy LLC, a wholly-owned subsidiary of Greenbacker Renewable Energy Company, will acquire all the membership interests in Weaver Wind, LLC and Weaver Wind Maine Master Tenant, LLC ("Weaver Wind") (upon consummation, making Weaver Wind a Related Person to Howard Wind and Hecate Energy).[95] Pursuant to the May 12 order, Jade Energy must file a notice within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **PURPA Enforcement Petition: Allco Finance Limited (EL23-84)**
  On July 24, 2023, Allco Finance Limited ("Allco") petitioned the FERC to initiate an enforcement action against the Massachusetts DPU and DOER (collectively, the "Massachusetts Agencies") to remedy what it asserts if the Massachusetts Agencies' improper implementation of PURPA. Allco states that the Massachusetts Agencies have implemented a state law that empowers the Massachusetts Agencies to compel wholesale energy transactions outside the confines of PURPA, and that empowers those Agencies to exclude all Qualifying Facilities from participating in solicitations for energy and capacity for Massachusetts utilities. Comments on Allco's PURPA Enforcement Petition are due on or before ***August 14, 2023***. Thus far, doc-less interventions have been filed by MA DOER, MA DPU, HQUS, MOPA, NEPGA, and Public Citizen. 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 July 26, 2023, ISO-NE and Rhode Island Energy ("RIE") filed two revised LGIAs to reflect RIE as the new Interconnecting Transmission Owner. A January 1, 2023 effective date was requested for each of the following LGIAs:
    - **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.
    - **ER23-2491:** First Revised LGIA that governs the interconnection of Tiverton's 305 MW generating facility located in Newport County in Tiverton, RI.

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[95] *Weaver Wind, LLC and Weaver Wind Maine Master Tenant, LLC*, 183 FERC ¶ 62,077 (May 12,2023).

Comments on these filings are due on or before ***August 16, 2023***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA Termination: CL&P/ISO-NE/NTE CT (ER23-2378)**

On July 11, 2023, CL&P and ISO-NE submitted a Notice of Termination of an executed LGIA with NTE Connecticut LLC ("NTE CT"). The LGIA covered the interconnection of NTE CT's 714 MW combined cycle generating facility located in Killingly, Connecticut. Filing Parties state that NTE CT is in breach of the LGIA, has failed to cure the Breach within a reasonable time, and has effectively abandoned the Large Generating Facility. The notice requested a July 12, 2023 effective date. Comments on the LGIA termination notice were due on or before August 1, 2023; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA Cancellation: NEP/TransCanada (ER23-2182)**

On June 14, 2023, the New England Power Company ("NEP") submitted a Notice of Cancellation of the Interconnection Agreement ("IA") between NEP and TransCanada Hydro Northeast Inc. ("TransCanada") that has been superseded by a new SGIA between NEP and Great River Hydro, TransCanada's successor in interest. NEP requested an August 14, 2023 effective date for the Notice of Cancellation. Comments on this filing were due on or before July 5, 2023; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement Cancellation: NSTAR/Medway Grid (ER23-2117)**

On June 12, 2023, NSTAR filed a notice of cancellation of the Engineering, Design and Procurement Agreement ("D&E Agreement") with Medway Grid, LLC ("Medway Grid"). The D&E Agreement set forth the terms and conditions under which NSTAR was to undertake certain design and engineering activities on the Interconnection Facilities for Medway Grid's proposed Large Generation Facility prior to the execution of an LGIA. Specifically, the Agreement addressed Qualified Transmission Upgrades ("QTUs") identified by ISO-NE in its FCA15 Post-Auction Overlapping Impact Restudy ("Restudy") for QP844. However, ISO-NE has subsequently performed a review of the Restudy results and has determined that the QTUs are not required for the interconnection of Medway Grid's facility. NSTAR, accordingly, filed a Notice of Termination to reflect the termination of the Agreement. All billing, refunds, and invoices have been finalized and no further work is being done under the Agreement. NSTAR requested a Jun 13, 2023 effective date. Comments on this filing were due on or before July 3, 2023; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Engineering & Test Agreement: CL&P / BPUS (ER23-2335)**

On July 5, 2023, CL&P filed an Engineering and Test Agreement ("Agreement") with BPUS Generation Development LLC ("Interconnection Customer" or "BPUS"). The Agreement sets forth the terms and conditions under which CL&P will perform necessary engineering and testing services in connection with the development of BPUS's large generating facility, and prior to the execution of 3-party IA with ISO-NE. CL&P has designated the Agreement IA-ESCLP-011. CL&P requested a July 6, 2023 effective date. Comments on this filing were due on or before July 26; none were filed. BPUS 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).

- **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. 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: National Grid/Millennium Power (ER23-2065)**
  On July 31, 2023, the FERC accepted an LGIA between National Grid and Millennium Power (designated as IA-NEP-59) that provides for continued interconnection service to Millennium's facility.[96] The Millennium LGIA follows the terms of the ISO-NE *pro forma* LGIA with only minor revisions primarily to reflect that it is a two-party agreement. The LGIA was accepted effective as of May 3, 2023, as requested. Unless the July 31 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).

- **NEP/ISO-NE/RIE Revised LSAs (ER23-1831; ER23-1830)**
  On June 30, 2023, the FERC accepted both the revised LSA between ISO-NE, NEP and RIE[97] and Service Agreement No. 23 between NEP and RIE.[98] The LSAs, as revised, will function solely to ensure that certain provisions related to the Contract Termination Charges ("CTCs") defined and set forth in the settlement agreements entered into by NEP, RIE, and certain other parties in order to accommodate the introduction of retail competition programs in Rhode Island remain in effect until such time as the CTCs are fully recovered. Each were accepted, *effective May 5, 2023*. The June 30 orders were not challenged and are final and unappealable. If you have any remaining questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Facilities Operating Agreement: Generate NB Fuel Cell/Farmington River Power Co, Stanley Black & Decker, EIP Investment (ER23-1979)**
  On July 24, 2023, the FERC accepted a modified Facilities Operating Agreement ("FOA"), by and among the Farmington River Power Company ("FRPC"), Stanley Black & Decker, Inc. ("SBD"), and EIP Investment, LLC ("EIP"), filed by Generate NB Fuel Cells, LLC ("Generate") on May 26, 2023.[99] As previously reported, the FOA covers a planned 20 MW fuel cell project on SBD's manufacturing campus located in New Britain (the "Project"). The FOA was assigned, in part, to Generate pursuant to a Partial Bill of Sale, Assignment and Assumption Agreement dated October 20, 2022 between Generate and EIP ("Assignment Agreement"). The FOA, as modified by the Assignment Agreement, sets forth the terms and conditions under which Generate may use, operate, modify, or augment transmission and interconnection facilities owned by FRPC in order to safely, efficiently, and reliably transmit electricity from the Project to the transmission grid and authorizes Generate to construct additional facilities and modify existing facilities as needed to connect Generate NB Fuel Cells' planned fuel cell installation to the grid. The FOA was accepted, effective as of *May 27, 2023*, as requested. Unless the July 24 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA: RIE/ISO-NE/Various Entities (ER23-1767, ER23-1748, ER23-1741)**
  On April 28, 2023, ISO-NE and RIE filed three revised LGIAs to reflect RIE as the new Interconnecting Transmission Owner pursuant to a FERC-approved transaction. A January 1, 2023 effective date was requested for each of the following LGIAs:
    - **ER23-1767**: First Revised LGIA (as supplemented May 31 and June 15, 2023) that governs the interconnection of Manchester Street, LLC's 516 MW facility located in Providence, RI.

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[96] *New England Power Co.*, Docket No. ER23-2065-000 (July 31, 2023) (unpublished letter order).

[97] *ISO New England Inc.*, Docket No. ER23-1831-000 (June 30, 2023) (unpublished letter order).

[98] *ISO New England Inc.*, Docket No. ER23-1830-000 (June 30, 2023) (unpublished letter order).

[99] *Generate NB Fuel Cells, LLC*, Docket No. ER23-1979-000 (July 24, 2023) (unpublished letter order).

  - **ER23-1748:** First Revised LGIA (as supplemented June 8, 2023) that governs the interconnection of Ocean State Power LLC's 656.157 MW facility located in Burrillville, RI.
  - **ER23-1741:** Second Revised LGIA that governs the interconnection of Rhode Island LFG Genco, LLC's 38 MW facility located in Johnston, RI.

Since the last Report, the FERC accepted, on July 5, 2023, the third of these LGIAs,[100] the RI LFG Genco LGIA, filed in ER23-1741, effective as of January 1, 2023, as requested.[101] Unless the FERC's orders approving the LGIAs 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).

- **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, [102] 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).

- **Versant Power MPD OATT *Order 881* Compliance Filing (ER22-2358)**

On July 12, 2022, in response to the requirements of *Order 881*, Versant Power filed a proposed new Attachment T to the Versant Power Open Access Transmission Tariff for the Maine Public District ("MPD OATT"). Attachment T, Versant reported, incorporates all the contents of the *pro forma* OATT's new Attachment M. An effective date of July 12, 2025 was requested in an errata filing submitted on August 1, 2022. On August 2, 2022, MPUC submitted comments asserting that Versant's Compliance Filing, without further detail, is insufficient to meet the requirements of *Order 881* and should either (i) be rejected outright, ordering Versant to re-file with sufficient detail, or (ii) subject to a deficiency letter requiring further information with respect to the Compliance Filing. MPUC withdrew those comments on August 31, 2022 in exchange for certain understandings with Versant Power (including MPUC's attendance, as a non-voting participant, at any NMISA working group discussions on *Order 881* implementation planning and Versant Power's submission of informational compliance filings to keep the FERC apprised of versant's progress in developing its AAR implementation plan). On September 6, 2022, Versant Power supplemented its compliance filing to confirm the MPUC's understandings, as delineated in its Notice of Withdrawal. This

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[100] The FERC accepted, on June 21, 2023, the LGIAs filed in ER23-1767 and ER23-1748, effective as of January 1, 2023. *See ISO New England Inc.*, Docket No. ER23-1767-000 (June 21, 2023) (unpublished letter order); *ISO New England Inc.*, Docket No. ER23-1748-000 (June 21, 2023) (unpublished letter order).

[101] *ISO New England Inc.*, Docket No. ER23-1741-001 (July 5, 2023) (unpublished letter order)

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

matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

On June 7, 2023, as amended on June 30, 2023, VEC filed for acceptance an Agreement for the Transfer of Use Rights on the Phase I/II HVDC Transmission Facilities ("Transfer Agreement") between itself and HQUS. An effective date of May 27, 2023 was requested. No comments on the filings were filed and the Transfer Agreement is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

XII. Misc. - Administrative & Rulemaking Proceedings[103]

- **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, 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. This matter is pending before the FERC.

- **Interregional HVDC Merchant Transmission (AD22-13)**

As previously reported, Invenergy Transmission ("Invenergy") filed a petition, on July 19, 2022, requesting that the FERC hold a technical conference to explore ways to potentially make available and compensate certain grid reliability and resilience benefits associated with interregional high voltage direct current ("HVDC") merchant transmission. Initial comments to be considered by the FERC in its determination of any action to be taken were due on or before August 26, 2022. Comments were filed by 13 parties and included, among others, CSC, ENGIE, Invenergy, Phase I/II Asset Owners and IRH, Joint Consumer Advocates, MISO, ACORE, ACPA, SEIA, and Neptune and Hudson. Invenergy answered the comments filed by MISO.

On November 10, 2022, Invenergy again urged the FERC to "hold a technical conference to examine and to improve the policy and processes relating to the interconnection of interregional MHVDC systems". In December, ENGIE, Grid United and SEIA filed comments supporting Invenergy's November 10 request. On February 6, 2023, the FERC issued a notice of Invenergy's November 10, 2022 request, providing any person interested in commenting a March 8, 2023 comment deadline. Comments were filed by the following parties: Advanced Energy United, NRDC, IRC, SPP, NARUC, Amer. Council on Renewable Energy, Assoc. Industries of MO, Clean Energy Buyers Assoc., Converge Strategies, ELCON, Grid United, IL Manufac. Assoc., MN PSC, Natl. Elec. Manufac. Assoc., ND PSC, Public Citizen, Niskanen Center, Prysmian Group, P. Stockton, R Street Institute, Rail Electrification

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[103] 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: Joint FERC-DOE Supply Chain Risk Management Tech. Conf. (Dec 7, 2022) (AD22-12).

Council, Renew Missouri Advocates, SOO Green HVDC Link ProjectCo, and World Resources Institute. 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 are due by ***August 24, 2023***. 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 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.

- **Transmission Planning and Cost Management Technical Conference (AD22-8)**

On October 6, 2022, the FERC convened a Commissioner-led technical conference regarding transmission planning and cost management for transmission facilities developed through local or regional transmission planning processes. The 5 panels throughout the day addressed: (1) the processes by which transmission providers develop local transmission planning criteria, identify local transmission needs using those criteria, and evaluate and choose local transmission facilities to address those needs; (2) whether local transmission facility costs are adequately scrutinized; (3) the processes by which transmission providers evaluate, select, and develop regional transmission facilities for reliability; (4) whether regional transmission facilities for reliability costs are adequately scrutinized; and (5) cross-cutting themes and potential best practices for both local transmission facilities and regional reliability transmission planning and cost management, in addition to innovative approaches that could be explored further, including the possibility of establishing a role for an Independent Transmission Monitor, and mechanisms to support enhanced transparency. Advance materials were submitted by representatives on behalf of: ISO-NE, CA PUC, KY PSC, NC Utils. Comm. Public Staff, NV PUC, RI PUC, AEU, AEP, Ameren, AMP/APPA, Ari Peskoe, L. Azar, Clean Energy Buyers Assoc., Coalition of MISO Customers, Harvard Electricity Law Initiative, ITC Holdings, LPPC, IA Consumer Advocate, J. Macey, NESCOE, Northern California Power Agency, Northwest & Intermountain Power Producers Coalition, OH Consumers' Counsel, OH PUC, Old Dominion Elec. Coop., PJM, G. Poulus, SPP, Potomac Economics, Southern California Edison, Southern Environmental Law Center, and TAPS/FMPA and WIRES.

On September 30 and October 4, the FERC issued supplemental notices that included a final agenda, including further details regarding the agenda and speakers, for this technical conference. On November 1, 2022, a transcript of the technical conference was posted in the FERC's eLibrary. On December 23, 2022, the FERC issued a notice inviting post-technical conference comments on questions listed in that notice. Those comments were due by March 23, 2023 and were filed by: ISO-NE, AEU, Avangrid, Cypress Creek Renewables, Eversource, LS Power, MA AG, NE Public Systems, NESCOE, NextEra, NRDC, NRG, Maine PUC, American Council on Renewable Energy ("ACRE"), APPA, EEI, Harvard Elec. Law Inst., LPPC, NASUCA, NRECA, and R Street Institute. Since the last Report, WIRES, AEP, and EEI filed reply comments. On June 8, 2023, CA Utilities[104] moved to lodge CA PUC Final Resolution E-5252 (which proposed a new CA PUC jurisdictional transmission review program called the Transmission Project Review Process). In comments filed on July 19, 2023, the CA PUC supported the Motion to Lodge, but emphasized that California's establishment of the TPR Process does not obviate the need for the FERC to adopt critical transmission policy reforms applicable to the CAISO (and the rest of the country). This matter is pending before the FERC.

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

Since the last Report, a seventh meeting[105] of the FERC-established Joint Federal-State Task Force on Electric Transmission ("Transmission Task Force" or "JFSTF")[106] was held July 16, 2023, at the JW Marriott in Austin, TX. In addition, on June 29, 2023, the National Association of Regulatory Utility Commissioners ("NARUC") nominated the state commissioners for the August 2023 to July 2024 term, including Commissioner Riley Allen (VT PUC) and Chair Marissa Gillett (CT PURA) from the NECPUC region.[107]

- **Modernizing Electricity Market Design - Resource Adequacy (AD21-10)**

ISO/RTO Reports. On April 21, 2022, the FERC issued an order[108] directing each independent system operator ("ISO") and regional transmission organization ("RTO"), including ISO-NE, to submit on or before October 18, 2022 a report that describes: (1) current system needs given changing resource mixes and load profiles; (2) how it expects its system needs to change over the next five and 10 years; (3) whether and how it plans to reform its energy and ancillary services ("EAS") markets to meet expected system needs over the next five and 10 years; and (4) information about any other reforms, including capacity market reforms and any other resource adequacy reforms that would help it meet changes in system needs. The *Order Directing Reports* followed a series of staff-

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[104] "CA Utilities" are Pacific Gas and Electric Co. ("PG&E"), Southern California Edison Co. ("SCE"), and San Diego Gas & Elec. Co. ("SDG&E").

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

[106] *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).

[107] The 2023/24 State Commissioner Transmission Task Force nominees 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.

[108] *Modernizing Wholesale Electricity Market Design*, 179 FERC ¶ 61,029 (Apr. 21, 2022) ("*Order Directing Reports*").

led technical conferences, convened in 2021 and summarized in previous Reports, addressing ISO/RTO resource adequacy[109] and energy and ancillary services markets.[110]

ISO-NE Report. On October 18, 2022, ISO-NE (as well as the other ISO/RTOs) filed its report in response to the *Order Directing Reports.* Comments in response to the RTO/ISO reports were due, following an EEI request, on or before January 18, 2023. Comments were filed by, among others: AEU, API, Constellation, New England Public Systems,[111] Shell, Clean Energy Assocs, Clean Energy Buyers Association, EEI, EPSA, Public Interest Orgs, and R Street Institute.

The FERC is reviewing the RTO/ISO reports and comments related thereto to determine whether further action is appropriate.

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

On July 28, 2022, the FERC issued a NOPR[112] 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 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[113] requested an additional month to submit comments.[114] 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,

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[109] The FERC held two staff-led technical conferences addressing resource adequacy, one on Mar. 23, 2021 (with post-conference comments focused on PJM-specific issues) and the other on May 25, 2021 (focused on the wholesale markets administered by ISO-NE). Following the Mar. 23 conference, more than 45 sets of initial comments were filed, including by: AEU, Calpine, Cogentrix, Dominion, Exelon, FirstLight, LS Power, NESCOE, NEPGA, NRG, PSEG, Shell, Vistra, CT DEEP, EEI, EPSA, and NRECA/APPA. Reply comments were filed by ACPA, AEP, EPSA, Exelon, Joint Consumer Advocates, LS Power, Old Dominion Electric Cooperative ("ODEC"), P3, Public Interest Organizations ("PIOs"), and the Retail Electric Supply Association ("RESA"). Following the May 25 conference, comments were filed by: AEU, Calpine, CT Parties, Dominion, Eversource, MMWEC, NESCOE, NEPGA, NextEra, NRG, Public Interest Orgs, Vistra, AEMA, EPSA, RENEW.

[110] The FERC held two staff-led technical conferences addressing ISO/RTO EAS markets, one on Sept. 14, 2021; the second on Oct. 12, 2021. Transcripts of both technical conferences are posted in eLibrary. In advance of the EAS technical conferences, FERC staff issued on Sept. 7, 2021 a White Paper entitled "Energy and Ancillary Services Market Reforms to Address Changing System Needs" summarizing recent EAS markets reforms as well as reforms then under consideration. Initial comments on the topics discussed during the EAS technical conferences were filed by: ISO-NE, Appian Way Energy Partners, Constellation, Dominion, Envir. Defense Fund, FirstLight, LS Power, CAISO, MISO, NYISO, PJM, SPP MMU, ACPA, Clean Energy Organizations, EEI, Energy Trading Institute, EPRI, EPSA, Middle River Power, National Hydropower Assoc., NYSERDA, PJM Providers Group, and Public Citizen. Reply comments were filed by EPRI, NERC and its Regional Entities and Vistra.

[111] "New England Public Systems" are CMMEC, MMWEC, NHEC, and VPPSA.

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

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

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

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 893*: Incentives for Advanced Cybersecurity Investment (RM22-19)**

On April 21, 2023, the FERC issued *Order 893*,[115] which revises the FERC's regulations to encourage investments by utilities in Advanced Cybersecurity Technology and participation by utilities in cybersecurity threat information sharing programs, as directed by the Infrastructure Investment and Jobs Act of 2021. *Order 893* (1) identifies the utilities permitted to request incentive-based rate treatment for cybersecurity investments; (2) establishes the criteria that the FERC will use to determine whether a cybersecurity investment is eligible to receive an incentive-based rate treatment; (3) discusses the approaches that a utility may use to demonstrate that a cybersecurity investment satisfies the eligibility criteria; (4) explains the type of incentive-based rate treatment available for qualifying cybersecurity investments; (5) sets limits on the duration of the incentive-based rate treatment; (6) describes what utilities must include in their applications for incentive-based rate treatment for cybersecurity investments; and (7) establishes the annual reporting requirements for utilities that receive incentive-based rate treatment for their cybersecurity investments. *Order 893* became effective July 3, 2023.[116]

Denied By Operation of Law: NRECA Request for Clarification and/or Rehearing. On May 22, 2023, the National Rural Electric Cooperative ("NRECA") requested clarification and/or rehearing of *Order 893.* Specifically, NRECA asked that the FERC clarify (i) the period during which a utility will be eligible for the "early compliance" cybersecurity incentive and the revised regulations and (ii) its statements concerning the right of utilities that make sales of energy, capacity, or ancillary services at market-based rates to also make sales at cost-based rates that include incentive-based rate treatment for eligible cybersecurity investments. On June 22, 2023, the FERC issued a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration".[117] The *Order 896 Allegheny Notice* confirmed that the 60-day period during which a petition for review of *Order 896* can be filed with an appropriate federal court was triggered when the FERC did not act on NRECA's request for rehearing of *Order 896* 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."

Order 893-A. On July 27, 2023, the FERC granted NRECA's request for clarification and, accordingly, dismissed NRECA's alternative request for rehearing.[118] Specifically, the FERC clarified that (i) pursuant to section 35.48(e)(3) of its regulations, a utility is required to demonstrate in its filing that it will make cybersecurity investments to comply with a cybersecurity-related CIP Reliability Standard after the effective date of FERC approval but before the effective date of the Reliability Standard itself (at which point the Standard is mandatory and enforceable); (ii) a utility must achieve compliance with a FERC-approved Reliability Standard before it becomes mandatory and enforceable to demonstrate satisfaction of the eligibility criteria in section 35.48(e)(3); (iii) utilities that seek incentive-based rate treatment for cybersecurity investments made prior to the effective date of the FERC's approval of a cybersecurity-related CIP Reliability Standard would do so under the case-by-case approach specified in section 35.48(e)(2) of the FERC's regulations; (iv) the duration of the incentive (other than for information sharing programs) is limited to the period between the date after the effective date of the FERC-approved incentive that the utility is in compliance and the date that the Reliability Standard becomes mandatory and enforceable; and (v) *Order 893* does not preclude utilities that make sales of energy, capacity, ancillary

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[115] *Incentives for Advanced Cybersecurity Investment*, Order No. 893, 183 FERC ¶ 61,033 (Apr. 21, 2023) ("*Order 893*"), *request for clarification granted and reh'g dismissed,* 184 FERC ¶ 61,053 (July 27, 2023).

[116] *Order 893* was published in the Fed. Reg. on May 3, 2023 (Vol. 88, No. 85) pp. 28,348-28,125.

[117] *Incentives for Advanced Cybersecurity Investment*, 183 FERC ¶ 62,154 (June 22, 2023) ("*Order 893 Allegheny Notice*").

[118] *Incentives for Advanced Cybersecurity Investment*, Order 893-A, 184 FERC ¶ 61,053 (July 27, 2023) ("*Order 893-A*").

services, or any other jurisdictional product at market-based rates from also making separate sales at cost-based rates that include incentive-based rate treatment for eligible cybersecurity investments.

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

On June 15, 2023, the FERC adopted a reporting requirement[119] 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[120] (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 [120 days after date of publication in the *Federal Register*].[121]

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

On July 28, 2023, the FERC issued Order 2023,[122] 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;[123] (ii) increase the speed of interconnection queue processing;[124] and (iii) incorporate technological advancements into the interconnection process.[125] Many of the reforms adopted in *Order 2023* closely track the reforms set out in the FERC's Notice of

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[119] *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*").

[120] 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.

[121] *Order 897* has still not, as of the date of this Report, been published in the *Federal Register*.

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

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

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

[124] 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.

[125] 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 Rulemaking.[126] However, the FERC did revise aspects of the reforms.[127] *Order 2023* will become effective [60 days after its publication in the *Federal Register*] ("Publication Date").

Importantly, the FERC is requiring the submission of compliance filings within 90 calendar days of the Publication Date (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).

We are still digesting *Order 2023*'s nearly 1,500 pages. A fulsome summary will be 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. Buckle up.

Interconnection Reforms NOPR. As previously reported, the FERC issued the Interconnection Reforms NOPR,[128] more than 400 pages long, on June 16, 2022. The *Interconnection Reforms NOPR* 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.

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.[129] *Order 895* will not permit information sharing to be

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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.

[126] *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.

[127] 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.

[128] *Improvements to Generator Interconnection Procedures and Agreements*, 179 FERC ¶ 61,194 (June 16, 2022) ("*Interconnection Reforms NOPR*").

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

conditioned on the specific consent of the market participant, would permit the receiving ISO/RTO to use market 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* will become effective *August 21, 2023*.[130]

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

On December 15, 2022, the FERC issued a NOPR[131] 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 on March 3, 2023, comments on the *Transmission Siting NOPR* are 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.

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

Following its ANOPR process,[132] the FERC issued on April 21, 2022 a NOPR[133] that would require public utility transmission providers to:

(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

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

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

[132] *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.

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

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.[134] 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 ("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

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[134] 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.

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).

- ***Order 898*: Accounting and Reporting Treatment of Certain Renewable Energy Assets (RM21-11)**

On June 29, 2023, the FERC issued Order 898[135] which amends the Uniform System of Accounts ("USofA") and relevant FERC forms to: (i) include new accounts for wind, solar, and other renewable generating assets; (ii) create a new functional class for energy storage accounts; (iii) codify the accounting treatment of renewable energy credits; (iv) create new accounts within existing functions for hardware, software, and communication equipment. As for hydrogen, the FERC found that existing and proposed public utility accounts are sufficient for current and anticipated uses of hydrogen as an electric fuel or energy storage medium and that no new public utility accounts, nor additional guidance are therefore needed. The FERC reiterated that, for either electric generation or energy storage, the recording and reporting of hydrogen specific fuel, equipment, and operations and maintenance expenses should follow the most appropriate account instructions for the function it is used to fulfill. *Order 898* will become effective on *January 1, 2025*.

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- **NRG (IN23-3)**

On July 20, 2023, the FERC approved a Stipulation and Consent Agreement with NRG Energy, Inc. ("NRG")[136] that resolved OE's investigation into whether NRG complied with the Parameter Limited Schedule requirements of the PJM Tariff. Specifically, OE concluded that NRG violated those requirements during the 2018-2020 delivery years.[137] Under the Settlement, in which NRG neither admits nor denies the alleged violations, NRG agreed to ***disgorge $32,658*** and to ***pay a civil penalty of $37,342*** to the United States Treasury. NRG also agreed to submit annual compliance monitoring reports for at least one year. PJM was again directed to distribute the disgorgement amount for the benefit of PJM customers and upon approval by Enforcement of PJM's plan for doing so. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Entergy Arkansas (IN23-5)**

On June 22, 2023, the FERC approved a Stipulation and Consent Agreement with Entergy Arkansas, LLC ("Entergy AK")[138] that resolved OE's investigation into whether Entergy AK, on four days in 2020, violated Section 40.2.5.e of the MISO Energy and Operating Reserve Markets Tariff and the FERC's Unit Operation and Communications market behavior rules[139] when it submitted erroneous offers for its Hot Springs generation facility ("Hot Springs"). On those days, Hot Springs' Real-Time offers incorrectly communicated that it was in a control mode that would respond to MISO's dispatch instructions. However, during certain hours, Hot Springs did not follow MISO's dispatch instructions or raised Hot Springs' Economic Minimums or lowered Economic Maximums in order to "block" or "pin" the unit (i.e., to restrict MISO's

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

[136] *NRG Energy, Inc.*, 184 FERC ¶ 61,026 (July 20, 2023).

[137] *Id.* at P 5.

[138] *Entergy Arkansas, LLC*, 183 FERC ¶ 61,207 (June 22, 2023).

[139] 18 C.F.R. § 35.41(a) and (b).

ability to dispatch the unit). Entergy AK did not financially benefit from blocking or pinning the Hot Springs facility through the Real-Time offers at issue. Under the Settlement, in which Entergy AK neither admits nor denies the alleged violations, Entergy AK agreed to ***pay a civil penalty of $52,000*** to the United States Treasury and to submit two annual compliance monitoring reports, with the requirement of a third report at OE's option. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

Natural Gas-Related Enforcement Actions

- **Pacific Summit Energy LLC (IN23-9)**

On June 30, 2023, the FERC approved a Stipulation and Consent Agreement with Pacific Summit Energy LLC ("Pacific Summit")[140] that resolved OE's investigation into whether Pacific Summit engaged in a related-positions fraudulent scheme involving physical trading at Transco Zone 6 for the purpose of benefiting related financial positions during the October 2017 Bidweek (September 25-29, 2017), in violation of section 4A of the Natural Gas Act and the FERC's Anti-Manipulation Rule. Under the Settlement, in which Pacific Summit neither admits nor denies the alleged violations, Pacific Summit agreed to ***disgorge $154,623*** and to ***pay a civil penalty of $360,000*** to the United States Treasury. Pacific Summit also agreed to submit annual compliance monitoring reports for at least two years. The disgorgement payments will be made at the direction of OE Staff *pro rata* to market participants who had financial instruments settle based on the effected indexes in October 2017. 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,[141] 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,[142] which (i) directed the Chief ALJ to reassign this proceeding to another ALJ not previously involved in the proceeding (i.e., designate a new presiding officer) once the *June 14 Order* takes effect; (ii) held that the *June 14 Order* will take effect once the Northern District clarifies or lifts its stay for the limited purpose of allowing the *June 14 Order* to take effect or the stay is lifted or dissolved such that hearing procedures may resume; and (iii) stated that this proceeding otherwise remains suspended until the Northern District's stay is lifted or dissolved such that hearing procedures may resume.

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

On December 16, 2021, the FERC issued a show cause order[143] 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

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[140] *Pacific Summit Energy LLC*, 183 FERC ¶ 61,236 (June 30, 2023).

[141] 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.

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

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

Regulations (18 C.F.R. § 157.20); and the FERC's Certificate Order,[144] 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;[145] (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.[146] This matter is pending before the FERC.

- **BP (IN13-15)**

On July 7, 2023, the FERC approved a Stipulation and Consent Agreement with BP America Inc., BP Corporation North America, Inc., BP America Production Company, and BP Energy Company (collectively "BP")[147] that resolves (i) the FERC's years long investigation into BP's violations of the FERC's Anti-Manipulation Rules, as well as (ii) the more recent litigation before the 5th Circuit Court of Appeals. BP agreed to ***pay a civil penalty of $10.75 million*** *(roughly ½ of the amount assessed in Opinion 549-A)*[148] and ***not to seek return of the $250,295 of disgorgement*** that it has already paid. This will conclude reporting on this matter.

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

On April 28, 2016, the FERC issued a show cause order[149] 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.[150]

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

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[144] *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").

[145] 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.

[146] *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.

[147] *BP America Inc. et al.*, 184 FERC ¶ 61,016 (July 7, 2023).

[148] *BP America Inc. et al.,* Opinion No. 549-A, 173 FERC ¶ 61,239 (Dec. 17, 2020) ("*BP Penalties Allegheny Order*").

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

[150] 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.

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

Hearing Procedures. On July 15, 2021, the FERC issued and order establishing hearing procedures to determine whether Respondents violated the FERC's Anti-Manipulation Rule, and to ascertain certain facts relevant for any application of the FERC's Penalty Guidelines.[151] 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.[152]

On June 14, 2023, the Commission issued an Order on Presiding Officer Reassignment,[153] 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.[154] The certificate was conditioned on: (i) Iroquois' completion of construction

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

[152] *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).

[153] *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*").

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

of the proposed facilities and making them available for service within ***three years*** of the date of the; (ii) Iroquois' compliance with all applicable FERC regulations under the NGA; (iii) Iroquois' compliance with the environmental conditions listed in the appendix to the order; and (iv) Iroquois' filing written statements affirming that it has executed firm service agreements for volumes and service terms equivalent to those in its precedent agreements, prior to commencing construction. The March 25, 2022 order also approved, as modified, Iroquois' proposed incremental recourse rate and incremental fuel retention percentages as the initial rates for transportation on the Enhancement by Compression Project.

- On April 18, 2022, Iroquois accepted the certificate issued in the *Iroquois Certificate Order*.
- On June 17, 2022, in accordance with the *Iroquois Certificate Order,* Iroquois submitted its Implementation Plan, documenting how it will comply with the FERC's Certificate conditions.
- The Project is targeted for a 4th quarter 2023 in-service date.

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,[155] and that effectively halted construction of the NECEC Project,[156] 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

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[155] 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?"

[156] 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[157]
  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*.[158] 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 is 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.

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[157] *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*").

[158] 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.

- **Seabrook Dispute Order (23-1094)**
  Underlying FERC Proceeding: EL21-6, EL 23-3[159]
  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.[160] As previously reported, initial submissions have been filed.[161] Since the last Report, the FERC filed the Certified Index to the Record and NextEra filed Petitioners' Brief. Remaining submissions include: Respondent's Brief (September 28, 2023); 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[162]
  Petitioner: Green Development
  Status: Petitions for Review Denied; Issuance of Mandate Withheld

On July 28, 2023, the DC Circuit issued an order denying Green Development's petitions for review. The Court held that each of Green Development's four grounds for vacatur lacked merit. The Court directed the Clerk to withhold issuance of the mandate until seven days after disposition of any timely petition for rehearing or petition for rehearing *en banc*.

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[159] *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*").

[160] 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.

[161] 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).

[162] *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*".

- **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,[163] -013[164] -017[165]
  Petitioners: Mystic, CT Parties,[166] MA AG, ENECOS
  Status: Being Held in Abeyance; Motions to Govern Future Proceedings Due July 24, 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*, 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[167]
  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

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[163] *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).

[164] *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).

[165] *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*).

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

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

dismissed as moot by the Court, referred to the merits panel (Judges Pillard, Katsas and Walker), and is to be addressed by the parties in their briefs.

Petitioners have moved to hold this matter in abeyance 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[168]
  Petitioners: TOs' (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[169] 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*[170] decision. On September 22, 2020, the FERC submitted an unopposed motion to hold this proceeding in abeyance for four months to allow for the Commission to "a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the Commission." On October 2, 2020, the Court granted the FERC's motion, and directed the parties to file motions to govern future proceedings in this case by February 2, 2021. On January 25, 2021, the FERC requested that the Court continue to hold this petition for review in abeyance for an additional three months, with parties to file motions to govern future proceedings at the end of that period. The FERC requested continued abeyance because of its intention to issue a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the FERC. Petitioners consented to the requested abeyance. On February 11, 2021, the Court issued an order that that this case remain in abeyance pending further order of the court. On April 21, 2021, the FERC filed an unopposed motion for continued abeyance of this case *because* the Commission intends to issue a future order on Petitioners' request for rehearing of the challenged Order Rejecting Compliance Filing, and because the remand proceeding in which the challenged order was issued remains ongoing.

On May 4, 2021, the Court ordered that this case remain in abeyance pending further order of the Court, directing the FERC to file a status report by September 1, 2021 and at 120-day intervals thereafter. The parties were directed to file motions to govern future proceedings in this case within 30 days of the completion of agency proceedings. The FERC's last status report, indicating that the proceedings before the Commission remain ongoing and that this appeal should continue to remain in abeyance, was filed on April 4, 2023.

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

[169] 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.

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

Other Federal Court Activity of Interest

- ***Northern* Access *Project (22-1233)***
  Underlying FERC Proceeding: *CP15-115*[171]
  Petitioners: Sierra Club
  Status: Briefing Complete; Oral Argument Not Yet Scheduled

On September 6, 2022, the Sierra Club petitioned the DC Circuit for review of *Northern Access Project Add'l Extension Order*. Briefing is complete. On June 23, 2023, the Court scheduled oral argument for ***September 18, 2023***. The composition of the merits panel will be provided on or about August 18, 2023.

- ***Order 872* (20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[172]
  Petitioners: SEIA et al.
  Status: Oral Argument Held March 8, 2022; Awaiting Decision

On September 17, 2020, SEIA petitioned the 9th Circuit Court of Appeals for review of *Order 872*.[173] Briefing was completed and oral argument held March 8, 2022 before Judges Nguyen, Miller and Bumatay. This matter remains pending before the Court.

- **Algonquin Atlantic Bridge Project Orders (21-1115*, 21-1138, 21-1153, 21-1155 consol.) and (22-1146, 22-1147 consol.)**
  Underlying FERC Proceeding: CP16-9-012[174]
  Petitioners: LS Power, Algonquin, INGA
  Status: Court Dismissed Petitions in Cases 22-1146/47; Remaining Cases (21-1115 et al.), Previously Being Held in Abeyance Pending Disposition of 22-1146/47, Will Return to Active Consideration

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 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

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

[172] *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).

[173] *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.

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

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.

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