NEPOOL
NEW ENGLAND POWER POOL

David T. Doot
Secretary

July 28, 2022

VIA ELECTRONIC MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of August 4, 2022
NEPOOL 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 meeting of the Participants Committee will be held **via teleconference on *Thursday*, August 4, 2022, 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**.

For your information, the August 4 meeting will be recorded. 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 the meeting are required to identify themselves and their affiliation during the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.

Looking ahead, the next regularly-scheduled Participants Committee meeting will be held on September 1, 2022. That meeting is a week earlier than initially planned to accommodate those that plan to participate in the FERC's September 8, 2022 New England Winter Gas-Electric Forum in Burlington, VT. Those interested in attending the Forum are strongly encouraged to register here at their earliest convenience.

We hope all of you are staying safe and healthy and enjoying your summers.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the draft minutes of the April 26, May 5, and June 21-23, 2022 Participants Committee meetings, which have been marked to show the changes since the drafts were circulated with the initial 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 and posted with the meeting materials.

4. To receive an ISO Chief Operating Officer report. The August COO report will be circulated and posted in advance of the meeting.

5. To receive an ISO Internal Market Monitor Report by David Naughton, Interim Internal Market Monitor. The IMM's 2021 Annual Markets Report is available on-line at https://www.iso-ne.com/static-assets/documents/2022/05/2021-annual-markets-report.pdf.

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.

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held beginning at 9:30 a.m. on Tuesday, April 26, 2022, at the AC Hotel in Worcester, Massachusetts. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the meeting.

Mr. David Cavanaugh, Chair, presided and Mr. Sebastian Lombardi, Acting Secretary, recorded.

APPROVAL OF MARCH 1, 2022 PATHWAYS STUDY MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the March 1, 2022 Pathways Study meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the Committee unanimously approved those minutes.

ANALYSIS GROUP (AGI) PRESENTATION ON FINAL PATHWAYS STUDY REPORT

Mr. Cavanaugh then introduced Mr. Todd Schatzki of AGI, who reviewed materials circulated and posted in advance of the meeting. Mr. Schatzki stated that the purpose of his presentation was to review comments received on the draft Pathways Study (Draft Report), to summarize the responses to those questions and to identify any changes made to the Draft Report.

At highest level, Mr. Schatzki reported that the comments received on the Draft Report generally were qualitative in nature, sought additional clarification or expansion on identified issues, and were for the most part reflected in the Final Report. The presentation grouped the comments by common policy theme and by technical question or comment. The Final Report also reflected clean-up changes identified by AGI. There were no material quantitative changes made to the Draft Report.

Common Policy Themes

Dr. Schatzki reported that many of the comments provided sought further clarification on the Study's scope and limits. The Report, which was largely focused on overall economic issues, had been revised to reflect that it was *not* intended to evaluate several of the other important dimensions of decarbonization policy, including legal and regulatory issues with alternative policy approaches, or reliability issues or transmission system needs (both of which were being addressed separately via the Future Grid Reliability Study and the 2050 Transmission Study, respectively). The Report was also revised to more directly acknowledge the assumptions being made. Other clarifications addressed the sources and significance of differences in impacts between the alternative policy approaches, challenges associated with those policy approaches, assumptions made with respect to investment incentives, and expected renewable portfolio standard (RPS) outcomes.

Technical Questions and Comments

Turning to more technical questions and comments, Dr. Schatzki provided additional information regarding storage "churning" (when batteries consume otherwise-curtailed variable renewable energy and earn net revenues through energy losses), particularly the circumstances and development of alternative technologies under which churning would be likely. In response to questions and comments in discussion and received since the release of the Draft Report, Dr. Schatzki expanded on the assumed drivers of capacity market prices. He noted that relative prices differed across the Central Case and scenarios.

With respect to social costs and payments, Dr. Schatzki explained why an estimate of *total* social costs and payments associated with decarbonization achieved over the 20-year study period could not be determined from the cases analyzed in the Pathways Study, which was designed to illustrate relative differences and inform choices among policy approaches rather than forecast the overall economic consequences of decarbonization. He also explained why incremental social costs and payments were compared to the Reference Case (which provided a baseline against the economic costs of undertaking each pathway), rather than against a particular pathway/approach.

Dr. Schatzki then reviewed AGI presentation material that highlighted and explained new exhibits added to the Final Report that provided additional information on the distribution of price impacts associated with net carbon pricing. The new exhibits illustrated that carbon pricing would increase LMP revenues to all supply resources, with a small incremental gain but decreasing share to fossil resources, and nearly all of the net payments going to non-carbon emitting resources (variable renewable, nuclear and storage resources). Additional discussion that addressed questions related to natural gas-fired generation, transmission and the relative magnitude of curtailments between variable renewable resources followed.

Next Steps

Dr. Schatzki concluded his presentation by stating that the Final Report (which would be updated to reflect a few corrections identified during the meeting) represented the end of a phase, but not the end point, in the Future Grid Pathways process. He noted that the ISO would continue to work on dimensions of the future grid efforts, and hoped that the Final Report~~Study~~ provided stakeholders with useful information to support the necessary determinations yet to be made relevant to the transition to a decarbonized New England electric grid. He expressed his appreciation and thanks for the even-handed and balanced Participant feedback and collaboration during the process. Mr. Cavanaugh similarly expressed appreciated for AGI's and the ISO's efforts getting to this point.

Looking forward, Dr. Chris Geissler, Principal Economist, ISO, identified other areas where the Future Grid efforts were continuing, including the work on the Future Grid Reliability Study and the 2050 Transmission~~ition~~ Study. He said that the ISO would continue to think of ways to leverage the work completed to date and to connect the Pathways work to the other F~~f~~uture G~~g~~rid efforts underway. He requested preliminary written feedback by May 17, 2022 on stakeholders' preferences with respect to an approach or pathway forward – those studied or variants thereof (and not additional feedback on the analysis or qualitative elements of the Report), and reviewed the details for submission of that desired feedback. The ISO hoped for some preliminary feedback from the New England States in the late May/June timeframe (coinciding with the NECPUC symposium and the Participants Committee Summer Meeting). Members again thanked the ISO and Dr. Schatzki and the AGI team for their work and presentation.

NRG STRAW PROPOSAL FOR A MARKET-BASED APPROACH TO NEW ENGLAND'S FUTURE GRID

Mr. Peter Fuller referred the Committee to the NRG-sponsored paper circulated and posted to the NEPOOL and ISO websites earlier that day which presented a straw proposal for a market-based approach to achieving the clean energy and de-carbonization objectives of the New England States (Straw Proposal). The Straw Proposal, which reflected the efforts by NRG and a group of stakeholders convened by NRG, as well as other regional conversations, was intended to facilitate the dialogue, negotiation and the consensus building that would be needed to enable the creation and implementation of an alternative market framework. He explained that the Straw Proposal proposed a hybrid approach – a combination of a Forward Clean Energy Market and some form of carbon pricing – intended to address many of the issues associated with the region's expected transition to a cleaner future grid. The Straw Proposal, Mr. Fuller clarified, was offered not as a suggested end point, but as a starting point for the discussions that would follow the completion of AGI's efforts, as well as to support a focus on the forums and mechanisms that could help to guide those discussions. Mr. Cavanaugh encouraged members to review the Straw Proposal and engage directly with Mr. Fuller with any questions or follow-up.

There being no further business, the meeting adjourned at 2:15 p.m.

Respectfully submitted,

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Sebastian Lombardi, Acting Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN APRIL 26, 2022 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Melissa Birchard (tel)		
Advanced Energy Economy	Associate Non-Voting	Caitlin Marquis (tel)		
Ampersand Energy Partners LLC	Supplier			Hannah Braun (tel)
AR Large Renewable Generation (RG) Group Member	AR-RG	Alex Worsley		
AR Small RG Group Member	AR-RG	Erik Abend (tel)		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell (tel)		
AVANGRID: CMP/UI	Transmission		Jason Rauch (tel)	Zach Teti (tel)
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity			Dave Cavanaugh
Brookfield Renewable Trading and Marketing LP	Supplier	Aleks Mitreski		
Calpine Energy Services, LP	Supplier	Brett Kruse (tel)		Bill Fowler (tel)
Castleton Commodities Merchant Trading	Supplier			Bob Stein (tel)
Centrica Business Solutions Optimize, LLC	AR-LR		Aaron Breidenbaugh (tel)	
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield (tel)		
Clearway Power Marketing LLC	Supplier			Pete Fuller
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw (tel)		
Connecticut Officer of Consumer Counsel	End User	Dave Thompson (tel)		
Consolidated Edison Energy, Inc.	Supplier	Grant Flagler (tel)	Matt Napoli (tel)	
Constellation Energy Generation, LLC	Supplier	Steve Kirk (tel)	Bill Fowler (tel)	
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dominion Energy Generation Marketing	Generation		Weezie Nuara (tel)	
DTE Energy Trading, Inc.	Supplier			José Rotger
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein (tel)		Bill Fowler (tel)
Emera Energy Services	Supplier	Drew Turner (tel)		Bill Fowler (tel)
Environmental Defense Fund	End User	Jolette Westbrook (tel)		
Eversource Energy	Transmission		Dave Burnham (tel)	Parker Littlehale
FirstLight Power Management	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger	Jeff Iafrati (tel)	
Generation Group Member	Generation		Abby Krich (tel)	Alex Worsley (tel)
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Granite Shore Companies	Generation			Bob Stein (tel)
Great River Hydro	AR-RG			Bill Fowler (tel)
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	Louis Guibault (tel)	Bob Stein (tel)	
Harvard Dedicated Energy Limited	End User			Jason Frost
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Jericho Power, LLC	AR-RG	Ben Griffiths		
Jupiter Power LLC	Provisional			Ron Carrier (tel)
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Mass. Attorney General’s Office (MA AG)	End User	Tina Belew (tel)		
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	

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PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
National Grid	Transmission		Tim Martin (tel)	
Natural Resource Defense Council	End User	Bruce Ho (tel)		
Nautilus Power, LLC	Generation		Bill Fowler (tel)	
New England Power Generators Association (NEPGA)	Associate Non-Voting			Molly Connors
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw (tel); Dave Cavanaugh
NextEra Energy Resources, LLC	Generation	Michelle Gardner (tel)		
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	
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Shell Energy North America	Supplier	Jeff Dannels		
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Pete Fuller
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Union of Concerned Scientists	End User		Francis Pullaro (tel)	
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw (tel)
Versant Power	Transmission	Lisa Martin (tel)		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Vitol Inc.	Supplier	Joe Wadsworth (tel)		
Walden Renewables Development LLC	Generation			Abby Krich (tel)
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler (tel)	

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Thursday, May 5, 2022, at the Seaport Hotel, One Seaport Lane, Boston, Massachusetts. A quorum, determined in accordance with the Second Restated NEPOOL Agreement, was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the meeting, either in person or by phone.

Mr. David Cavanaugh, Chair, presided, and Mr. David Doot, Secretary, recorded.

EXECUTIVE SESSION

CONFIDENTIAL VOTE ON SLATE OF CANDIDATES FOR ISO BOARD

Mr. Cavanaugh reminded the Committee that the identities of the candidates on the proposed slate were to remain confidential until the ISO Board reports publicly on its final vote on the slate, and indicated that discussion of this matter would proceed entirely in executive session. Mr. Cavanaugh then introduced Mr. Brook Colangelo, ISO Board Member and Chairman of the Joint Nominating Committee (JNC), who joined this portion of the meeting to present and answer any questions regarding the slate and the process undertaken to identify that slate. Following general comments on the JNC process, Mr. Colangelo 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. Colangelo then introduced Chairman Matt Nelson, Massachusetts Department of Public Utilities, who had participated in the JNC efforts on behalf of NECPUC. Chairman Nelson offered his thoughts on the nomination process and the proposed slate and then he and Mr. Colangelo left the meeting.

The slate was then discussed in executive session among members and alternates, with initial comments offered by the NEPOOL members 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 secret written ballot per prior direction of the Participants Committee:

> 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.

GENERAL SESSION

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

He invited Ms. Meredith Hatfield, NECPUC Executive Director, to provide an update on the upcoming 74th NECPUC Symposium, to be held May 22-25, 2022 at the Ocean~~'s~~ Edge Resort in Brewster, Massachusetts~~A~~. Ms. Hatfield summarized the topics on issues of importance to the region to be discussed during the Symposium. She encouraged all those interested to register and come and directed those with questions to visit NECPUC's website for more information.

APPROVAL OF APRIL 7, 2022 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the April 7, 2022 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of that meeting were unanimously approved as circulated, with an abstention by Mr. Sam Mintz's representative noted.

CONSENT AGENDA

There was no consent agenda for this meeting.

REVISIONS TO ISO-NE OP-14, OP-18 AND PP5-6

Ms. Emily Laine, Reliability Committee (RC) Chair, referred the Committee to the revisions to Operating Procedure 14 (OP-14 Revisions), Operating Procedure 18 (OP-18 Revisions) and ISO-NE Planning Procedure 5-6 (PP 5-6 Revisions). She reported that the Reliability Committee unanimously recommended Participants Committee support for the OP-14 Revisions, the OP-18 Revisions and the PP 5-6 Revisions at its April 27, 2022 meeting, as described in materials circulated in advance of the Participants Committee meeting, and that the revisions would have been ~~on the~~ Consent Agenda items but for the timing of the RC's consideration and vote.

The following motions were duly made, seconded and unanimously approved in a single vote without comment, with an abstention by the representative of Mr. ~~Sam~~ Mintz noted.

> RESOLVED, that the Participants Committee supports the OP-14 Revisions, as recommended by the Reliability Committee at its April 27, 2022 meeting and as reflected in the materials distributed to the Participants Committee for its May 5, 2022 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.
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> RESOLVED, that the Participants Committee supports the OP-18 Revisions, as recommended by the Reliability Committee at its April 27, 2022 meeting and as reflected in the materials distributed to the Participants Committee for its May 5, 2022 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.
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> RESOLVED, that the Participants Committee supports the PP 5-6 Revisions, as recommended by the Reliability Committee at its April 27, 2022 meeting and as reflected in the materials distributed to the Participants Committee for its May 5, 2022 meeting,

together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee

ISO CEO REPORT

Mr. van Welie joined the meeting by phone. He indicated that, because there had been no ISO Board or Board Committee meetings since his last report during the April meeting, no summaries had been circulated. He invited any questions or comments from members. No questions were asked or comments made.

ISO COO REPORT

Operations Highlights Report

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by referring the Committee to the May COO report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through April 27, 2022, unless otherwise noted. The report highlighted: (i) Energy Market value for April 2022 was $525 million, down $197 million from the updated March 2022 value and up $279 million from April 2021; (ii) April 2022 average natural gas prices were 4.8% lower than March average prices; (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for April ($59.51/MWh) were 10% lower than March averages; (iv) average April 2022 natural gas prices and Real-Time Hub LMPs over the period were up 170% and 129%, respectively, from April 2021 average prices; (v) average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 98.2% during April (down from the 100.8% reported for March), with the minimum value for ~~the~~ April~~month~~ of 92.5% on April 17; and (vi) Daily Net Commitment Period Compensation (NCPC) payments for April totaled $1.9 million, which was down $2.2 million from March 2022 and down $0.8 million from April 2021. April NCPC payments, which were 0.4% of total Energy Market value, were comprised of $1.9 million in first contingency payments (down $2 million from March 2022) and there were no second contingency, voltage or distribution payments. He noted that this was the first time in nearly 20 years (since March 2003) that second contingency, voltage and distribution payments were all zero.

Addressing in follow-up a few items from the April 7, 2022 Participants Committee meeting, Dr. Chadalavada indicated that, as requested, a comparison of energy market revenues for five of the past nine winters had been added to the 2020-21 Winter Review posted on the NEPOOL and ISO websites. He also reported that the lowest minimum load recorded by the ISO, prior to April 2022, was 8,000 MW in May 2020. However, since then, on April 23, 2022, a new record low was recorded – 7,938 MW, attributable to a roughly 4 GW mid-day solar penetration, and superseded again on May 1, 2022, when minimum load hit a new low of 7,580 MW. He added that since the beginning of 2022, there had been 28 days when minimum load during the day was lower than overnight load (compared to 18 in all of 2021). He said this was indicative of a new load shape going forward. He suggested that the increasing solar penetration was likely to help in a variety of ways (e.g. by curtailing energy usage from other resources when solar usage is at its peak) and foretold a trend over the next few years that would see more and more days where daytime minimum load would be lower, even significantly lower, than overnight loads.

In response to questions, Dr. Chadalavada addressed transmission outages expected during the month of May. While he noted the large number of outages given the season, he did not believe any particular outage was worthy of highlighting. He did, however, encourage members to pay attention to how cumulatively the outages would impact and potentially increase the volatility of the transfer limits on the New England-New York interface. A member noted that, beginning in July, when the NEPOOL GIS would begin to report on all generation by nameplate and generation technology, members might find additional useful information, particularly on solar generation. Another member suggested that, given the faster-than-predicted penetration of solar and other intermittent resources, it might be in the region's best interest to begin consideration of ways, and market-based products, to manage that situation. Dr. Chadalavada indicated that the ISO had already begun to consider these issues and plans for future efforts would be reflected in the multi-year budget overview to be provided at the Summer Meeting.

CPV PROPOSAL TO CHANGE NON-COMMERCIAL CAPACITY RESOURCES' FCM FINANCIAL ASSURANCE REQUIREMENTS

Mr. Tom Kaslow, Budget & Finance Subcommittee (B&F) Chair, provided an overview of the proposal by Competitive Power Ventures (CPV), supported by RENEW Northeast (RENEW), to change the financial assurance requirements for non-commercial resources by revising the Financial Assurance Policy (FAP) and a corresponding Market Rule 1 provision that were circulated in advance of the meeting (the Proposal). Mr. Kaslow summarized the stakeholder discussions that took place at both the Markets Committee and B&F. Specifically, he reported that, in part, because the ISO had not yet opined on the acceptability of the Proposal, various Markets Committee members abstained and that Committee did not recommend support for the Proposal. For the B&F, a non-voting subcommittee, Mr. Kaslow reported that many members supported the changes, that none expressed substantive concerns, but that, in absence of ISO review and feedback, some members could not take a position on the Proposal.

The Chair suggested that the Committee consider the Market Rule 1 and FAP changes together in a single vote, absent objection. Mr. Doot explained that the Market Rule 1 changes required a 60% vote to pass, while the FAP changes required a 66.677% vote to pass. Thus, to effectuate the Proposal, the Participants Committee vote needed to be at or above 66.67%. No one raised any objections to taking a single vote on the two sets of changes.

With that understanding, the following motions were together duly made and seconded:

> RESOLVED, that the Participants Committee supports the Market Rule 1 Tariff revisions related to changing the financial assurance requirements for Non-Commercial Capacity, as proposed by CPV 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.
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> RESOLVED, that the Participants Committee supports revisions to Sections VII.B.2.b, VII.B.3, and VII.D of the ISO New England Financial Assurance Policy to change the financial assurance requirements for Non-Commercial Capacity, as proposed by CPV and circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair of the Budget & Finance Subcommittee.

With the motions before the Participants Committee, the CPV representative explained that the Proposal had been designed to provide distinct economic outcomes for non-commercial capacity projects meeting their milestones as compared to those projects whose development is delayed or fails. He summarized changes made to the Proposal to address concerns that RENEW previously raised. At his request, RENEW's representative reported that RENEW supported the Proposal and urged others to do so as well. The representative opined that members who voted in favor of the ISO's minimum offer price rule (MOPR) proposal that included a two-year transition mechanism should favor this Proposal because it was responsive to reliability concerns cited in support of the two-year transition mechanism. The RENEW representative also urged the ISO to review the proposed Tariff revisions and offer feedback to permit a FERC filing in time for implementation before the 17th Forward Capacity Auction. The CPV and RENEW representatives then noted that they had worked closely together to reach a comprehensive proposal that addressed concerns with a prior version of the Proposal and expressed appreciation for the engagement and collaboration.

The Chair then turned to the ISO to report on its position on the Proposal. Dr. Chadalavada confirmed that the ISO remained unable to opine on the Proposal and- recognized the frustration felt by some because the ISO had been unable to evaluate and provide feedback on the Proposal. He explained that the ISO's resources were fully occupied with other projects from the work plan. Dr. Chadalavada noted that this experience illustrated the importance of ensuring that NEPOOL and the ISO communicate to optimize the priorities in the work plan. Responding to questions from members, Dr. Chadalavada expressed hope that further dialogue on priorities between NEPOOL stakeholders and the ISO would help to optimize resource allocation. He explained that the ISO was committed to allocate resources, when available, in 2023 to work on NEPOOL's priorities, including CPV's Proposal if it was identified as a NEPOOL priority.

The CPV representative indicated that CPV's interest was in working with the ISO to gain support for the Proposal as soon as possible. He reported that CPV did not intend to file a complaint with the FERC seeking an order requiring the ISO to effect the changes.

The Committee then received comments from members on the motions. Members that supported the Proposal noted that it was non-discriminatory and that it could address prior market issues created by projects that cleared the Forward Capacity Market (FCM) but either were delayed or never built, such as the Killingly project. No one spoke in opposition to the Proposal although numerous members explained that they could not support the Proposal until the ISO had analyzed it and indicated whether the Proposal was acceptable to it. Thus, those members indicated that they would abstain or oppose subject to substantive ISO input and confirmation that implementation of the Proposal would not detract from other work, such as the resource capacity accreditation project. A NESCOE representative stated that NESCOE would like to hear from the ISO but supported CPV's Proposal being placed in the work plan. Many

Committee members thanked the co-sponsors for their collaborative approach and opined that it exemplified the value and benefits of the Participant Processes.

The motions were then voted and resulted in a 64.74% Vote in favor (Generation Sector – 16.7%; Transmission Sector – 0%; Supplier Sector – 16.7%; AR Sector – 16.5%; Publicly Owned Entity Sector – 0%; End User Sector – 14.84%; and Provisional Members – 0%). (*See* Vote 1 on Attachment 2). With this result, there was sufficient support for the Market Rule 1 revisions, but not for the FAP changes, which meant that the CPV Proposal did not achieve NEPOOL's support.

Following the vote, a Committee member, on behalf of a number of Participants, expressed frustration with the process. Specifically, the member noted that this vote reflected a Catch-22 situation because the ISO would not review the proposal without NEPOOL support, but many members would not support the proposal without the ISO's review and feedback. Dr. Chadalavada stated that the ISO's planning process for the upcoming year had started. The Chair noted that NEPOOL was not in a position to do more at this time but that efforts were underway to define NEPOOL priorities, which may help to minimize future frustration.

LITIGATION REPORT

Mr. David Doot referred the Committee to the May 3 Litigation Report that had been circulated and posted before the meeting. He highlighted the following litigation-related developments since the April 5 Report:

(i) FERC approval of the acceleration FCM billing acceleration and Requested Billing Adjustment (RBA) changes;

(ii) The hearing and settlement judge procedures established to address Mystic Cost of Service Agreement issues;

(iii) The substantial number of pleadings in the proceeding to consider the proposed MOPR elimination~~ of the Minimum Offer Price Rule~~, the complaint proceeding seeking changes to the rules for capacity accreditation and operating reserve designations, and the proceeding to consider changes in response to the requirements of Order 2222;

(iv) The FERC's Transmission NOPR, with a July 18 deadline set by the FERC~~ommission~~ for comments;

(v) The FERC's order directing the submission by the ISO of an additional report on resource adequacy issues in connection with the Modernizing Electricity Market Design proceeding; and

(vi) The ISO's filing of its Winter 2022 quarterly markets report, which would be discussed at the May Markets Committee meeting.

COMMITTEE & OTHER REPORTS

Markets Committee (MC). Mr. William Fowler, the MC Vice-Chair, reported that the MC would meet virtually on May 10. Looking forward, he noted that registration would open shortly for the M~~arkets ~~C~~ommittee~~ Summer Meeting at Mills Falls on Lake Winnipesaukee ~~.~~in Meredith, NH, and encouraged all those interested to register early and to attend.

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that the next regularly-scheduled RC meeting would take place on May 17. The RC would receive a report on the results of step one of the extreme weather study and discuss the preparation and results of the 2022 load forecast.

Transmission Committee (TC). Mr. José Rotger, the TC Vice-Chair, reported that the next TC meeting was scheduled for May 31. He highlighted potential votes on changes to the interconnection process that would require all distribution-connected projects to follow state-jurisdictional distribution utility interconnection processes and a vote on Tariff changes to comply with Order 881 (FERC's Ambient Air Transmission Line Ratings order). There would also be direction from the TC on comments if any that NEPOOL might file in response to the FERC's Transmission Notice of Proposed Rulemaking, following the same procedure the TC followed in response to the Advanced Notice of Proposed Rulemaking. Finally, the TC would discuss the ISO's proposal to treat storage as a transmission-only asset.

~~Budget & Finance (~~B&F~~)~~ Subcommittee. Mr. Thomas Kaslow, Subcommittee Chair, reported that the next B&F Subcommittee meeting was scheduled for May 12 and would include review of a number of ISO financial reports.

Membership Subcommittee. Ms. Sarah Bresolin, Subcommittee Chair, reported that the next Membership Subcommittee meeting was scheduled for May 16.

ADMINISTRATIVE MATTERS

Looking ahead, Mr. Doot noted that the next Participants Committee was scheduled for June 2, 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 (June 21-23) at The Samoset Resort in Rockport, Maine. He encouraged members to pay attention to e-mails related to the Summer Meeting. Members were reminded to complete both a meeting and a hotel reservation and encouraged again to bring their families given the long hiatus since the last in-person Summer Meeting. - Mr. Doot also reminded the Committee of the need for each Sector to assemble an agenda and background materials for its meetings with the Board and State panels, encouraging members to spend time with their Sector Vice-Chairs to maximize the value of those meetings and to ensure that the meetings could proceed efficiently.

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

Respectfully submitted,

____
David Doot, Secretary

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN MAY 5, 2022 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Melissa Birchard (tel)		
Advanced Energy Economy (AEE)	Associate Non-Voting	Caitlin Marquis (tel)		
Algonquin Gas Transmission	Associate Non-Voting			Blair Hastey
Anbaric Development Partners LLC	Provisional Member		Theodore Paradise	
AR Large Renewable Gen. (RG) Group Member	AR-RG	Alex Worsley		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell (tel)		
AR Small Renew. Generation (RG) Group Member	AR-RG	Erik Abend (tel)		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
Associated Industries of Massachusetts (AIM)	End User			Mary Smith (tel)
AVANGRID: CMP/UI	Transmission	Alan Trotta (tel)	Jason Rauch (tel)	Alex Novicki (tel) Zach. Teti (tel)
Bath Iron Works Corporation	End User			Bill Short
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Borrego Solar Systems Inc.	AR-DG	Liz Delaney (tel)		
Boylston Municipal Light Department	Publicly Owned Entity		Brian Thomson	
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Brookfield Renewable Trading and Marketing LLC	Supplier	Aleks Mitreski		
Calpine Energy Services, LP	Supplier	Brett Kruse		Bill Fowler; Jung Suh; John Flumerfelt (tel)
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Central Rivers Power	AR-RG		Dan Allegretti	
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
CleaResult Consulting, Inc.	AR-DG	Tamera Oldfield (tel)		
Clearway Power Marketing LLC	Supplier			Pete Fuller
Competitive Energy Services, LLC	Supplier		Eben Perkins (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		Dave Thompson (tel)	
Conservation Law Foundation (CLF)	End User	Phelps Turner (tel)		
Consolidated Edison Energy, Inc.	Supplier	Grant Flagler (tel)		
Constellation Energy Generation	Supplier	Steve Kirk (tel)	Bill Fowler	
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
DTE Energy Trading, Inc.	Supplier			José Rotger
Durgin and Crowell Lumber Co.	End User			Bill Short
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		Bill Fowler
Emera Energy Services	Supplier			Bill Fowler
Enel X North America, Inc.	AR-LR	Michael Macrae		Alex Worsley
ENGIE Energy Marketing, LLC	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission		Dave Burnham	Vandan Divatia
Excelerate Energy LP	Associate Non-Voting	Gary Ritter (tel)		
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger		
Garland Manufacturing Company	End User			Bill Short
Generation Group Member	Generation		Abby Krich (tel)	Alex Worsley
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN MAY 5, 2022 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Granite Shore Power Companies	Generation			Bob Stein
Great River Hydro	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned Entity		Brian Thomson	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	Louis Guilbault (tel)	Bob Stein	
Hammond Lumber Company	End User			Bill Short
Harvard Dedicated Energy Limited	End User			Jason Frost
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		Brian Thomson	
Holyoke Gas & Electric Department	Publicly Owned Entity		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
InBalance, Inc.	Supplier		Ida Petajasoja (tel)	
Ipswich Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths (tel)	Nancy Chafetz (tel)	
Jupiter Power	Provisional Member			Ron Carrier
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 Lighting Company (LIPA)	Supplier		Bill Kilgoar (tel)	
Maine Power LLC	Supplier	Jeff Jones (tel)		
Maine Public Advocate’s Office	End User	Drew Landry (tel)		
Mansfield Municipal Electric Department	Publicly Owned Entity		Brian Thomson	
Maple Energy LLC	AR-LR			Doug Hurley (tel)
Marblehead Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Mass. Attorney General’s Office (MA AG)	End User	Tina Belew (tel)		
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Brian Thomson		
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		Rich Heidorn (tel)	
Moore Company	End User			Bill Short
National Grid	Transmission		Tim Martin	Dave Burnham
Natural Resources Defense Council (NRDC)	End User	Bruce Ho (tel)		
Nautilus Power, LLC	Generation	Dan Pierpont (tel)	Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski		Brian Forshaw (tel)
New Hampshire Office of Consumer Advocate	End User		Jason Frost	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson	Dan Dolan	
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
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	
Nylon Corporation of America	End User			Bill Short
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Peabody Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PowerOptions, Inc.	End User			Jason Frost

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN MAY 5, 2022 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Princeton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Brian Thomson	
Saint Anselm College	End User			Bill Short
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Brian Thomson	
South Hadley Electric Light Department	Publicly Owned Entity		Brian Thomson	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Brian Thomson	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Peter Fuller
Taunton Municipal Lighting Plant	Publicly Owned Entity	Devon Tremont (tel)	Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Texas Retail, LLC	Supplier		Jim Staggs (tel)	
The Energy Consortium	End User	Bob Espindola (tel)	Mary Smith (tel)	
Union of Concerned Scientists	End User		Francis Pullaro (tel)	
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny (tel)		
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corp. (VEIC)	AR-LR		Doug Hurley (tel)	
Vermont Public Power Supply Authority	Publicly Owned			Brian Forshaw (tel)
Versant Power	Transmission	Lisa Martin (tel)		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Vitol Inc.	Publicly Owned Entity	Joe Wadsworth (tel)		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Brian Thomson	
Walden Renewables Development LLC	Generation			Abby Krich (tel)
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	
Z-TECH, LLC	End User			Bill Short

ATTACHMENT 2

MAY 5, 2022 PARTICIPANTS COMMITTEE MEETING
VOTE TAKEN ON CPV PROPOSAL

TOTAL

Sector	Vote 1
GENERATION	16.70
TRANSMISSION	0.00
SUPPLIER	16.70
ALTERNATIVE RESOURCES	16.50
PUBLICLY OWNED ENTITY	0.00
END USER	14.84
PROVISIONAL MEMBERS	0.00
% IN FAVOR	**64.74**

GENERATION SECTOR

Participant Name	Vote 1
CPV Towantic, LLC	F
FirstLight Power Management, LLC	F
Generation Group Member	F
Granite Shore Power Companies	F
Nautilus Power, LLC	F
NextEra Energy Resources, LLC	F
Walden Renewables Development	A
IN FAVOR (F)	6
OPPOSED (O)	0
TOTAL VOTES	6
ABSTENTIONS (A)	1

TRANSMISSION SECTOR

Participant Name	Vote 1
Avangrid (CMP/UI)	A
Eversource Energy	O
National Grid	O
VELCO	A
Versant Power	A
IN FAVOR (F)	2
OPPOSED (O)	0
TOTAL VOTES	2
ABSTENTIONS (A)	3

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote 1
Renewable Generation Sub-Sector	
Central Rivers Power	F
ENGIE Energy Marketing NA, Inc.	F
Great River Hydro, LLC	F
Jericho Power LLC	F
Wheelabrator/Macquarie	F
Large RG Group Member	F
Distributed Gen. Sub-Sector	
Borrego Solar Systems Inc.	F
CLEAResult Consulting, Inc.	A
Sunrun Inc.	F
Load Response Sub-Sector	
Enel X North America, Inc.	F
Maple Energy	F
Vermont Energy Investment Corp.	F
Small LR Group Member	F
IN FAVOR (F)	12
OPPOSED (O)	0
TOTAL VOTES	12
ABSTENTIONS (A)	1

SUPPLIER SECTOR

Participant Name	Vote 1
BP Energy Company	A
Brookfield Renew. Trading & Mktg	F
Calpine Energy Services, LP	F
Castleton Comm. Merchant Trading	F
Clearway Power Marketing LLC	F
Competitive Energy Services, LLC	F
Consolidated Edison Energy Inc.	A
Constellation Energy Generation	F
Cross-Sound Cable Company	A
DTE Energy Trading, Inc.	A
Dynegy Marketing and Trade, LLC	F
Emera Energy Services Companies	F
Galt Power, Inc.	F
H.Q. Energy Services (U.S.) Inc.	F
InBalance, Inc.	A
LIPA	A
Maine Power, LLC	F
Mercuria Energy America, Inc.	A
NRG Power Marketing, LLC	F
Shell Energy North America (US)	F
Texas Retail, LLC	F
IN FAVOR (F)	14
OPPOSED (O)	0
TOTAL VOTES	14
ABSTENTIONS (A)	7

ATTACHMENT 2

MAY 5, 2022 PARTICIPANTS COMMITTEE MEETING
VOTE TAKEN ON CPV PROPOSAL

PUBLICLY OWNED ENTITY SECTOR

Participant Name	Vote 1
Belmont Municipal Light Dept.	A
Block Island Utility District	A
Braintree Electric Light Dept.	A
Chester Municipal Light Dept.	A
Concord Municipal Light Plant	A
Conn. Mun. Electric Energy Coop.	A
Danvers Electric Division	A
Georgetown Municipal Light Dept.	A
Groveland Electric Light Dept.	A
Hingham Municipal Lighting Plant	A
Littleton (MA) Electric Light Dept.	A
Littleton (NH) Water & Light Dept.	A
Mass. Bay Transportation Authority	A
Merrimac Municipal Light Dept.	A
Middleborough Gas and Elec. Dept.	A
Middleton Municipal Electric Dept.	A
New Hampshire Electric Cooperative	A
North Attleborough	A
Norwood Municipal Light Dept.	A
Pascoag Utility District	A
Reading Municipal Light Dept.	A
Rowley Municipal Lighting Plant	A
Stowe (VT) Electric Dept.	A
Taunton Municipal Lighting Plant	A
Village of Hyde Park (VT) Elec. Dept.	A
VT Electric Cooperative	A
VT Public Power Supply Authority	A
Wallingford, Town of	A
Wellesley Municipal Light Plant	A
Westfield Gas & Electric Light Dept.	A
IN FAVOR (F)	0
OPPOSED (O)	0
TOTAL VOTES	0
ABSTENTIONS (A)	30

END USER SECTOR

Participant Name	Vote 1
Acadia Center	F
Associated Industries of Mass.	F
Bath Iron Works Corporation	F
Conn. Office of Consumer Counsel	O
Conservation Law Foundation	F
Durgin and Crowell Lumber Co.	F
Elektrisola, Inc.	F
Garland Manufacturing Co.	F
Hammond Lumber Company	F
Harvard Dedicated Energy Limited	A
High Liner Foods (USA) Inc.	F
Maine Public Advocate Office	F
Mass. Attorney General's Office	O
Mintz, Samuel	A
Moore Company	F
Natural Resources Defense Council	F
New Hampshire OCA	A
Nylon Corporation of America	F
PowerOptions, Inc.	A
St. Anselm College	F
The Energy Consortium	F
Union of Concerned Scientists	--
Z-TECH, LLC	F
IN FAVOR (F)	16
OPPOSED (O)	2
TOTAL VOTES	18
ABSTENTIONS (A)	4

PROVISIONAL MEMBERS

Participant Name	Vote 1
Jupiter Power LLC	A
IN FAVOR (F)	0
OPPOSED (O)	0
TOTAL VOTES	0
ABSTENTIONS (A)	1

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PRELIMINARY

The 2022 Summer Meeting of the NEPOOL Participants Committee was held at The Samoset Resort, Rockport, Maine, on Tuesday, June 21, and Wednesday, June 22, pursuant to notice duly given, followed on Thursday, June 23, by meetings between modified Sector groups and ISO Board Members, state officials, and staff from the FERC’s Office of Energy Market Regulation (OEMR) respectively. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. All motions acted on at the meeting were voted on Tuesday, June 21. Attachment 1 identifies the members, alternates and temporary alternates attending the meeting and voting that day.

Mr. David Cavanaugh, Chair, presided and Mr. David Doot, Secretary, recorded for the meeting.

JUNE 21, 2022 SESSION

The June 21, 2022 session began at 9:30 a.m., with Mr. Cavanaugh welcoming the members, alternates, federal and state officials, ISO colleagues, including members of the ISO Board, and guests who were present. He invited Mr. Melvin Williams, recently elected to a first term as a Director on the ISO Board, to offer a few remarks to the Committee. Mr. Williams highlighted the impacts and lessons learned from his career in the U.S. N~~n~~avy (where he rose to be an admiral), government (including time as Deputy Secretary of Energy), and academia. He noted, in particular, the times that he had spent in New England, including an important stretch as a child in Groton, CT, where he benefitted from a first class education and first developed his commitment to the service of others. He thanked the Participants for the opportunity to come home and to serve with all those around the table in supporting New England and looked forward to meeting with Participants in the future.

CONSENT AGENDA

Mr. Cavanaugh referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting, which included four items unanimously recommended for Participants Committee support by the Technical Committees. Following motion duly made and seconded, the Consent Agenda was unanimously approved as circulated, with an abstention by Mr. Sam Mintz noted.

CONTINUOUS STORAGE FACILITY MARKET RULE REVISIONS

Ms. Mariah Winkler, Markets Committee (MC) Chair, referred the Committee to Tariff revisions, circulated and posted with the meeting materials in advance of the meeting, that would allow storage resources that inject energy into the grid but do not receive energy from the grid to register and operate as a Continuous Storage Facility. She reported that the MC recommended Participants Committee support for the revisions at its June 8, 2022 meeting and, but for the timing of the MC recommendation, this matter would have been on the Consent Agenda.

The following motion was duly made, seconded, and unanimously approved without discussion, with an abstention noted for Mr. Mintz:

> RESOLVED, that the Participants Committee supports the revisions to Section III.1.10.6 of the Tariff pertaining to storage resources operating as Continuous Storage Facilities, as recommended by the Markets Committee and as circulated in advance of this meeting, together with such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

ISO CEO REPORT

ISO Board and Board Committee Meeting Summaries

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the May 5, 2022 meeting, which had been circulated and posted in advance of the meeting, and invited questions. There were no questions or comments on those summaries.

Winter 2022-23

Noting that the summaries identified a Board Markets Committee discussion on winter reliability issues, and in light of requests received at the NECPUC Symposium that the ISO consider options to mitigate risks to reliability for Winter 2022-23, Mr. van Welie, together with Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), provided context and a summary of preliminary thoughts regarding potential options for incremental actions for Winter 2022-23.

Mr. van Welie summarized ISO actions already taken to bolster reliability, including the actions in 2018 to retain the Mystic Generating Station (Mystic) and thereby the Everett liquefied natural gas (LNG) terminal. He then noted two significant variables beyond the ISO's control – weather and the global fuels markets – and the fragility/uncertainty that those~~y~~ variables add to the re-supply chain specifically and reliability generally. Mr. van Welie reported that the ISO had not yet identified any cost-effective and impactful actions that could fully cover the risk presented by an unusually cold winter (like that experienced in 2013-14). However, in light of requests received during and following the NECPUC Symposium the month before, the ISO was gathering information and updating its data and cost information from recent, representative winters and programs to inform consideration of possible incremental actions that might mitigate reliability risks and/or costs. That consideration, which Mr. van Welie suggested needed to happen swiftly, would take place in July, and if and to the extent there would be any next steps (on which the ISO remained open to considering, but had not either taken a position or committed to), action on those steps would be taken in August.

In any case, Mr. van Welie said that the ISO would, as it had the year prior, forecast, report and evaluate the risk profile of the current winter period against three winter scenarios – an extreme (Winter 2013-14), a moderate but tight (Winter 2017-18), and a mild (Winter 2020-21) scenario. He hoped that the joint energy-security study on extreme winter weather being conducted with the Electric Power Research Institute (EPRI) would provide valuable input into further mitigating the region's winter reliability risk. He also noted the discussion that was planned for the FERC's September 8 technical conference to be held in Burlington, Vermont and the need to address the structural challenges that impede mitigating reliability risks, including possible exploration of cost-based, rather than market-based, ~~infrastructure~~ development of fuel infrastructure, as is being done with wholesale electric transmission.

Dr. Chadalavada then provided highlights from the winter readiness and replenishment information gathered to that point from large generating and storage (oil and LNG) assets. He estimated that the likely starting point for fuel storage for Winter 2022-23, when compared to the prior winter, would be similar if not better (with less fuel oil, but with more LNG on hand). Replenishment plans from oil asset owners, evaluated in the context of a non-extreme winter, raised minimal concerns.

Turning to the Analysis Group's update on the costs of previous winter programs, Dr. Chadalavada expected that the ISO would have, by the end of June, the cost data necessary to inform possible next steps, and which would be shared with Participants after the Fourth of July holiday and in advance of the July Markets Committee summer meeting. By way of example, he expected that, given the price of oil futures, the costs of any potential Winter 2022-23 program would be materially more than the costs of the last winter reliability program (Winter 2017-18). The update would also permit evaluation of the cost of potential technology-specific contributions via a design based on the Inventoried Energy Program (IEP) (as limited by the DC Circuit Court's order on ~~the Inventoried Energy Program (~~IEP~~)~~ the week before). He stated that Participants could expect benchmarking of winter readiness against a mild winter scenario.

The Committee then commented and asked questions. A member urged the ISO, should it decide to pursue a Winter 2022-23 reliability program, to distinguish between baseline and incremental fuel inventory compensation; Dr. Chadalavada noted the difficulty with that approach, but looked forward to further discussion on potential approaches to address those difficulties. Other members offered thoughts and asked clarifying questions on potential options and consequences for incremental actions for Winter 2022-23, with Dr. Chadalavada addressing how the ISO approaches and balances variables and considerations associated with those actions.

In response to questions on pricing and consumer conservation, Dr. Chadalavada indicated that, while the ISO had focused on wholesale supply-side issues and was operationally better prepared than previous winters, the ISO did not have tools for projecting prices, particularly given the challenges of the external global variables described earlier. Mr. van Welie elaborated on the advantages of, and need for, dynamic pricing at the retail level, as well as on wholesale market refinements implemented after Winter 2017-18 to enhance the early warnings that can be provided to the market when the system was facing potential adequacy shortfalls. Members again underscored some of the economic signals already available to the market and the difficult balancing between risk and reliability facing the ISO. Many expressed appreciation to the ISO for the information provided and their efforts in this area.

ISO COO REPORT

Operations Update

Dr. Chadalavada, whose June 2022 report had been circulated and posted earlier in the month, began by addressing a question on the Minimum Generation (Min Gen) Emergency declared by the ISO on May 21, 2022. He explained that the ISO went into May 21 with temperature forecasts for 90° F or above in all of New England's major load centers. However, due to an unusually cool weather front that moved through the region on the morning of the 21st, where actual morning temperatures did not exceed 75° F, loads were 1,800 MW lower than forecast. The lower loads left the ISO with more supply on the system than necessary, but without enough room to back down the unneeded generation, resulting in ~~the~~ a three-hour Min Gen event, including negative LMPs (-$150/MWh) for a few hours during the early afternoon.

In response to a question on the hardware malfunction experienced by the ISO on May 18, Dr. Chadalavada reported that the outage lasted for nearly 6 hours. The outage, caused by a faulty manufacturer's setting in ~~the~~ firewall software, did not impact the ISO's reliability functions, but did impact all of the ISO's market systems until the manufacturer was able to correct the setting defect. The ISO was working with the vendor to ensure better communications regarding defects discovered or needed patches going forward.

2022-2025 Roadmap to the Future Grid

Referring the Committee to materials circulated and posted in advance of the meeting, Dr. Chadalavada reviewed a projection of the major projects and associated timelines anticipated over the next four years to advance New England's grid transition. He identified and provided additional information on the projected projects, which were grouped generally into three categories – markets, transmission planning/operational, and IT initiatives.

With respect to the Markets initiatives, he noted projects underway, including the Future Grid Pathways process, Resource Capacity Accreditation, Day-Ahead Ancillary Services Improvements, and Storage Modeling Enhancements projects. He highlighted and described new projects, including an Energy Shortage Pricing Assessment, ongoing work to enhance the Forward Capacity Market (FCM), including Parameters for FCA21, Intertemporal Pricing and Optimization, and Replacement Reserve and Reserve Zone reforms.

Transmission Planning and operational initiatives included the 2050 Transmission Study, extended-term Transmission Planning, storage as Transmission-Only Asset (SATOA), the Future Grid Reliability Study (FGRS), and efforts related to the operational impacts of extreme weather, energy adequacy, and load, solar, and wind forecast improvements. IT initiatives identified in the report but not reviewed with the Committee included future grid models & simulators, next generation market (nGem) software implementation, cyber-security initiatives, Order 2222 implementation, and Energy Management System (EMS) modeling enhancements.

In response to comments and questions, Dr. Chadalavada provided additional detail related to the projects and explained how the project descriptions incorporate and might be refined to incorporate other various long-term efforts. He tied the initiatives to the 2023 budget presentation to follow. Members were also directed to the Appendices that identified work associated with known and anticipated FERC mandates, as well as a list of 2023 priority items that had been identified to date by the NEPOOL Sectors.

ISO CFO REPORT: 2023/2024 ISO PRELIMINARY BUDGETS

Mr. Robert Ludlow, the ISO’s Chief Financial Officer and Compliance Officer (CFO), referred the Committee to the presentation of the ISO’s 2023 and 2024 preliminary Operating and Capital Budgets (Budgets) included with the materials posted in advance of the meeting. He reported that he had also shared this information with New England state officials earlier in the month.

Mr. Ludlow discussed the following four key components that were driving changes to the 2023 and 2024 Operating Budget: (i) staffing additions (in markets development, information technology (IT), system planning, and participant support and external affairs and corporate communications); (ii) professional fees (including for studies supporting major market and reliability efforts); (iii) IT support (system maintenance, software licenses, data storage, and inflationary costs); and (iv) inflation impacting salaries and benefits. He projected that the 2023 Operating Budget would reflect an overall increase over 2022's Operating Budget of about 11%, to be largely offset, however, by a $15 million true-up from 2021 (a true-up resulting from a $3 million underspend and $12 million over-collection in 2021). The 2023 Capital Budget was projected to be $33.5 million, with increases being driven by upgrades to the core market software (nGEM), major market and reliability-related efforts, cyber security, and IT asset and infrastructure replacement.

In response to questions, Mr. Ludlow provided additional explanation regarding staffing increases and retention efforts, and the top-down estimates used to establish the preliminary budget numbers. He noted that the detailed budgets to be presented in August would include additional information supporting proposed headcount increases. He confirmed that the ISO had sufficient physical space to support the headcount increases. He also confirmed that the increase in the headcount for external affairs and corporate communications was designed to support enhanced regional educational and outreach efforts.

LITIGATION REPORT

Mr. Doot referred the Committee to the June 17 Litigation Report that had been circulated and posted in advance of the meeting. He highlighted the following developments: (i) FERC approval of regional plan for transforming the minimum offer price rule (MOPR), with requests for rehearing due on or before June 27, 2022; (ii) FERC extension to August 17 of the deadline for filing comments on the transmission Notice of Proposed Rulemaking (NOPR), with reply comments due by September 19; (iii) FERC Staff issuance of a deficiency letter in response to the proposal for addressing Order No. 2222, and the ISO's submission of a response to that letter on June 17; (iv) FERC notice of a forum to be held on September 8 in Burlington, Vermont~~T~~ to discuss winter operation plans; (v) the order of the U.S. Court of Appeals for the DC Circuit (the DC Circuit) vacating the FERC's approval of payments to nuclear, biomass, coal and hydro generators under the IEP~~nventoried Energy Program~~; (vi) FERC's issuance of the interconnection NOPR, which NEPOOL counsel proceeded to summarize briefly, referring members to the Reliability Committee for more detailed information; and (vi) the dismissal by the DC Circuit of the appeal by NTE challenging FERC's approval the termination of Killingly's Capacity Supply Obligation (CSO). He noted that the September Participants Committee, originally scheduled for September 8, was being rescheduled to September 1 in light of the FERC's scheduled forum. He encouraged anyone with questions on the status of relevant proceedings to contact NEPOOL Counsel.

COMMITTEE REPORTS

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that the next regularly-scheduled RC meeting was scheduled for July 19. The RC would receive another report on the EPRI/ISO-NE study of the impact of extreme weather on reliability.

Transmission Committee (TC). Mr. José Rotger, the TC Vice-Chair, reported that the next TC meeting was scheduled for June 28 and would include a discussion of the Interconnection NOPR, input on whether NEPOOL should file comments on the Transmission NOPR, the ISO's SATOA Tariff changes, and changes to the Attachment K economic study process (to implement a repeatable study framework).

Markets Committee. Mr. William Fowler, the MC Vice-Chair, reported that the MC would hold its 2022 summer meeting at Mills Falls at the Lake (Winnipesaukee) in Meredith, New Hampshire from July 12-14. The summer MC meeting was projected to have a full agenda, to include discussion on the Resource Capacity Accreditation project and, as discussed earlier in this meeting, whether and what incremental changes might be proposed for the Winter 2022-23 period. Those still seeking accommodations for that meeting were encouraged to reach out to Mr. Fowler or Ms. Winkler for recommendations.

Budget & Finance (B&F) Subcommittee. Mr. Thomas Kaslow reported that the B&F Subcommittee was scheduled to meet on July 22 to review NESCOE's preliminary (fourth) 5-year pro forma budget, and then twice in August, first on August 11 to review the ISO's proposed 2023 ~~Operating and Capital~~ Budgets and NESCOE's 2023 Annual Budget, and second on August 23 to receive its usual reports and address any proposed B&F-related Tariff issues.

Membership Subcommittee. Ms. Sarah Bresolin, Membership Subcommittee Chair, reported that the Subcommittee was next scheduled to meet on July 11 to consider any applications for membership that might be received.

ACKNOWLEDGEMENT - HERB HEALY

Mr. Doot announced that this would be Mr. Herb Healy's last Participants Committee meeting. Mr. Healy was retiring after more than a half century in the energy industry, nearly 40 years spent with United Technologies developing fuel cell projects, and another 15 supporting the demand response sector, including nearly 10 as a vice president for regulatory affairs for his son's company, EnerNOC. On behalf of the Committee, Mr. Doot acknowledged Mr. Healy's contributions to the region over the years (not the least of which was his penchant for probing questions at the Participants Committee) and the sentiment that he would be missed. Mr. Healy expressed his appreciation for those thoughts and for the long standing working and personal relationships developed over the years.

COMMENTS BY FERC OEMR STAFF

Mr. Cavanaugh welcomed, introduced and thanked Ms. Nicole Businelli and Mr. Noah Schlosser, co-leads for the ISO New England virtual team within the FERC's OEMR – East Division, for their attendance and participation. Ms. Businelli and Mr. Schlosser were focused on New England activities before the FERC, and grateful for the opportunity to put faces to New England's voices before the Commission.

Ms. Businelli began her comments by making clear that their remarks reflect their views and opinions, and not those of the Commission or any of the Commissioners. She provided a brief personal and professional background, describing OEMR's functions in general, their roles within OEMR specifically, and the relationship of OEMR to the other offices within the FERC.

Mr. Schlosser similarly provided a brief personal and professional background, noting his specialty in financial modeling (cost of capital and reactive power). He described the role of FERC's ISO New England virtual team (whose name pre-dated the pandemic), and acknowledged Eric Jacobi, a virtual team member based in the FERC's regional office in Massachusetts. He identified opportunities to interface with FERC staff, expanding on the role and purpose of the Commission's rules regarding *ex parte* communications.

In response to questions, Ms. Businelli identified pre-filing meetings as particularly helpful to getting their work done, both with filers and with parties who have specific positions on a future filing, either in support or opposition. Comments that develop a robust public record and make points substantiated by evidence in that record were also critically important. Mr. Schlosser acknowledged an appreciation for, and both agreed that there was little downside to, submissions with humor, resonance, or other features making the submission a bit livelier, though he emphasized that there was no substitute for substantiated record evidence given the review and necessary findings of the just and reasonableness of any proposal. In response to a question, Mr. Schlosser explained that the manner in which pleadings are reviewed and summarized by analysts was largely proceeding-specific, and varied from analyst to analyst. Ms. Businelli and Mr. Schlosser both encouraged all those communicating with the Commission to provide historic and contextual information relating to filings, and to present clearly their perspectives and perceived impacts of those filings on various regional groups.

EMM 2021 ANNUAL MARKETS REPORT

Overview

Dr. David Patton, President of Potomac Economics and the ISO's External Market Monitor (EMM), presented highlights from the EMM's 2021 Markets Report (EMM Annual Report), which had been circulated and posted in advance of the meeting. Dr. Patton introduced his presentation by noting that the EMM Annual Report complimented the report published by the ISO's Internal Market Monitor. He opined that the ISO's markets performed competitively in 2021 and that the EMM Annual Report included recommendations to improve the markets' performance.

Cross-Market Comparison

Referring to his presentation, Dr. Patton started by comparing the "all-in" energy prices across various markets, noting that energy prices nearly doubled since ~~last year~~2020, driven largely by higher natural gas prices. In New England, as he explained, energy prices rose in large part due to a 140% increase in average natural gas prices, while average load in the region rose by 2%. In addition, carbon pricing (e.g., the Regional Greenhouse Gas Initiative) increased supply costs in New England, contributing to the higher prices. Although New England's energy prices were greater than in most other regions, Dr. Patton noted that New England's energy prices were in line or lower than in regions with high transmission congestion, which wa~~i~~s not a material issue in New England.

Next, Dr. Patton addressed capacity prices. He explained that New England's capacity prices were generally higher than in other markets because, in part, the ISO's load forecast was too high. But as the ISO had~~s~~ adjusted the forecast downward, as shown in the most recent CELT (Capacity, Energy, Loads, and Transmission) Report (which showed a load forecast reduction of 5%), capacity prices had decreased to a $2 per kilowatt hour (kWh) range.

Dr. Patton then reviewed transmission congestion costs. With an average of less than $0.38 per megawatt hour (MWh), New England's transmission congestion costs were exceedingly small when compared to other regions. The EMM explained that New England's investment in transmission over the last decade mitigated congestion costs but had increased transmission rates to nearly $22 per MWh in 2021, which was higher than in any other market. He noted, however, that transmission rates in other markets were likely to increase due to upcoming and/or ongoing investment in transmission to incorporate intermittent resources. In response to comments and questions, Dr. Patton acknowledged that the region justified major transmission investment on the basis of reliability rather than congestion reduction and that the ISO was utilizing highly conservative assumptions in its calculation. He anticipated that other regions would likely see higher growth in transmission investments relative to New England as renewable resources increase. He also opined that allowing some transmission congestion to exist increased the incentives for wind developers to site those resources where they could minimize costs to consumers and that those incentives would be reduced if transmission costs were socialized.

Turning to virtual trading, Dr. Patton observed that virtual transactions (Increment Offers and/or Decrement Bids in the Day-Ahead Energy Market) in New England were much lower as a percentage of load than in other markets. He attributed this to the region's uplift cost allocation methodology. Dr. Patton again recommended that the ISO modify its methodology, noting that the upcoming Day-Ahead Ancillary Services improvements project could address his recommendation.

Out-of-Market Commitments and Operating Reserve Markets

Dr. Patton then discussed the O~~o~~perating R~~r~~eserve M~~m~~arkets, starting with the need for a T~~t~~en-M~~m~~inute S~~s~~pinning R~~r~~eserve product. As he explained, the Day-Ahead Market's constraint to satisfy the Ten- and Thirty-Minute Reserve requirements without corresponding market products resulted in the commitment of more resources Day-Ahead but not in the scheduling of those resources to provide Reserves in Real-Time. Consequently, market prices were depressed and Net Commitment Period Compensation (NCPC) costs increased. The EMM noted that, in 2021, out-of-market commitments occurred in nearly 3,400 hours to satisfy New England's Ten-Minute Spinning Reserve requirement, which accounted for 35% of Day-Ahead

NCPC. He also pointed out that the $2 per MWh average reserve value, as shown in his presentation, offered a sense of the magnitude that energy prices were depressed.

Dr. Patton then discussed Day-Ahead commitments for Local Second Contingency Protection. He highlighted that the NH-ME and NE West-to-East interfaces had seen the greatest number of out-of-market commitments for local needs in 2021, with the latter region creating the greatest distortion to the market. He explained that tho~~e~~se regions were not defined in the Real-Time markets and that the Reserve requirements were not priced in the Day-Ahead markets. Dr. Patton noted that pricing tho~~e~~se local needs in the Day-Ahead market could produce between $6 and $15 per kW-year of additional revenue for resources in th~~e~~ose local areas.

The EMM concluded this section of his presentation by recommending that the ISO introduce Operating Reserves in the Day-Ahead market and define local reserve zones when local second contingency issues appear, which would allow the ISO to dynamically introduce a local reserve requirement in the market.

Market Operations in January 2022

In the next section, Dr. Patton discussed the system’s performance during January 2022. He presented a table showing the average daily amount of oil-capable units (in terms of MW) that would have been economic to produce energy based on Day-Ahead and Real-Time clearing prices. Dr. Patton observed that, as oil became more economic due to the increased natural gas prices, oil-capable units became more economic. Yet, only 41% of economic oil-capable units used oil to generate electricity, while 27% of the economic oil-capable units chose to burn natural gas for reasons not related to maintaining inventory. Ultimately, Dr. Patton concluded that the market operated as expected during cold January days and that generators seemed to respond to price signals. Members questioned the calculations and discussed with Dr. Patton a number of reasons for running at a higher cost, in particular during hours for which the EMM might not have fully accounted (e.g., minimum take requirements for LNG, efforts to manage inventories, environmental constraints, or incentive to avoid mitigation). Overall, the EMM noted that he did not see any behavior from oil-capable generators that was inconsistent with the market signals. Dr. Patton stressed that this conclusion was important as winter reliability concerns increase.

Assessment of the Forward Capacity Market

Dr. Patton then reviewed various slides assessing the FCM. He began by discussing capacity accreditation, noting that the principles and recommendations applied to all resources. One such principle was that the amount of accredited capacity should reflect the benefit resources provide, measured on the basis of Loss of Load Expectation or Expected Unserved Energy, to resource adequacy, with the most valuable resources being those that are available when the risk of losing load is the highest. The EMM also urged the use of marginal ratings for calculating accreditation rather than the average approach, describing potential inaccuracies in valuing capacity for (1) intermittent resources as penetrations increase, (2) older, less flexible resources as needs come with less notice, (3) large resources, such as nuclear that is available most hours, and (4) pipeline gas-dependent resources.

Next, Dr. Patton discussed a chart depicting the 30 winter days with the highest peak loads from December 2017 to February 2022. The EMM interpreted the chart to indicate that, without LNG injection on certain days, there was not enough natural gas available in New England for all the gas-fired resources in the region to generate electricity. Dr. Patton explained that, during times of constrained gas availability, most of the gas piped into New England was used by gas utilities for their firm customers.

Discussion about the formation of the chart and conclusions that could be drawn followed. The EMM noted that overall availability of pipeline gas for electric generation would be heavily impacted by temperature, noting that there was a high correlation between electric load and gas demand. He acknowledged that the chart in the presentation only included LNG injections from the larger LNG facilities such as Canaport and Everett, and it did not track LNG from satellite facilities located in the region. Members observed that gas-only generators enter hedging transactions to cover expected needs regardless of whether it is pipeline or LNG, that LNG also helps maintain pressures in the pipeline to the benefit of all, and that generators seek to manage inventories and optimize value of their transactions.

Dr. Patton went on to discuss his recommendation to apply a marginal reliability methodology by comparing a pipeline gas resource's accredited capacity rating using two approaches. Specifically he summarized the EMM's calculations of the marginal reliability improvement (MRI) and average effective load carrying capability (ELCC) metrics at system criteria (i.e., without the current surplus) for pipeline gas resources during different seasons. He explained that the calculation of MRI values for gas-only resources not backed by LNG or pipeline capacity commitments declines rapidly during the winter at system criteria. The EMM calculated a 0% MRI value at system criteria during a winter when there are about 8 gigawatts (GW) of gas-only resources on the system. By way of comparison, Dr. Patton added that the MRI for solar approaches zero in the winter, but both of these types of resources have much higher MRI values in the summer. The EMM further explained that, as the reliability risk shifts from summer to winter, it becomes much more important to have marginal seasonal ratings with a seasonal prompt market for resources, which would encourage availability when those resources are most needed. The EMM acknowledged that the region would need also to change how it establishes regional capacity requirements. He re-emphasized that, based on this information, the importance of accrediting resources with a marginal methodology rather than an average one.

Discussion concerning the EMM's accreditation recommendations and modeling followed. In response to a question seeking his opinion as to whether there was a need for a potential future winter reliability program, Dr. Patton indicated he did not believe such a program was needed for Winter 2022-23 because Mystic remained in operation. When Mystic ceases to operate, however, Dr. Patton urged adopting market solutions such as a resource accreditation to allow resources to respond to market signals, which could reduce costs to consumers. In response to the EMM's comments, a member questioned whether the much higher prices for oil and LNG might alter that recommendation. Another member suggested that the planning model used in the future should account for the factors that drive the availability of generators, such as their location along the natural gas pipeline. The EMM explained in response to questions that its analysis was intended to show that a mechanism needs to be put in place to provide market incentives for an appropriate amount of gas-only generators to firm up their fuel supply for the winter.

FCM Improvements

Dr. Patton next transitioned to a discussion of his recommendations for improving the FCM. He opined that the region's FCM had not met its objective to coordinate new entry, especially now that a price lock-in mechanism no longer exists. Dr. Patton stated that requiring a resource that clears the auction to take on a CSO that begins three years later creates uncertainty for the resource. To support his observation, Dr. Patton showed statistics on the timeliness of commercial operation for new CSOs of at least 50 MW for the Capacity Commitment Periods beginning June 2016 through June 2022. Those statistics showed that less than half the resources entered service on time, with the remaining resources either late or cancelled altogether. He added his views that the FCM requires older resources to assess the likelihood that the resource will be operational three and a half years later when the new capacity year begins. That~~is~~ assessment create~~s~~d significant risk and may result in early retirements of economic resources.

Another concern of the EMM with the FCM was the difficulty in accrediting resources in light of forecast errors. Because the expected resource mix is a key assumption when accrediting resources, Dr. Patton opined that resources' marginal accreditation three and a half years later creates inaccuracies. Further, forecasting loads three years in advance also introduces more inaccuracies. To address these concerns, Dr. Patton recommended the region shift from a forward market to a prompt market along with making it seasonal. He did not have specific recommendations on the precise timing of the capacity auction for each prompt market delivery period, opining that it could be worked out to provide sufficient lead time needed for generators to plan to participate in a capacity auction. Responding to questions about the current market, Dr. Patton opined that transitioning to a sealed bid-auction would work for both the current FCM and a prompt market. He expressed concern that a move to increase financial assurance for new resources that are delayed could be counterproductive

Dr. Patton concluded his presentation with a slide referring to his list of recommendations, emphasizing that some of the recommendations were from prior reports and identified the prior report in which the recommendation was first made without repeating the supporting information from that prior report.

JUNE 22 SESSION

The Summer Meeting reconvened at 9:10 a.m. on June 22, 2022.

WELCOME REMARKS BY PHIL BARTLETT

Mr. Cavanaugh welcomed members and guests back to the meeting and introduced Maine Public Utilities Commission Chair Philip Bartlett for welcoming remarks. Chair Bartlett welcomed all to Maine and expressed appreciation for the opportunity to meet in person with members and colleagues on the very challenging issues facing the region. He urged active participation in the meetings and encouraged attendees to enjoy Maine and support the Maine businesses in the area.

RESOLUTION OF APPRECIATION FOR FORMER CHAIR NANCY CHAFETZ

At the request of the Chair, Mr. Doot introduced the following resolution of appreciation, which was approved by acclamation, for the services of Nancy Chafetz during her two years as Chair of the Participants Committee:

RESOLUTION OF APPRECIATION

Nancy P. Chafetz

WHEREAS, Ms. Nancy P. Chafetz was elected Chair of the New England Power Pool (NEPOOL) Participants Committee for, and led NEPOOL during, 2019 and 2020, following five years serving as the elected Vice-Chair of the Supplier Sector and many more years (and questions to the ISO COO) as a NEPOOL representative and thought leader; and

WHEREAS, Nancy has been an unwavering advocate for NEPOOL’s role in influencing and guiding the trajectory of New England’s competitive wholesale power markets and its operations by working collaboratively and collegially with members, state and federal officials, and ISO colleagues; and

WHEREAS, Nancy' guided the operation of the NEPOOL Participants Committee through the unprecedented COVID-19 pandemic, seamlessly maintaining NEPOOL work and priorities through virtual meetings; and

WHEREAS, Nancy's leadership and her hallmark thoroughness, compassion, and warm and graceful style have deftly advanced NEPOOL's mission and the interests of the many Participants she has represented through the years; and

WHEREAS, Nancy has left an indelible mark on the Pool, not only through her participation and leadership, but in the adoption of a newly-charged NEPOOL logo and website.

NOW, THEREFORE, the Participants Committee of the New England Power Pool, on behalf of the NEPOOL Participants, hereby expresses its sincere appreciation to Nancy for her service as its Chair and for her leadership and dedication to moving New England forward, together, first and foremost through the NEPOOL stakeholder process.

REMARKS OF FERC COMMISSIONER MARK CHRISTIE

Mr. Cavanaugh welcomed and introduced FERC Commissioner Mark Christie, summarizing his background and service on the Commission. Commissioner Christie expressed his appreciation for the invitation to participate in the meeting, describing his time in and appreciation for this part of Maine.

Commissioner Christie concentrated his remarks on the Transmission NOPR that had recently been issued by the FERC. He emphasized that the NOPR did not apply to reliability or economic transmission projects. Rather, it applied specifically and narrowly to regional public policy projects, where the States have primacy in deciding on the projects and cost allocation. He emphasized his view that, while the projects are regional and subject to FERC jurisdiction, the NOPR requirements would be satisfied for public policy requirements if states agree on cost allocation. He sought comments from interested parties on how best to handle cost allocation for public power and cooperatives, encouraging state regulators to reach out to address cost allocation issues. He emphasized that, from his viewpoint, the NOPR was drafted with maximum flexibility for the states. He described his respect for and recognition of the states' knowledge of what works best for them and his inclination to defer to that knowledge and expertise. In response to questions, he expressed his preference for maximum flexibility in the final proposed rule for states to decide what works best for their region for public policy projects.

Pivoting slightly from discussion of the Transmission NOPR, he referred to the recent interconnection queue reform NOPR and underscored his respect for regional variation. He emphasized the number of times that he saw the role of regulators to first do no harm. Further, he re-emphasized his view that states should be the final arbiter on how planning for public policy projects are to be determined and handled. He looked to the states also as best equipped to ensure cost containment for transmission projects and opined that the states retain ultimate responsibility for assuring resource adequacy for their own states. He expressed his view that the FERC should ensure that states receive from the RTOs all of the information they need to perform their job in assessing need for and prudence of expenditures. He received a suggestion from a member to ensure competition for new projects.

Following further discussion, Mr. Cavanaugh thanked Commissioner Christie for his comments and time, and invited him to join NEPOOL at future meetings, either in person or virtually, if desired.

PANEL DISCUSSION WITH NEW ENGLAND STATE OFFICIALS ON FUTURE GRID PATHWAYS

Mr. Cavanaugh then introduced the following New England state (States) officials for a panel discussion of the various pathways being considered within the region to support New England's clean energy transition: Vermont (VT) Public Service Commissioner June Tierney; Massachusetts (MA) Department of Public Utilities (MA DPU) Chair Matthew Nelson; Maine

Public Utilities Commission Chair Philip Bartlett; MA Department of Energy Resources (MA DOER) Commissioner Patrick Woodcock; New Hampshire Department of Energy ~~Public Utilities Commission~~ (NHDOE~~PUC~~) staff member Dan Phelan; and Connecticut Public Utilities Regulatory Authority (CT PURA) staff member Eric Annes. Mr. Cavanaugh summarized the Future Grid Pathways process followed to date and then turned to each panelist to comment on the ISO-commissioned Analysis Group Study Report that had quantitatively assessed four potential pathways: status quo, a forward clean energy market (FCEM), net carbon pricing, and a hybrid approach.

The state officials generally agreed that while status quo was certainly implementable into the future, it was not the most desirable pathway forward as it would likely impose increased costs on consumers in the region. One of the state panelists opined that sticking with status quo also would take longer than acceptable to achieve desired outcomes and would endanger the current markets. While not necessarily expressing a clear preference for one pathway over the other, there was general support among the state panelists for further exploration and consideration of a form of FCEM. Certain of the state officials explained that a carbon pricing adder was not a politically feasible alternative at that time. The CT PURA representative, though, indicated support for further consideration of a hybrid approach, indicating that current higher fuel prices could conceivably result in a net-carbon price at or near zero. VT's Commissioner also agreed that she could conceptually support a hybrid approach if the governance issues could be worked out to the satisfaction of all the States.

On the subject of governance, the panelists spoke about a governance framework that would provide greater involvement and oversight by the States while protecting their sovereign roles. Some panelists opined that in order to promote and maintain the stability and sustainability of a new market construct, the governance structure/process utilized would benefit from a certain amount of insulation from political pressures at both the state and federal levels. That opinion was not uniform, with VT's Commissioner noting that politics necessarily must be respected and the MA DPU Chair noting that stability for investments, not necessarily political insulation, was the desired outcome in order to ensure least cost to consumers. Representatives from MA and VT both expressed the view that a priority for the States, through the NESCOE managers or NECPUC, was to arrive at a consensus on governance issues.

Focusing on next steps, the MA officials indicated that they planned to identify additional details that they would find acceptable and workable and to work to educate state and regional policy makers on the need for market reform. Other of the state officials expressed the need for more input from market participants on what they would find effective and help to communicate the expected benefits of an alternative market mechanism to the public.

In response to follow on questions, some of the state officials acknowledged the potential need to rely on certain existing generation for transition purposes, with markets that support directionally the goals of the states. They expressed the need to ensure transparent and honest discussions about what resources are required for reliability while moving toward increased carbon-free resources. One of the panelists also expressed the need for other active market improvement efforts, such as capacity accreditation and improved Ancillary Service Markets, to remain on track.

In response to questions as to whether there is any way to overcome the political impasse over carbon pricing, panelists explained that they were simply unable in their respective roles to change support for a carbon adder without far more efforts from the industry to build political support. Voters and elected officials needed to be educated and willing to support carbon pricing.

Although there remained strong political support within some of the S~~s~~tates for advancing long-term contracting options, the panelists concluded generally in response to questions that alternative pathways/market reforms were preferable to help achieve State policy objectives/mandates over the longer term.

There being no other business, the June 22 session ended at 11:55 a.m., with the following day set for Sector meetings beginning at 8:00 a.m.

Respectfully submitted,

David T. Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
JUNE 21-23, 2022 SUMMER MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Melissa Birchard (tel)		
Advanced Energy Economy (AEE)	Associate Non-Voting	Caitlin Marquis		
Ampersand Energy Partners	Supplier			Hannah Braun (tel)
AR Large Renewable Gen. (RG) Group Member	AR-RG	Alex Worsley		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell (tel)		
AR Small Renew. Generation (RG) Group Member	AR-RG	Erik Abend (tel)		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matt Ide	
Associated Industries of Massachusetts (AIM)	End User			Mary Smith (tel)
AVANGRID: CMP/UI	Transmission	Alan Trotta	Jason Rauch	Zach Teti (tel)
Bath Iron Works Corporation	End User			Bill Short; Gus Fromuth
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Borrego Solar Systems Inc.	AR-DG	Liz Delaney		
Boylston Municipal Light Department	Publicly Owned Entity		Matt Ide	
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Calpine Energy Services, LP	Supplier	Brett Kruse	Brett Howell	Bill Fowler; John Flumerfelt
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Central Rivers Power	AR-RG		Dan Allegretti	
Centrica Business Solutions Optimize, LLC	AR-LR		Aaron Breidenbaugh (tel)	
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
Clearway Power Marketing LLC	Supplier		Dan Hendrick	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		Dave Thompson	
Conservation Law Foundation (CLF)	End User		Priya Gandbnir (tel)	
Constellation Energy Generation	Supplier	Steve Kirk (tel)	Bill Fowler	
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dominion Energy Generation Marketing	Generation	Mike Purdie		
DTE Energy Trading, Inc.	Supplier			José Rotger
Durgin and Crowell Lumber Co., Inc.	End User			Bill Short; Gus Fromuth
Dynegy Marketing and Trade, LLC	Supplier		Andy Weinstein	Arnie Quinn; Bill Fowler
Elektrisola, Inc.	End User		Gus Fromuth	Bill Short
Emera Energy Services	Supplier			Bill Fowler
Enel X North America, Inc.	AR-LR		Greg Geller	
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission		Dave Burnham	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger		
Garland Manufacturing Company	End User			Bill Short
Generation Group Member	Generation		Abby Krich	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Granite Shore Power Companies	Generation			Bob Stein
Great River Hydro	AR-RG			Bill Fowler

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN JUNE 21-23, 2022 SUMMER MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Groton Electric Light Department	Publicly Owned Entity		Matt Ide	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	Louis Guilbault (tel)	Bob Stein	
Hammond Lumber Company	End User			Bill Short
Harvard Dedicated Energy Limited	End User			Jason Frost
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	
Holyoke Gas & Electric Department	Publicly Owned Entity		Matt Ide	
Hull Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
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	
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths	Nancy Chafetz	
Jupiter Power	Provisional Member		Hans Detweiler	Ron Carrier
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned Entity		Craig Kieny	
Long Island Power Authority (LIPA)	Supplier	Bill Kilgoar (tel)		
Maine Power LLC	Supplier	Jeff Jones		
Maine Public Advocate's Office	End User	Drew Landry		
Maine Skiing, Inc.	End User	Dan Collins		
Mansfield Municipal Electric Department	Publicly Owned Entity		Matt Ide	
Maple Energy LLC	AR-LR			Doug Hurley
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide	
Mass. Attorney General's Office (MA AG)	End User	Tina Belew		
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide		
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, Samuel	End User	Sam Mintz		
Moore Company	End User			Bill Short; Gus Fromuth
Morgan Stanley Capital Group, Inc.	Supplier	Jennifer Harding		
Onward Energy (Blue Sky West LLC)	AR-RG		Katie Bellezza	
Narragansett Electric Company	Transmission		Brian Thomson	
National Grid	Transmission	Tim Brennan	Tim Martin	
Nautilus Power, LLC	Generation	Dan Pierpont	Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski (tel)		Brian Forshaw; Dave Cavanaugh
New Hampshire Office of Consumer Advocate	End User			Jason Frost
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson	Dan Dolan	
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
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; Gus Fromuth
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		Matt Ide	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN JUNE 21-23, 2022 SUMMER MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Peabody Municipal Light Department	Publicly Owned Entity		Matt Ide	
Princeton Municipal Light Department	Publicly Owned Entity		Matt Ide	
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Matt Ide	
Saint Anselm	End User	Gus Fromuth		Bill Short
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matt Ide	
South Hadley Electric Light Department	Publicly Owned Entity		Matt Ide	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Matt Ide	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG	Chris Rauscher		Peter Fuller (tel)
Taunton Municipal Lighting Plant	Publicly Owned Entity	Devon Tremont	Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
Tenaska Power Services Co.	Supplier		Eric Stallings	
The Energy Consortium	End User		Mary Smith (tel)	
Union of Concerned Scientists	End User		Francis Pullaro	
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny		
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw
Versant Power	Transmission	Lisa Martin	Dave Norman	
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide	
Walden Renewables Development LLC	Generation			Abby Krich
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	Jim Ginnetti (tel)
Z-TECH LLC	End User		Gus Fromuth	Bill Short

CONSENT AGENDA

Reliability Committee (RC)

From the previously-circulated notice of actions of the RC's July 19, 2022 meeting, dated July 20, 2022.[1]

1. Changes to OP-12 Appendix D (Periodic Updates)

Support the revisions to ISO New England Operating Procedure (OP) No. 12 (Voltage and Reactive Control) Appendix D (Voltage Schedule Annual Transmittal Form), including for the Option A & B tasks modifications to question 3 and the addition of a "High Side Visibility" title to the voltage table, as recommended by the RC at its July 19, 2022 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

2. Changes to OP-16 and OP-16 Appendices A-C and G-I (Periodic Updates – Ratings Requirements Clarifications; One-Line Diagram Requirements Clarifications and Submission Schedule Modifications)

Support the revisions to OP-16 (Transmission System Data) and OP-16 Appendices A-C and G-I to (i) add references to NERC Standards IRO-010 and TOP-003; (ii) add additional facility rating requirements; (iii) modify reference to ISO-NE Compliance Bulletin – MOD-032; (iv) modify the one-line diagram requirements for New Generating Facilities; (v) update the submission schedule for one-line diagrams; and (vi) clarify generator equipment requirements, all as recommended by the RC at its July 19, 2022 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was unanimously approved.

Markets Committee (MC)

From the previously-circulated notice of actions of the MC's July 12-14, 2022 summer meeting, dated July 15, 2022.[2]

3. Changes to Tariff § III.13.2.4 (FCM Parameters Recalculation Schedule Modification)

Support the revisions to Market Rule 1 Section III.13.2.4 to defer recalculation of the Cost of New Entry (CONE), Net CONE, and the Performance Payment Rate (PPR, and together with CONE and Net CONE, the FCM Parameters), until Forward Capacity Auction 21 for the Capacity Commitment Period beginning on June 1, 2030, and thereafter to recalculate the FCM parameters no less often than once every four years, as recommended by the MC at its July 12-14, 2022 summer meeting, together with such further non-material changes as the Chair and Vice-Chair of the MC may approve.

The motion to recommend Participants Committee support was unanimously approved, with abstentions noted (6 in the Supplier Sector; 2 in each of the AR and End User Sectors).

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

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

Summary of ISO New England Board and Committee Meetings

August 4, 2022 Participants Committee Meeting

Since the last update, the Compensation and Human Resources Committee and the Markets Committee met on June 20. The System Planning and Reliability Committee and the Information Technology and Cyber Security Committee met on June 21, and the Nominating and Governance Committee and the Board of Directors met on June 22. The meetings were held in Rockport, Maine. In addition, the Markets Committee met virtually on July 7.

The Compensation and Human Resources Committee. The Committee discussed the 2023 medical benefit program for employees, and preliminary survey data regarding compensation budgets at other employers. The Committee also reviewed best practices around the use of employment contracts, and concurred with the decision made in approximately 2008 to discontinue the use of employment contracts for executives and instead rely on Company policies. The Committee received updates on Department of Labor reporting requirements regarding the Company's benefits plans and the funding of annual performance incentives. Regarding Board compensation, the Committee reviewed current practices related to board of directors meeting fees and virtual participation at meetings. The Committee then reviewed the Committee's charter for compliance, and conducted its annual assessment of the risks within the Committee's purview. Finally, the Committee met in executive session to review the Company's succession plans for management and discuss the results of its self-evaluation.

The Markets Committee, at its June meeting, continued a discussion of the External Market Monitor's draft annual markets report from its previous meeting, and received an update on reliability issues for the 2022-2023 winter. The Committee also received a summary of FERC's recent order directing ISOs and RTOs to report on modernizing wholesale electricity market design and the Company's plans for compliance. In executive session, the Committee discussed the External Market Monitor's contract and reviewed the results of its self-evaluation. At its July meeting, the Committee discussed an operational analysis of winter 2022/23 and potential reliability issues.

The System Planning and Reliability Committee received several updates on regional planning activities, the results of the sixteenth Forward Capacity Auction, economic and special study requests, long-term transmission planning, and planned activities for the second half of 2022. The Committee also received updates on the system operations outlook for summer 2022. The Committee reviewed compliance with its charter, and received a summary of FERC's proposed rulemaking on transmission planning and cost allocation reforms and the Company's plans for compliance therewith. The Committee also discussed plans to discuss energy adequacy with a working group of the Board and states. During executive session, the Committee reviewed the results of its self-evaluation.

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 various projects. The Committee also received an update on the Company's three-year IT infrastructure work plan, and an overview of the Next Generation Electricity Market (nGEM) project, noting that Phase 1 implementation has been completed and that development for Phase 2 is on schedule. Next, the Committee considered topics for discussion at the annual cyber security "deep dive" for the full board in September and agreed to focus on a ransomware update, effects of the Ukraine conflict, and a report on the Company's May 18 IT outage. The Committee discussed the annual risk review of the Company's key IT vendors, observing that only one key vendor has been identified as high risk. The Committee and management discussed contingency plans should the vendor cease to provide services. The Committee received a summary of the Company's IT and cyber security staffing resource requirements, and then discussed the IT outage on May 18, which affected the Company's market and enterprise systems, and the development of a solution to prevent such a recurrence.

The Nominating and Governance Committee discussed the attendance of director-elect Melvin Williams at upcoming board meetings as orientation. The Committee then discussed Board leadership, state liaison and committee assignments, and adopted a recommendation to present to the full Board in September. The Committee reviewed a proposed work plan regarding diversity, equity and inclusion on the Board, and noted that its goal is to achieve a diversity of experience on the Board. The Committee also reviewed topics for an annual corporate governance review and agreed to use the opportunity to organize a facilitated evaluation of the Board and the committees and work on resulting governance recommendations. Next, the Committee received an update on plans for the 2022 open board meeting in November. The Committee also received updates on communications issues and states' activities.

The Board of Directors received a report from the CEO with updates on winter reliability issues and progress toward corporate goals. The Board prepared for its meetings with the NEPOOL sectors and reviewed the discussion topics that were submitted in advance by the sectors. The Board then continued its discussion of the Company's strategic plan. As part of that discussion, the Board agreed on the following resolution, as requested by the states, to document the Board's continuing commitment to review the cost impacts of significant ISO proposals:

> WHEREAS, the ISO New England Board of Directors continues to believe that consumer costs are a critical consideration in assessing the wholesale electricity market, transmission projects, and operations initiatives within the ISO's scope of responsibility; and
>
> WHEREAS, this consciousness of consumer costs is part of the ISO's culture, as reflected in the ISO's mission, which includes the commitment to perform its services in a cost-effective manner and to provide quantitative and qualitative analysis on the costs of major regional initiatives; and
>
> WHEREAS, the ISO Board recognizes that execution of the ISO's responsibilities for the wholesale markets, bulk power system operations, and transmission planning affects a portion of retail rates; and
>
> WHEREAS, the ISO Board seeks to ensure that consumer costs continue to be meaningfully considered as ISO New England provides the regional with reliable, competitively priced wholesale electricity today and in the future;
>
> NOW, THEREFORE,
>
> BE IT
>
> RESOLVED, that the ISO New England Board of Directors is committed to continuing its practice of considering the cost impacts on New England's consumers of significant wholesale market, transmission planning, and operations initiatives, including proposals to enhance the ISO's wholesale markets and operations or that are identified through the ISO's transmission planning process; and
>
> FURTHER RESOLVED, that the ISO New England Board of Directors will provide information regarding the Board's consideration of those cost impacts in public communications.

The Board also received reports from the standing committees. During the Nominating and Governance Committee report, the Board considered a stakeholder's suggestion to seek a change in the Board's age limit. The Board also reviewed the Company's Form 990 for 2021 to be filed with the Internal Revenue Service. During executive session, the Board discussed the results of its self-evaluation, among other topics.

July 27, 2022

The Honorable Jennifer Granholm
U.S. Department of Energy
1000 Independence Ave., SW
Washington, DC 20585

Dear Secretary Granholm,

We are writing you regarding the high and volatile global energy prices and specific implications in New England for this coming winter.

The Russian invasion of Ukraine has exacerbated the pricing of nearly all energy commodities which is directly impacting energy consumers in our respective states. The increase in global liquified natural gas (LNG) pricing has been particularly acute - while global petroleum prices increased by 50 percent over the last year, global LNG prices have increased by almost 300 percent. During winter months, when domestic natural gas capacity is constrained, New England relies on imported LNG to meet demand for both electricity generation and thermal usage. The region has invested in energy efficiency and pursued a variety of clean energy projects such as offshore wind and hydroelectricity that will reduce the region's reliance on LNG imported into New England. Some of these critical projects will not be in place for this upcoming winter. As a result, the anticipated pricing will have significant implications for our region's electric and natural gas customers and raises reliability concerns if the region suffers a severe winter.

We would request some immediate steps to mitigate the current energy situation.

- **Fuel Supplies to New England.** We appreciate that the Biden Administration has been working with European allies to expand fuel exports to Europe. A similar effort should be made for New England. The Jones Act, which restricts the types of ships that may transport products between US ports, effectively precludes all US exported LNG from being delivered into New England. The insecurity of global natural gas markets in 2022 exacerbates the long-standing ramifications of the restriction and undermines reliability. We request that the Biden Administration work with the New England states to alleviate the unique fuel challenges that the region faces, including beginning to explore the conditions under which it might be appropriate to suspend the Jones Act for the delivery of LNG for a portion or all of the winter of 2022-2023.
- **Strategic Energy Reserve.** Our region has long recognized that extreme winter events could strain our energy supplies and the Department of Energy (DOE) manages the

regional Northeast Home Heating Oil Reserve that could be used if heating oil supplies are severely disrupted. Since the reserve was established in 2000 the region has had a significant increase in natural gas consumption and the forecast is that electric load will significantly increase, especially in the winter months. Given this, our energy reserve system needs to be modernized given the rapidly changing resource mix in New England. As a result, we request that the DOE support the New England states in assessing how these reserves may be utilized this winter and consider the development of a new or modernized strategic energy reserve to protect against low probability weather events to ensure energy system reliability.

- **Coordination.** Finally, we request that the federal government and the New England states commence coordinating immediately to monitor the developments as winter approaches. While New England has existing programs to support system reliability, the combination of the Russian invasion with a severe cold winter would strain the reliability of the system. Further, the New England states are facing high energy prices and we must work across the federal government to address the funding needed to support our energy consumers. We should commence these discussions without delay.

While our immediate focus is on this upcoming winter, the ramifications of Russia’s invasion and the realignment of natural gas supplies will have long-term global consequences and could have adverse impacts in New England. While our region has been building an energy strategy to reduce our reliance on imported fuels, we must accelerate those efforts. We would like to work with you on expanding on this energy strategy and building the critical infrastructure to support the plan.

Thank you for consideration of these requests.

Sincerely,

Charles Baker

Charles D. Baker
Governor
State of Massachusetts

Ned Lamont

Ned Lamont
Governor
State of Connecticut

Janet T. Mills
Governor
State of Maine

Christopher T. Sununu

Christopher T. Sununu
Governor
State of New Hampshire

Daniel McKee

Daniel J. McKee
Governor
State of Rhode Island

Phil Scott

Philip B. Scott
Governor
State of Vermont

CC: Secretary Buttigieg
New England Congressional Delegation
Gordon van Welie, President and Chief Executive Officer of ISO New England Inc.

NESCOE
New England States Committee on Electricity

To: ISO New England
From: NESCOE
Date: August 3, 2022
Subject: Winter 2022/23 Analysis and Recommendation

Winter reliability has been a persistent concern in New England. Over the past decade, ISO New England (ISO-NE) has periodically recommended incremental actions to shore up winter reliability, including "winter programs" designed to secure fuel needed for electric generation and an out-of-market agreement with two generation facilities. Last fall, ISO-NE elevated its concern about keeping the lights on when temperatures drop, which led to robust communications.[1] This summer, state officials and others asked ISO-NE for analysis and its recommendation as to whether New England needed to take incremental action such as a winter reliability program, as it has in the past. In mid-July 2022, ISO-NE shared its analysis and recommended that New England not pursue a winter program for winter 2022/2023.[2]

First, NESCOE thanks ISO-NE for its analysis and recommendation. It has helped states and stakeholders assess the winter outlook and tradeoffs of possible additional action. We also appreciate your willingness to reevaluate options to address reliability within your authority, such as a winter or inventoried energy program. As ISO-NE is responsible for ensuring the reliable operation of the regional electric power system, we give significant weight to your reliability-related recommendations. For this winter, absent new information you bring to light, we plan to respect ISO-NE's conclusion that interventions such as those New England has taken heading into past winters are not needed or helpful to shore up system reliability this coming winter.

Second, we encourage you to share the confidential data that drove your recommendation with FERC prior to its *New England Gas-Electric Forum* on September 8, 2022.[3] As the reliability coordinator, you have access to information about fuel supplies, resource availability, historical resource performance, and overall system conditions that we do not. We understand that your recommendation for this winter rests in part on your confidence in your assumptions about oil and LNG availability over the coming months, which are based on both economic expectations grounded in historical actions and information not available to us or other stakeholders. Sharing your analysis and the confidential information behind your fuel supply assumptions and recommendation with FERC would behelpful and appropriate given FERC's regulatory role,

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[1] *See, e.g.*, Letter from NESCOE to ISO New England, Jan. 18, 2022, at https://bit.ly/3yQL3a5.

[2] ISO-NE, Winter 2022/23 Analysis: Assessment and Recommendations, July 14, 2022, at https://www.iso-ne.com/static-assets/documents/2022/07/a09_mc_2022_07_12-14_winter_2022_2023_presentation.pptx.

[3] *See*, Supplement Notice of New England Winter Gas-Electric Forum, Docket No. AD22-9-000 (July 21, 2022), at https://www.ferc.gov/media/supplemental-notice-new-england-winter-gas-electric-forum.

ability to receive and protect confidential information, and expressed interest in discussing New England's winter 2022/2023 outlook.[4]

We remain very concerned that the long-known, significant structural issues contributing to winter reliability challenges remain unresolved. Winters with a string of below-average cold weather days are not unusual in New England. Our region should have confidence each season that our system will ensure that the lights will stay on. We appreciate continued open communications with states on solutions to regional issues. To the extent ISO-NE has concerns about keeping the lights on in future winters, we encourage you to share as much information and analysis with states, stakeholders, and FERC as early in the year as possible.

With appreciation for your analysis and recommendation for winter 2022/2023, we look forward to continuing work on the way forward to resolve reliability challenges in the near- and longer-term.

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[4] *See id.* at *Panel 2: Concerns for Winter 2022/23 and Future Winters.*

NEPOOL Participants Committee Report

August 2022

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Highlights

Data is through July 27th unless otherwise noted.

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: June 2022 Energy Market value totaled $741M
  - July 2022 Energy market value was $1.1B, up $380M from June 2022 and up $658M from July 2021
    - July 2022 natural gas prices over the period were 4.1% lower than June average values
    - Average RT Hub Locational Marginal Prices ($89.06/MWh) over the period were 24% higher than June averages
      - DA Hub: $89.42/MWh
    - Average July 2022 natural gas prices and RT Hub LMPs over the period were up 117% and up 149%, respectively, from July 2021 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 98.9% during July, up from 97% during June*
    - The minimum value for the month was 95% on Thursday, July 14th

Underlying natural gas data furnished by:

ICE Global markets in clear view

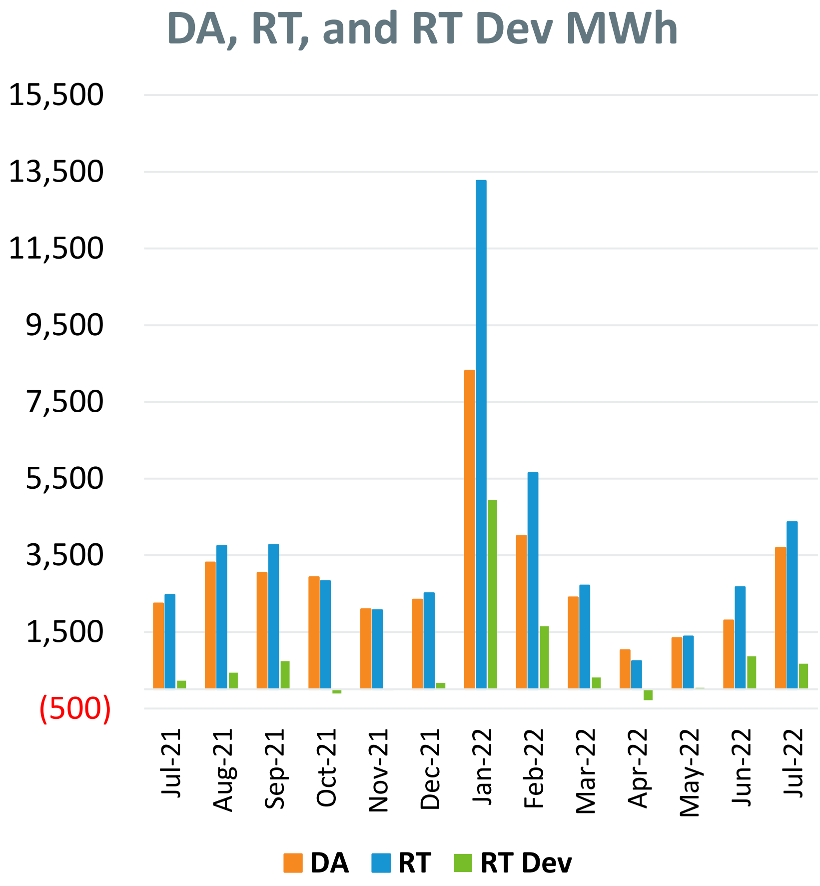
*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

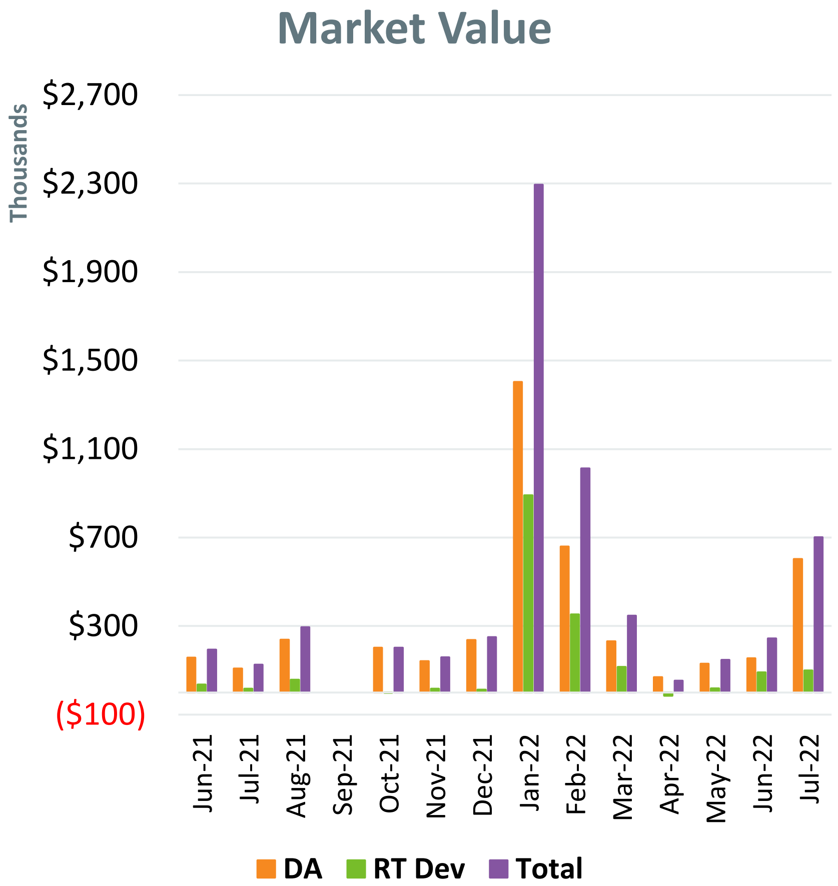
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - July 2022 NCPC payments totaled $8M over the period, up $5.1M from June 2022 and up $4.3M from July 2021
    - First Contingency payments totaled $7.3M, up $4.3M from June
      - $6.6M paid to internal resources, up $4.1M from June
        - » $1.0M charged to DALO, $3.9M to RT Deviations, $1.8M to RTLO*
      - $551K paid to resources at external locations, up $86K from June
        - » $481K charged to DALO at external locations, $70K to RT Deviations
    - Second Contingency payments totaled $249K, up $222K from June
    - Distribution payments totaled $495K, up $495K from June
    - Voltage payments were zero
  - NCPC payments over the period as percent of Energy Market value were 0.7%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $610K; Rapid Response Pricing (RRP) Opportunity Cost - $1.2M; Posturing - $0K; Generator Performance Auditing (GPA) - $0K**

Price Responsive Demand (PRD) Energy Market Activity by Month





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

Highlights

- Discussions on the second phase of the 2050 Transmission Study are expected to begin at the NEPOOL committees in late 2022/early 2023
- 2021 Economic Study (FGRS Phase 1) final report expected to be posted by mid-August
- The Installed Capacity Requirement (ICR) related values for the 2022 Annual Reconfiguration Auctions (ARAs) were incorrect
  - The ISO reported the errors to FERC Office of Enforcement and discussed them with the Reliability Committee
  - After studying and presenting the feasible options to stakeholders, the ISO is running ARA 2 in August, as scheduled, with the FERC-accepted values

Forward Capacity Market (FCM) Highlights

- CCP 13 (2022-2023)
  - Third and final annual reconfiguration auction (ARA3) was held on March 1-3, and results were posted on March 30
- CCP 14 (2023-2024)
  - Second annual reconfiguration auction (ARA2) will be held on August 1-3, and results will be posted no later than August 31
- CCP 15 (2024-2025)
  - First annual reconfiguration auction (ARA1) was held on June 1-3, and results were posted on June 28
- CCP 16 (2025-2026)
  - 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 17 (2026-2027)
  - ISO submitted the "MOPR Removal" filing to FERC on March 31, which includes a "Transition Mechanism" for FCA 17 and FCA 18
    - FERC issued an order accepting ISO's filing on May 27
  - ISO posted existing capacity values on April 29
  - ISO posted the Retirement and Permanent De-List Bid summary on May 11
  - Show of Interest Submission Window closed on June 6
  - At the June 29 PSPC meeting, the ISO confirmed FCA 17 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 opened on July 20 and closed on July 27
  - ICR and related values assumptions are being discussed with the PSPC and on track for RC vote in September

Load Forecast

- The next Load Forecast Committee meeting is rescheduled for September 23 and will kick off the 2023 forecast cycle
- The ISO identified errors in its calculation of forecast adjustments used to develop ICRs for ARAs, and discussed the issue with the Reliability Committee on August 2

Highlights

- The lowest 50/50 and 90/10 Summer Operable Capacity Margins are projected for week beginning September 10, 2022
- The lowest 50/50 and 90/10 Preliminary Fall Operable Capacity Margins are projected for week beginning September 24, 2022

Summary of Operations, July 19th through July 24th, 2022

Highlights

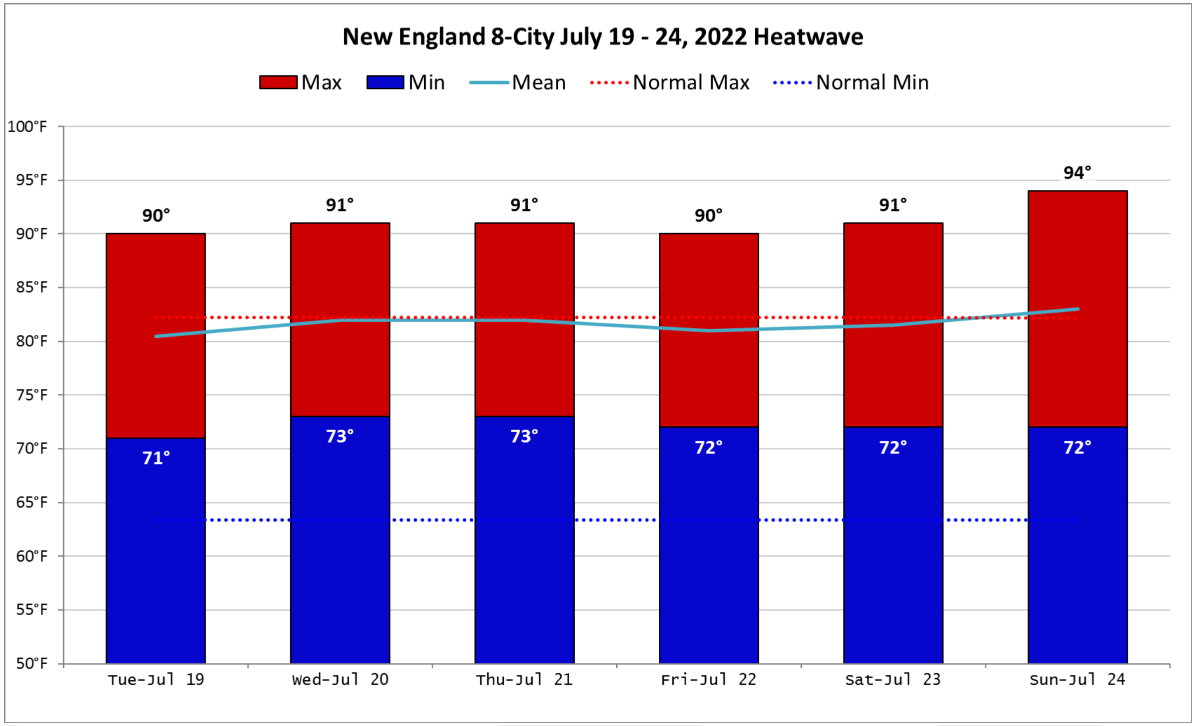
- On average, temperatures in the region were well above normal during the six-day heat wave
- Weather and load forecasts were accurate
- The system was operated reliably in accordance with all NERC and NPCC standards
- Despite some unplanned outages, New England's transmission system and resource fleet generally performed well
- System energy and reserve pricing properly reflected the tight system conditions on several days during the heat wave

Preparation Activities

- Beginning on Monday, 7/18, and periodically throughout the week, ISO Operations staff held conference calls and meetings with neighboring NPCC area and Local Control Center staff
- Due to the forecasted system conditions and expectations for reduced capacity, ISO declared M/LCC-2, Abnormal Conditions Alert, at 1600 on Tuesday, 7/19

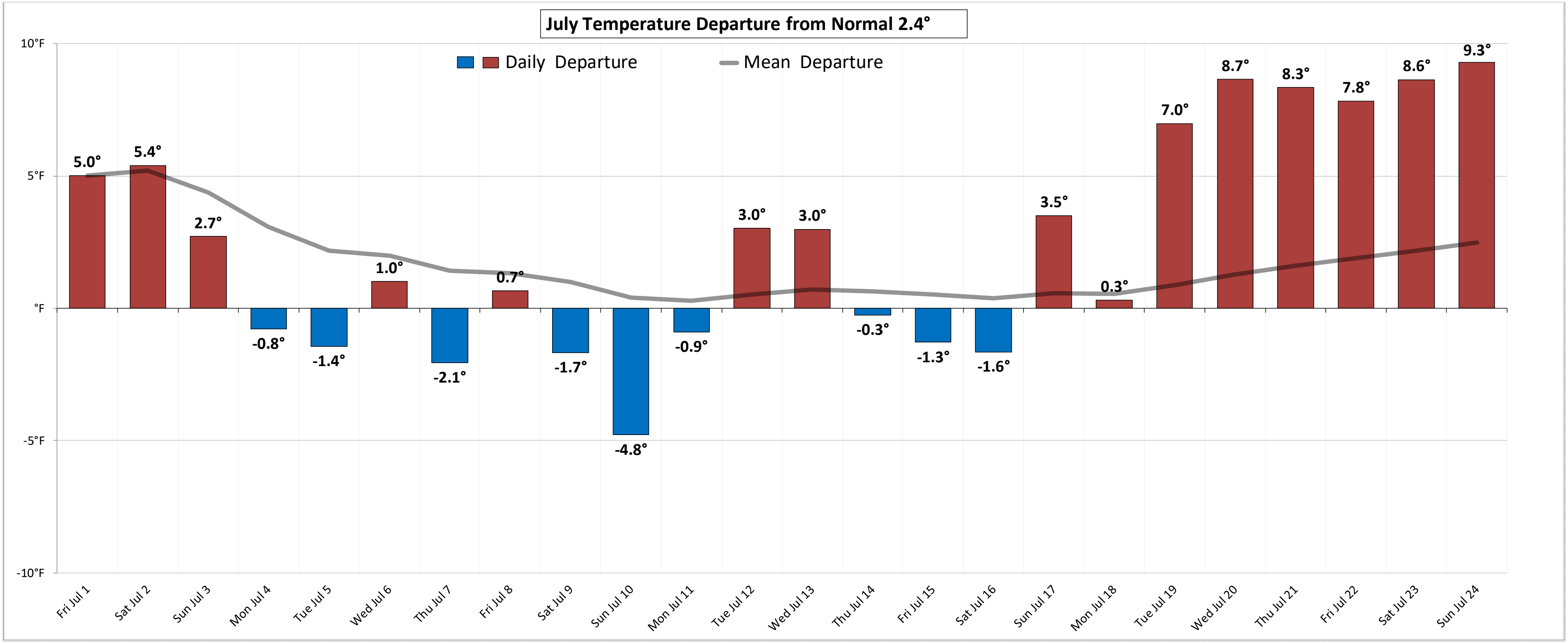
New England Temps Reached 90°F For Six Consecutive Days

- While the heat wave was the region's longest in several years, it was not extreme in a historical sense
  - Boston's week-long high temps ranked 11th all-time; Hartford's ranked 20th all-time
- The highest 8-city weighted-average temperature of 94°F occurred on 7/24



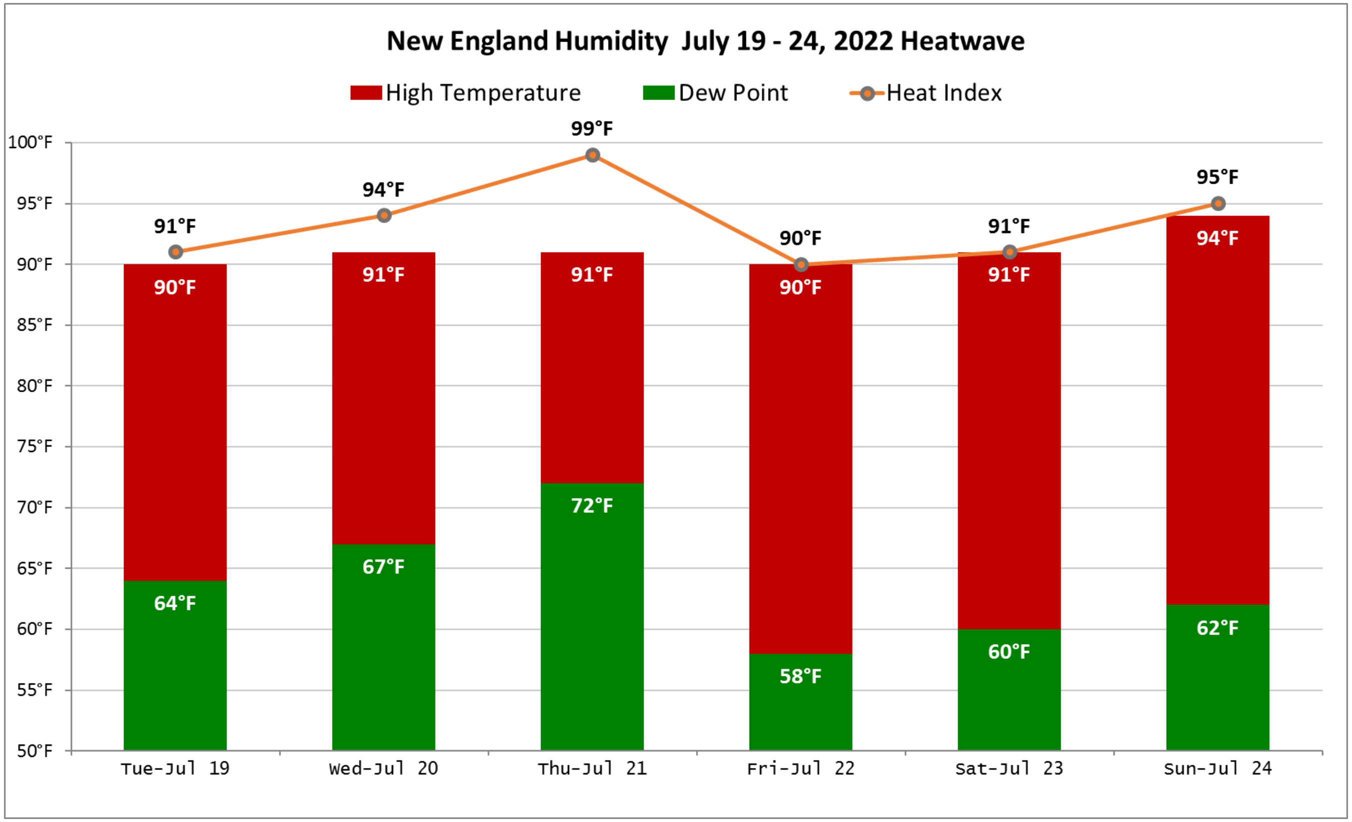
Average Temperatures Departed Significantly From Normal

- Through 7/24, the region’s 8-city weighted-average temperature departure from normal for the month of July measured +2.4°F



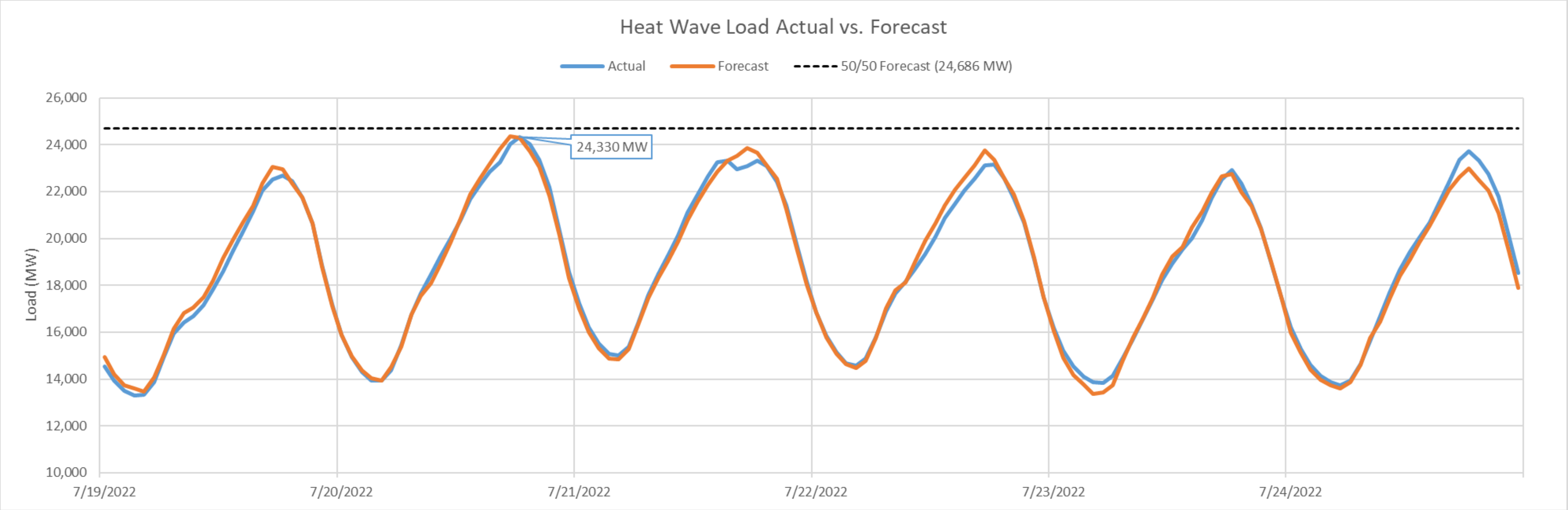
New England Dew Points Were Not Excessive

- Regional dew points were not excessive, resulting in a heat index below 100°F throughout the heat wave



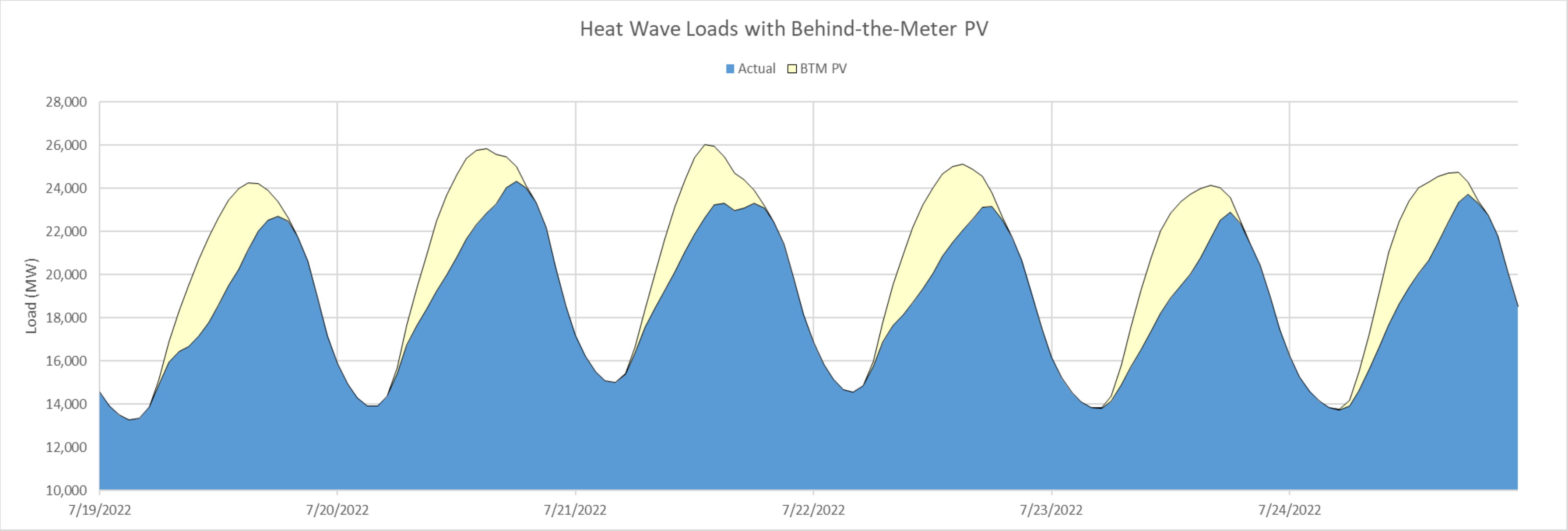
Weather Forecasts and ISO’s Load Forecast Were Accurate

- Weather forecasts used by ISO to forecast load averaged less than 1°F error over all hours; ISO’s load forecast absolute percent error was 1.3%
- Peak integrated load of 24,330 MW occurred on Wednesday, 7/20; peak hourly integrated load, including load served by settlement only generators, was 24,609 MW
  - 50/50 load forecast for summer 2022 is 24,686 MW
- Total energy demand over the 6 days was 2,691 GWh; avg. ~ 450 GWh/day



Energy Contributions From Behind-the-Meter PV Was Significant

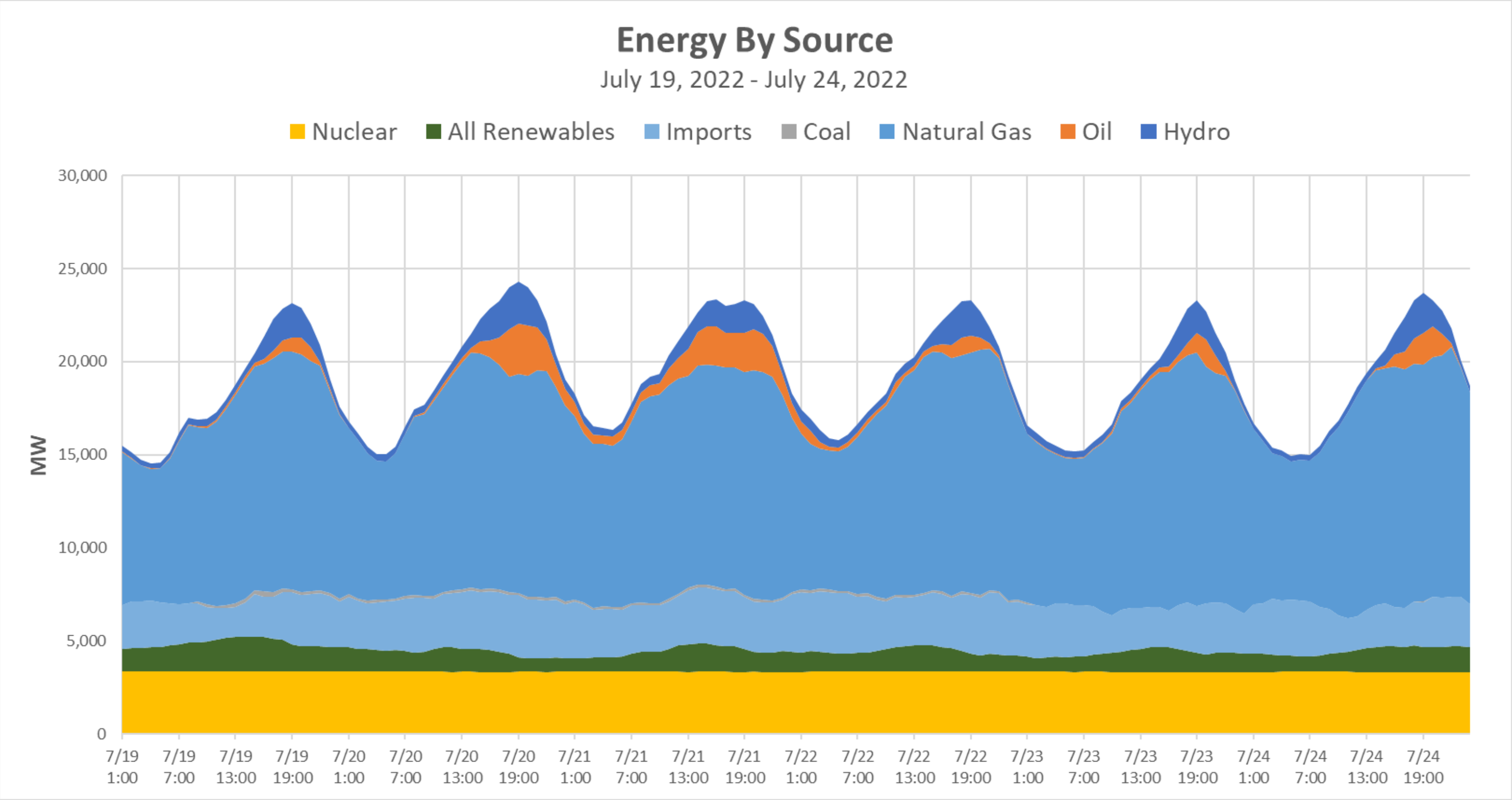
- The peak contribution from behind-the-meter (BTM) PV during the six-day heat wave was approx. 4,000 MW on 7/19; BTM PV contributions were significantly lower during peak hours



In the figure above, load served behind-the-meter is added to load served by the power grid to show total New England demand during the heat wave

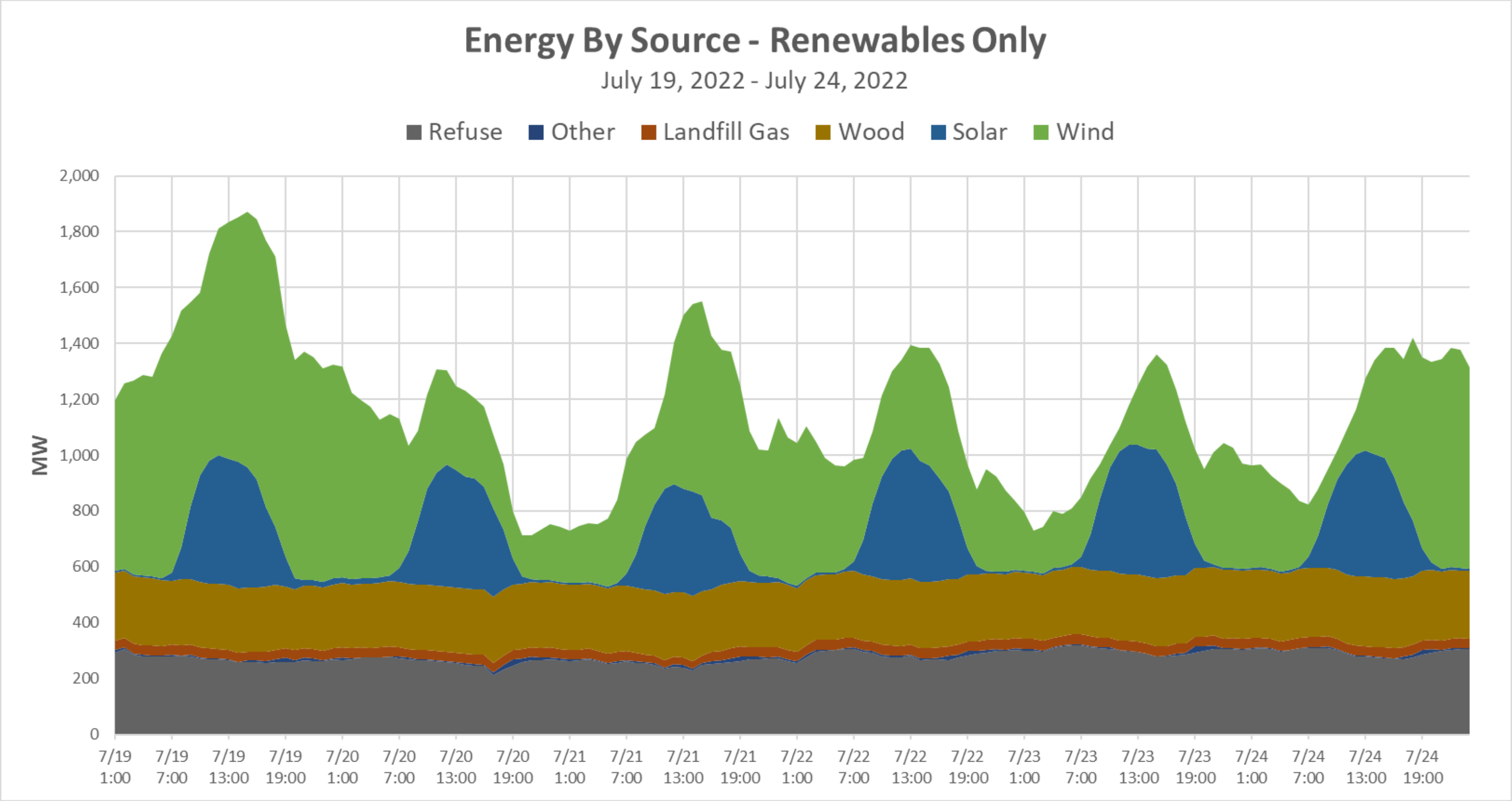
Energy Sources During the Heat Wave

- Natural gas, oil, and hydro power resources ramped up to provide energy during times of peak demand



Energy Sources During the Heat Wave – Renewables Only

- Aggregate contributions from wind energy peaked in HE18 on 7/19, and averaged approx. 450MW/hour during the six-day period



Stored Fuel Usage During the Heat Wave

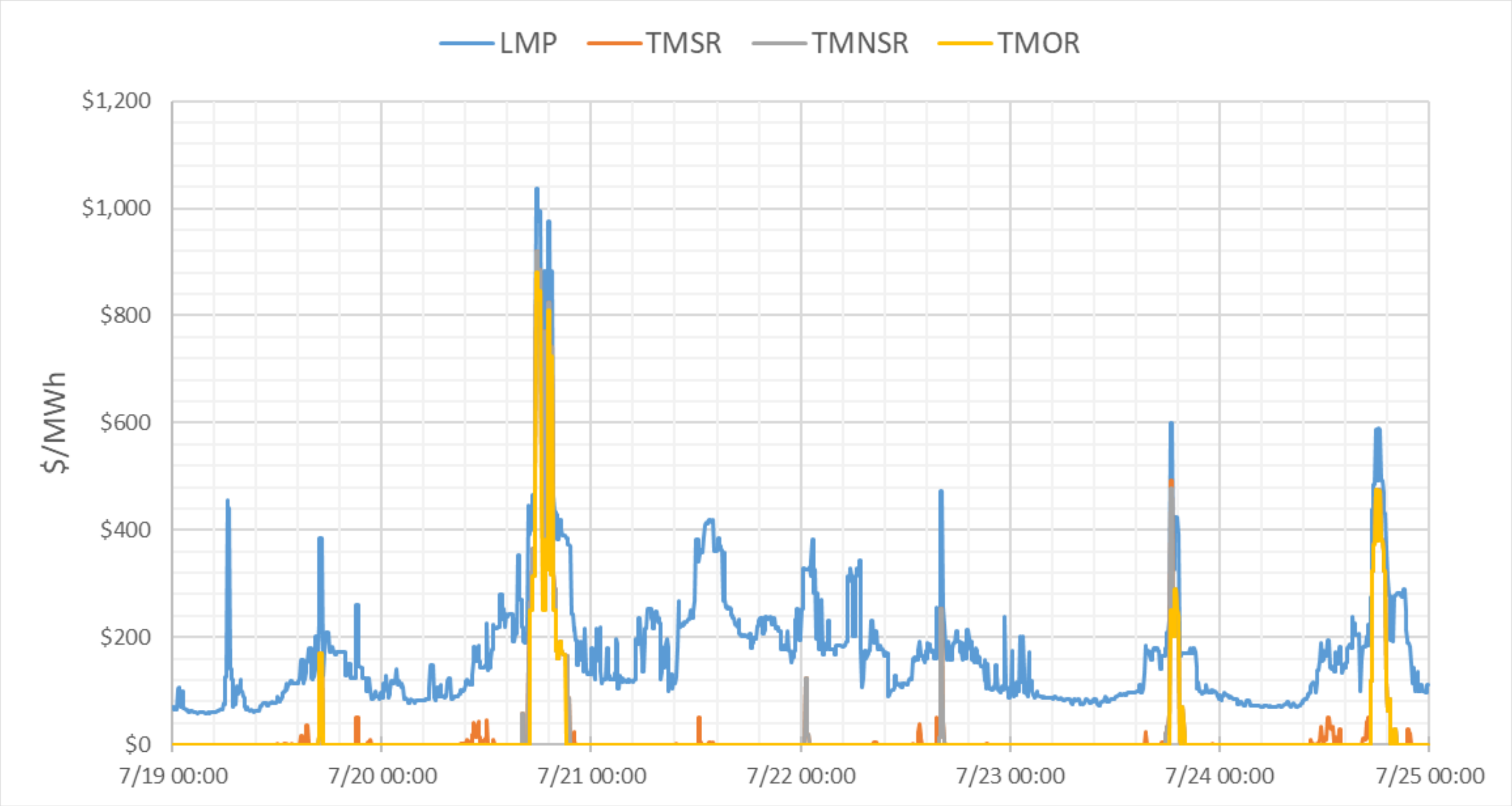
- Injection of LNG to pipelines for use by generators was minimal
- According to the most recent generator survey responses, during the two-week span of 7/12 to 7/25;
  - Approx. 6M gallons of fuel-oil was used by generators; a majority of fuel-oil usage occurred during the six-day heat wave
  - Some replenishment has already occurred and additional replenishment of distillate fuel oil (DFO) and residual fuel oil (RFO) is expected over the next few weeks

New England's Transmission System and Resource Fleet Performed As Expected

- Unplanned transmission outages were minimal and those that occurred did not significantly impact generation availability or transfer capability
- Unplanned resource outages and reductions occurred at times throughout the heat wave, averaging ~1,500 MW/day
  - Unplanned outages and reductions occurring on the peak load day of Wednesday, 7/20, totaled ~3,500 MW
- With the exception of Saturday, 7/23, supplemental commitment of resources averaged ~850 MW/day
  - Supplemental commitment is performed in order to meet load and operating reserve requirements following either insufficient DA clearing or unplanned resource outages and reductions

System Energy and Reserve Pricing

- System LMPs averaged ~ $171/MWh during the six-day heat wave; non-zero system reserve prices occurred periodically, but were most prevalent during peak hours on 7/20, 7/23, and 7/24



SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (3.5°F) Max: 100°F, Min: 61°F Precipitation: 0.62" – Below Normal Normal: 3.27"	Hartford	Temperature: Above Normal (2.5°F) Max: 97°F, Min: 56°F Precipitation: 2.66" - Below Normal Normal: 4.17"

Peak Load:	24,330 MW	July 20, 2022	19:00 (ending)

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

Procedure	Declared	Cancelled	Note
M/LCC 2	7/19 16:00	7/24 22:00	

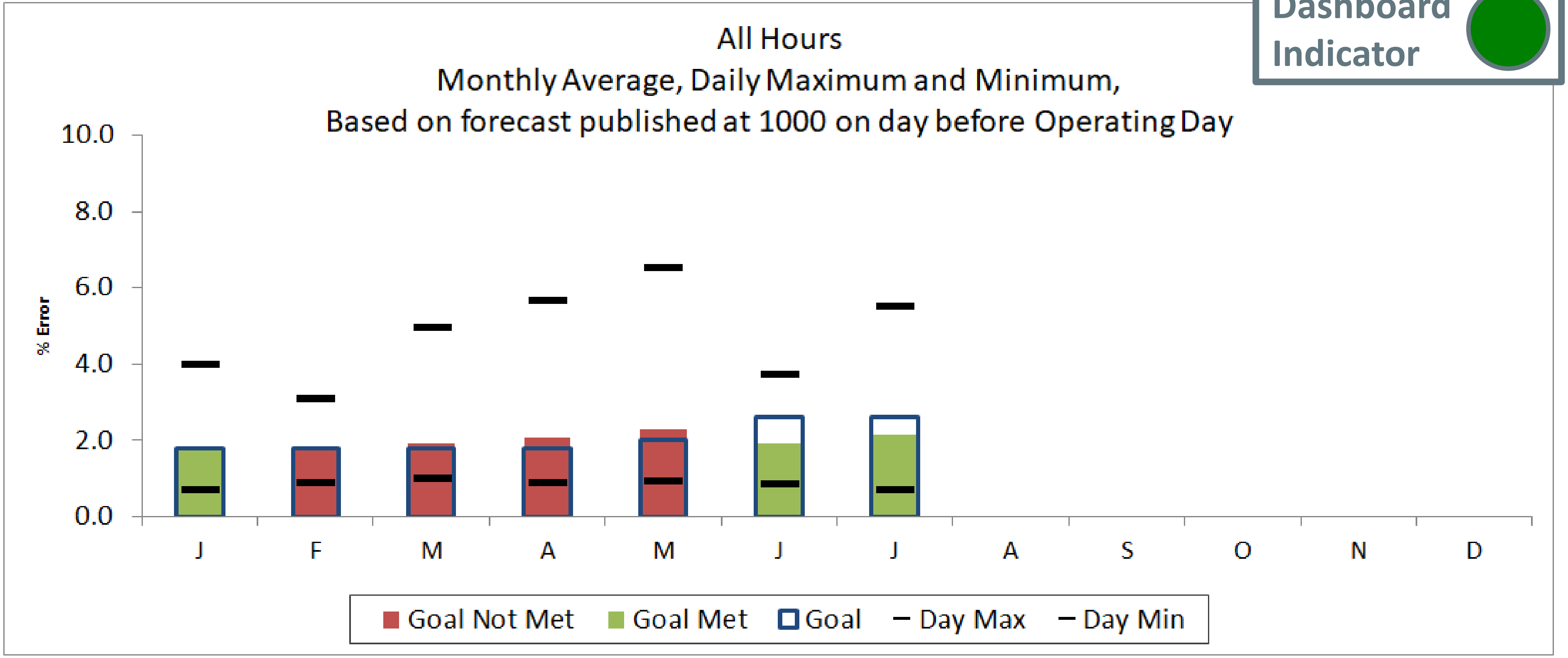
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
7/8	NYISO	1221
7/7	PJM	1200
7/19	ISO-NE	550
7/21	ISO-NE	800
7/23	ISO-NE	700

2022 System Operations - Load Forecast Accuracy

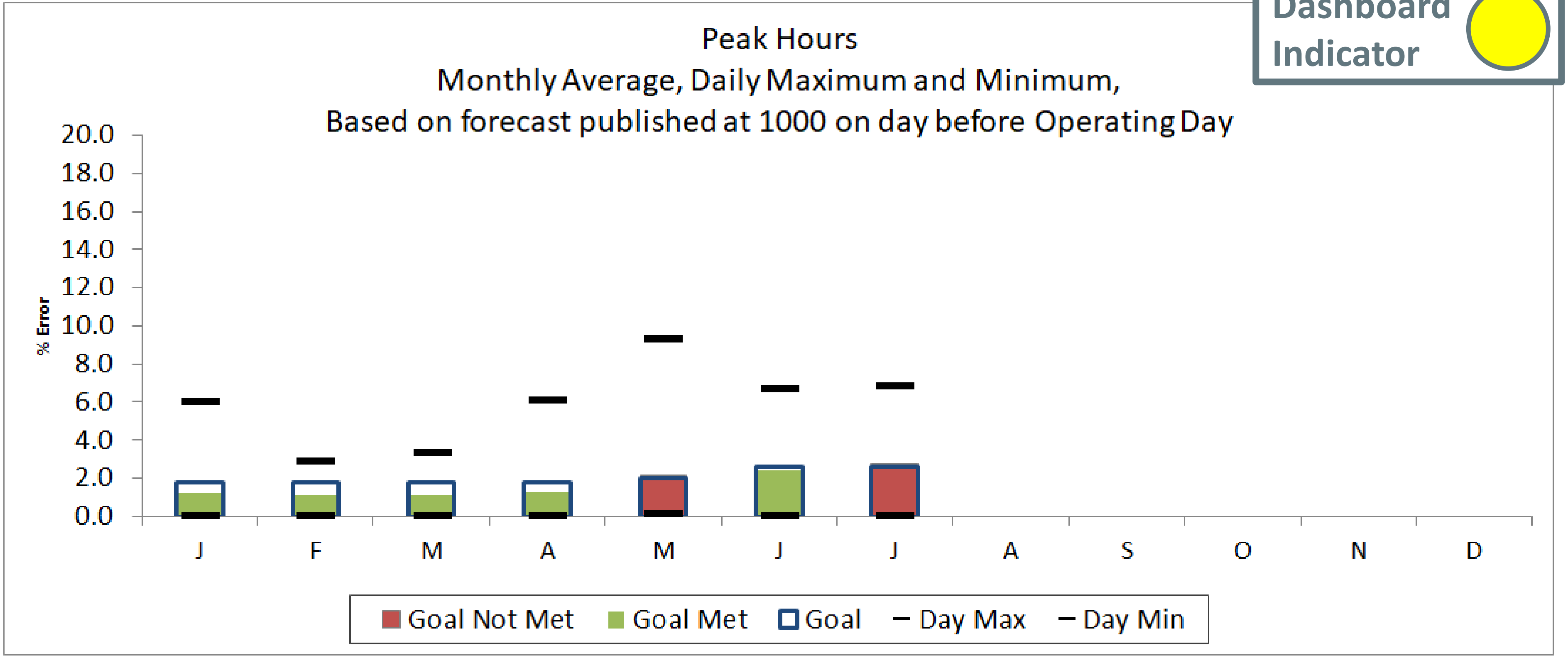
Dashboard Indicator ●



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	3.97	3.07	4.92	5.66	6.52	3.71	5.48						6.52
Day Min	0.69	0.87	0.97	0.85	0.91	0.83	0.69						0.69
MAPE	1.79	1.81	1.93	2.05	2.30	1.92	2.13						1.99
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60						

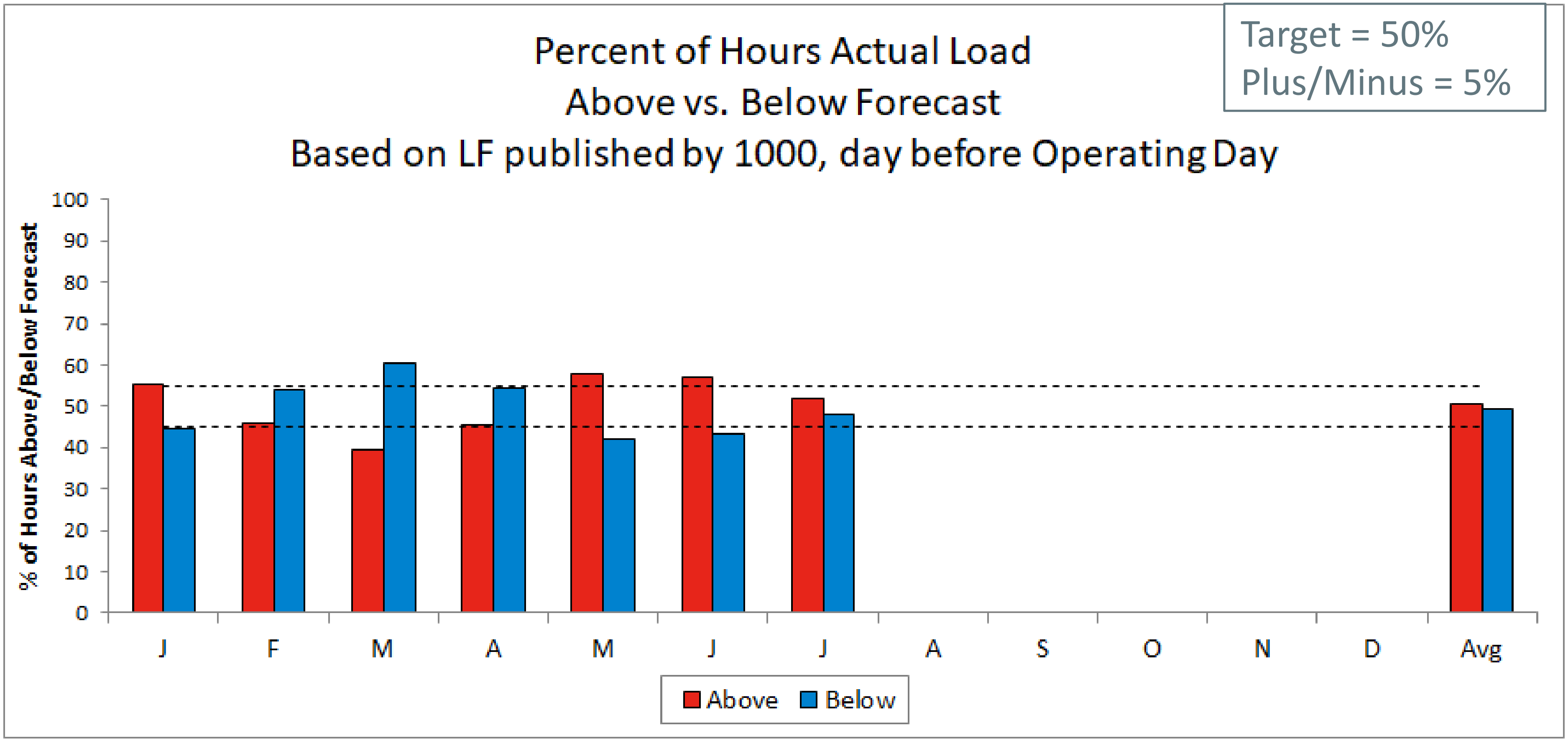
2022 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator ●



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	6.01	2.85	3.32	6.08	9.27	6.70	6.85						9.27
Day Min	0.02	0.03	0.04	0.00	0.06	0.01	0.02						0.00
MAPE	1.25	1.11	1.13	1.29	2.14	2.43	2.73						1.73
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60						

2022 System Operations - Load Forecast Accuracy cont.

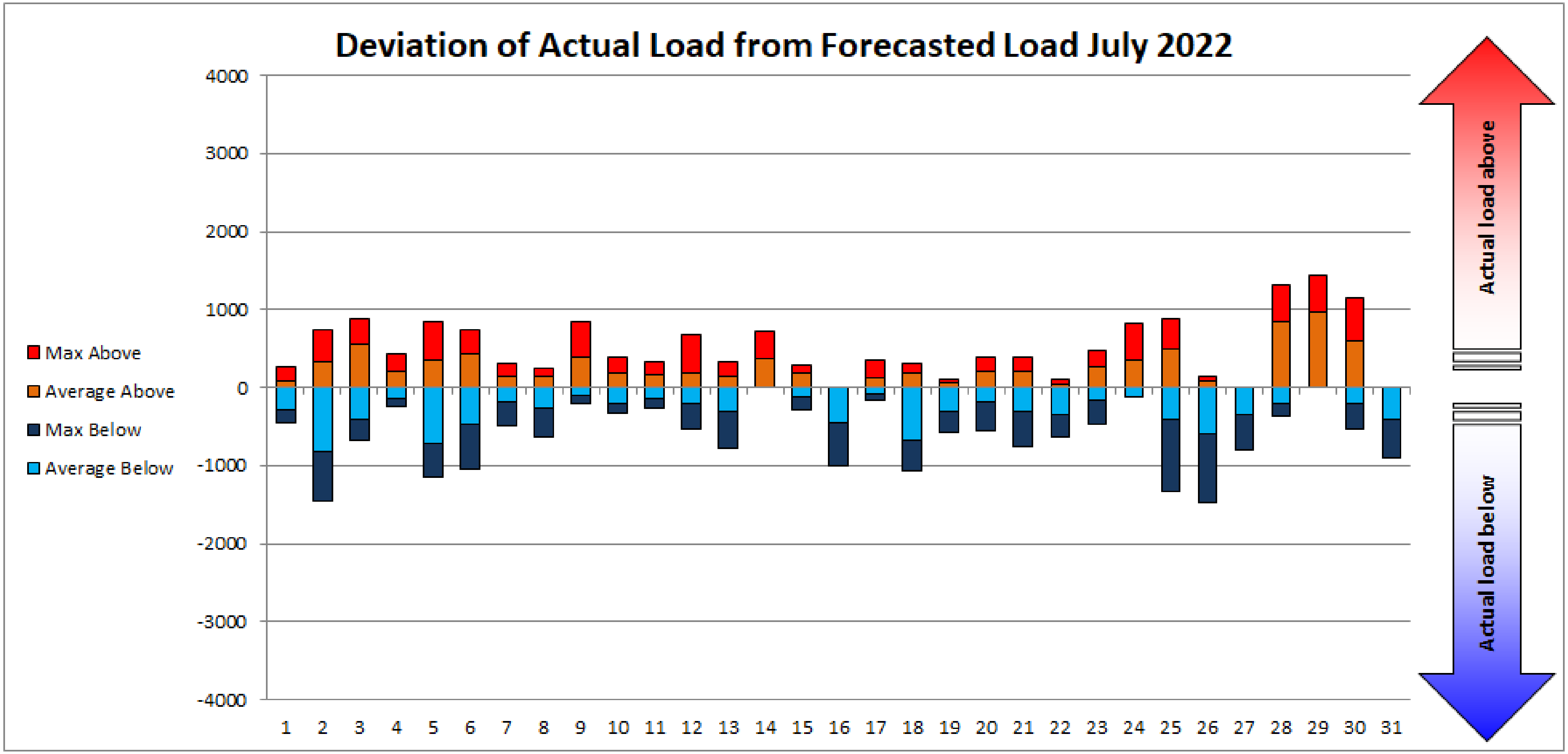


Percent of Hours Actual Load
Above vs. Below Forecast
Based on LF published by 1000, day before Operating Day

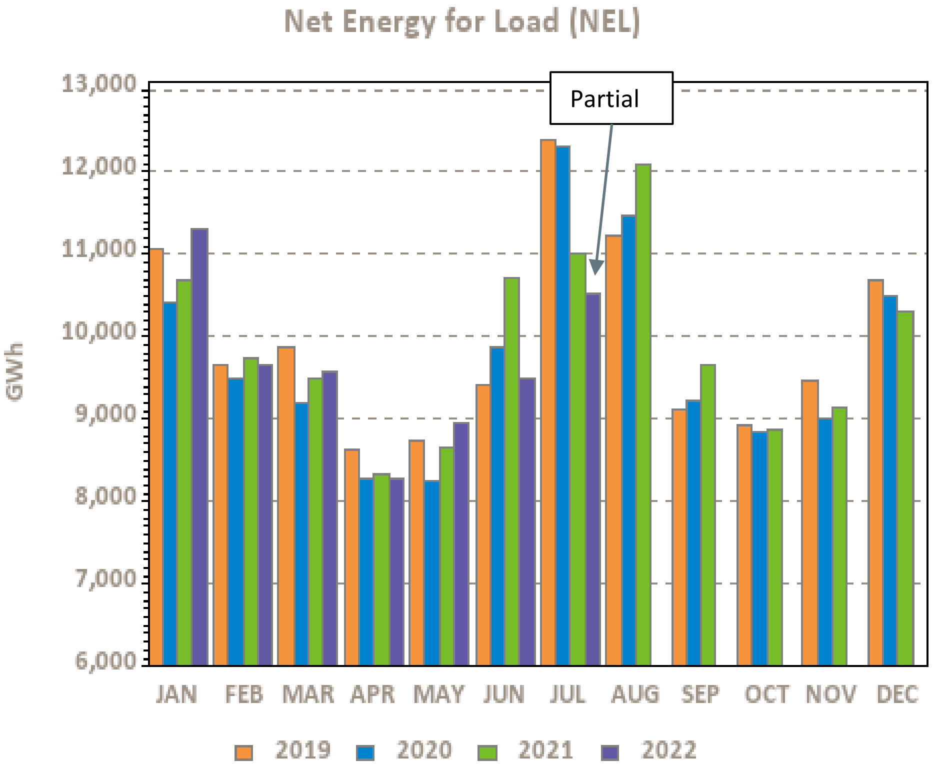
Target = 50%
Plus/Minus = 5%

	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	55.2	46	39.7	45.6	57.8	56.8	51.9						50
Below %	44.8	54	60.3	54.4	42.2	43.2	48.1						50
Avg Above	219.5	245.7	175.9	180	217.2	209.6	268.3						268
Avg Below	-223.1	-207.6	-240.0	-191.5	-192.2	-215.9	-295.8						-296
Avg All	22	6	-78	-18	30	23	5						-2

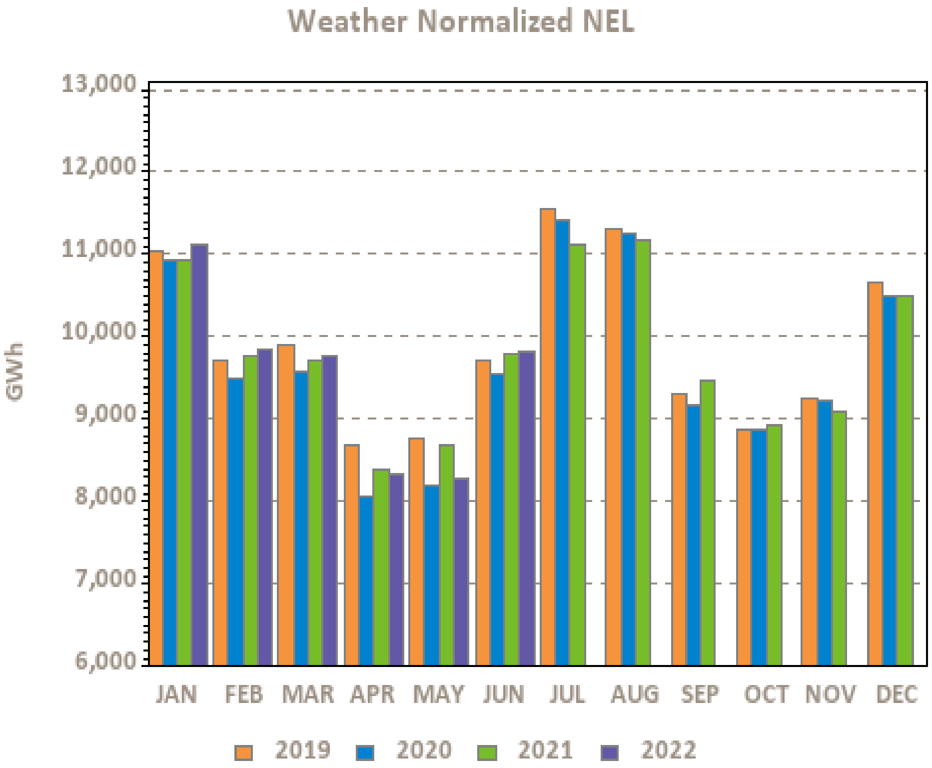
2022 System Operations - Load Forecast Accuracy cont.



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



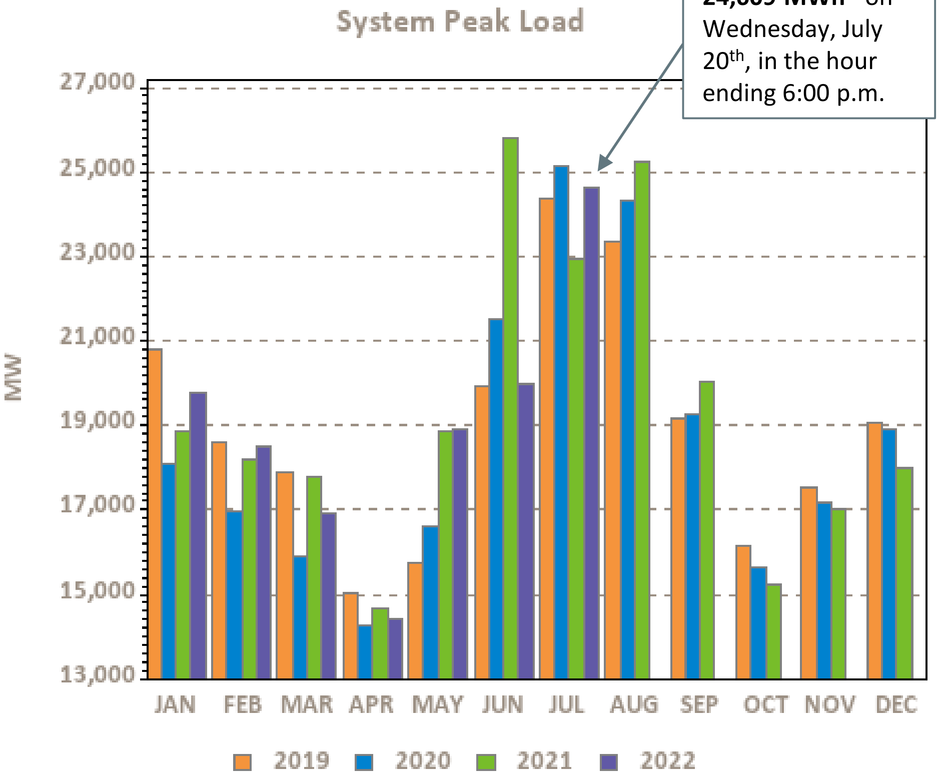
Ann Tot (TWh): 119.2 116.9 118.8 67.8



Ann Tot (TWh): 118.8 116.3 117.6 57.2

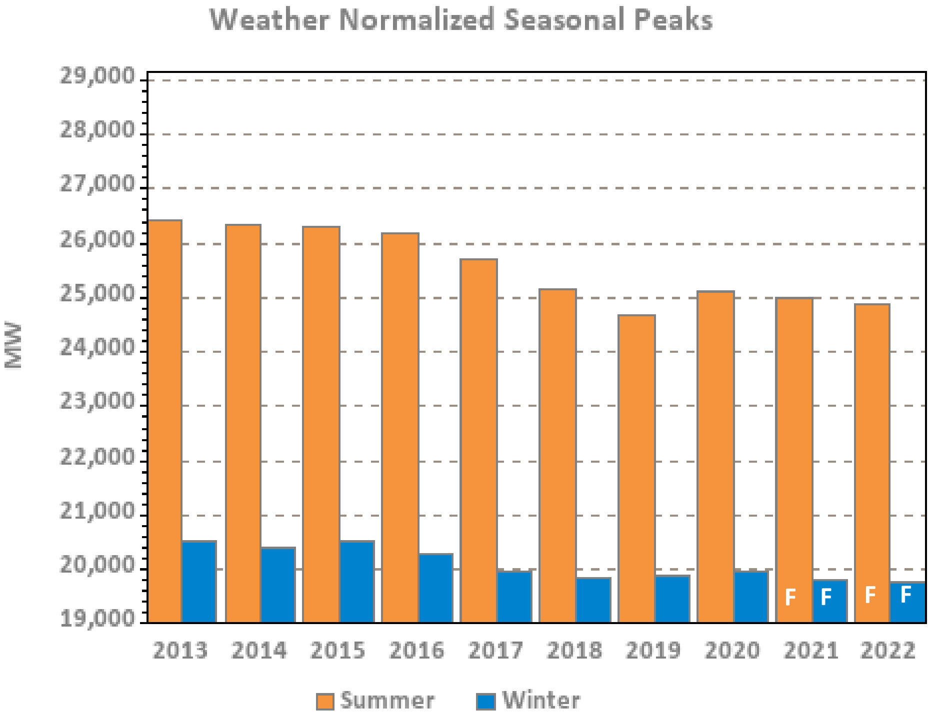
NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather normalized NEL is typically reported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

Monthly Peak Loads and Weather Normalized Seasonal Peak History



24,609 MWh* on Wednesday, July 20th, in the hour ending 6:00 p.m.

*Revenue quality metered value

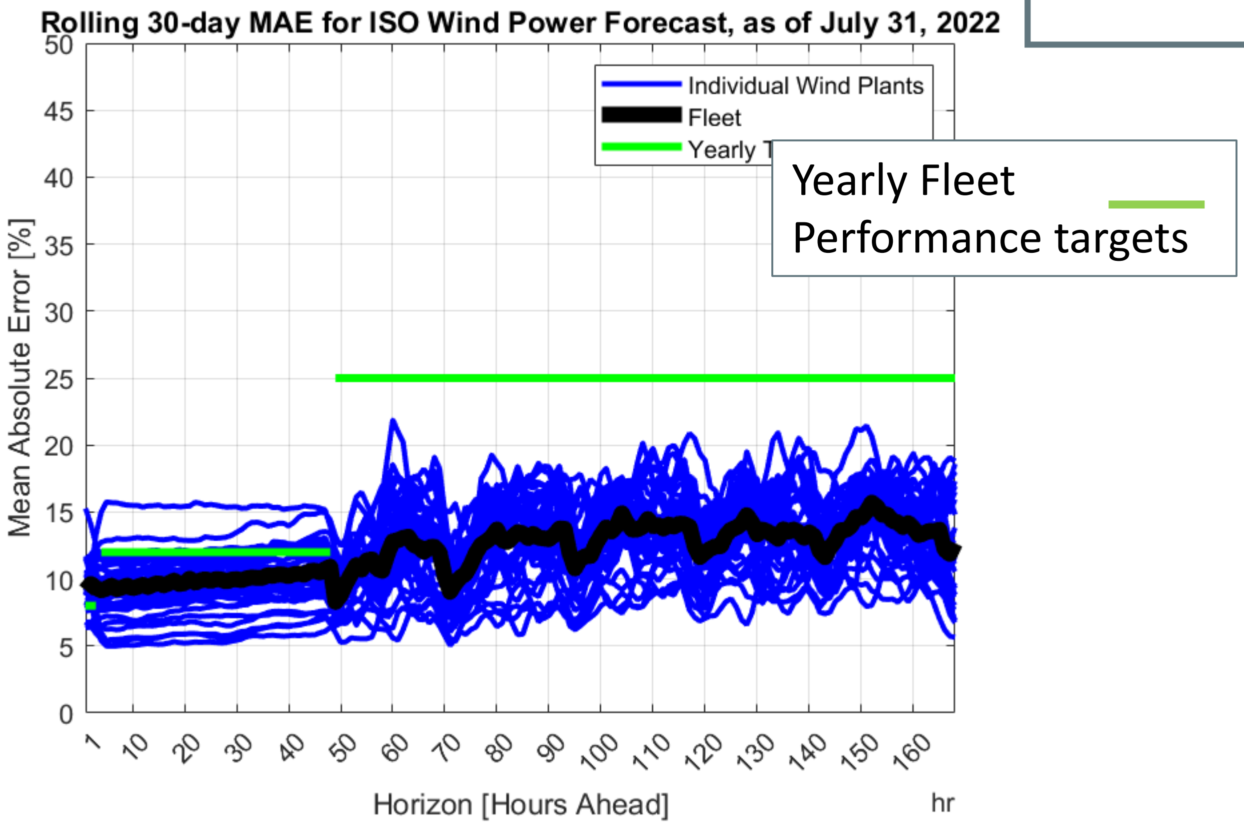


Winter beginning in year displayed

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

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

Dashboard Indicator ●

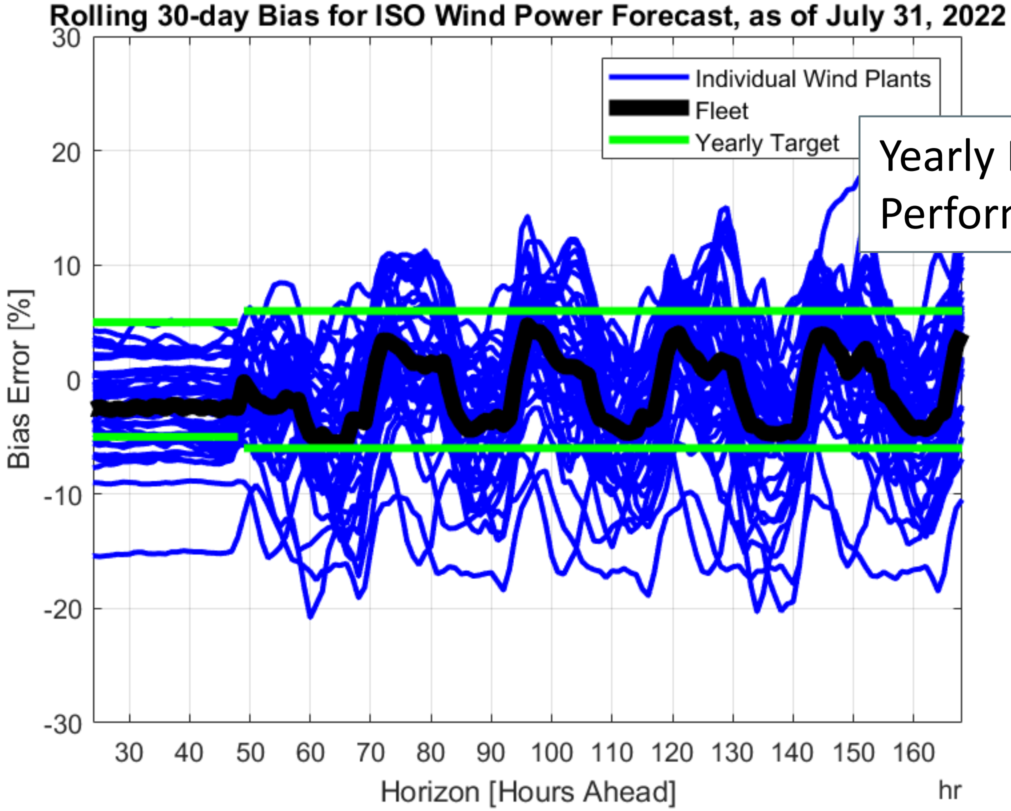


Yearly Fleet Performance targets

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 🟢

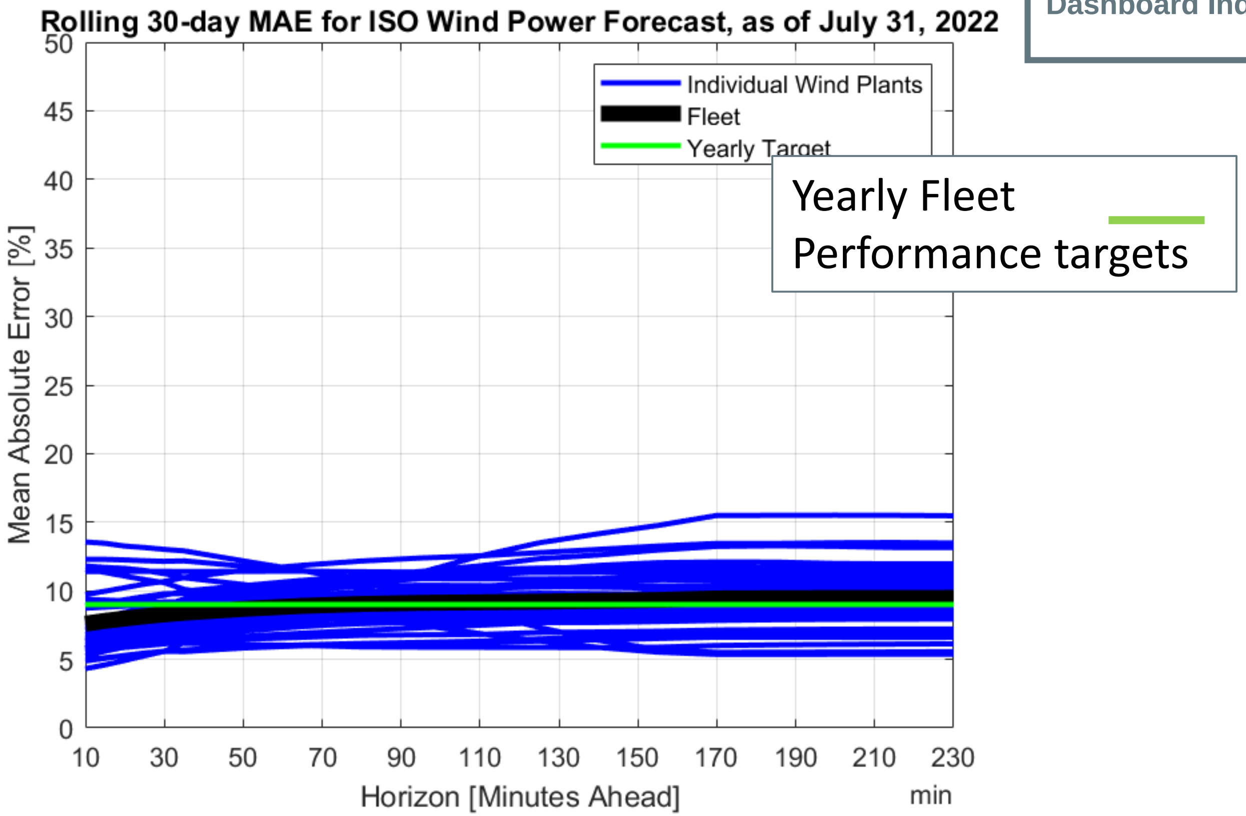


Yearly Fleet Performance targets

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 targets.

Wind Power Forecast Error Statistics: Short Term Forecast MAE

Dashboard Indicator ●



Yearly Fleet Performance targets

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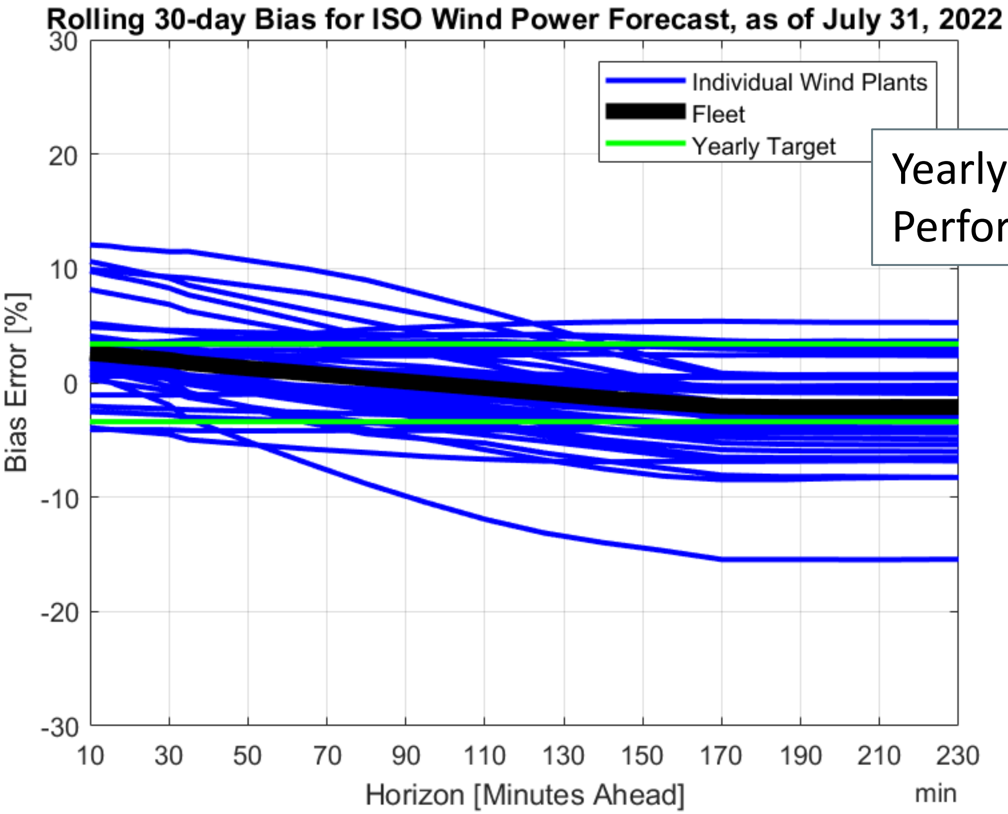
Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator ●

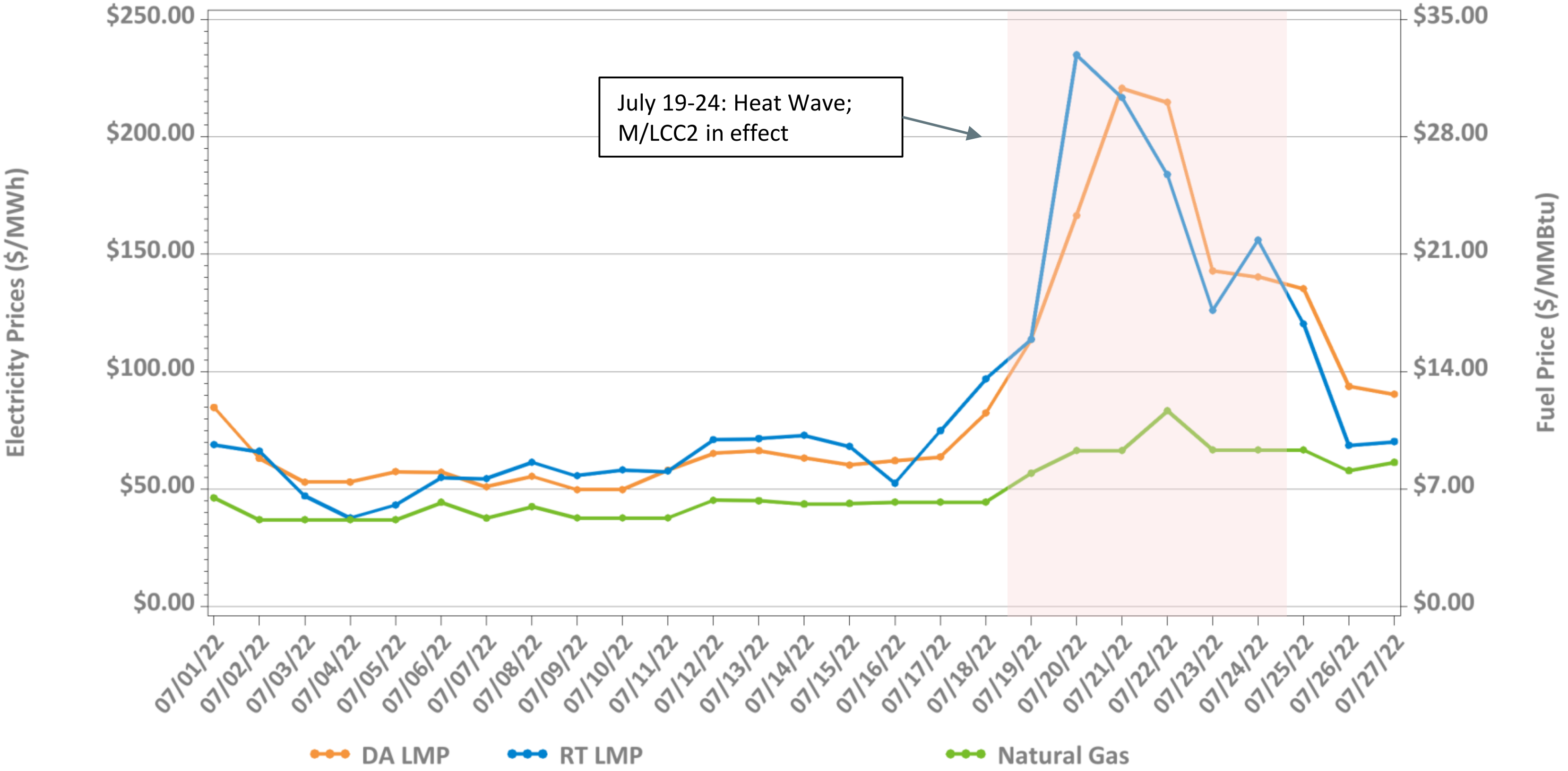


Yearly Fleet Performance targets 🟩

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 1-27, 2022



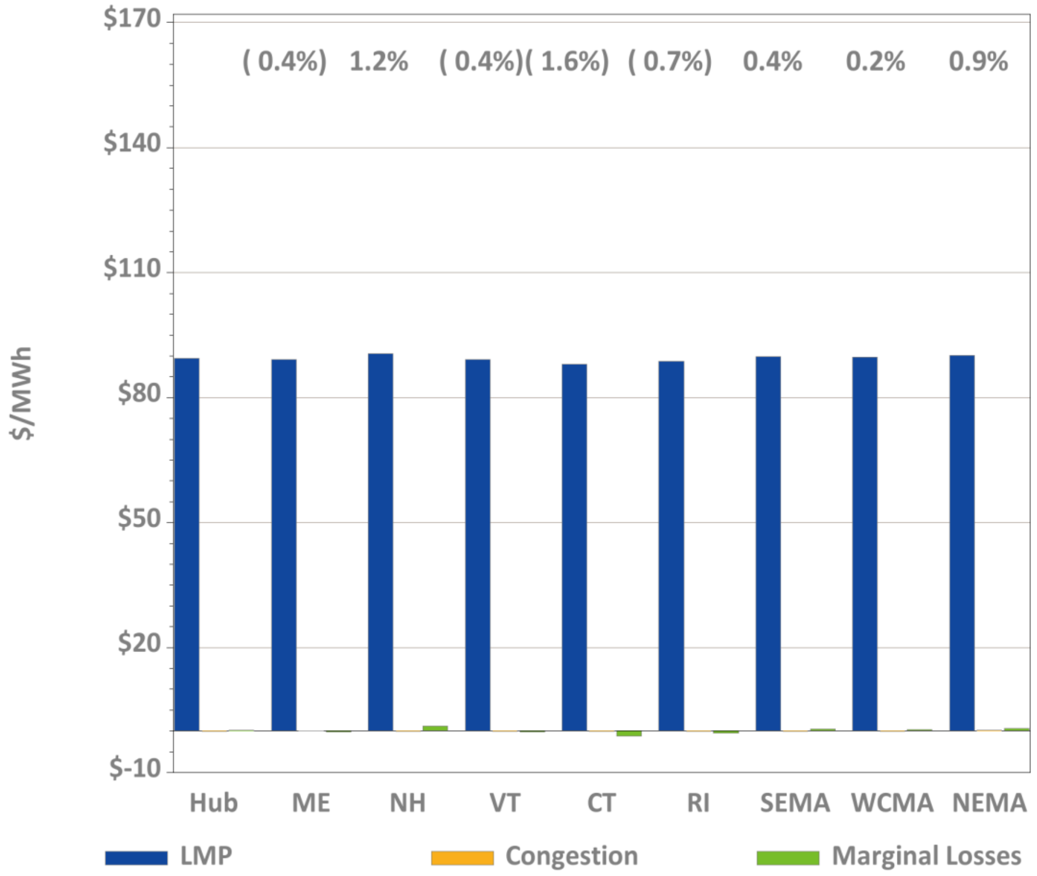
July 19-24: Heat Wave; M/LCC2 in effect

Underlying natural gas data furnished by:

ICE Global markets in clear view

Average price difference over this period (DA-RT): $0.37
Average price difference over this period ABS(DA-RT): $12.62
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 14%
Gas price is average of Massachusetts delivery points

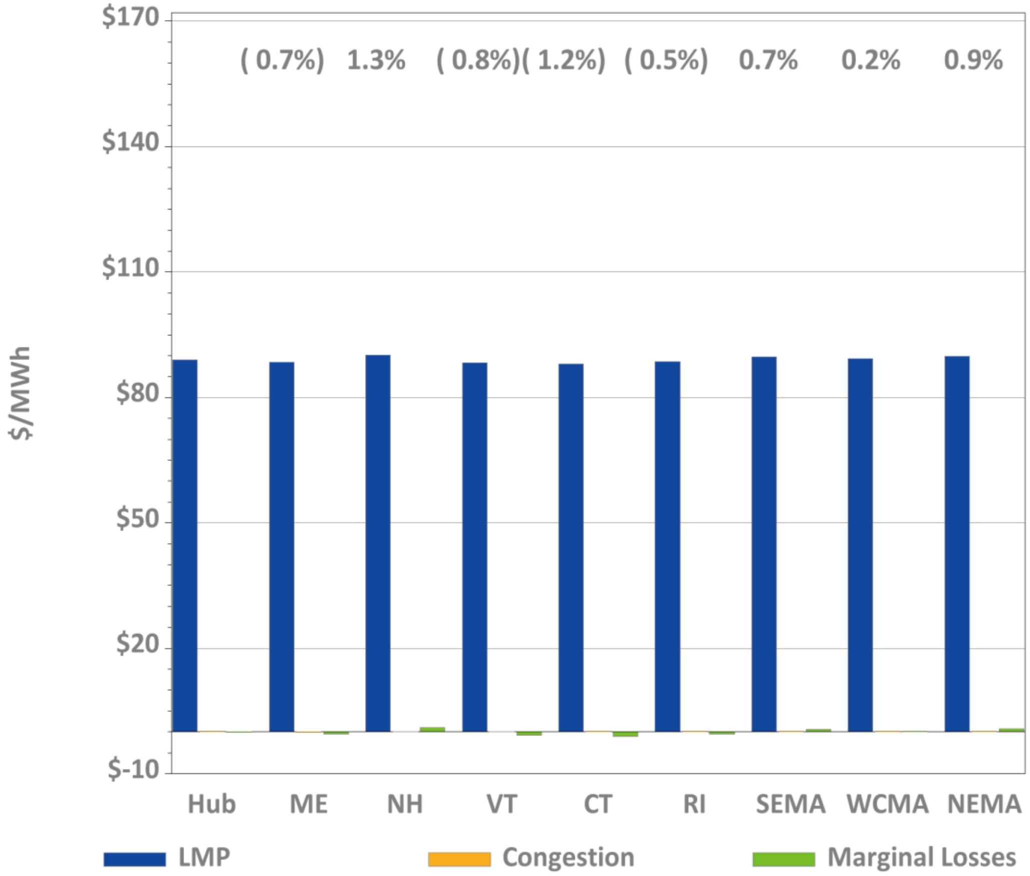
DA LMPs Average by Zone & Hub, July 2022



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

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

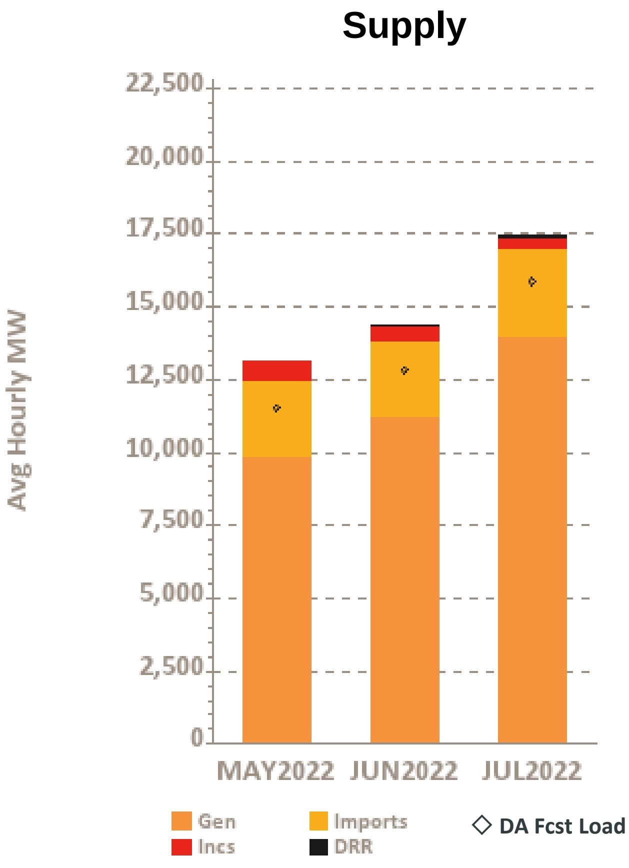
RT LMPs Average by Zone & Hub, July 2022

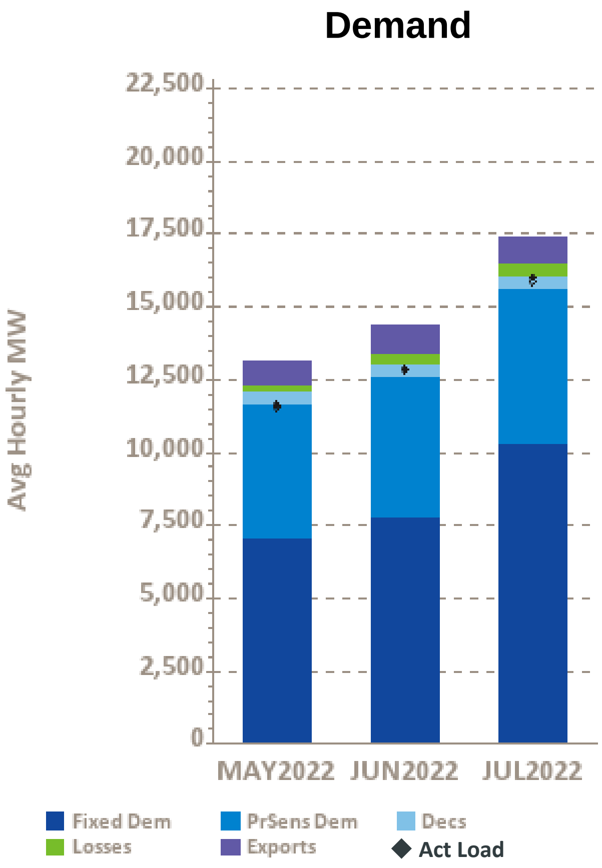


Definitions

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

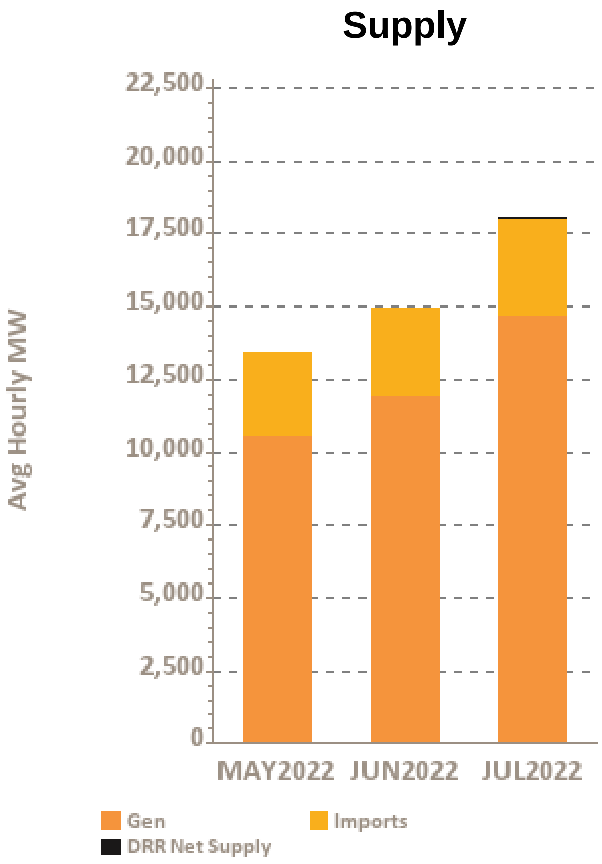


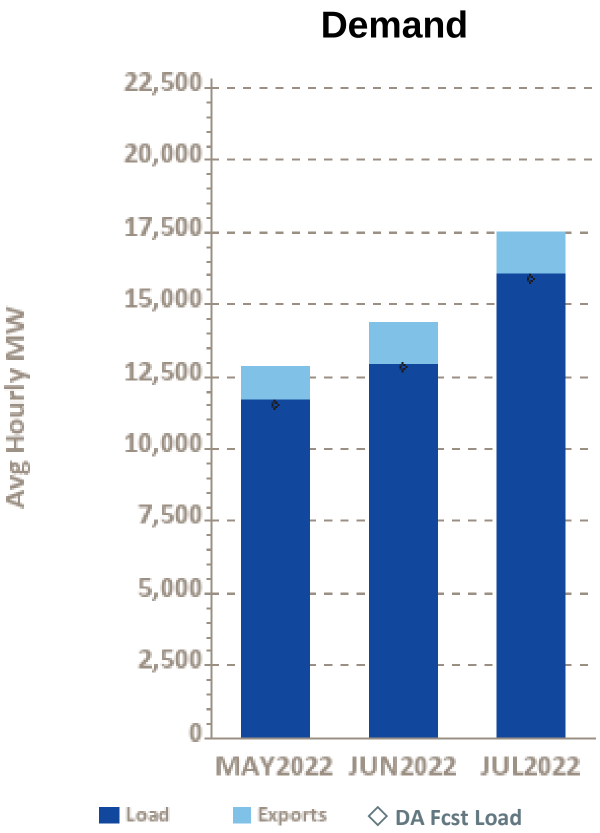


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

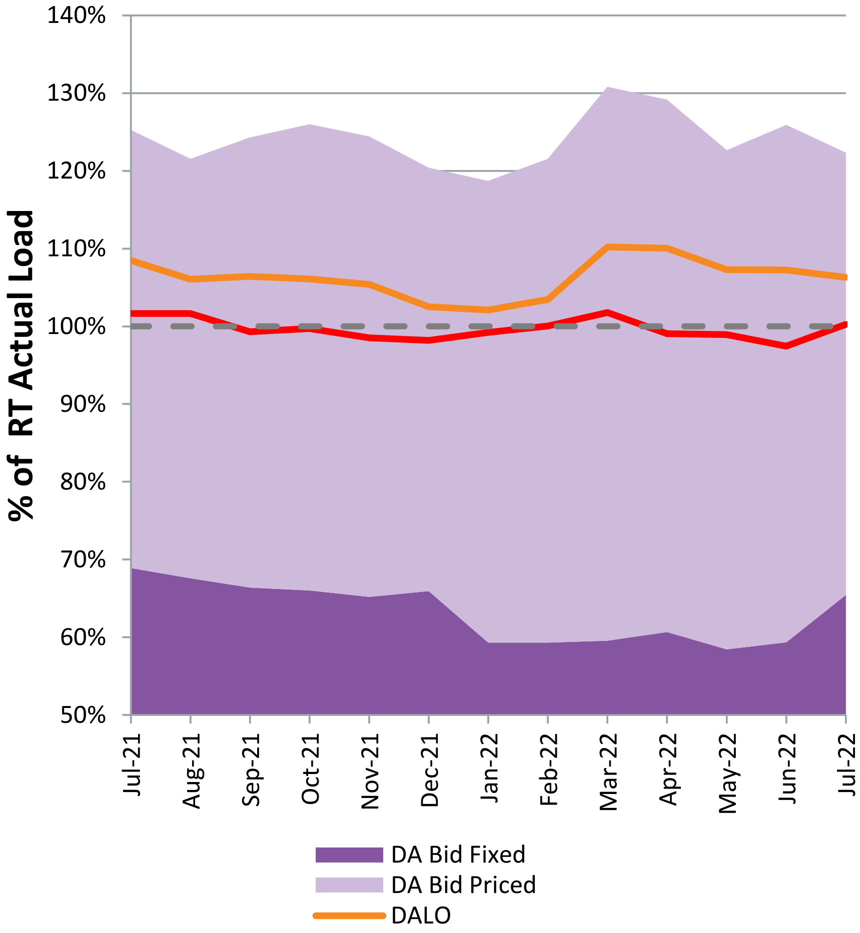
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

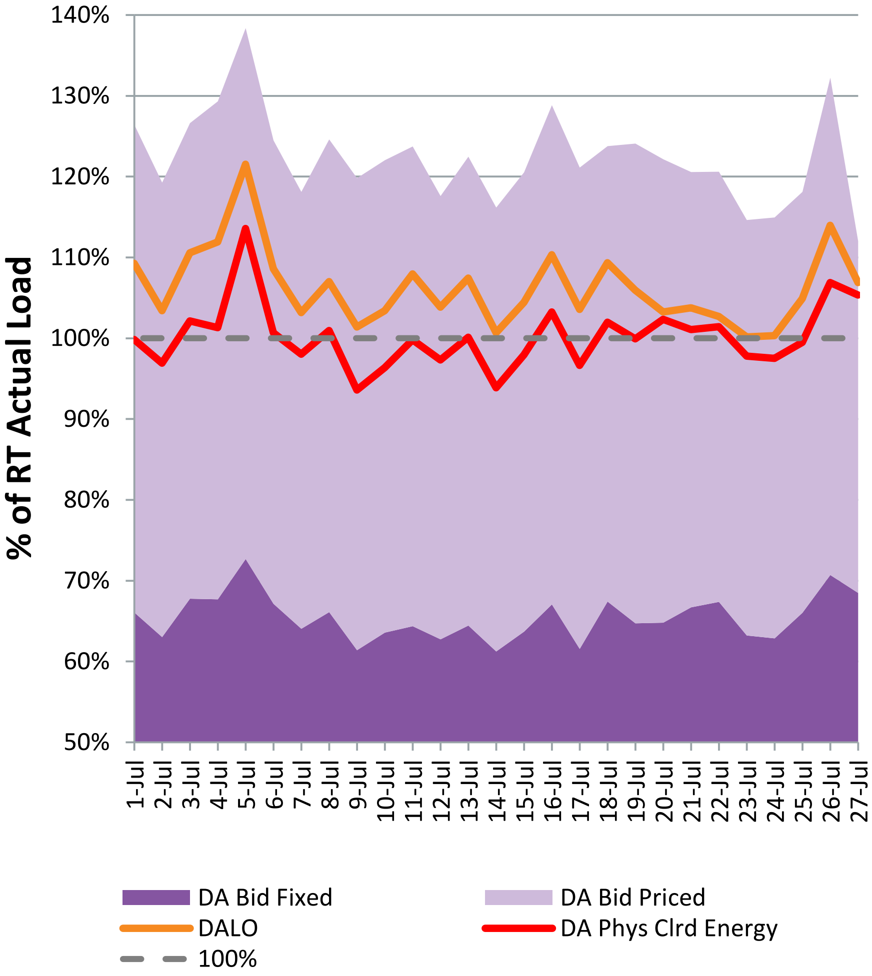
Components of RT Supply and Demand – Last Three Months





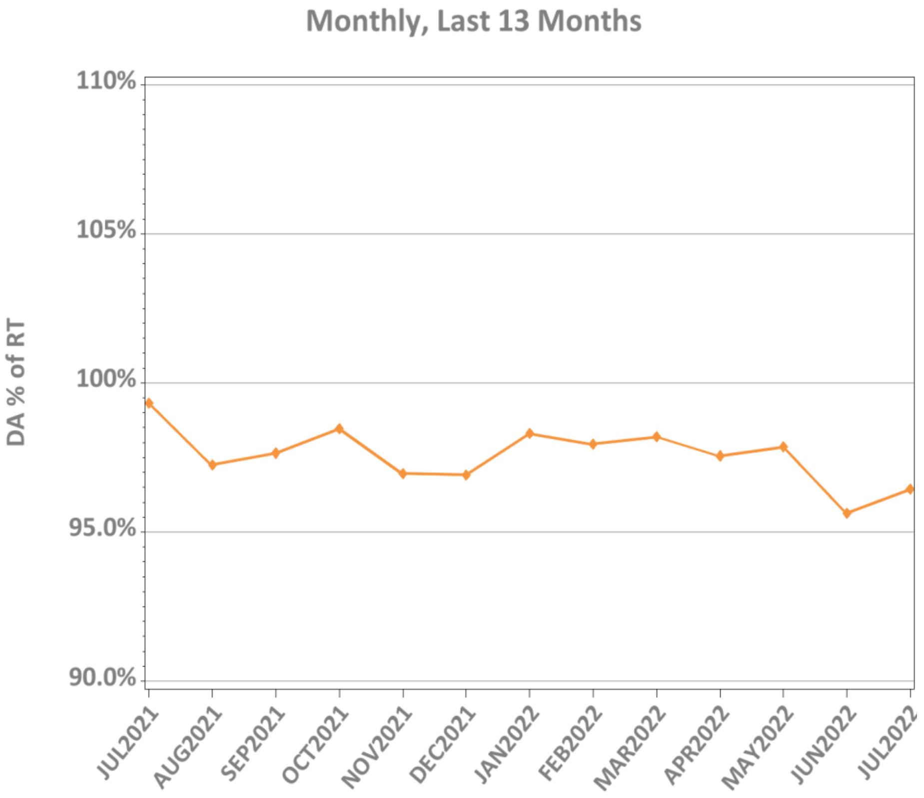
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

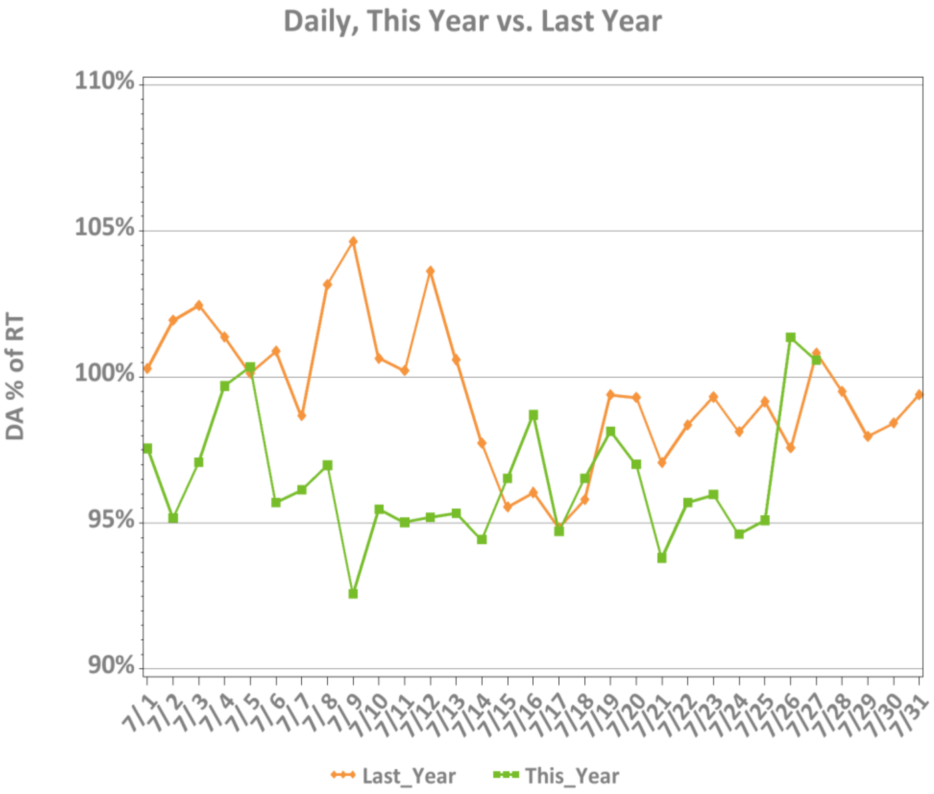




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

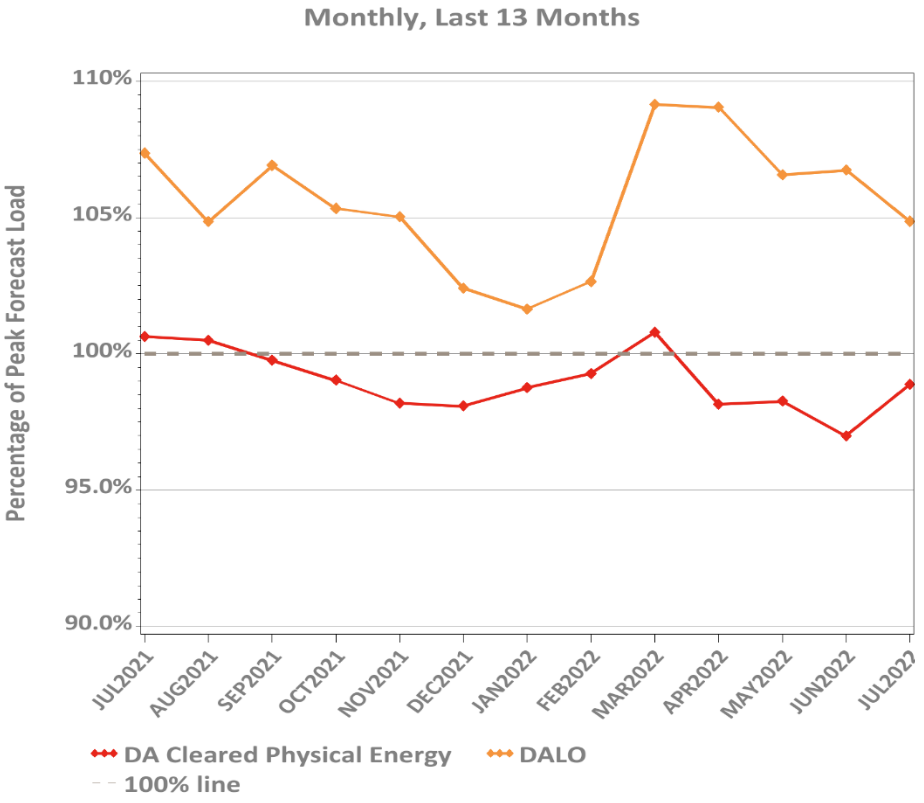
DA vs. RT Load Obligation: July, This Year vs. Last Year

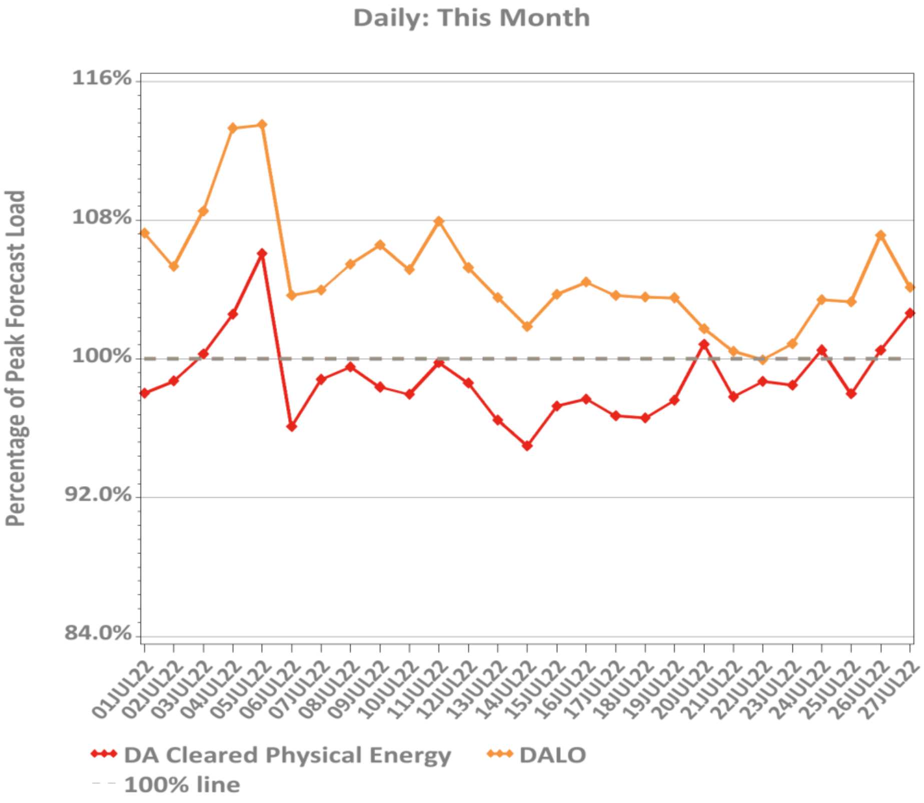




*Hourly average values

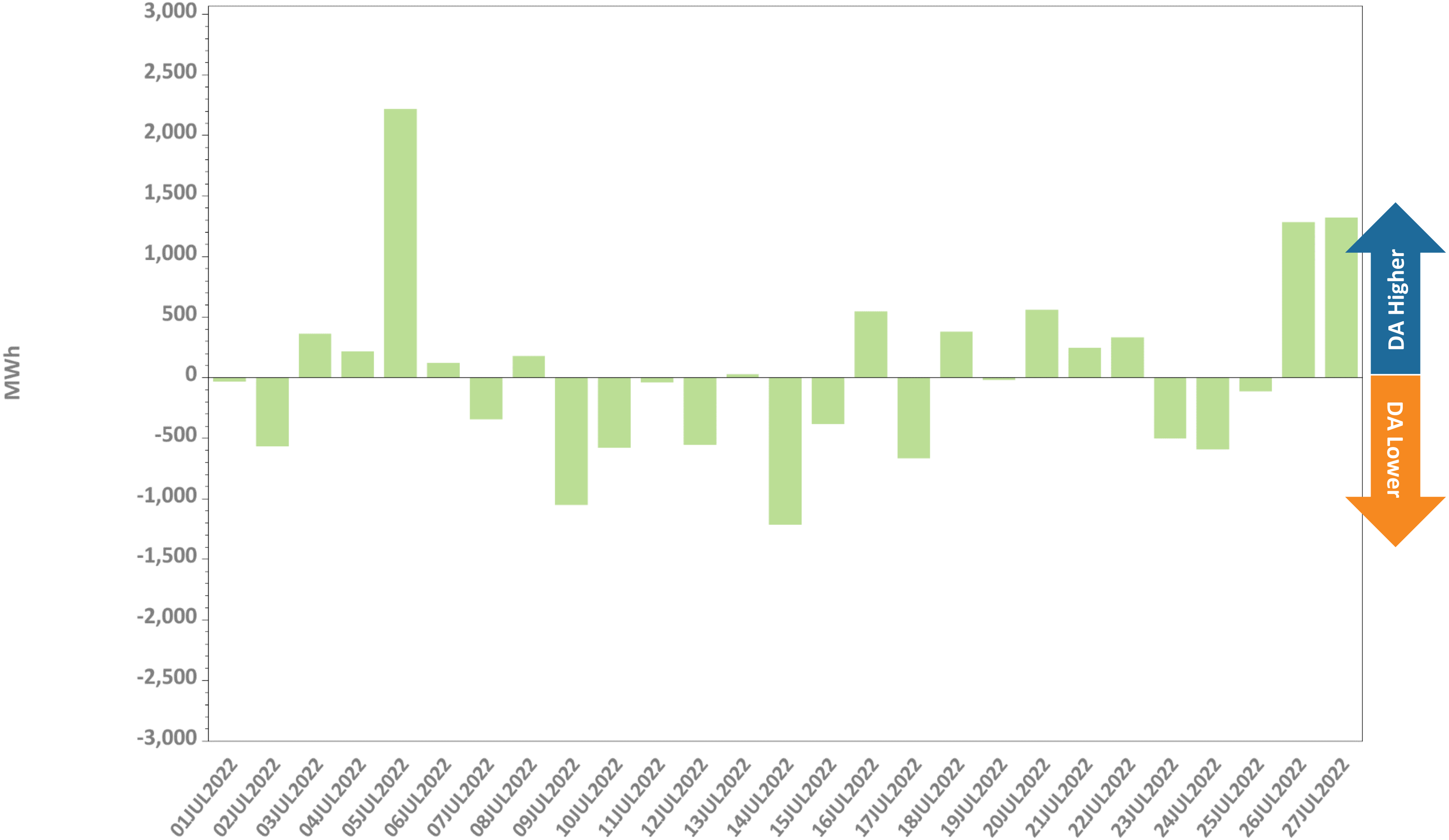
DA Volumes as % of Forecast in Peak Hour


Monthly, Last 13 Months


Daily: This Month

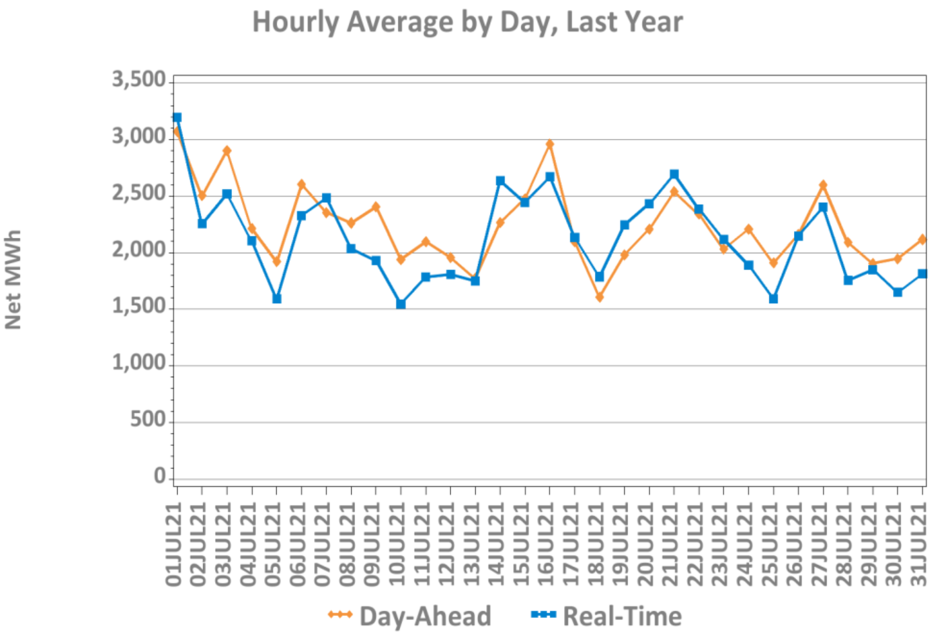
Note: There was one system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month.

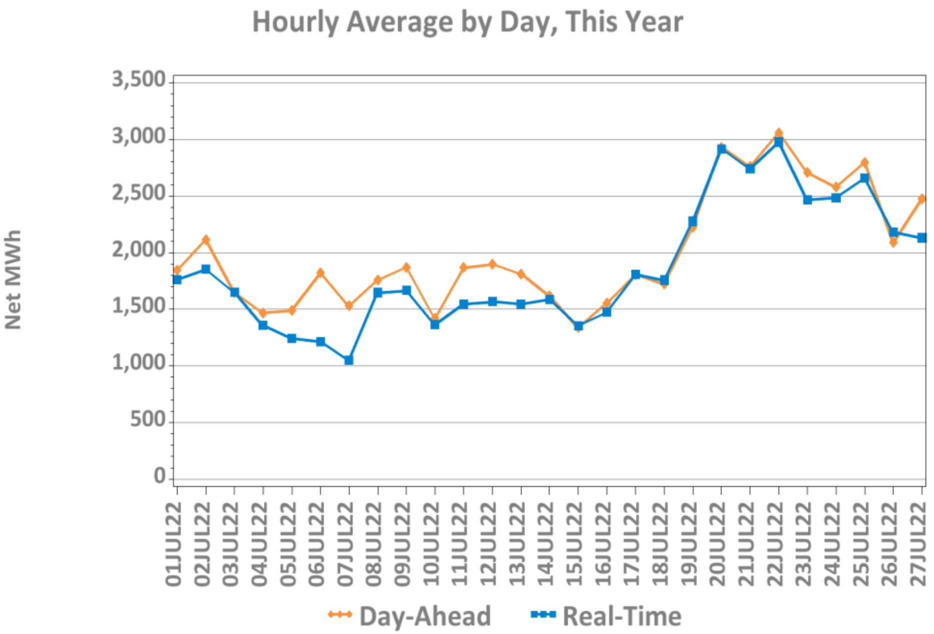
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



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

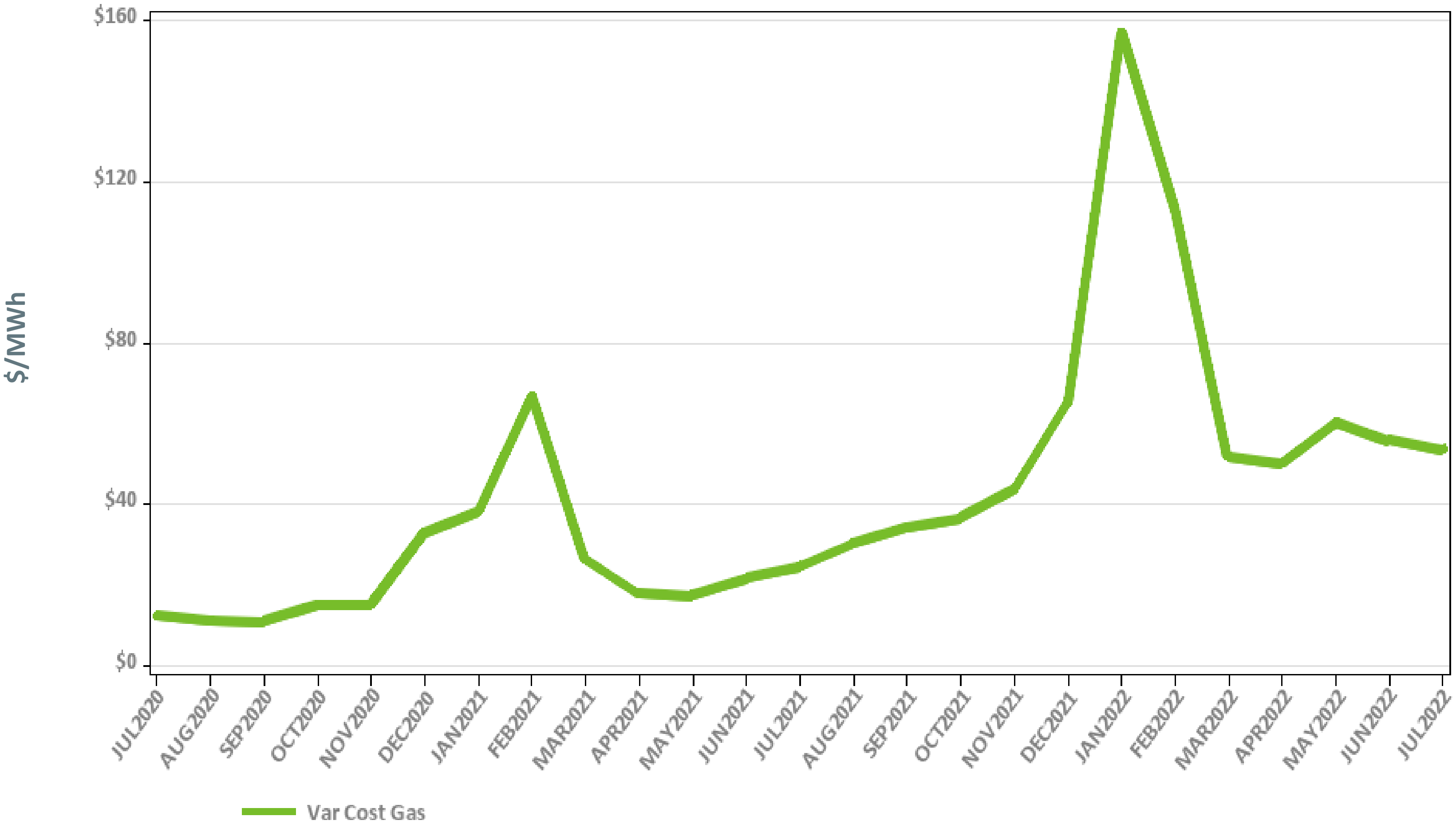
DA vs. RT Net Interchange July 2021 vs. July 2022





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

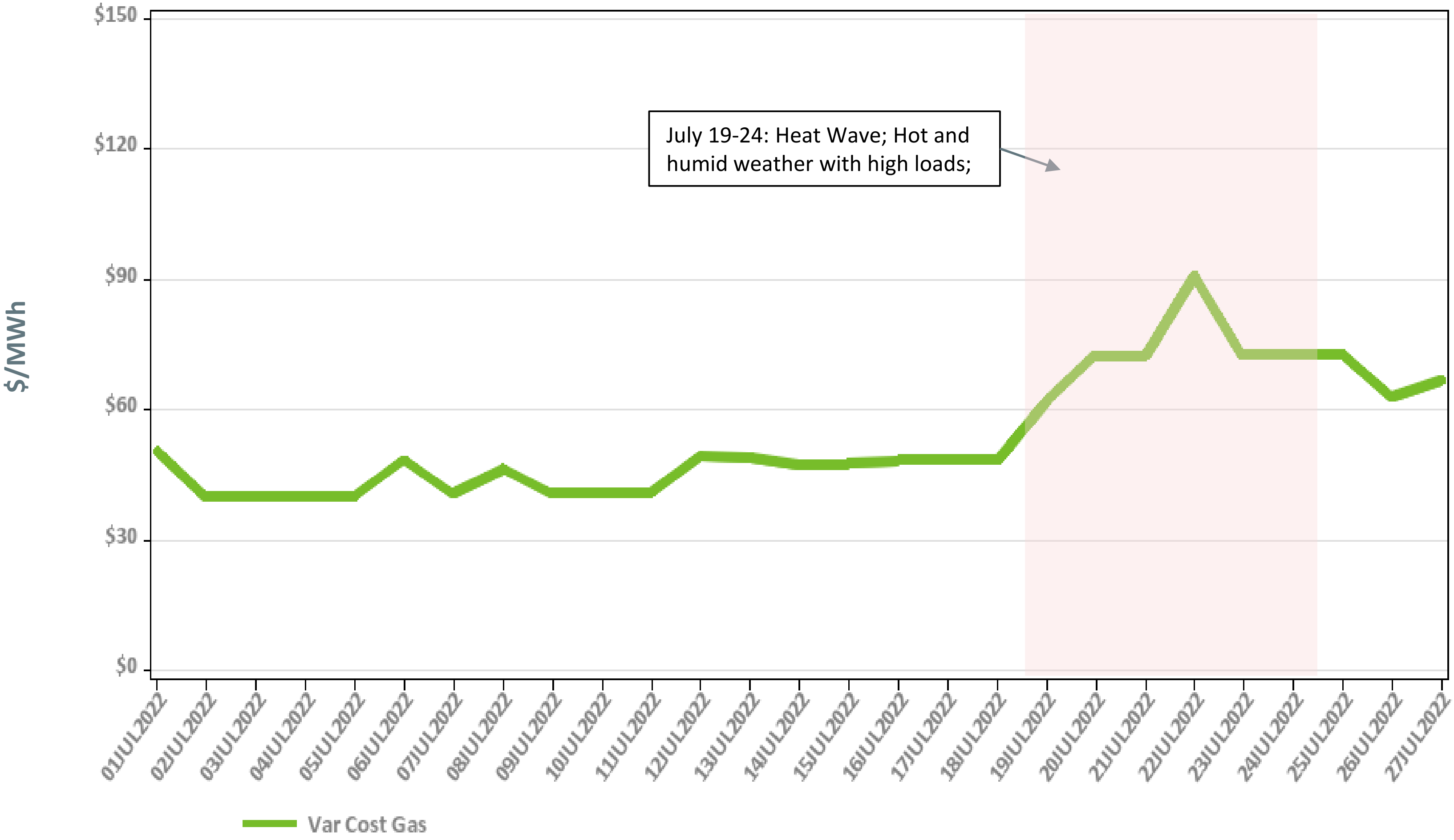
Variable Production Cost of Natural Gas: Monthly



Underlying natural gas data furnished by:

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

Variable Production Cost of Natural Gas: Daily



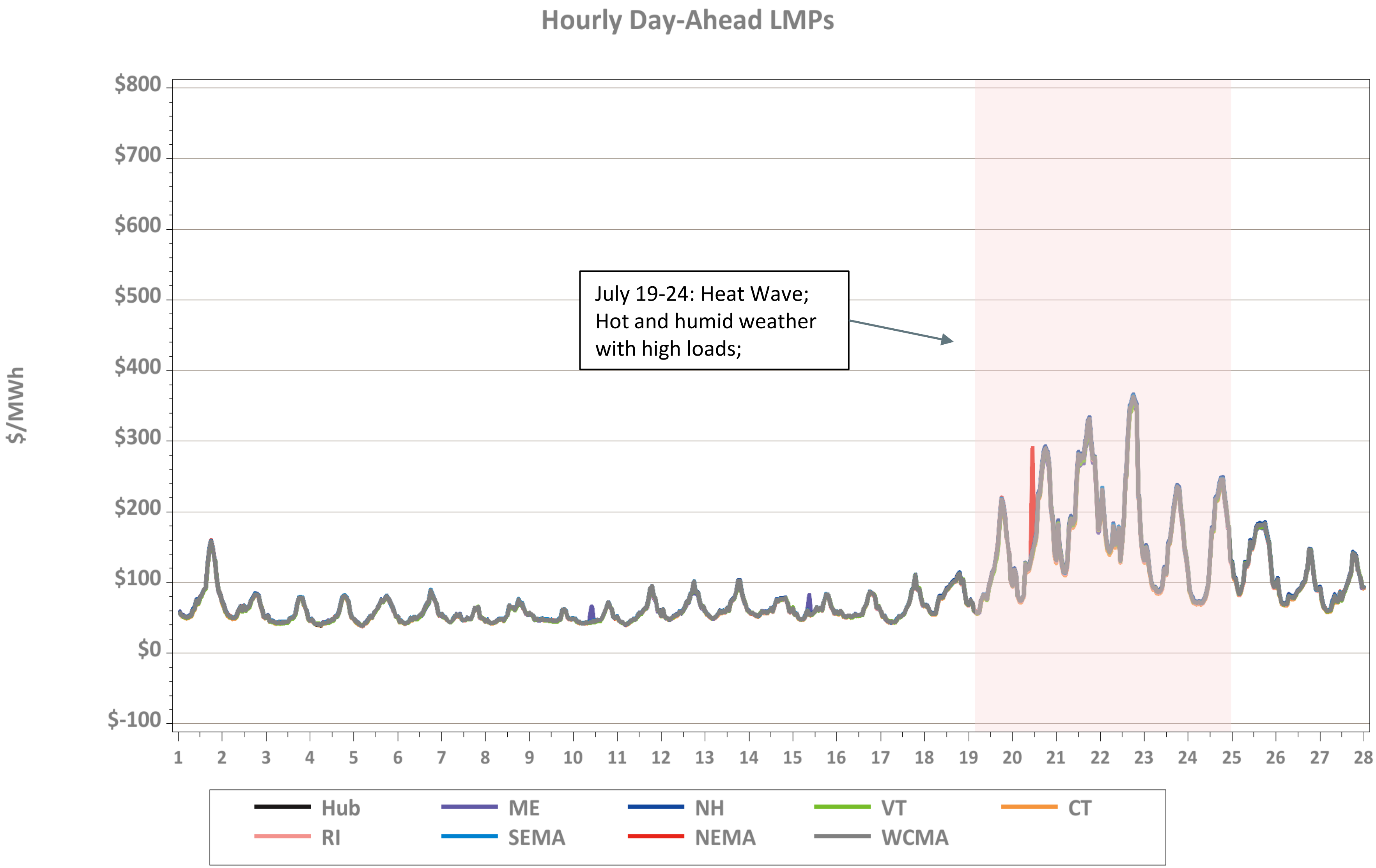
July 19-24: Heat Wave; Hot and humid weather with high loads;

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

Underlying natural gas data furnished by:

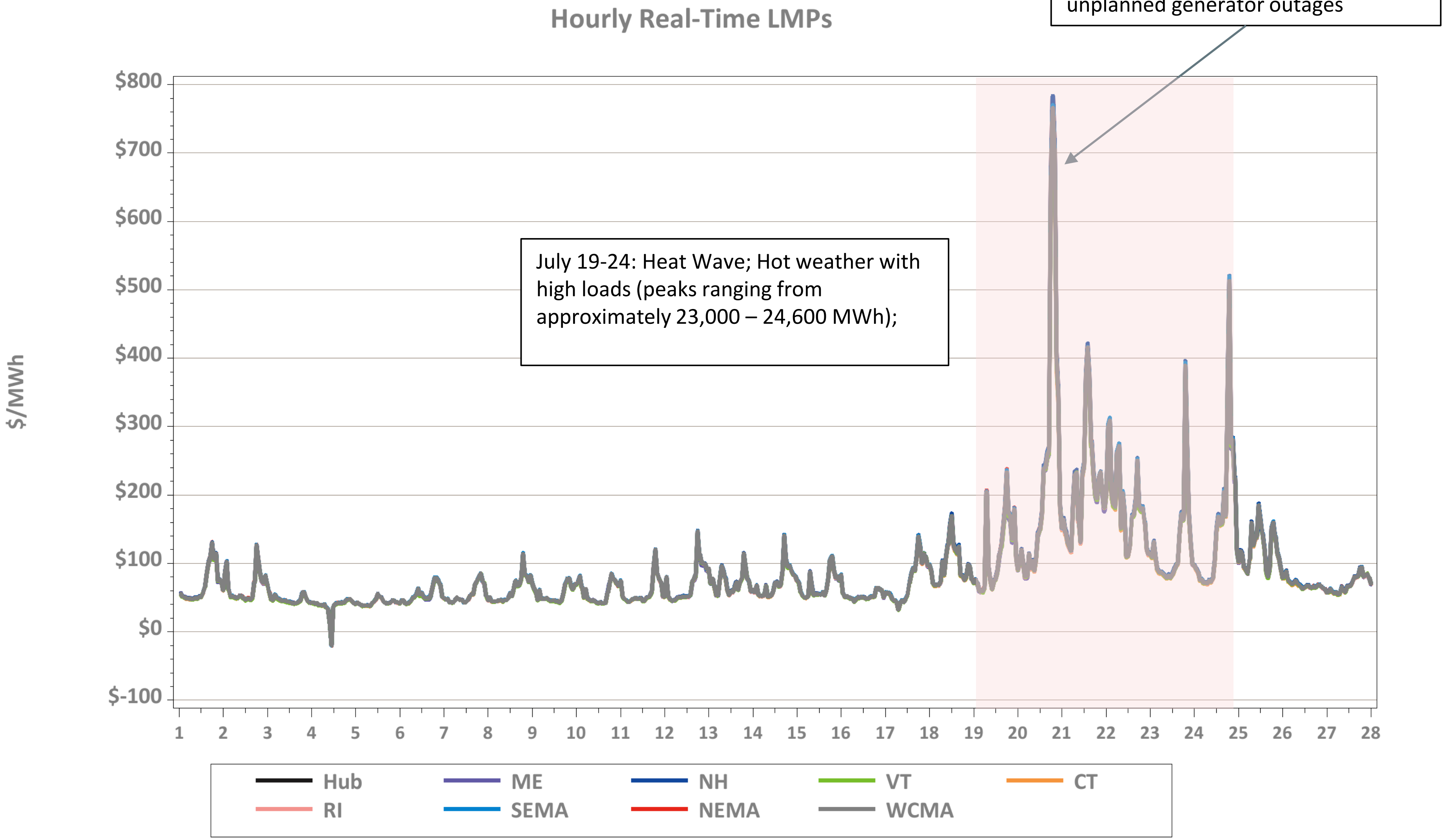
ICE Global markets in clear view

Hourly DA LMPs, July 1-27, 2022



July 19-24: Heat Wave; Hot and humid weather with high loads;

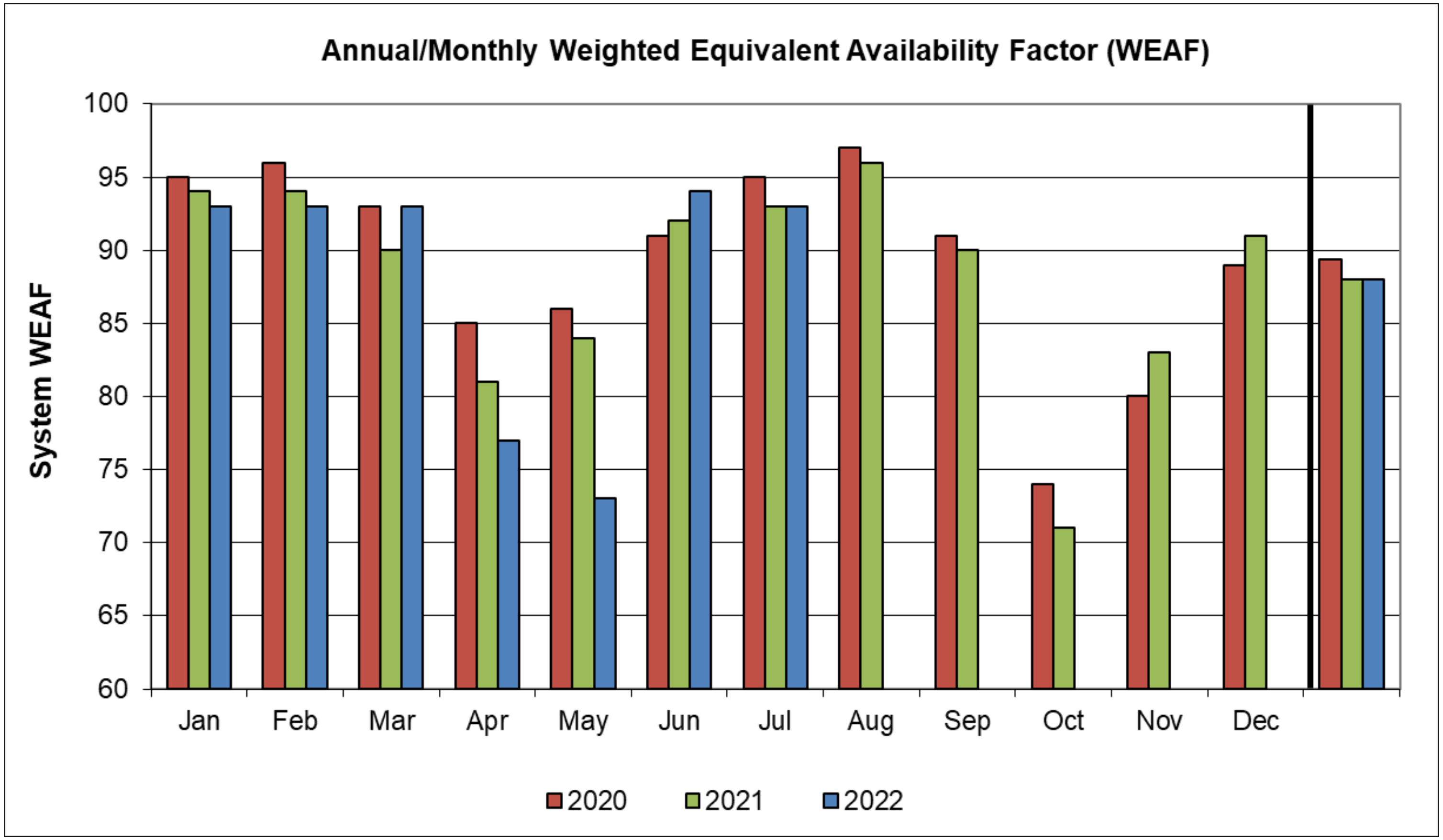
Hourly RT LMPs, July 1-27, 2022



Tight capacity with binding reserve constraints due to high loads and unplanned generator outages

July 19-24: Heat Wave; Hot weather with high loads (peaks ranging from approximately 23,000 – 24,600 MWh);

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2022	93	93	93	77	73	94	93						88
2021	94	94	90	81	84	92	93	96	90	71	83	91	88
2020	95	96	93	85	86	91	95	97	91	74	80	89	89

Data as of 7/26/2022

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for August 2022

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	91.1	209.3	0.0	300.4
NH	43.2	169.4	0.0	212.6
VT	40.7	127.9	0.0	168.6
CT	136.4	232.6	614.4	983.4
RI	40.5	341.3	0.0	381.9
SEMA	49.1	530.9	0.0	580.0
WCMA	90.6	559.1	35.2	684.9
NEMA	78.6	863.2	0.0	941.8
Total	**570.2**	**3,033.8**	**649.5**	**4,253.5**

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

NEW GENERATION

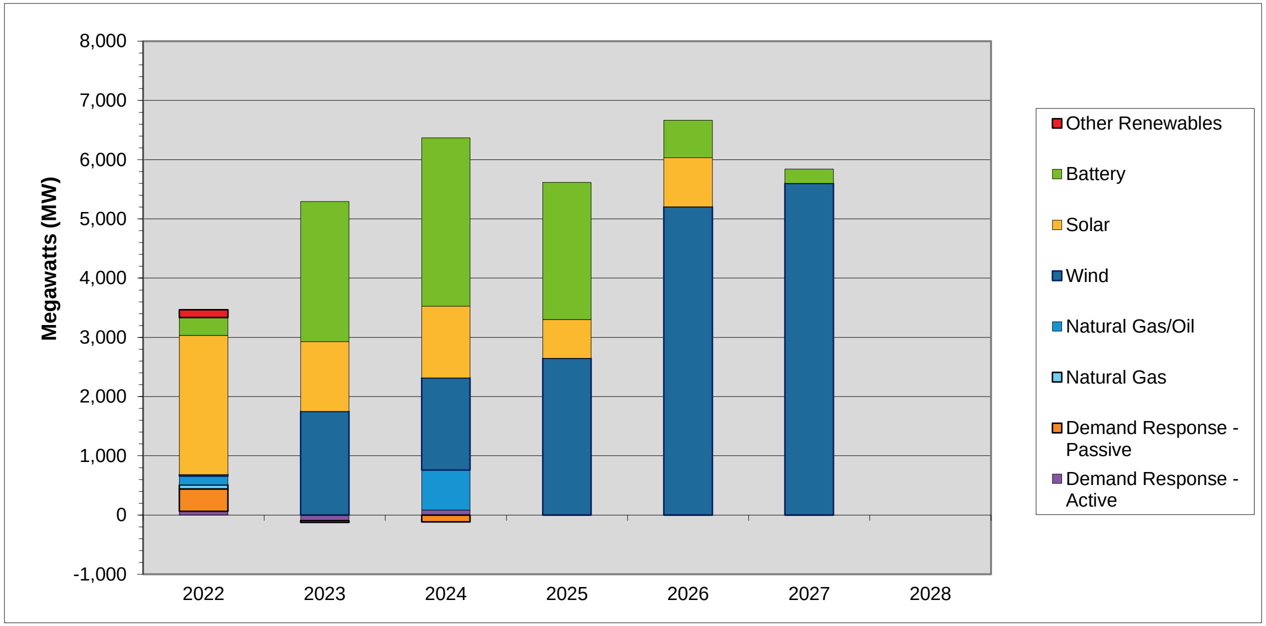
New Generation Update

Based on Queue as of 07/29/22

- One project totaling 95 MW was added to the interconnection queue since the last update
  - One battery project with an in-service date of 2023
- One project was withdrawn
- In total, 354 generation projects are currently being tracked by the ISO, totaling approximately 33,924 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2022	2023	2024	2025	2026	2027	2028	Total MW	% of Total[1]
Other Renewables	129	0	0	0	0	0	0	129	0.4
Battery	305	2,367	2,841	2,316	634	242	0	8,705	26.4
Solar[2]	2,348	1,175	1,213	654	831	0	0	6,221	18.8
Wind	24	1,752	1,556	2,645	5,203	5,599	0	16,779	50.8
Natural Gas/Oil[3]	151	0	672	0	0	0	0	823	2.5
Natural Gas	67	0	0	0	0	0	0	67	0.2
Demand Response - Passive	380	-28	-114	0	0	0	0	238	0.7
Demand Response - Active	62	-94	86	0	0	0	0	54	0.2
Totals	3,466	5,172	6,254	5,615	6,668	5,841	0	33,016	100.0

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

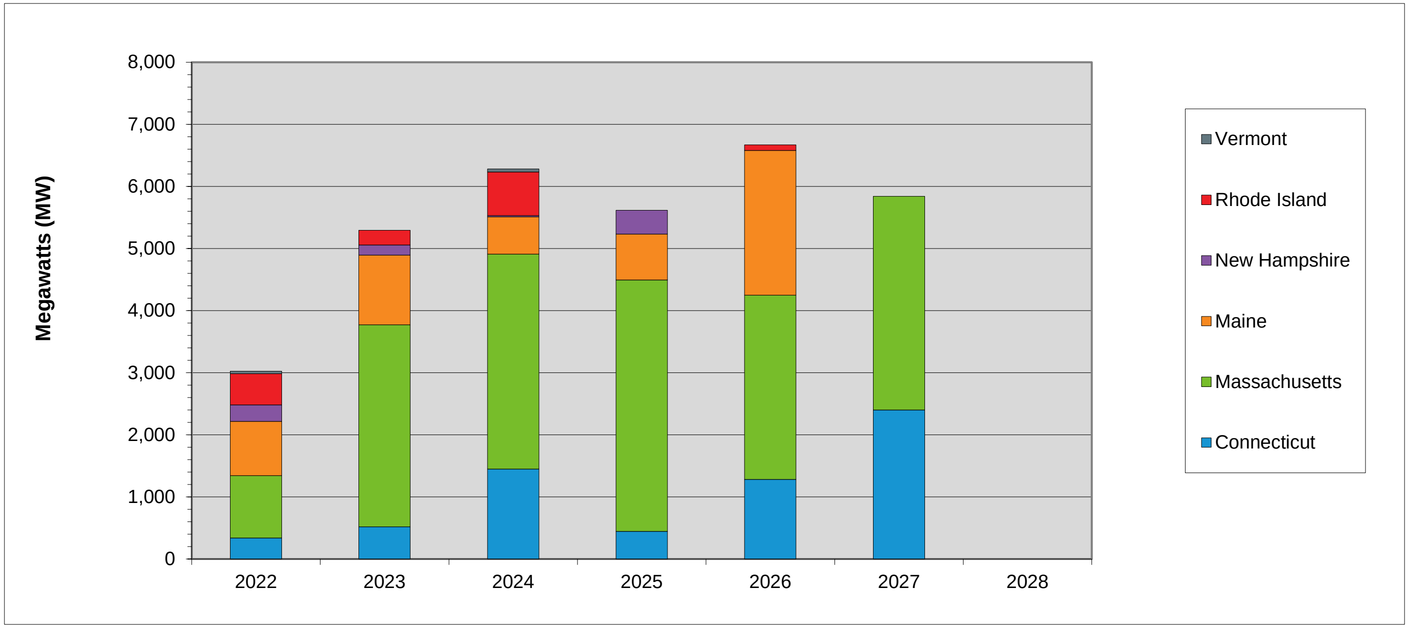
[2] This category includes both solar-only, and co-located solar and battery projects

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

- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2022	2023	2024	2025	2026	2027	2028	Total MW	% of Total[1]
Vermont	40	0	50	0	0	0	0	90	0.3
Rhode Island	502	236	704	0	91	0	0	1,533	4.7
New Hampshire	266	164	20	385	0	0	0	835	2.6
Maine	875	1,123	597	737	2,328	0	0	5,660	17.3
Massachusetts	1,001	3,251	3,462	4,049	2,966	3,441	0	18,170	55.5
Connecticut	340	520	1,449	444	1,283	2,400	0	6,436	19.7
Totals	**3,024**	**5,294**	**6,282**	**5,615**	**6,668**	**5,841**	**0**	**32,724**	**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	60	8,705	0	0	60	8,705
Fuel Cell	2	30	0	0	2	30
Hydro	3	99	2	71	1	28
Natural Gas	7	67	0	0	7	67
Natural Gas/Oil	5	823	1	62	4	761
Nuclear	0	0	0	0	0	0
Solar	249	6,221	23	242	226	5,979
Wind	28	17,979	1	20	27	17,959
Total	354	33,924	27	395	327	33,529

- 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
- 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	5	70	1	5	4	65
Intermediate	7	804	0	0	7	804
Peaker	314	15,071	25	370	289	14,701
Wind Turbine	28	17,979	1	20	27	17,959
Total	354	33,924	27	395	327	33,529

- Green denotes projects with a high probability of going into service
- 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	60	8,705	0	0	0	0	60	8,705	0	0
Fuel Cell	2	30	2	30	0	0	0	0	0	0
Hydro	3	99	2	33	0	0	1	66	0	0
Natural Gas	7	67	1	7	3	43	3	17	0	0
Natural Gas/Oil	5	823	0	0	4	761	1	62	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	249	6,221	0	0	0	0	249	6,221	0	0
Wind	28	17,979	0	0	0	0	0	0	28	17,979
Total	354	33,924	5	70	7	804	314	15,071	28	17,979

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 13

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*	685.554	683.116	-2.438	658.659	-24.457	609.826	-48.833
	Passive Demand	3,354.69	3,407.507	52.817	3,450.899	43.392	3,512.604	61.705
Demand Total		**4,040.244**	**4,090.623**	**50.38**	**4,109.558**	**18.935**	**4,122.43**	**12.872**
Generator	*Non-Intermittent*	28,586.498	27,868.341	-718.157	28,105.411	237.07	27,426.242	-679.169
	Intermittent	1,024.792	901.672	-123.12	896.285	-5.387	778.962	-117.323
Generator Total		**2,9611.29**	**28,770.013**	**-841.28**	**29,001.696**	**231.683**	**28,205.204**	**-796.492**
Import Total		**1,187.69**	**1,292.41**	**104.72**	**1,292.41**	**0**	**1,115.22**	**-177.19**
Grand Total*		**34,839.224**	**34,153.046**	**-686.18**	**34,403.664**	**250.618**	**33,442.854**	**-960.81**
Net ICR (NICR)		**33,750**	**32,465**	**-1,285**	**32,765**	**300**	**31,590**	**-1,175**

* 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 bilaterals and reconfiguration auction 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 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

ARA – Annual Reconfiguration Auction
CSO – Capacity Supply Obligation

FCA – Forward Capacity Auction
ICR – Installed Capacity Requirement

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				
	Passive Demand	3,327.071	3,327.932	0.861				
Demand Total		**3,919.114**	**4,016.002**	**96.888**				
Generator	*Non-Intermittent*	27,816.902	28,275.143	458.241				
	Intermittent	1,160.916	1,128.446	-32.47				
Generator Total		**28,977.818**	**29,403.589**	**425.771**				
Import Total		**1,058.72**	**1,058.72**	**0**				
Grand Total*		**33,955.652**	**34,478.311**	**522.661**				
Net ICR (NICR)		**32,490**	**32,980**	**490**				

* 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 bilaterals and reconfiguration auction 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 2015-2020 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 bilaterals and reconfiguration auction 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 2015-2020 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						
	Passive Demand	2,557.256						
Demand Total		**3,322.606**						
Generator	*Non-Intermittent*	26,805.003						
	Intermittent	1,178.933						
Generator Total		**27,983.936**						
Import Total		**1,503.842**						
Grand Total*		**32,810.384**						
Net ICR (NICR)		**31,645**						

* 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 bilaterals and reconfiguration auction 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 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/Passive	Existing	New	Grand Total
2019-20	Active	357.221	20.304	377.525
	Passive	2,018.20	350.43	2,368.63
	Grand Total	**2,375.422**	**370.734**	**2,746.156**
2020-21	Active	334.634	85.294	419.928
	Passive	2,236.73	554.292	2,791.02
	Grand Total	**2,571.361**	**639.586**	**3,210.947**
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	**3,085.734**	**514.072**	**3,599.806**
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	**3,386.703**	**653.541**	**4,040.244**
2023-24	Active	560.55	31.493	592.043
	Passive	3,035.51	291.565	3,327.07
	Grand Total	**3,596.056**	**323.058**	**3,919.114**
2024-25	Active	674.153	3.520	677.673
	Passive	3,046.064	166.801	3,212.865
	Grand Total	**3,720.217**	**170.321**	**3,890.538**
2025-26	Active	664.01	101.34	765.35
	Passive	2,428.638	128.618	2557.256
	Grand Total	**3,092.648**	**229.958**	**3,322.606**

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

What are Daily NCPC Payments?

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

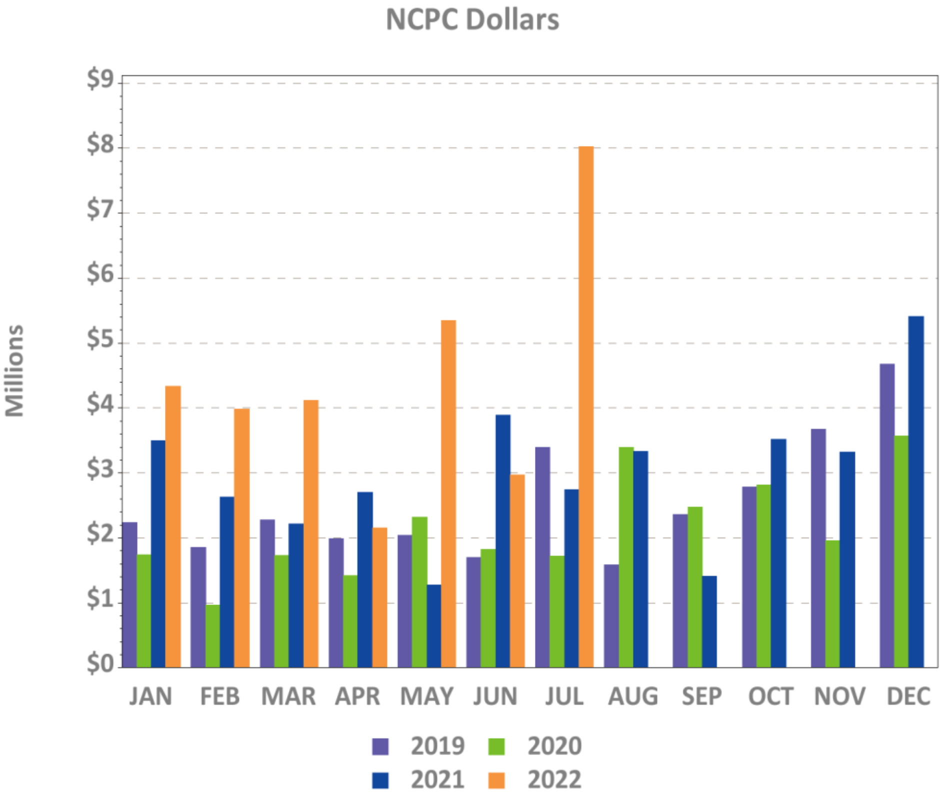
Definitions

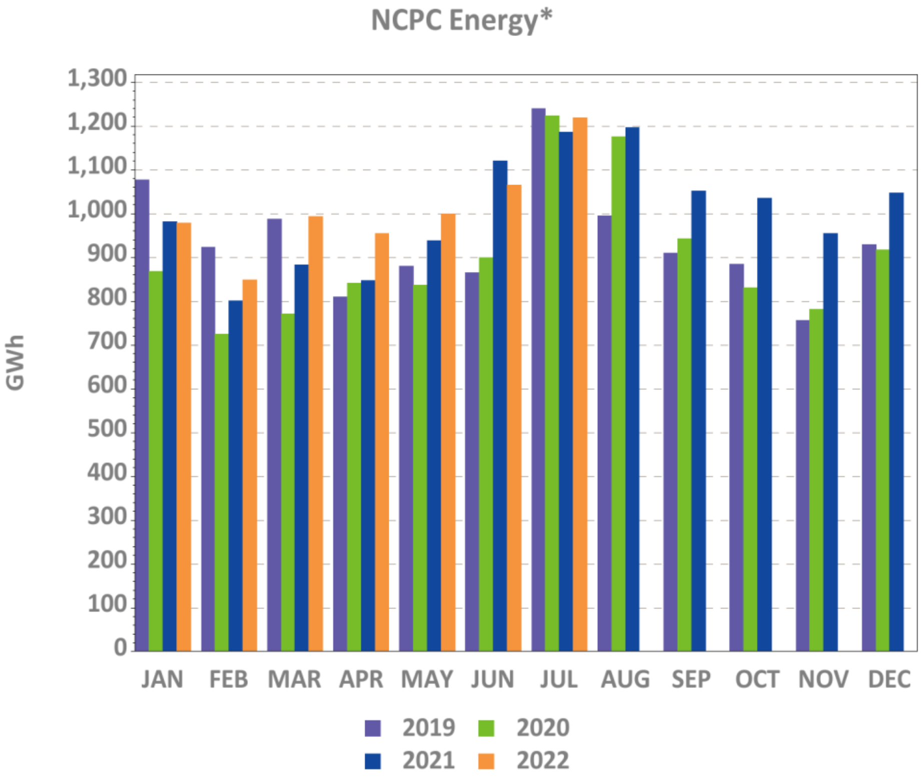
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

Charge Allocation Key

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

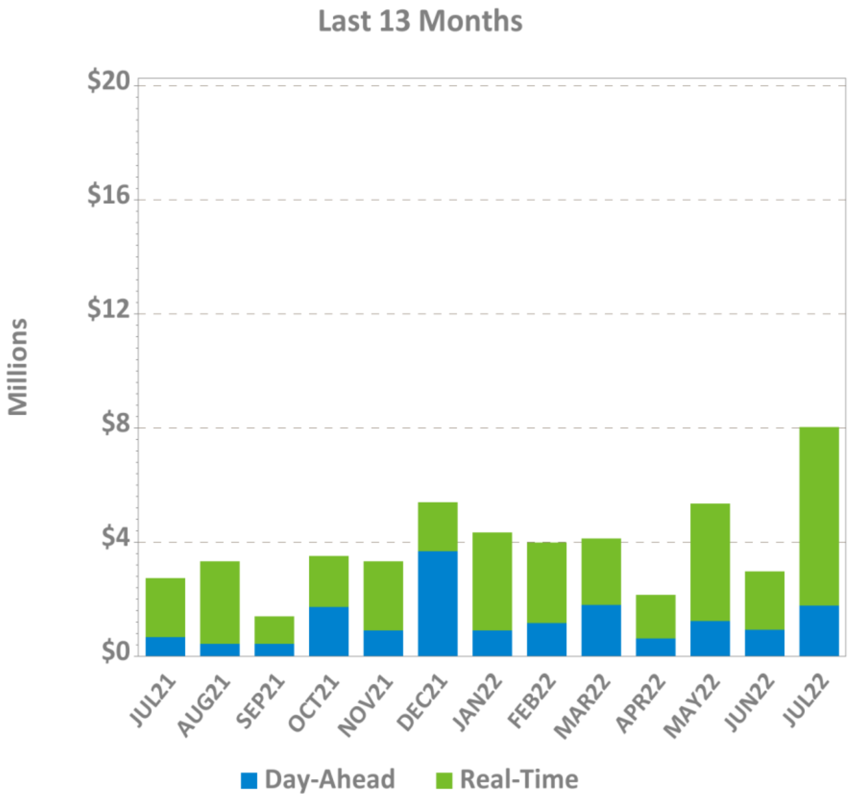
Year-Over-Year Total NCPC Dollars and Energy



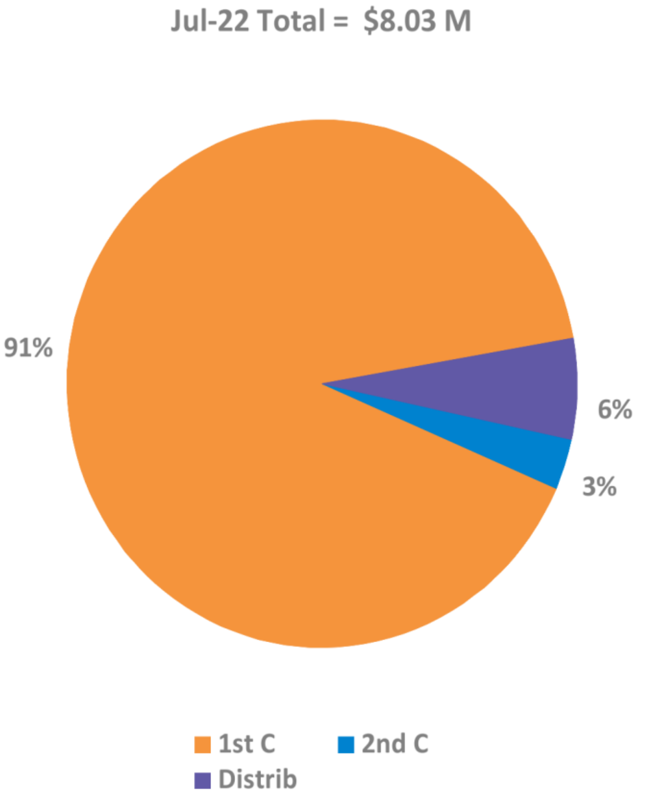


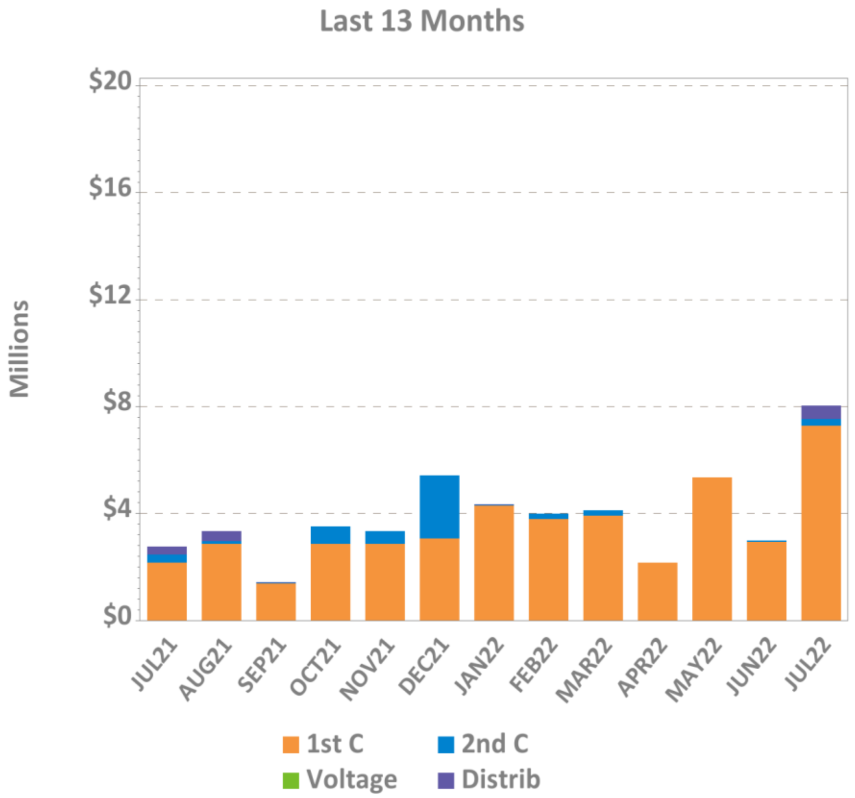
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

DA and RT NCPC Charges



NCPC Charges by Type

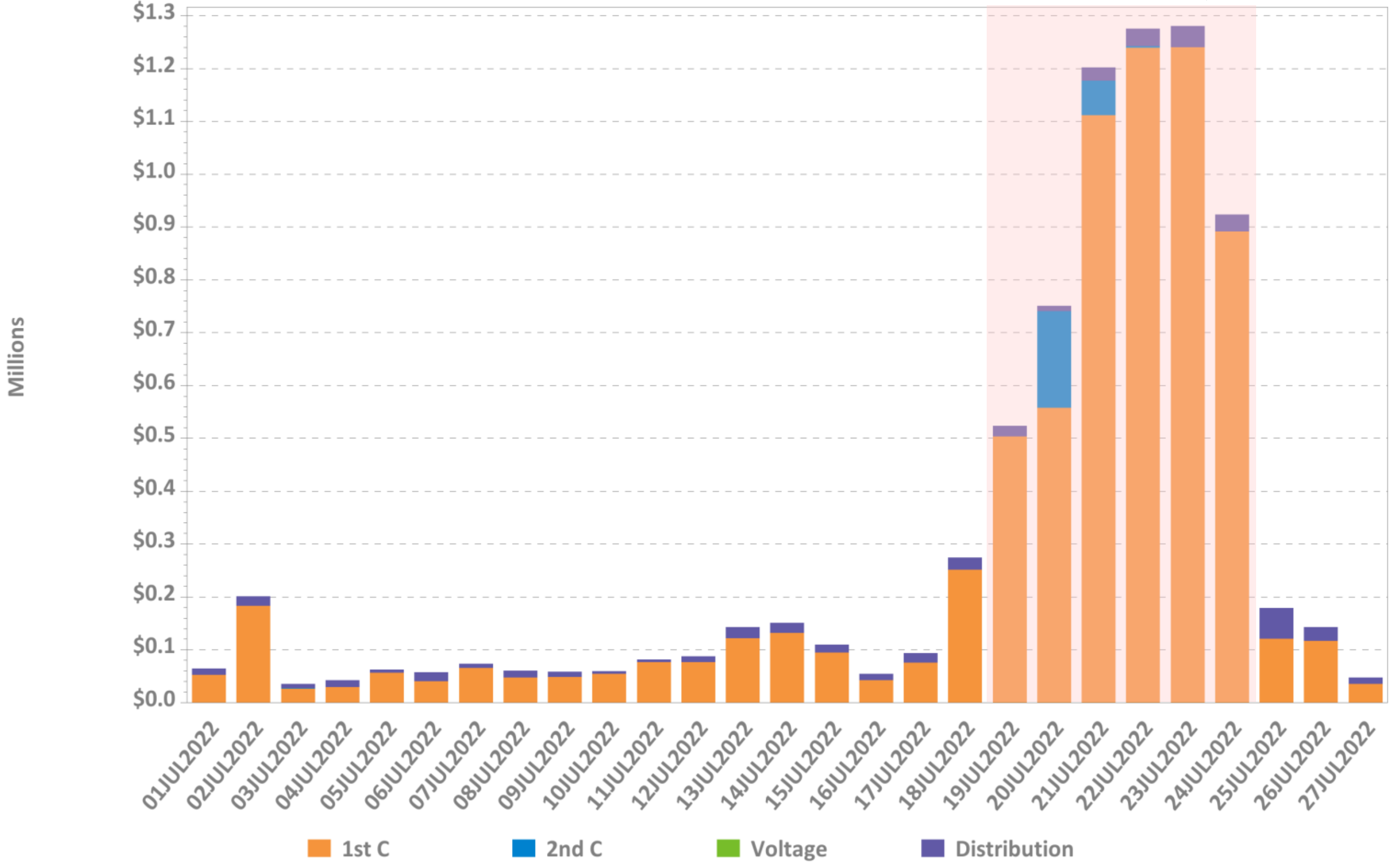




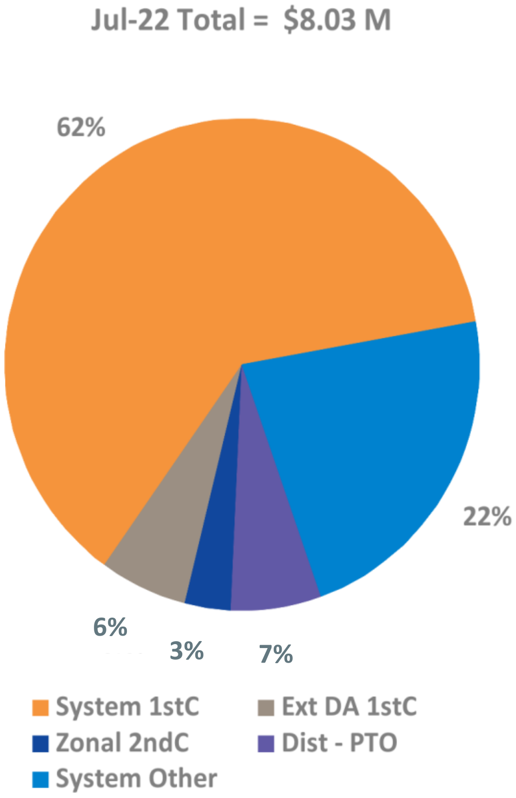
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

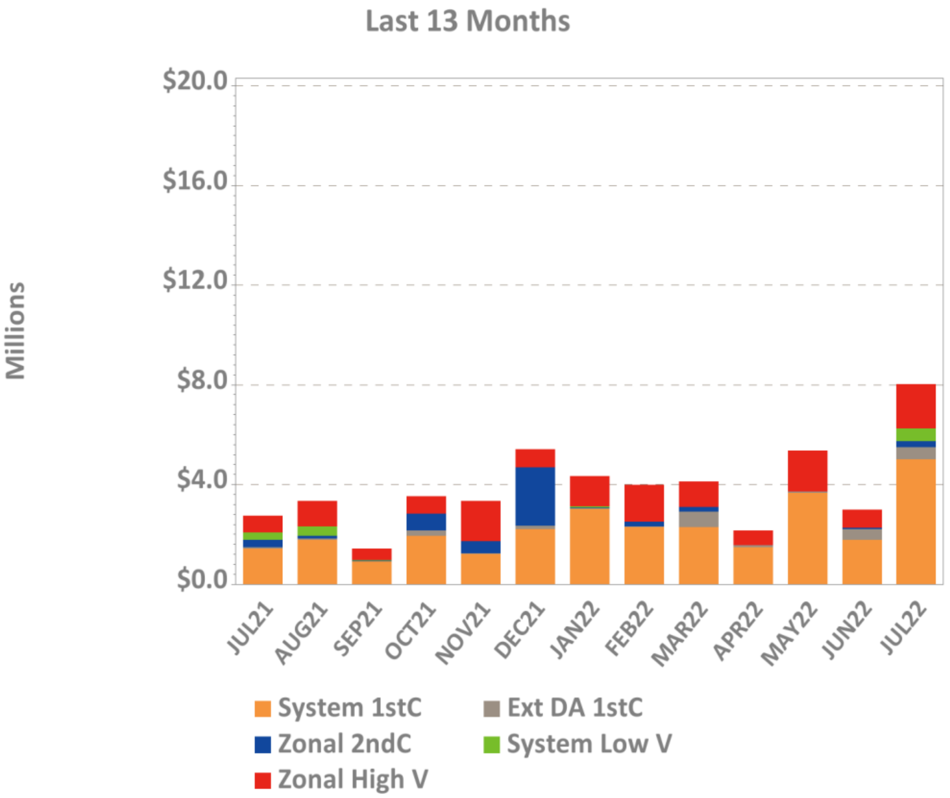
Daily NCPC Charges by Type

July 19-24: Elevated NCPC associated with supplemental commitments and operations required to mitigate projected capacity deficiency during a heat wave, and increased input fuel prices that raised commitment offer costs



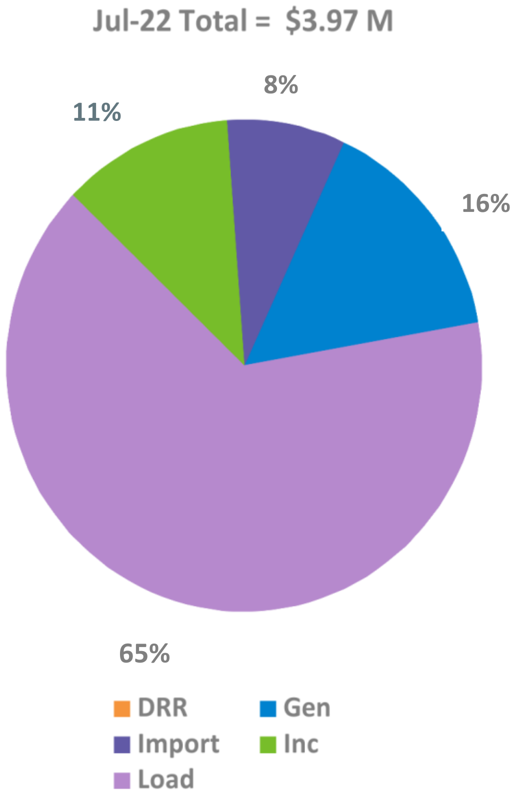
NCPC Charges by Allocation

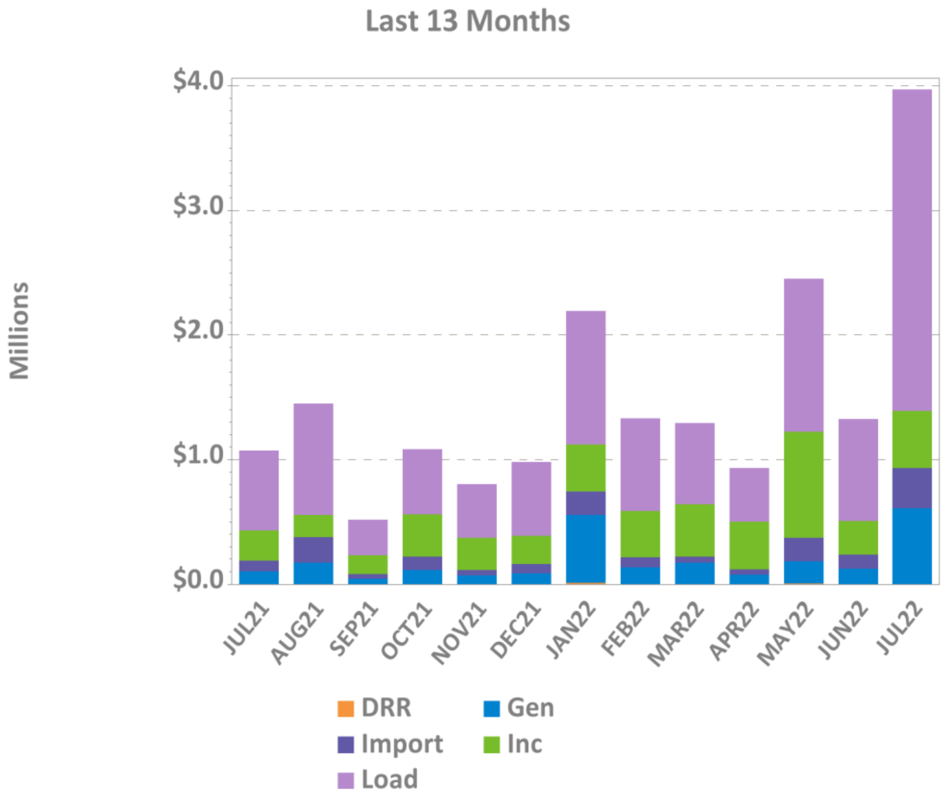




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

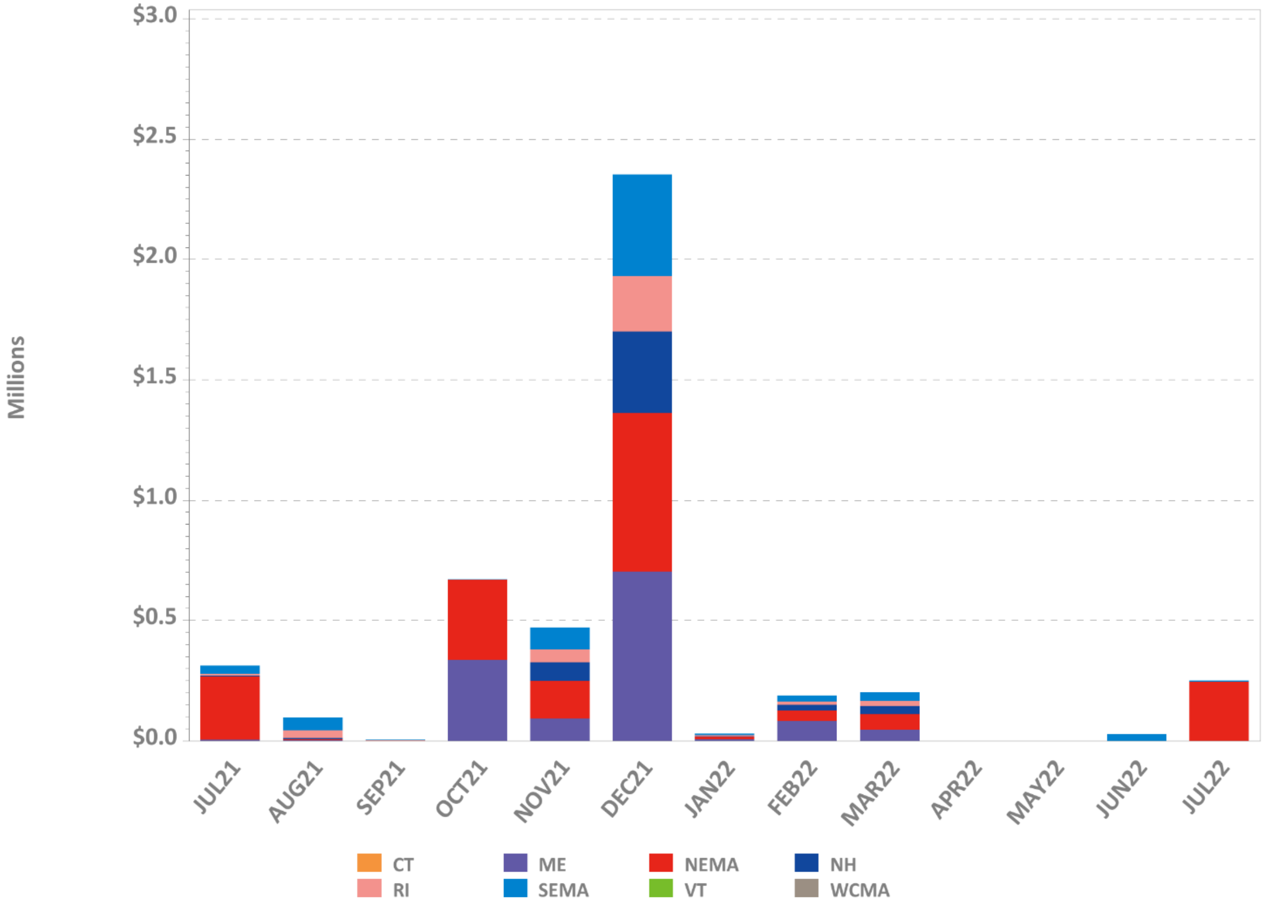
RT First Contingency Charges by Deviation Type





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

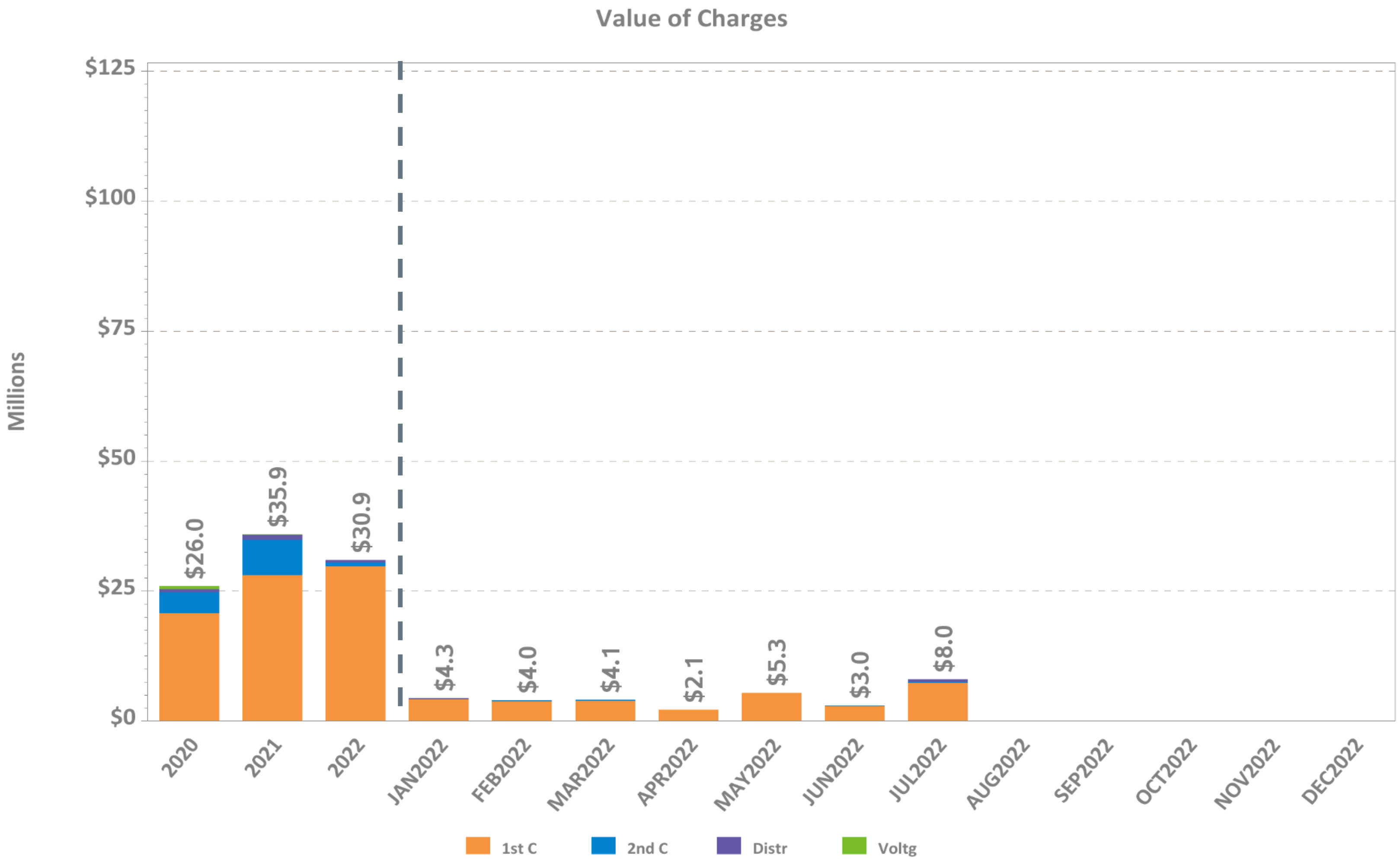
LSCPR Charges by Reliability Region



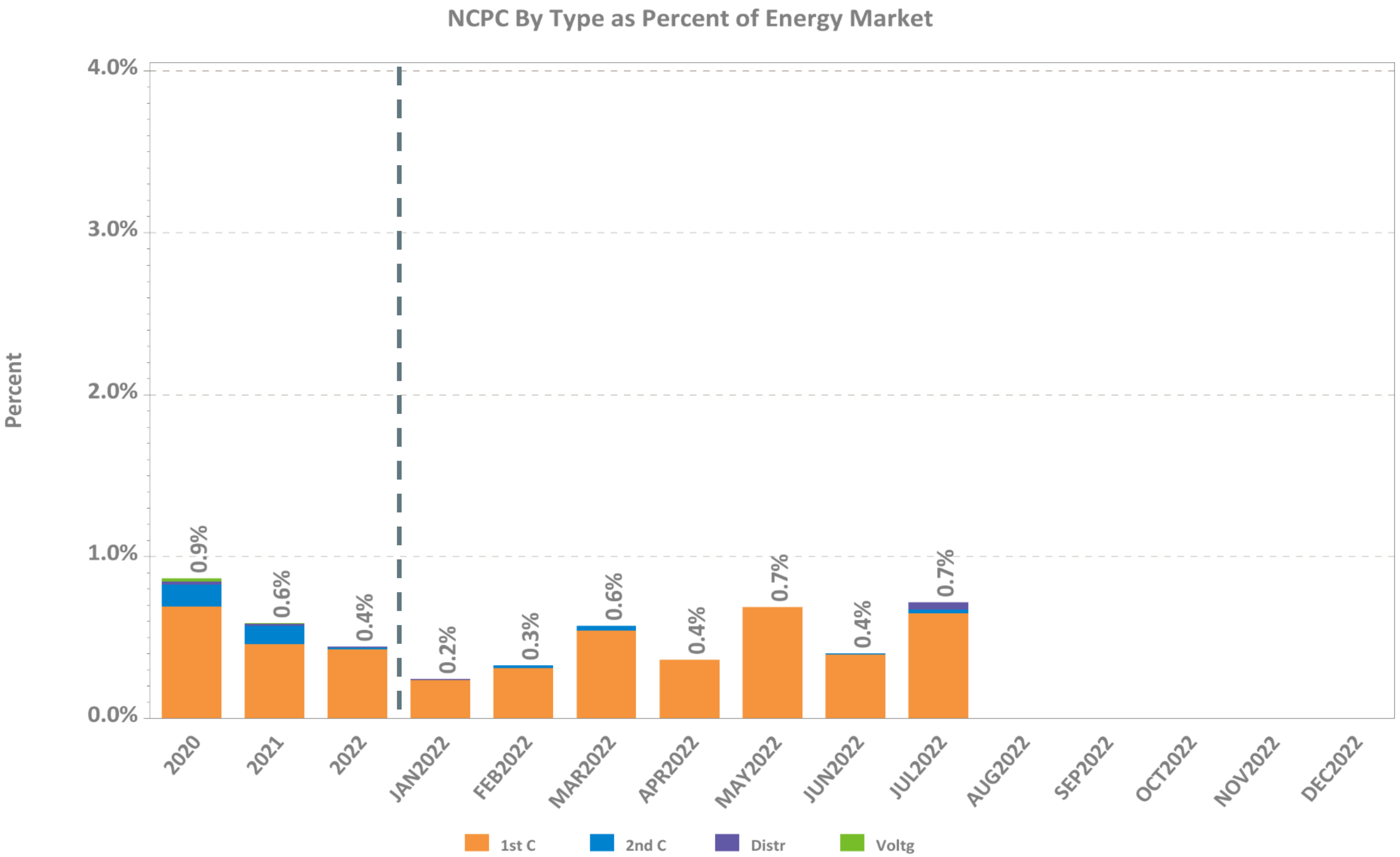
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

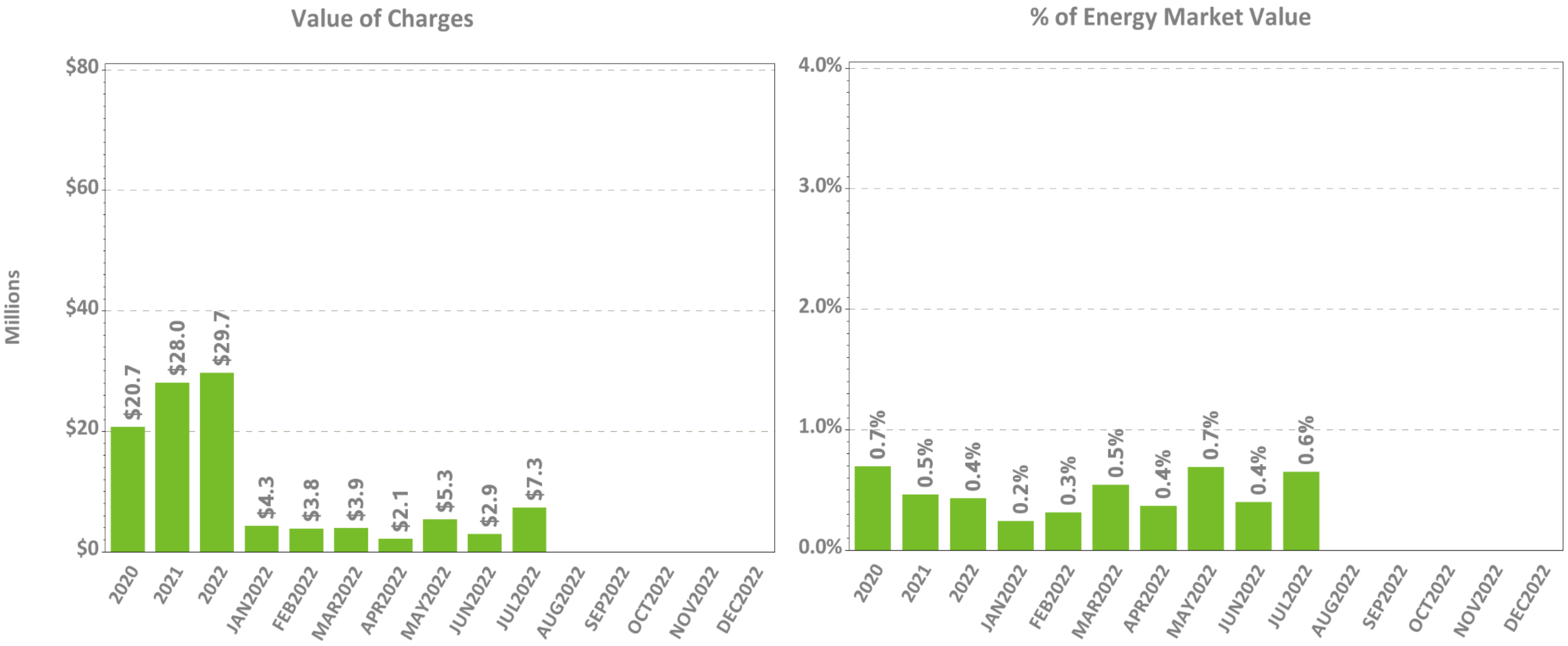
NCPC Charges by Type



NCPC Charges as Percent of Energy Market

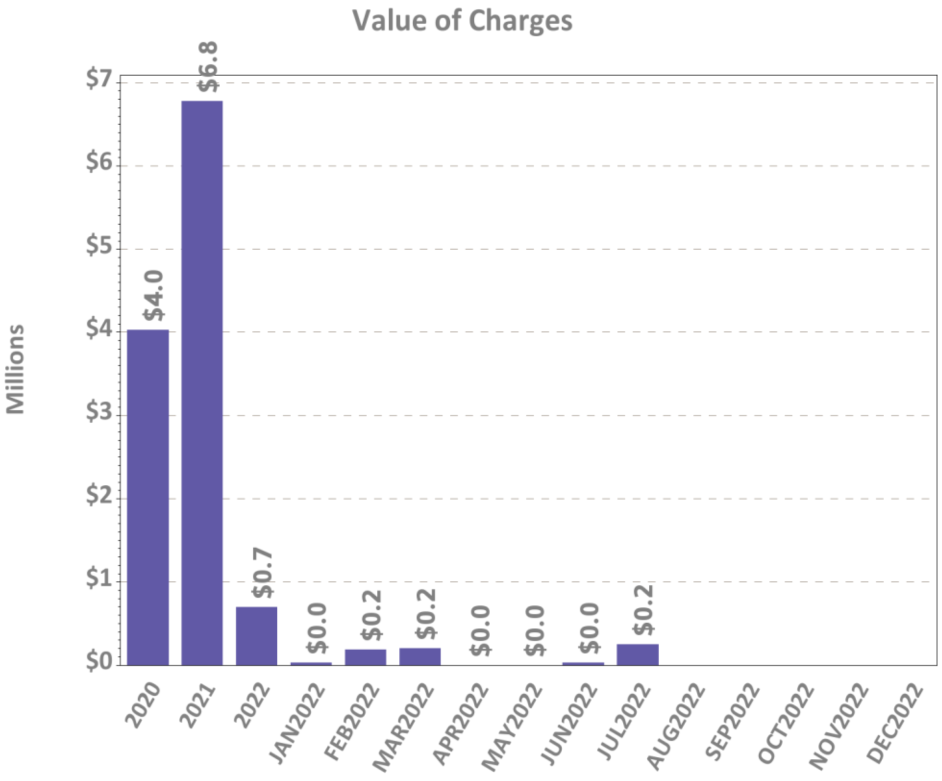


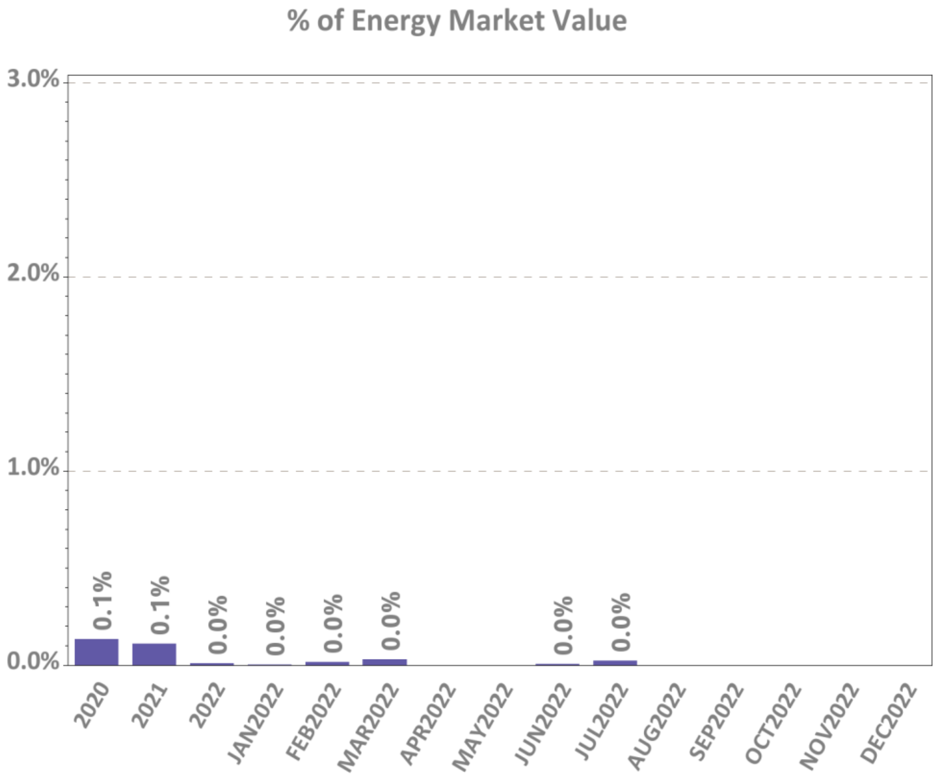
First Contingency NCPC Charges



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

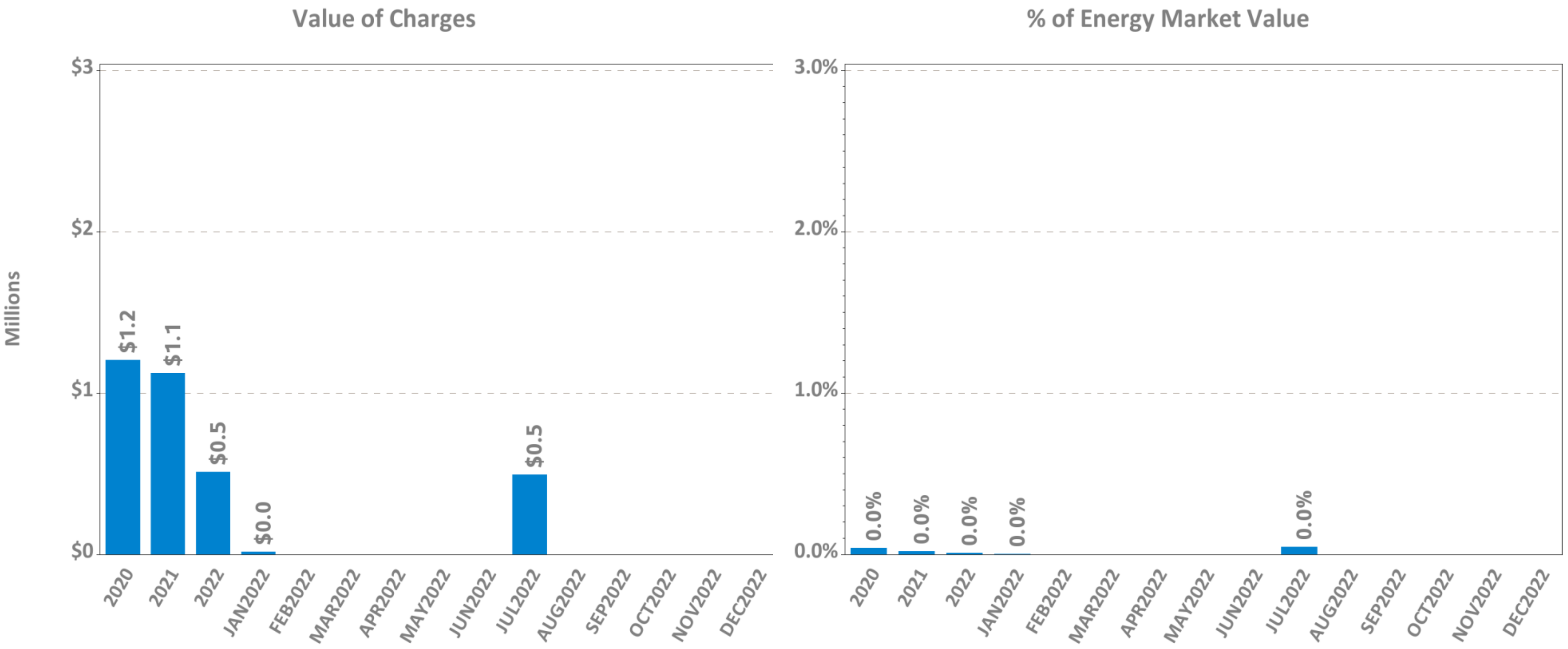
Second Contingency NCPC Charges





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

Voltage and Distribution NCPC Charges



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

DA vs. RT Pricing

The following slides outline:

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

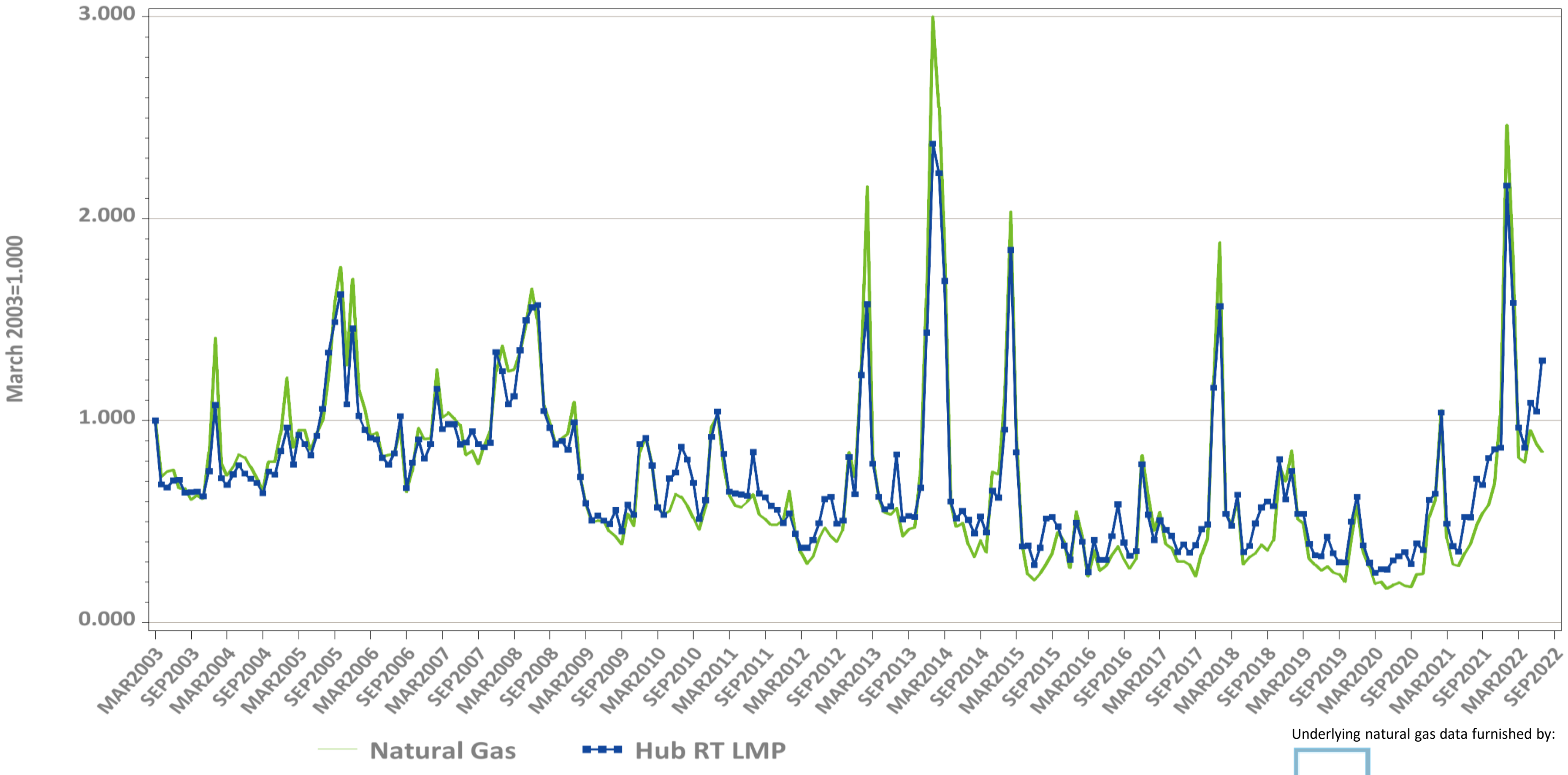
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2020	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$23.62	$22.59	$23.27	$23.50	$22.76	$23.27	$23.57	$23.30	$23.32
Real-Time	$23.62	$22.91	$23.23	$23.54	$22.90	$23.29	$23.56	$23.37	$23.38
RT Delta %	0.0%	1.4%	-0.2%	0.2%	0.6%	0.1%	-0.1%	0.3%	0.3%
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%

July-21	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$37.52	$36.68	$36.79	$37.40	$36.96	$36.92	$37.35	$37.21	$37.16
Real-Time	$36.12	$35.51	$35.53	$35.98	$35.48	$35.55	$35.96	$35.80	$35.76
RT Delta %	-3.7%	-3.2%	-3.4%	-3.8%	-4.0%	-3.7%	-3.7%	-3.8%	-3.8%
July-22	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$90.19	$88.00	$89.08	$90.53	$89.08	$88.78	$89.80	$89.64	$89.42
Real-Time	$89.90	$88.03	$88.47	$90.17	$88.32	$88.60	$89.71	$89.27	$89.06
RT Delta %	-0.3%	0.0%	-0.7%	-0.4%	-0.9%	-0.2%	-0.1%	-0.4%	-0.4%
Annual Diff.	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Yr over Yr DA	140.4%	139.9%	142.1%	142.0%	141.0%	140.5%	140.4%	140.9%	140.6%
Yr over Yr RT	148.9%	147.9%	149.0%	150.6%	148.9%	149.2%	149.5%	149.4%	149.1%

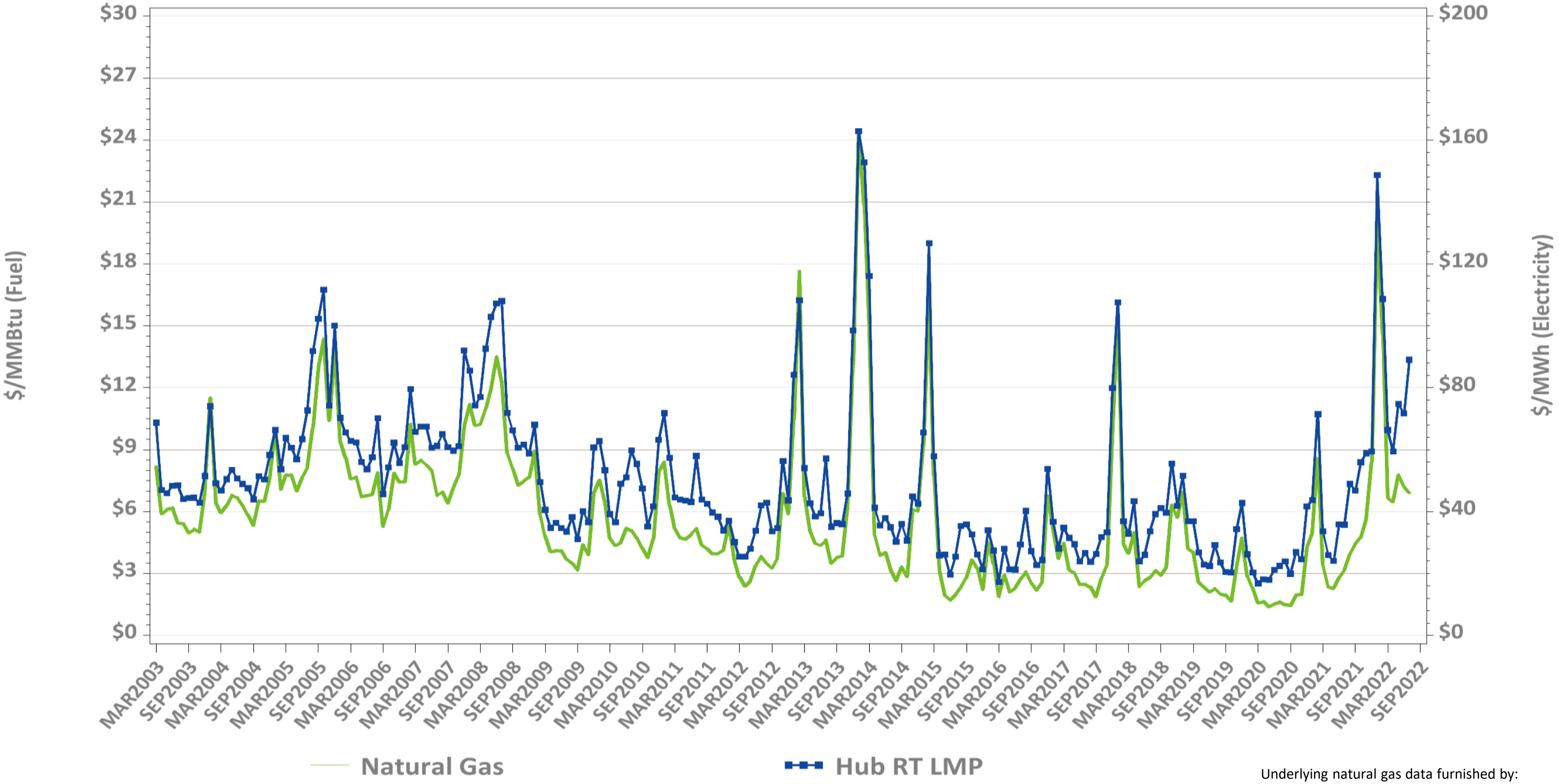
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ice Global markets in clear view

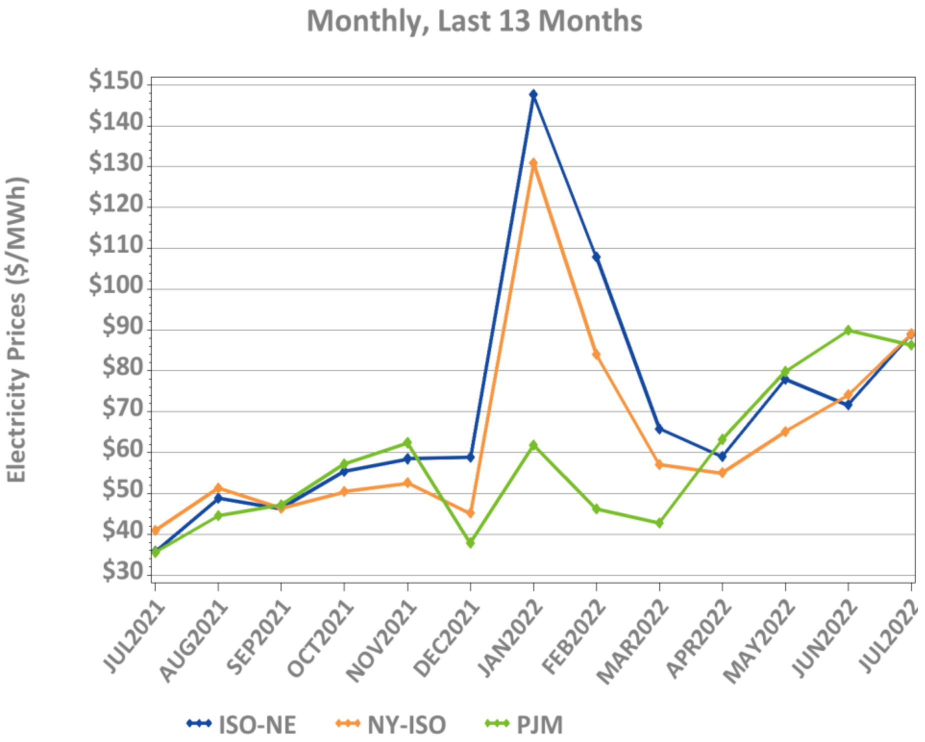
Monthly Average Fuel Price and RT Hub LMP



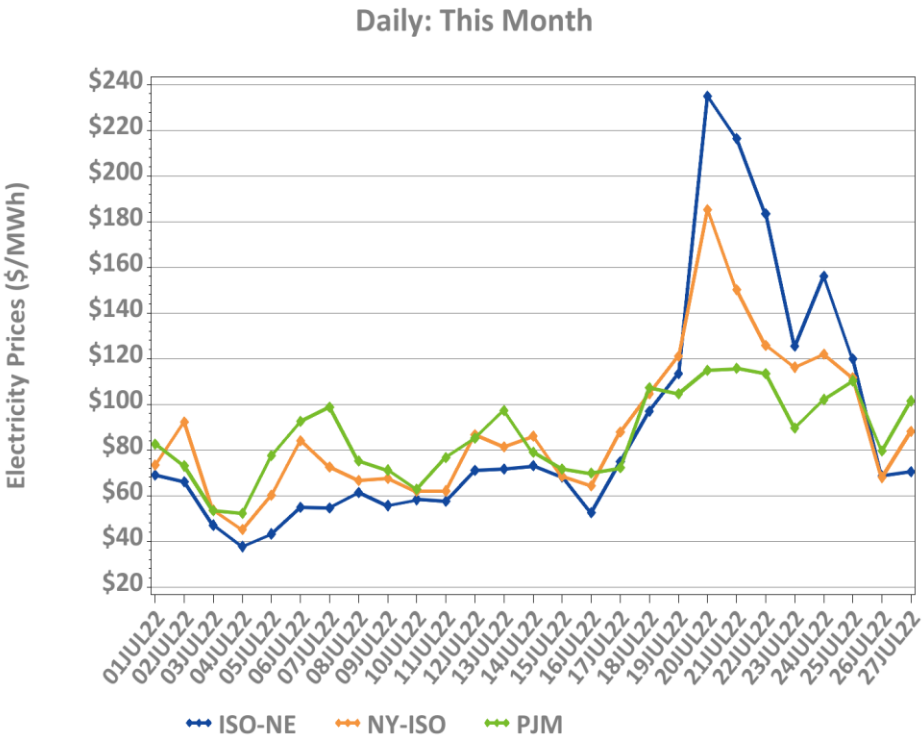
Underlying natural gas data furnished by:

ice Global markets in clear view

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

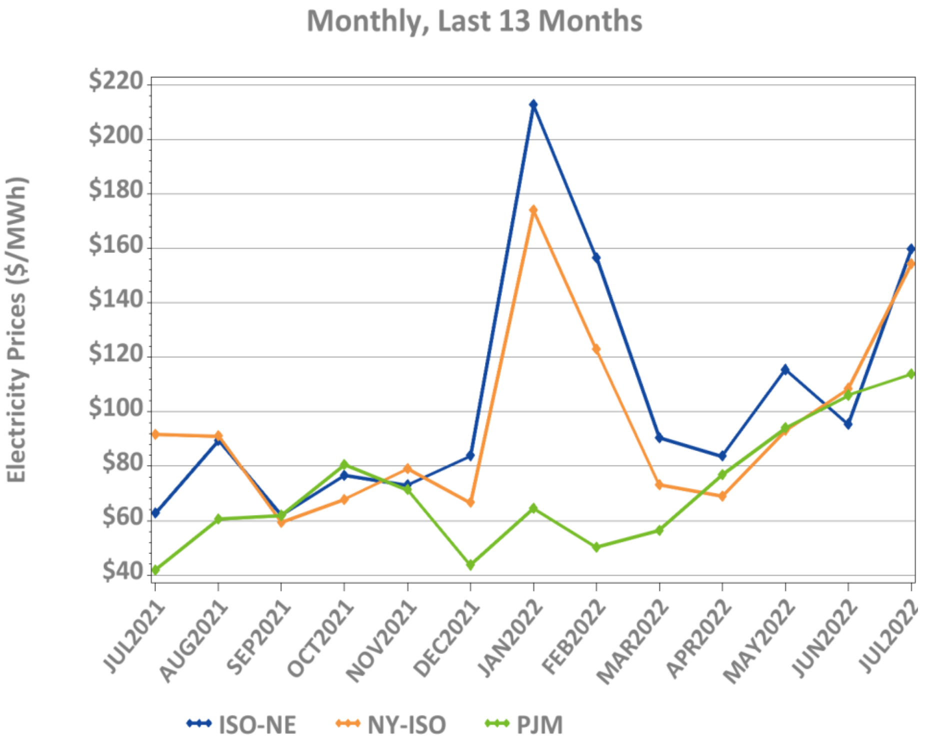


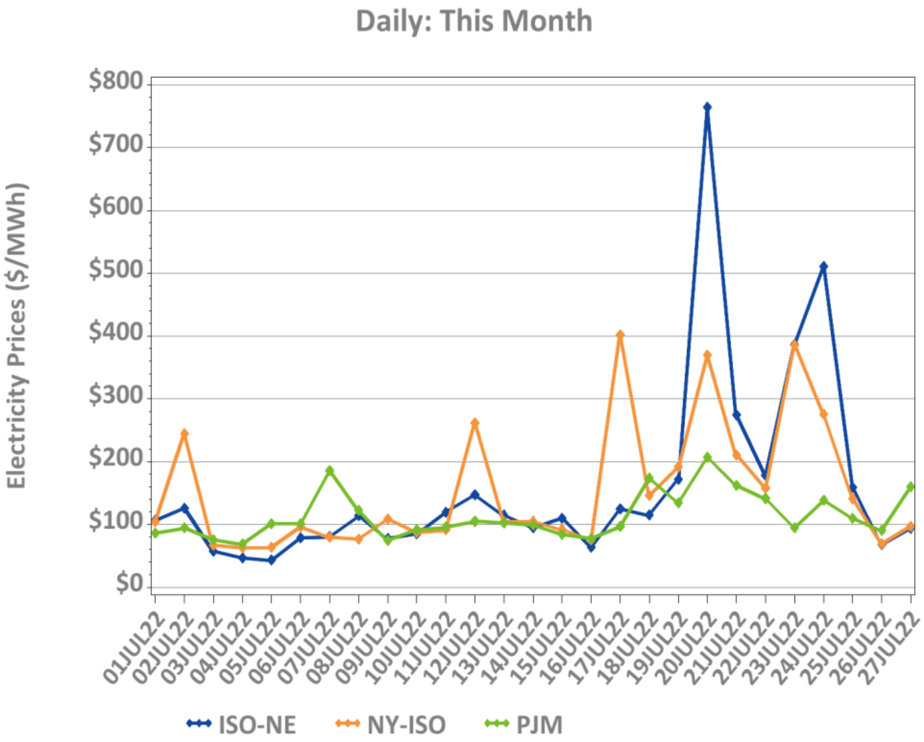
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





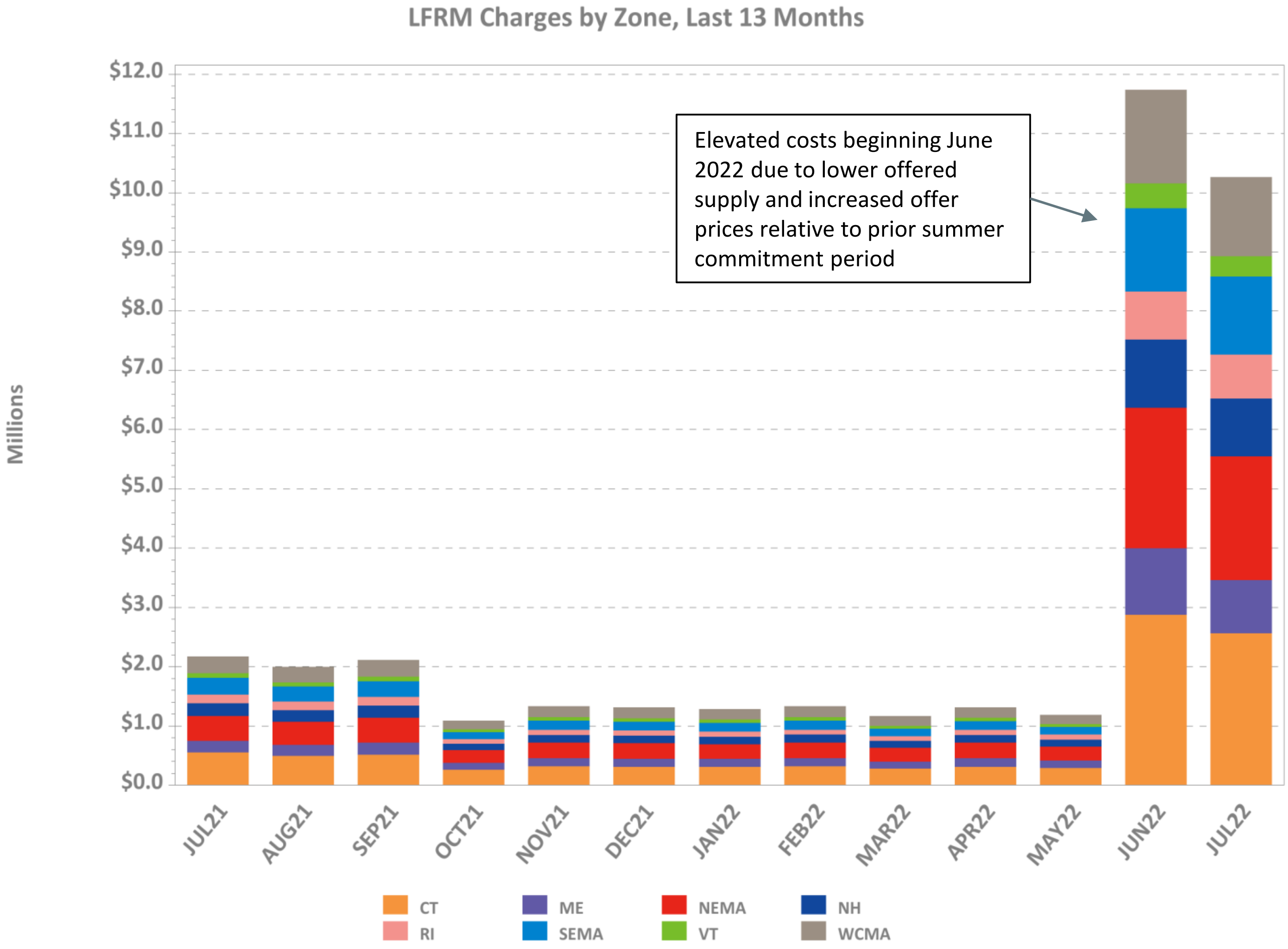
***Forecasted New England daily peak hours reflected**

Reserve Market Results – July 2022

- Maximum potential Forward Reserve Market payments of $10.8M were reduced by credit reductions of $66K, failure-to-reserve penalties of $347K and failure-to-activate penalties of $76K, resulting in a net payout of $10.3M or 96% of maximum
  - Rest of System: $7.64M/7.87M (97%)
  - Southwest Connecticut: $5K/41K (12%)
  - Connecticut: $2.52M/2.74M (92%)
  - NEMA: $4K/98K (94%)
- $9.9M total Real-Time credits were reduced by $2.6M in Forward Reserve Energy Obligation Charges for a net of $7.3M in Real-Time Reserve payments
  - Rest of System: 212 hours, $3.6M
  - Southwest Connecticut: 212 hours, $1.5M
  - Connecticut: 212 hours, $1.3M
  - NEMA: 212 hours, $943K

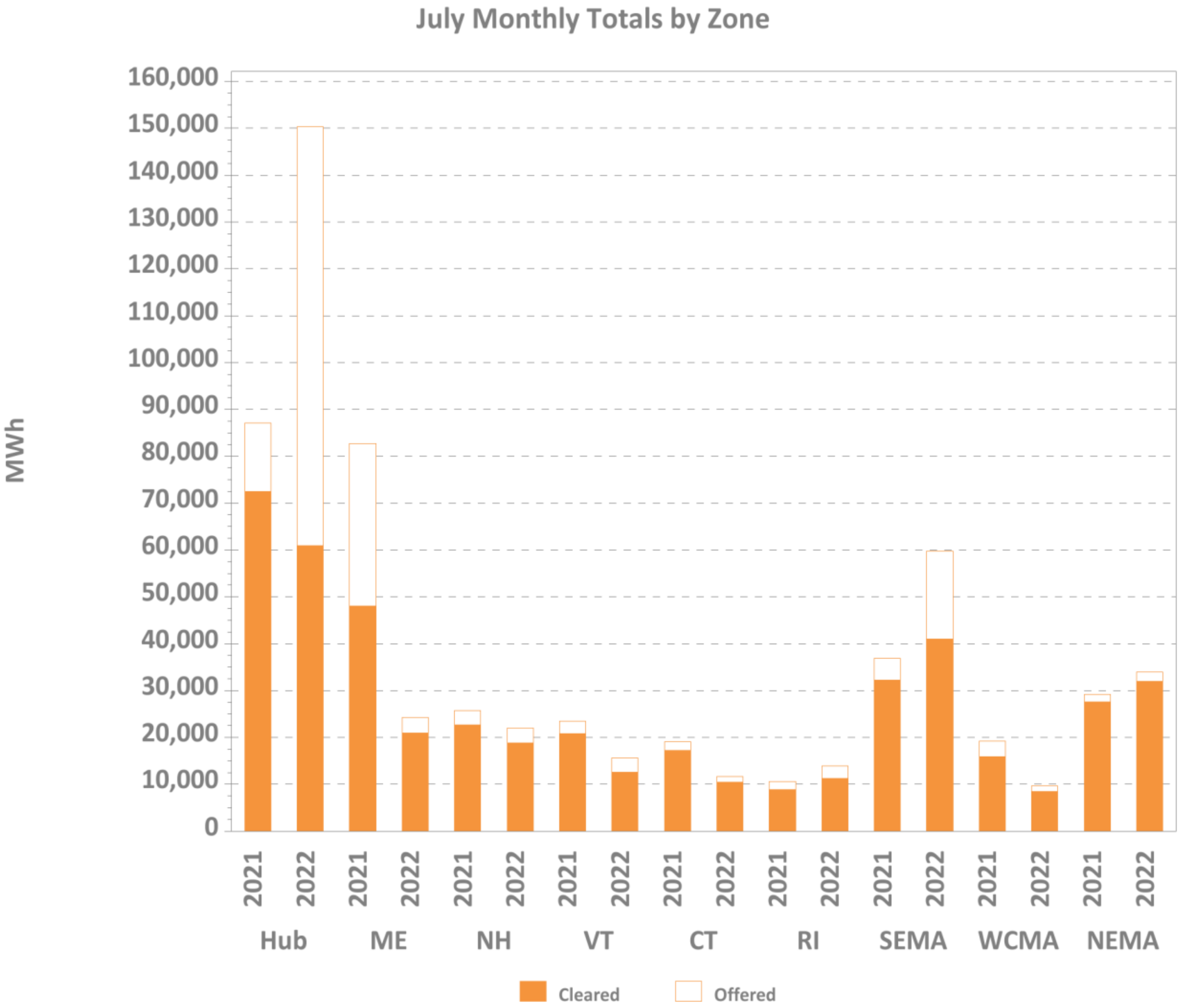
Note: "Failure to reserve" results in both credit reductions and penalties in the Locational Forward Reserve Market. While this summary reports performance by location, there were no locational requirements in effect for the current Forward Reserve auction period.

LFRM Charges to Load by Load Zone ($)

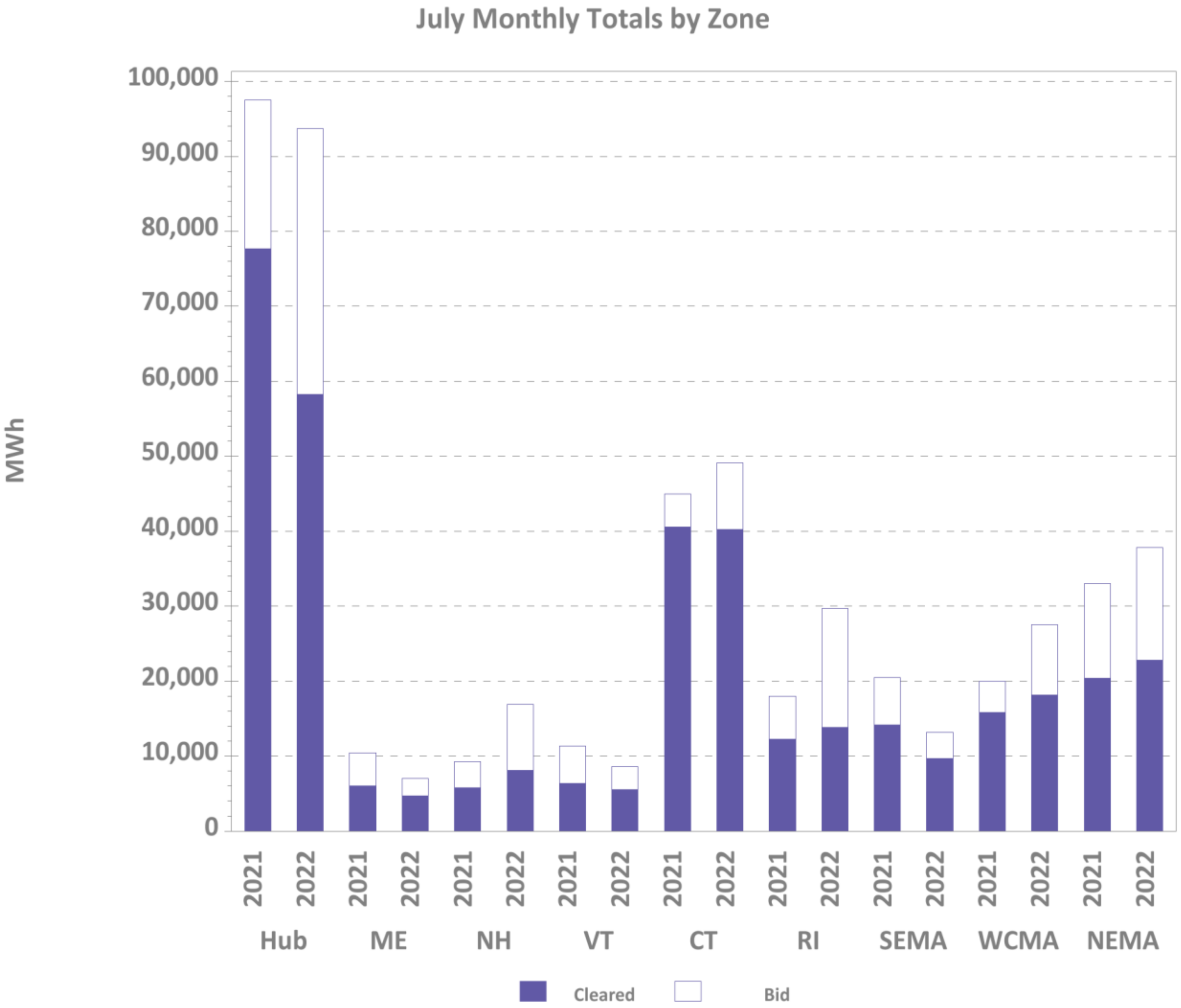


Elevated costs beginning June 2022 due to lower offered supply and increased offer prices relative to prior summer commitment period

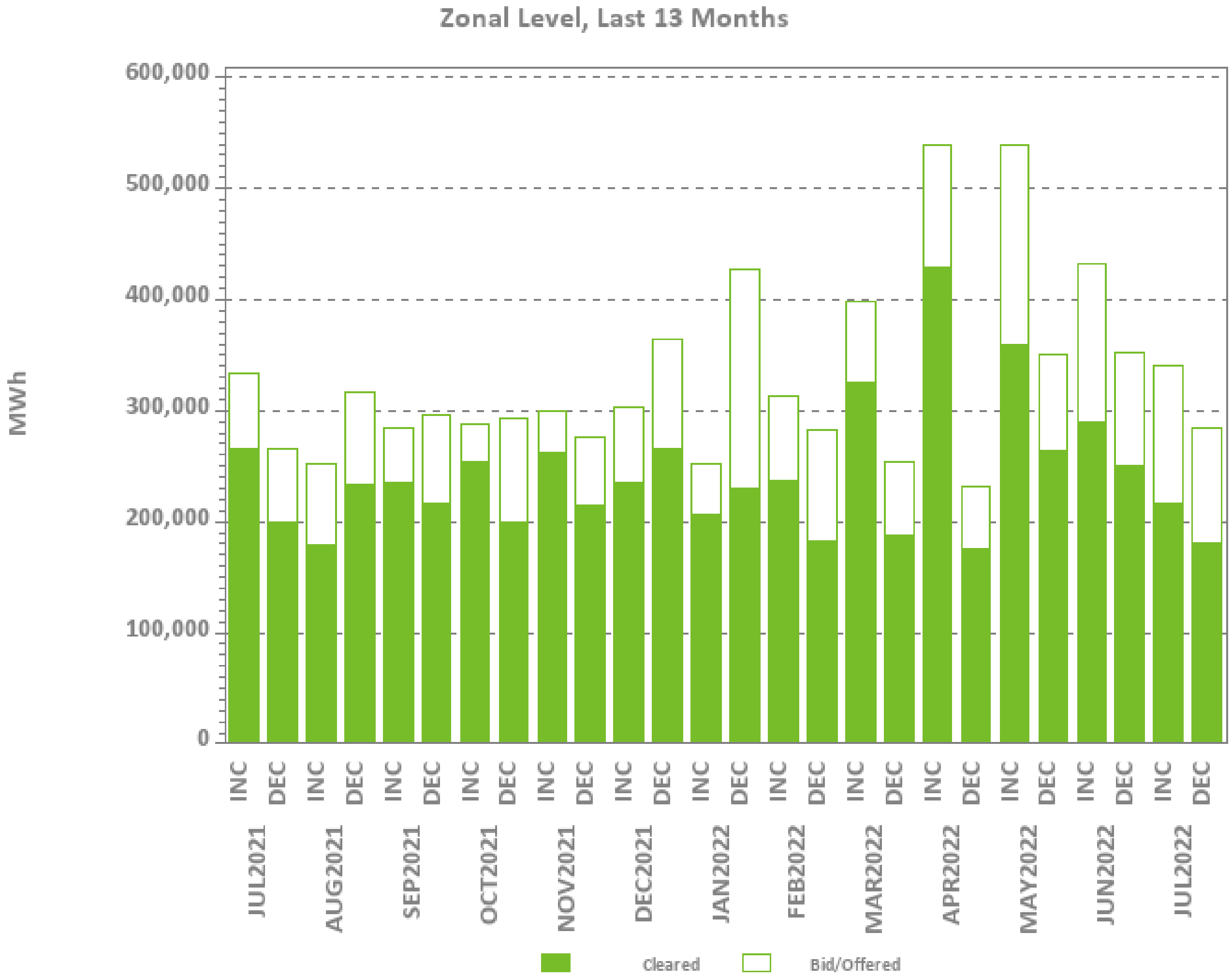
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

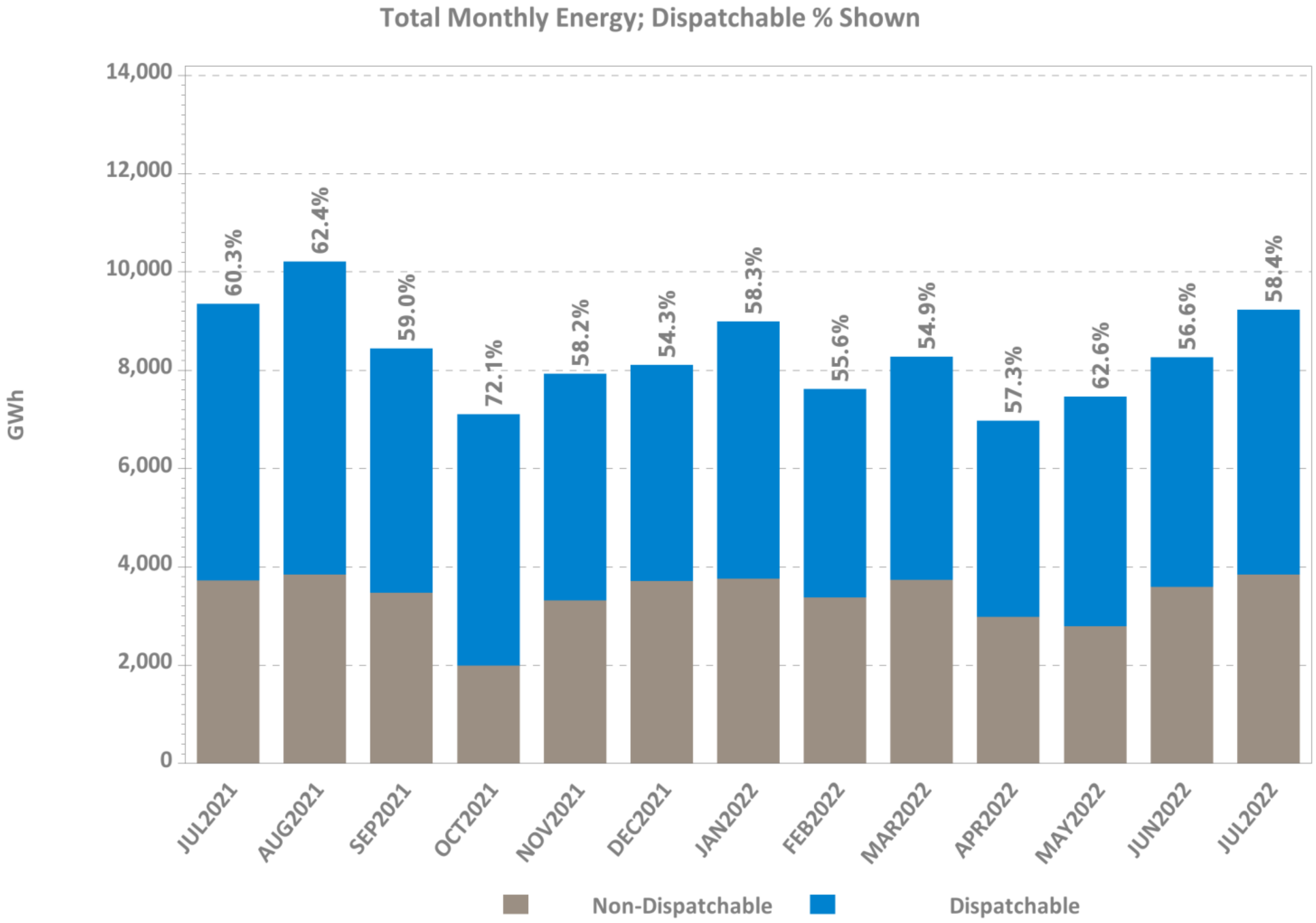


Total Increment Offers and Decrement Bids



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)

Planning Advisory Committee (PAC)

- August 24 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - Tewksbury #22 Asset Condition Replacements (National Grid)
    - Greggs Substation Rebuild (Eversource)
    - Holbrook Station 345/115 kV Autotransformer Replacement Asset Condition Project (Eversource)
    - Eagle Auto Transformer Repairs (Eversource)
    - 1231/1242 Reconductor and Structure Replacements Update (Eversource)
  - Mid-Cape Reliability Project
  - Generator Outage and Interface Transfers for Needs Assessments – Proposed Assumptions
  - Representative Future Locational Reserve Needs for Current Reserve Zones
  - Distributed Energy Resource Protection Assumptions
  - Economic Planning for the Clean Energy Transition (EPCET) Pilot Study: New Modeling Features and Initial Benchmark Scenario Results

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

Transmission Planning for the Clean Energy Transition (TPCET)

- On 9/24/20 the ISO initiated discussions with the PAC about proposed refinements to transmission planning study assumptions that better reflect long-term trends, such as increased amounts of distributed-energy resources (primarily solar PV), offshore wind generation, and battery energy storage
- A follow-up presentation at the 11/19/20, 12/16/20, and 1/21/21 PAC meetings outlined a proposal for a pilot study, with the following goals:
  - Explore transmission reliability concerns that may result from various system conditions possible by 2030
  - Quantify trade-offs necessary between transmission system reliability/flexibility and transmission investment cost
  - Inform future discussions on transmission planning study assumptions
- Results were discussed at the 6/16/21, 7/22/21, and 8/18/21 PAC meetings
- The ISO published final revisions to the Transmission Planning Technical Guide reflecting these changes on 9/30/21
- CEII supplement to the PAC presentations was released on 10/5/21
- The final TPCET Pilot Study Report was posted to the PAC website on 1/14/22
- Status updates on ongoing transient stability modeling and performance criteria were discussed at the 4/28/22, 5/18/22, and 6/15/22 PAC meetings

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
- Written stakeholder comments were due on 12/2/21
- ISO worked with NESCOE to address the comments and finalized the scope on 12/22/21
- 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

Economic Studies

- 2021 Economic Study Request
  - Also known as Future Grid Reliability Study – Phase 1 (FGRS)
  - Study proponent is NEPOOL
  - Final report expected to be posted by mid-August
- Economic Planning for the Clean Energy Transition Pilot Study
  - New effort to review all assumptions in economic planning and perform a test study consistent with the proposed changes to the Tariff
  - Initial scope of work presented at the April PAC meeting and the next presentation on input assumptions is expected at the August PAC meeting

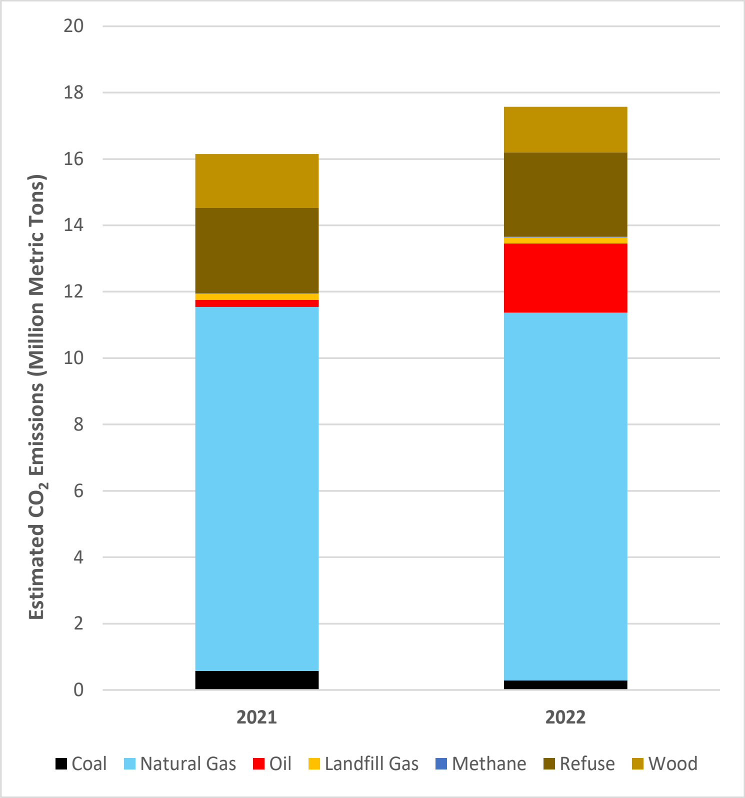
Future Grid Reliability Study (FGRS)

- Phase 1
  - Studies include: Production Cost Simulations; Ancillary Services Simulations; Resource Adequacy Screen; and Probabilistic Resource Availability Analysis
  - Framework Document and supporting assumptions table, which describe study scenarios and objectives, have been developed by stakeholders
  - Phase 1 work was submitted as the only 2021 Economic Study
- Phase 2
  - Studies include: Revenue Sufficiency Analysis and Transmission Security
  - Studies will be delayed as the Pathways and 2050 Transmission studies are performed
  - Scope expected to be shared with stakeholders in the 2nd half of 2022

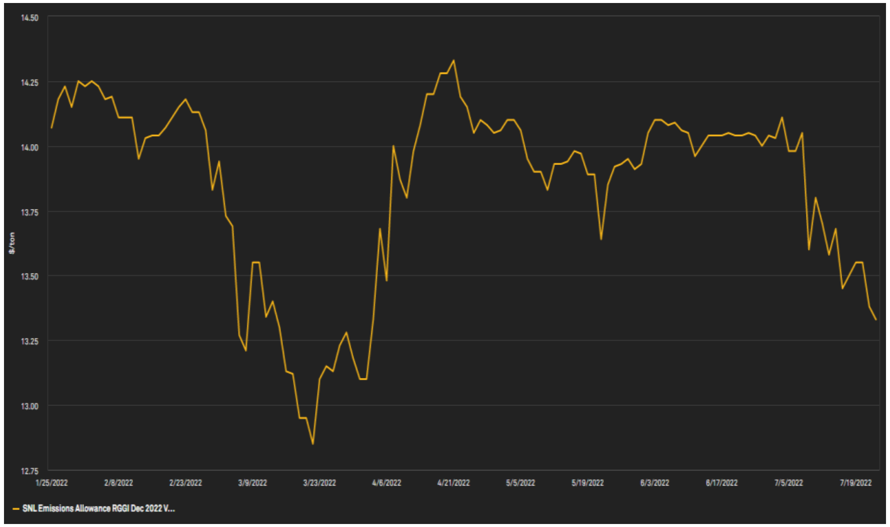
New England Power System Carbon Emissions

CO_2 emissions Up 9% year to year, reflects January oil-fired generation spike

2021 vs. 2022 New England Power System Estimated Carbon Dioxide (CO_2) Emissions



RGGI Allowance Prices Affected by Factors External to New England



- 7/22/22: RGGI allowance spot price - $13.33 per allowance (1 allowance = 1 short ton CO_2)
- 6/1/22 56th RGGI auction cleared at $13.90
  - 97 million allowances will be auctioned in 2022
  - 192 million allowances already in circulation

Data as of 7/17/22

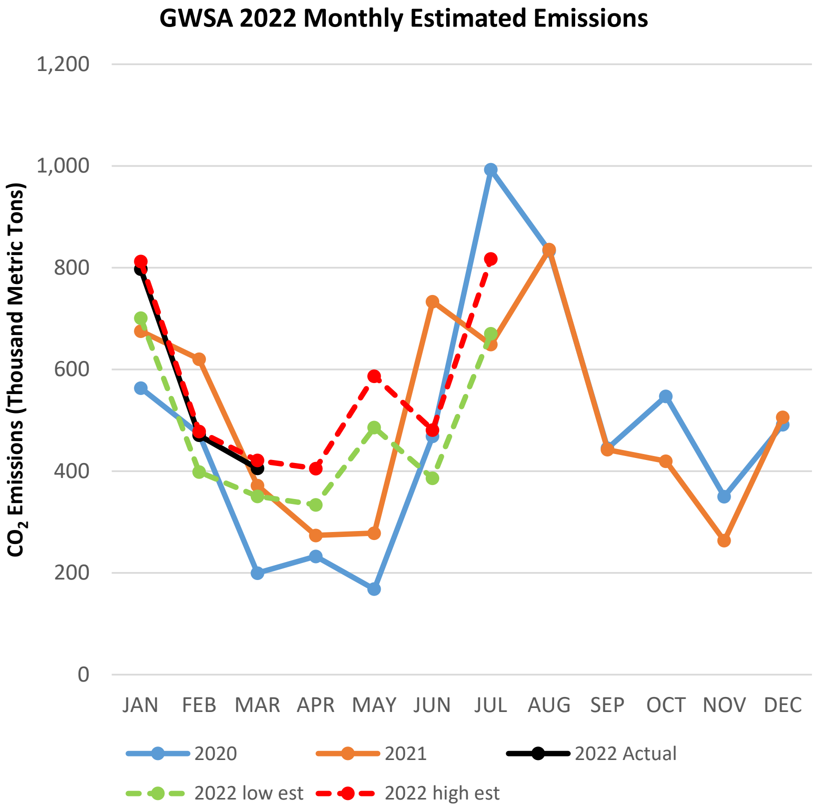
RGGI – Regional Greenhouse Gas Initiative

Massachusetts CO_2 Generator Emissions Cap

Uptick in 2022 Estimated Emissions Under CO_2 Cap

- 7/17/22: 2022 estimated GWSA CO_2 emissions range between 3.3 and 4.0 MMT
  - 41% to 50% of the 8.06 MMT 2022 cap
- 6/10/22 GWSA auction cleared at $9.75; 1.20 million 2022 vintage allowances sold
  - 2022 RGGI allowance spot price at $14.05 per metric ton
  - 0.39 million 2023 vintage GWSA allowances were also offered, clearing at $4.0
- 2022 year-to-date estimated GWSA emissions were between 10% lower and 8% higher than year-to-date 2021 emissions

2020-2022 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 7/21/2022

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*	May-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 7/21/2022

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	Dec-23	2

Greater Boston Projects, cont.

Status as of 7/21/2022

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 7/21/2022

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-22	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 7/21/2022

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 7/21/2022

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 7/21/2022

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	May-25	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	Dec-23	3
1722	Extend the Line 114 from the Dartmouth town line (Eversource-National Grid border) to Bell Rock substation	Dec-24	1
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 7/21/2022

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	Dec-23	1
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	Jun-23	2
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Jun-23	2
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 7/21/2022

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 7/21/2022

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 7/21/2022

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	2
1850	Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation	Mar-23	2
1851	Upgrade Card 115 kV to BPS standards	Mar-23	2
1852	Install one 115 kV circuit breaker in series with Card substation 4T	Mar-23	2
1853	Convert Gales Ferry substation from 69 kV to 115 kV	Dec-23	2
1854	Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Dec-22	3

Eastern CT Reliability Projects, cont.

Status as of 7/21/2022

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	Dec-23	2
1856	Rebuild 400-1 Line section to allow operation at 115 kV (Tunnel to Ledyard Jct.)	Dec-22	3
1857	Add one 115 kV circuit breaker and re-terminate the 400-1 line section into Tunnel substation. Energize 400 Line at 115 kV	Dec-23	3
1858	Rebuild 400-2 Line section to allow operation at 115 kV (Ledyard Jct. to Border Bus with CMEEC)	Dec-22	3
1859	Rebuild the 400-3 Line Section to allow operation at 115 kV (Gales Ferry to Ledyard Jct.)	Dec-22	3
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 7/21/2022

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 50 MVAR synchronous condenser with two 115 kV breakers at Shunock	Dec-24	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), convert Buddington to 115 kV	Dec-23	3

Boston Area Optimized Solution Projects

Status as of 7/21/2022

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	Oct-23	3

New Hampshire Solution Projects

Status as of 7/21/2022

Project Benefit: Addresses system needs in the New Hampshire area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1878	Install a +50/-25 MVAR synchronous condenser at N. Keene 115 kV Substation with a 115 kV breaker	Aug-23	3
1879	Install a +50/-25 MVAR synchronous condenser at Huckins Hill 115 kV Substation with a 115 kV breaker	Aug-23	3
1880	Install a +100/-50 MVAR synchronous condenser at Amherst 345 kV Substation with two 345 kV breakers	Dec-23	2
1881	Install two 50 MVAR capacitors on Line 363 near Seabrook Station with three 345 kV breakers	Oct-23	1

Upper Maine Solution Projects

Status as of 7/21/2022

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-27	2
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	2

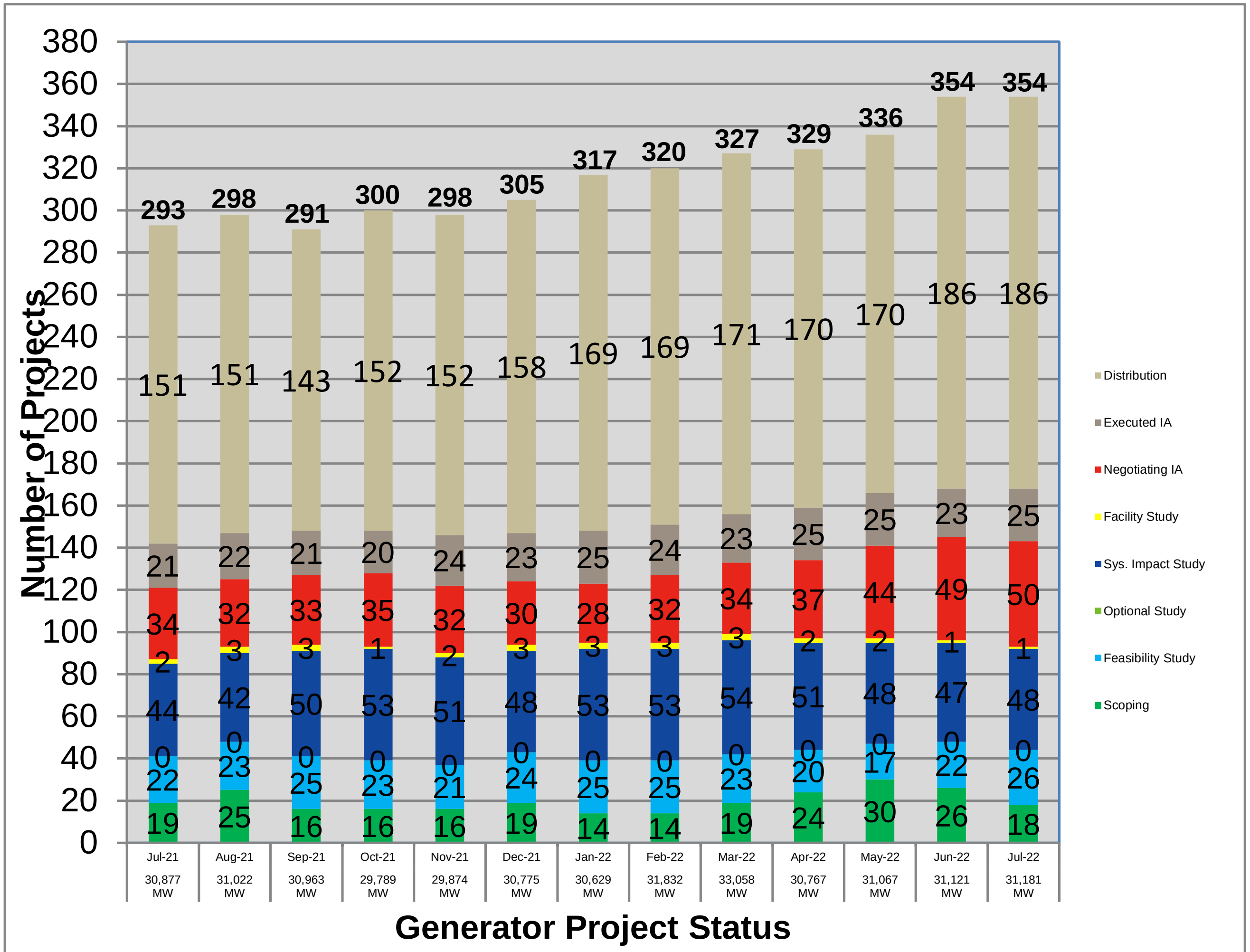
Upper Maine Solution Projects, cont.

Status as of 7/21/2022

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	2
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

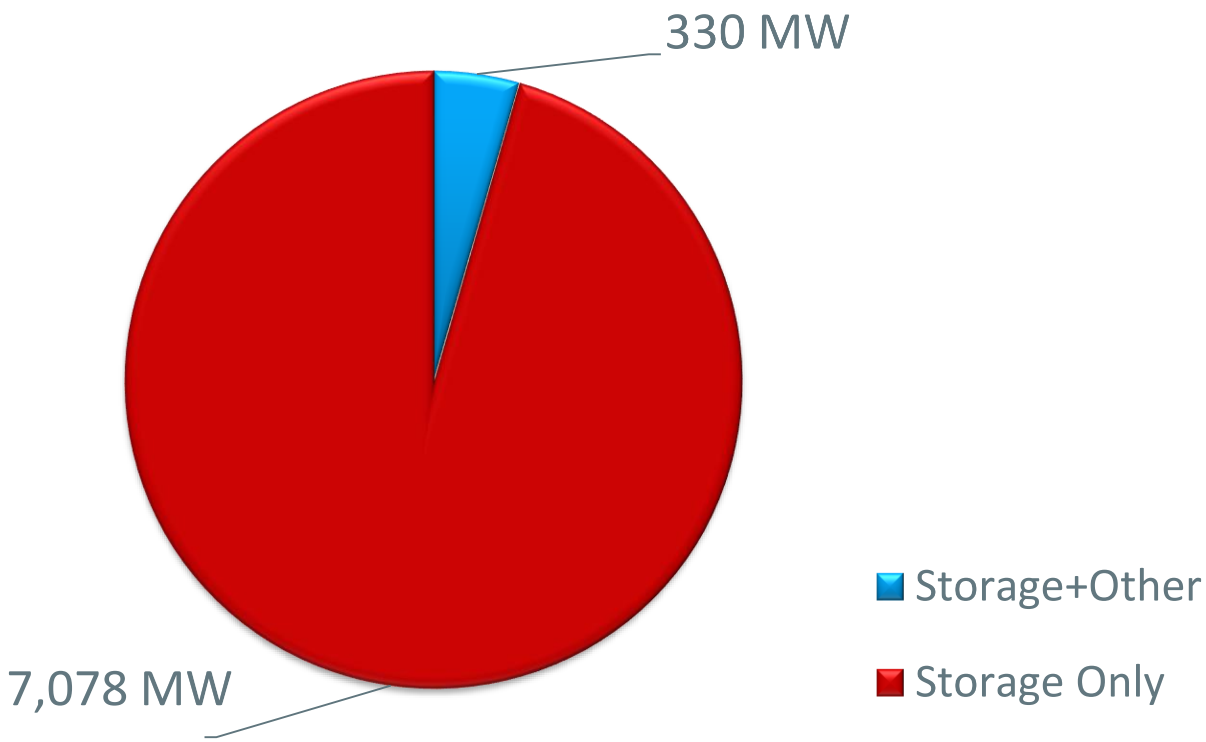
Status of Tariff Studies as of July 26, 2022



Note: July 2022 is based on partial data.
5 ETUs in Scoping, 2 in FS, 1 in SIS, 0 in OIS, 0 in FAC, 2 Negotiating IA, and 2 with Executed IA
Transmission Service Requests needing study: 1 in Scoping
https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of July 26, 2022)

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



OPERABLE CAPACITY ANALYSIS

Summer 2022 Analysis

Summer 2022 Operable Capacity Analysis

50/50 **Load Forecast** (Reference)	**September - 2022[2] CSO (MW)**	**September - 2022[2] SCC (MW)**
Operable Capacity MW [1]	27,870	29,867
Active Demand Capacity Resource (+) [5]	559	461
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,115	1,115
Non Commercial Capacity (+)	127	127
Non Gas-fired Planned Outage MW (-)	805	1,175
Gas Generator Outages MW (-)	272	342
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)	26,494	27,953
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	24,686	24,686
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	26,991	26,991
Operable Capacity Margin	-497	962

[1] Operable Capacity is based on data as of **July 20, 2022** 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 20, 2022.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **September 10, 2022.**

[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 2022 Operable Capacity Analysis

90/10 Load Forecast	**September - 2022[2] CSO (MW)**	**September - 2022[2] SCC (MW)**
Operable Capacity MW [1]	27,870	29,867
Active Demand Capacity Resource (+) [5]	559	461
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,115	1,115
Non Commercial Capacity (+)	127	127
Non Gas-fired Planned Outage MW (-)	805	1,175
Gas Generator Outages MW (-)	272	342
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)	26,494	27,953
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	26,416	26,416
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	28,721	28,721
Operable Capacity Margin	-2,227	-768

[1] Operable Capacity is based on data as of **July 20, 2022** 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 20, 2022.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **September 10, 2022.**

[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 2022 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

July 20, 2022 - 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 during August and September.

Report created: 7/20/2022

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
8/6/2022	27791	530	1089	20	136	0	2100	0	27194	24686	2305	26991	203	N	Summer 2022
8/13/2022	27791	530	1089	20	109	0	2100	0	27221	24686	2305	26991	230	N	Summer 2022
8/20/2022	27791	530	1089	20	101	0	2100	0	27229	24686	2305	26991	238	N	Summer 2022
8/27/2022	27791	530	1089	20	50	0	2100	0	27280	24686	2305	26991	289	N	Summer 2022
9/3/2022	27870	559	1115	127	69	0	2100	0	27502	24686	2305	26991	511	N	Summer 2022
9/10/2022	**27870**	**559**	**1115**	**127**	**805**	**272**	**2100**	**0**	**26494**	**24686**	**2305**	**26991**	**-497**	**Y**	**Summer 2022**

Column Definitions

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

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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 2022 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 2022 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

July 20, 2022 - 90/10 FORECAST using CSO MW

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8/6/2022	27791	530	1089	20	136	0	2100	0	27194	26416	2305	28721	-1527	N	Summer 2022
8/13/2022	27791	530	1089	20	109	0	2100	0	27221	26416	2305	28721	-1500	N	Summer 2022
8/20/2022	27791	530	1089	20	101	0	2100	0	27229	26416	2305	28721	-1492	N	Summer 2022
8/27/2022	27791	530	1089	20	50	0	2100	0	27280	26416	2305	28721	-1441	N	Summer 2022
9/3/2022	27870	559	1115	127	69	0	2100	0	27502	26416	2305	28721	-1219	N	Summer 2022
9/10/2022	**27870**	**559**	**1115**	**127**	**805**	**272**	**2100**	**0**	**26494**	**26416**	**2305**	**28721**	**-2227**	**Y**	**Summer 2022**

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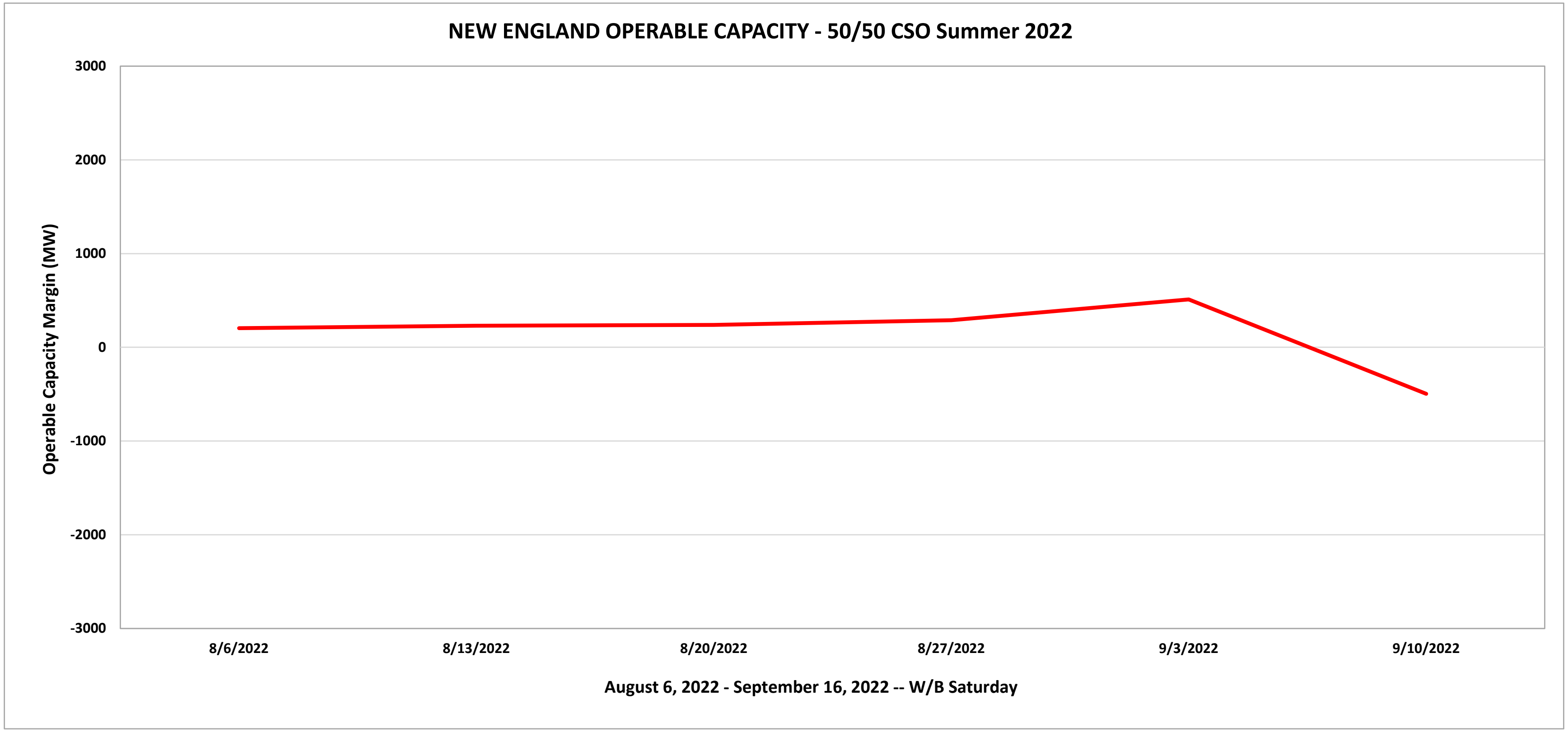
***Highlighted week is based on the week determined by the 50/50 Load Forecast Reference week**

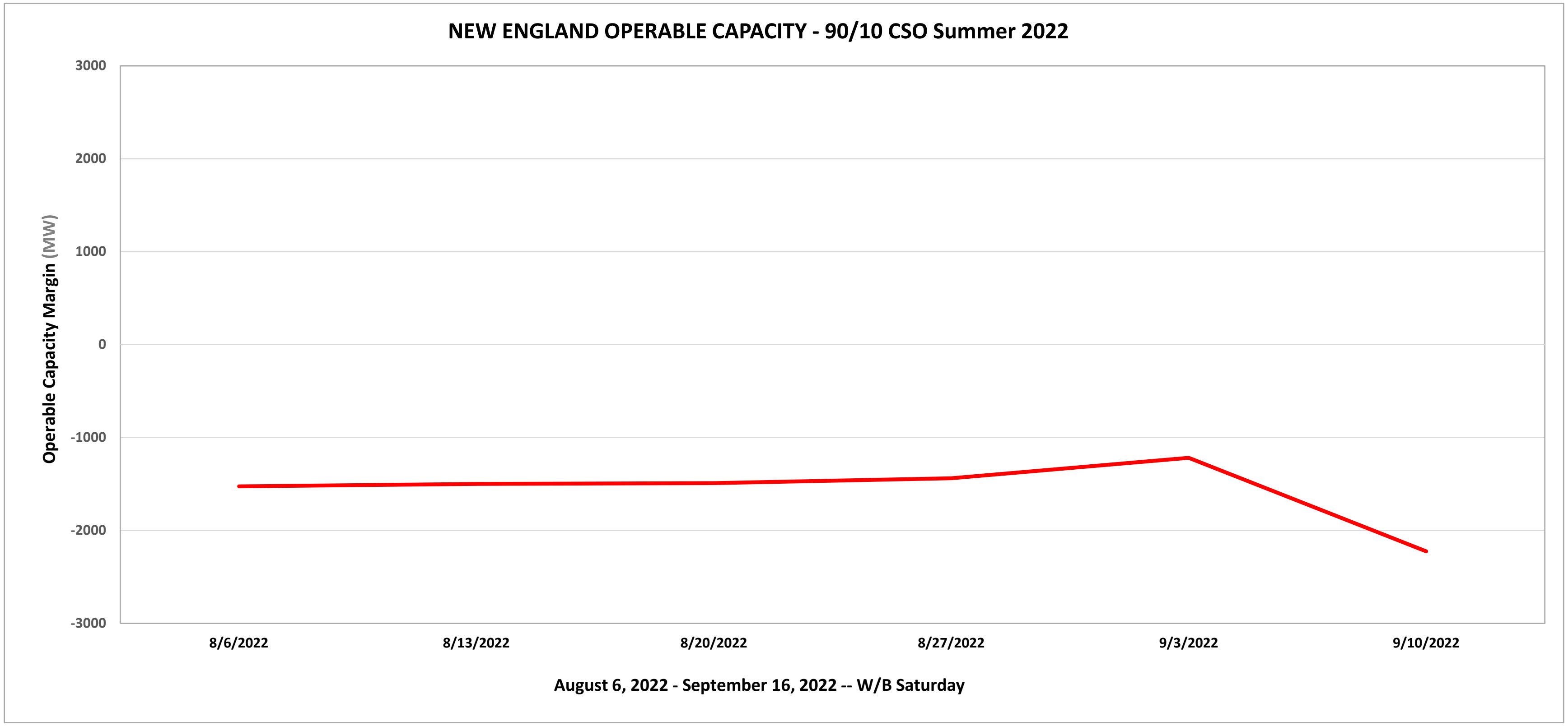
Summer 2022 Operable Capacity Analysis

50/50 Forecast (Reference)



Summer 2022 Operable Capacity Analysis

90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Preliminary Fall 2022 Analysis

Preliminary Fall 2022 Operable Capacity Analysis

50/50 Load Forecast (Reference)	**September - 2022[2] CSO (MW)**	**September - 2022[2] SCC (MW)**
Operable Capacity MW [1]	27,870	29,867
Active Demand Capacity Resource (+) [5]	559	461
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	684	684
Non Commercial Capacity (+)	127	127
Non Gas-fired Planned Outage MW (-)	2,185	2,553
Gas Generator Outages MW (-)	974	1,049
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)	23,981	25,437
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,619	20,619
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,924	22,924
Operable Capacity Margin	1,057	2,513

[1] Operable Capacity is based on data as of **July 20, 2022** 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 20, 2022.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **September 24, 2022.**

[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 2022 Operable Capacity Analysis

90/10 Load Forecast	**September - 2022[2] CSO (MW)**	**September - 2022[2] SCC (MW)**
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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)	23,981	25,437
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	22,095	22,095
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,400	24,400
Operable Capacity Margin	-419	1,037

[1] Operable Capacity is based on data as of **July 20, 2022** 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 20, 2022.**

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Preliminary Fall 2022 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

July 20, 2022 - 50-50 FORECAST using CSO MW

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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
9/17/2022	27870	559	684	127	1303	272	2100	0	25565	20711	2305	23016	2549	N	Fall 2022
9/24/2022	**27870**	**559**	**684**	**127**	**2185**	**974**	**2100**	**0**	**23981**	**20619**	**2305**	**22924**	**1057**	**Y**	**Fall 2022**
10/1/2022	28158	559	1070	70	2837	3273	2800	0	20947	15169	2305	17474	3473	N	Fall 2022
10/8/2022	28158	559	1070	70	3913	4158	2800	0	18986	15205	2305	17510	1476	N	Fall 2022
10/15/2022	28158	559	1070	70	3490	2239	2800	0	21328	16121	2305	18426	2902	N	Fall 2022
10/22/2022	28158	559	1070	70	1851	2479	2800	0	22727	16482	2305	18787	3940	N	Fall 2022
10/29/2022	28158	559	1070	70	2310	3229	3600	0	20718	16687	2305	18992	1726	N	Fall 2022
11/5/2022	28158	559	1070	70	2332	1766	3600	0	22159	16802	2305	19107	3052	N	Fall 2022
11/12/2022	28158	559	1070	70	1882	940	3600	0	23435	17143	2305	19448	3987	N	Fall 2022
11/19/2022	28158	559	1070	70	1137	306	3600	1064	23750	17875	2305	20180	3570	N	Fall 2022

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Preliminary Fall 2022 Operable Capacity Analysis 90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

July 20, 2022 - 90/10 FORECAST using CSO MW

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10/15/2022	28158	559	1070	70	3490	2239	2800	0	21328	16690	2305	18995	2333	N	Fall 2022
10/22/2022	28158	559	1070	70	1851	2479	2800	0	22727	17063	2305	19368	3359	N	Fall 2022
10/29/2022	28158	559	1070	70	2310	3229	3600	0	20718	17274	2305	19579	1139	N	Fall 2022
11/5/2022	28158	559	1070	70	2332	1766	3600	0	22159	17392	2305	19697	2462	N	Fall 2022
11/12/2022	28158	559	1070	70	1882	940	3600	595	22840	17744	2305	20049	2791	N	Fall 2022
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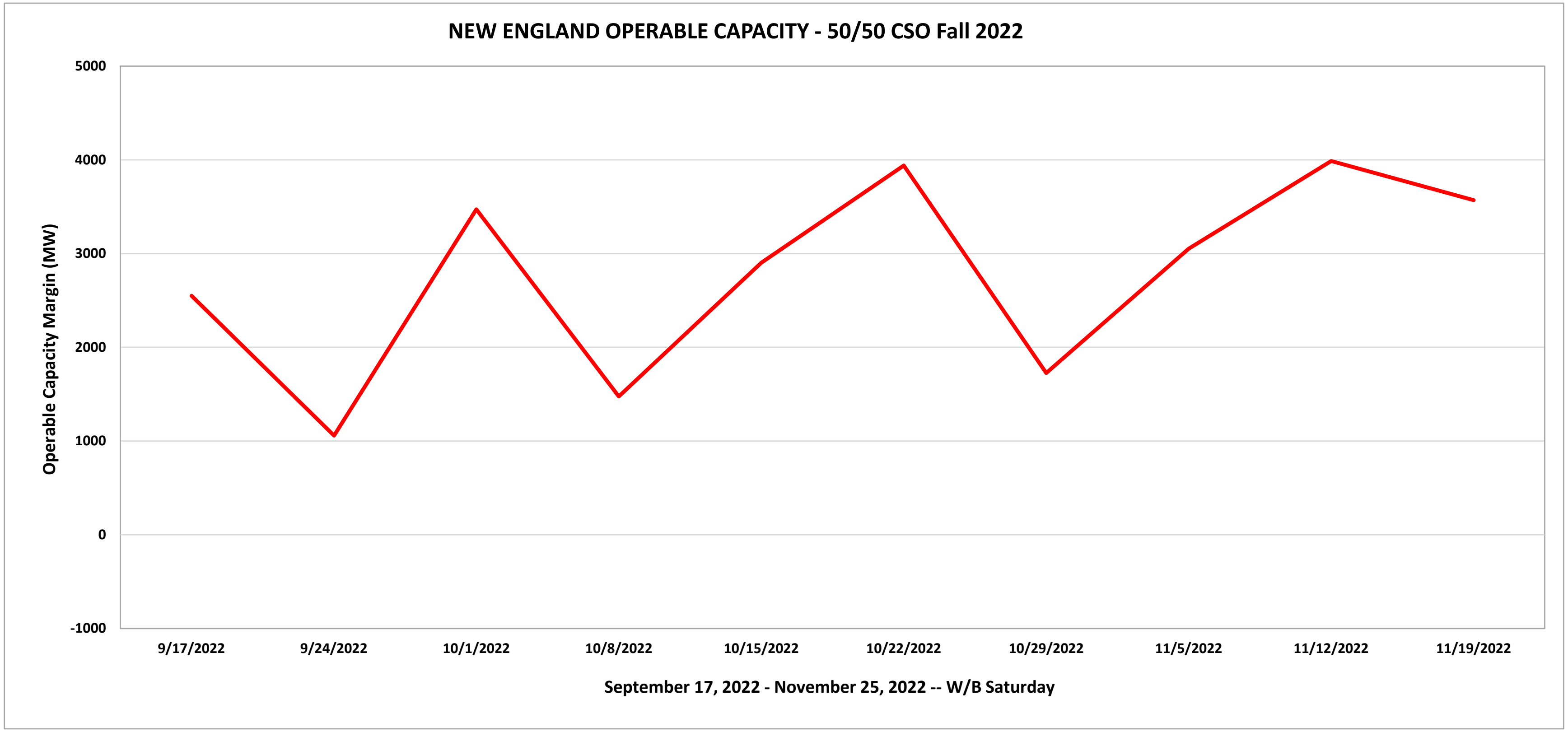
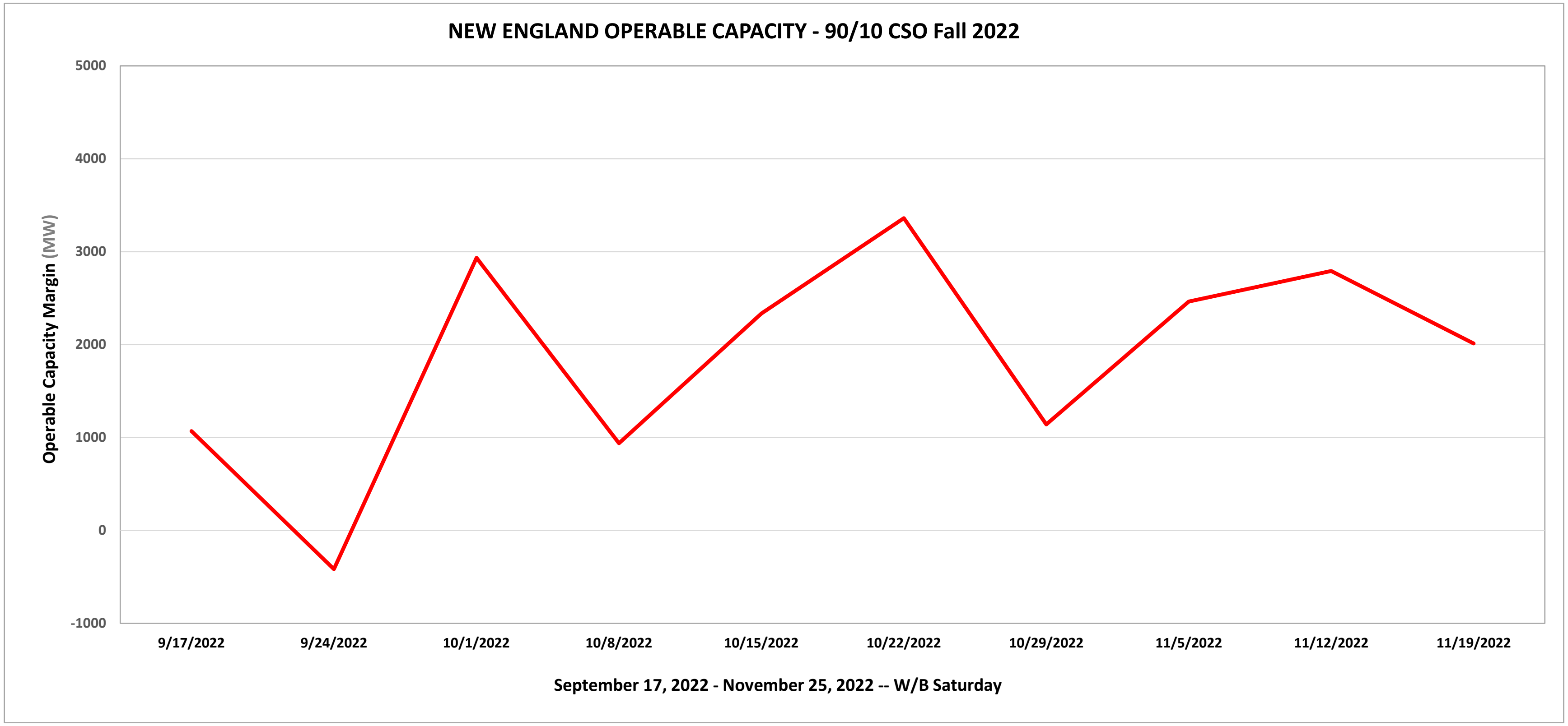
Preliminary Fall 2022 Operable Capacity Analysis

50/50 Forecast (Reference)



Preliminary Fall 2022 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:
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AUGUST 4, 2022 | BRIEFING WITH NEPOOL

IMM Annual Markets Report on 2021

Report Highlights

2021 Annual Markets Report
© ISO New England Inc.
Internal Market Monitor
MAY 26, 2022

Dave Naughton

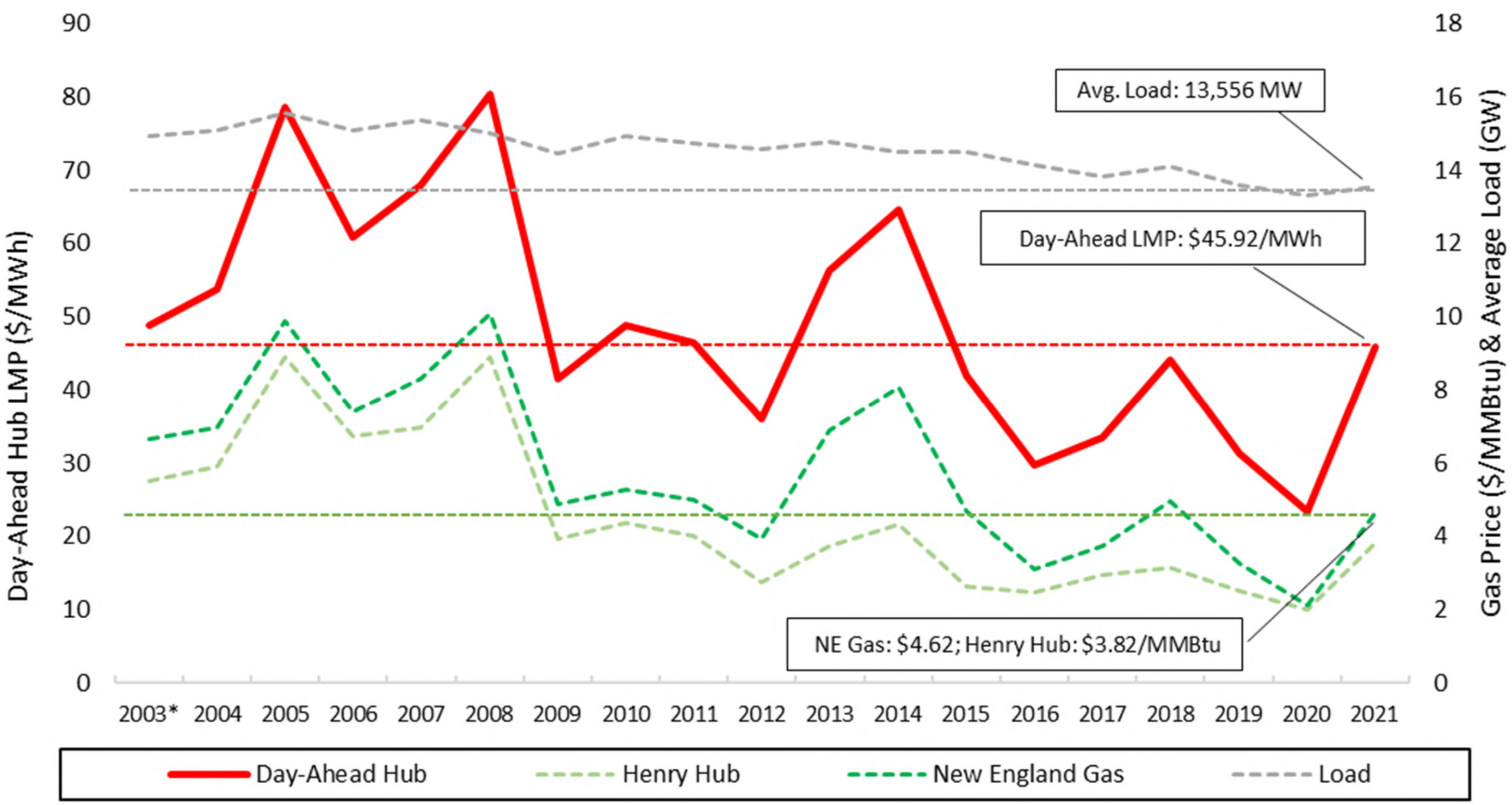
DIRECTOR, INTERNAL MARKET MONITOR

Natural gas prices drive high wholesale energy prices in New England

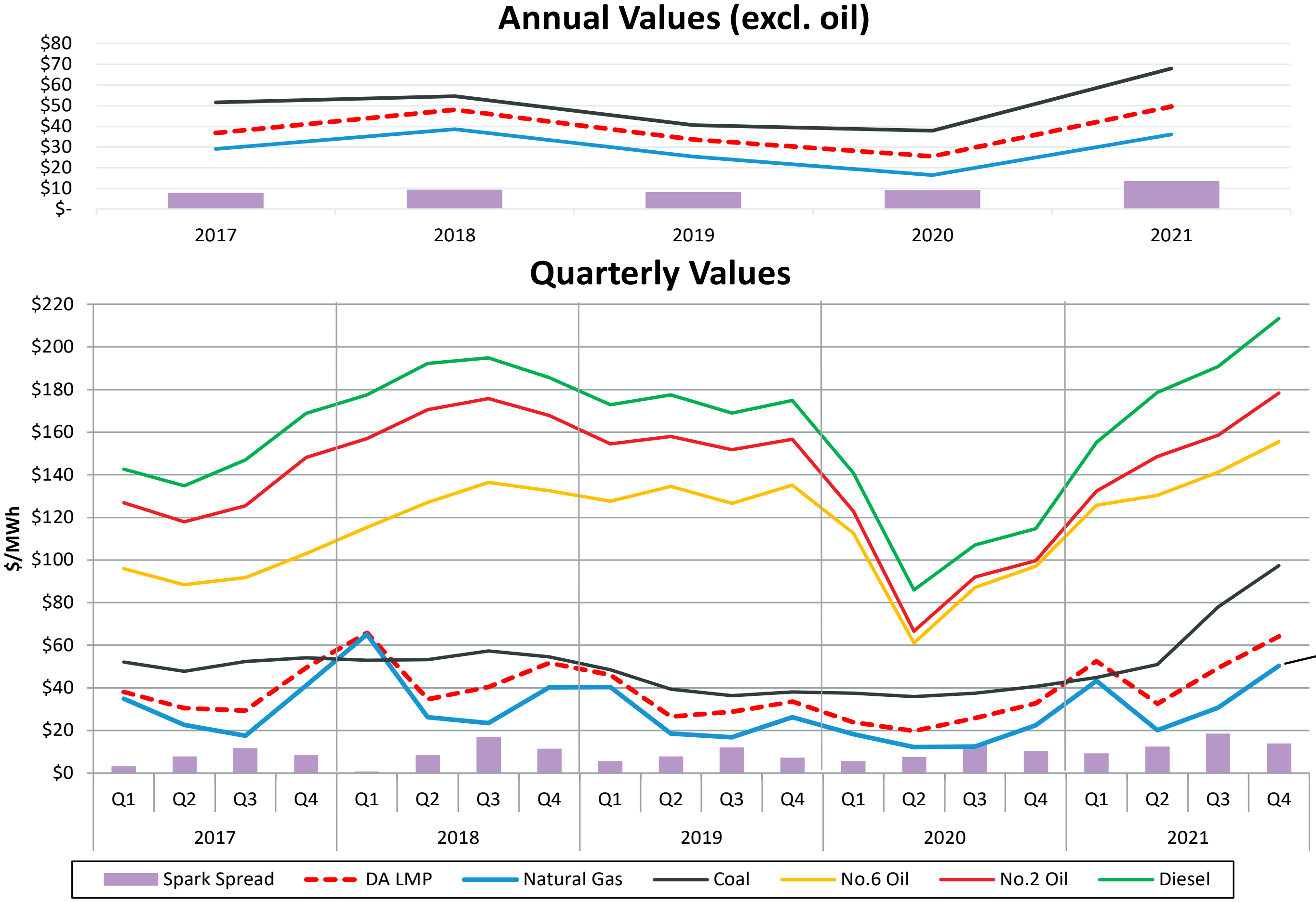
- Energy prices were consistent with changes in natural gas prices, demand and the region's supply mix.
- Natural gas prices continue to be the primary driver of higher wholesale energy prices*.
  - Gas and energy prices in 2021 were at their highest level since 2014, rebounding from record lows in 2020 due to the impacts of the pandemic.
  - Henry Hub prices jumped 91% to $3.92/MMBtu as demand outpaced supply; New England gas prices increased 121% to $4.62/MMBtu.
  - Day-ahead LMP averaged $45.92/MWh (up 97%), and coupled with higher demand (up 2%), resulted in energy costs of $6.1 billion (up 104% from $3.1 billion in 2020).
- No shortage events or major reliability issues in 2021 due to high overall reserve surplus and few system incidents.
  - However, a cold spell at the end of Jan. and first two weeks of Feb. led to high gas demand and pipeline constraints, with gas prices averaging $10.76/MMBtu; energy costs in Q1 accounted for 30% (about $1 billion) of the increase in annual energy payments.
- Demand rebounded following the impacts of the pandemic in 2020, and long-term trend of declining demand expected to reverse from 2022.
- Energy market profitability higher for gas-fired combined cycles and combustion turbines but short of the cost of new entry, reflecting surplus conditions.

* Note: High-level market data is shown on the Highlights slide at end of the slide deck

Historical context: highest energy and gas prices since 2014, rebounding from record lows in 2020



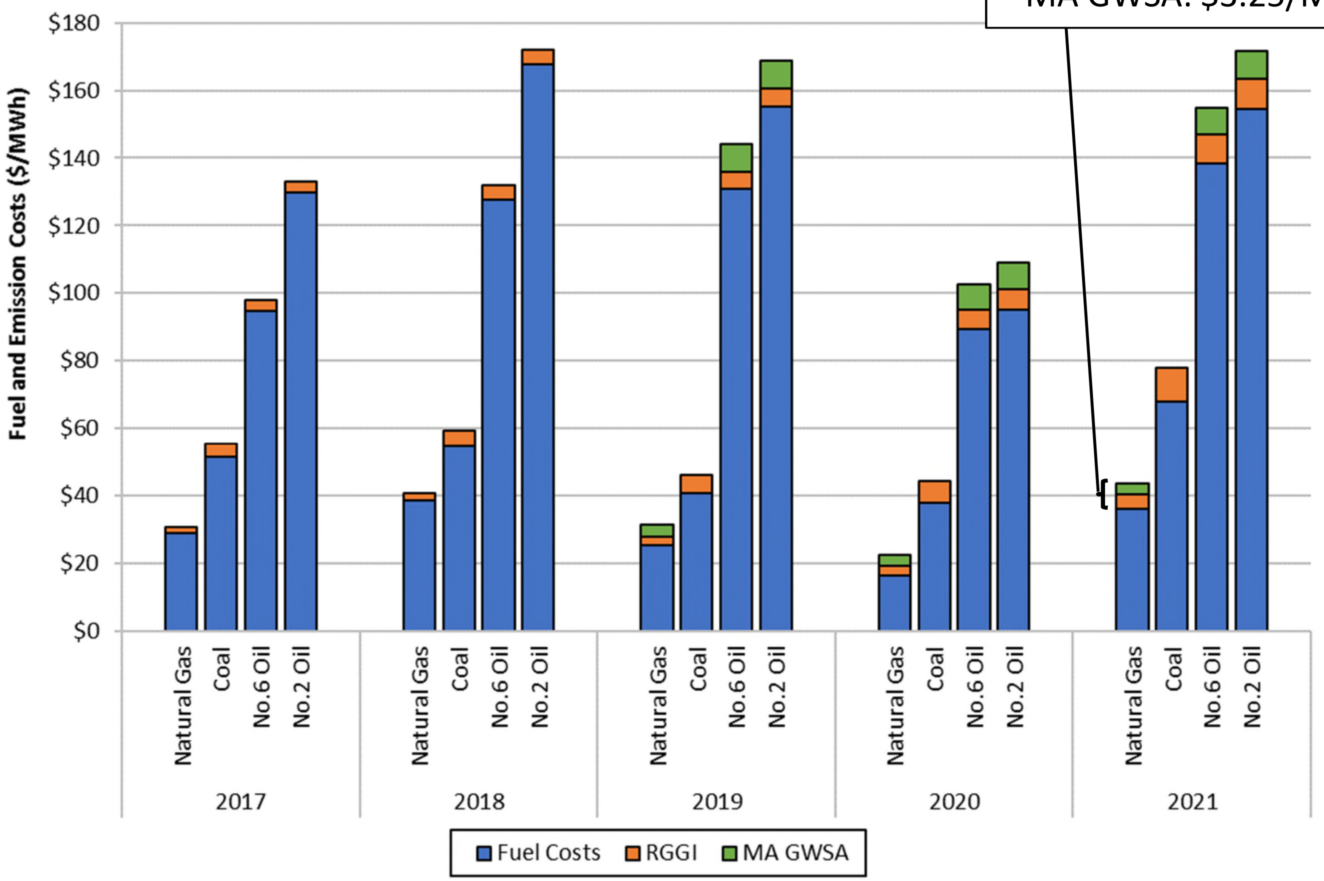
Significant increase in all fuel costs, with higher gas costs driving increase in LMP and spark spreads



Quarterly gas costs showed more variation in 2021 (from $20/MWh in Q2 to $50/MWh in Q4), three times the $10/MWh range of 2020, but more in line with the typical gas price range in years prior to 2020.

Variable generation costs are calculated by multiplying the average daily fuel price ($/MMBtu) by the average standard efficiency of generators of a given technology and fuel type. Our standard heat rates are measured in MMBtu/MWh as follows: Natural Gas 7.8, Coal – 10.0, No. 6 Oil – 10.7, No. 2 Oil – 11.7. The spark spread is the difference between the LMP and the fuel cost of a gas-fired generator with a heat rate of 7.8.

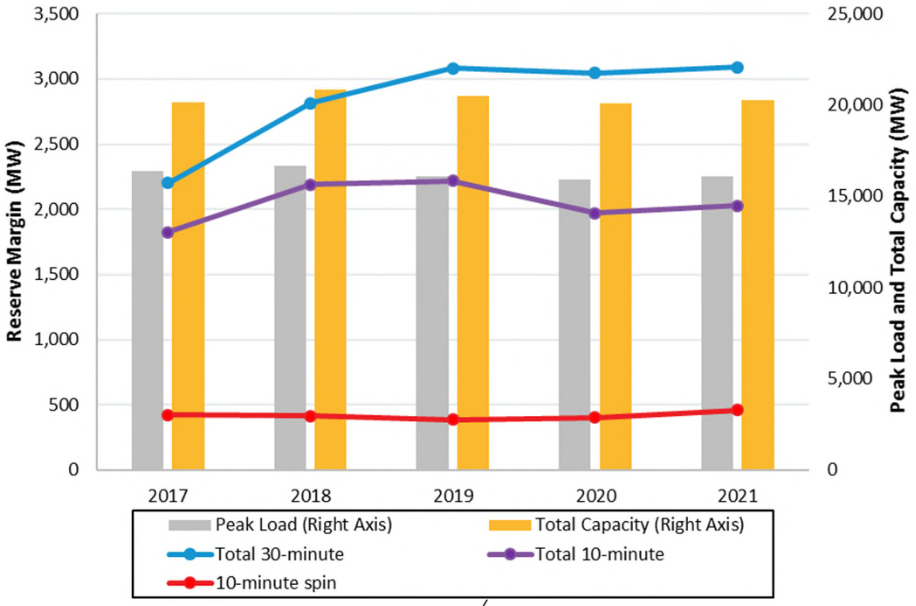
CO_2 costs still comprise a small (but increasing) proportion of variable production costs with little impact on economic merit order



CO_2 costs for typical gas generator (7.8 heat rate):
- RGGI: $4.36/MWh ($2.88 in 2020)
- MA GWSA: $3.25/MWh ($3.08 in 2020)

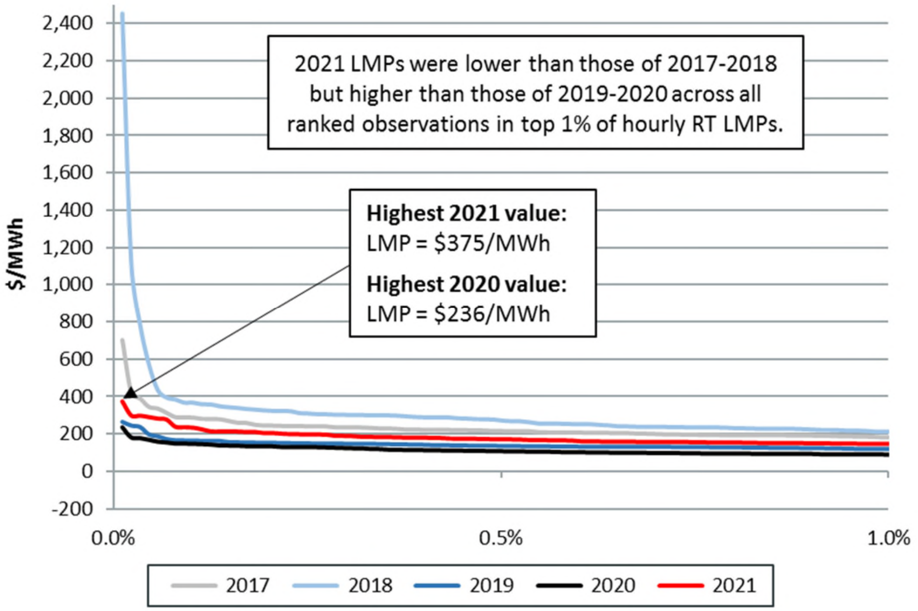
Large average energy market surplus with few periods of relatively high pricing

Reserve Margin, Peak Load, and Available Capacity



Bars show the avg. available capacity (that can be delivered within 30 mins) and demand during the *daily peak* hour. Difference is about 4,200 MW Reserve margin lines show the average surplus of reserves for each product are for *all hours*.

LMP Duration Curves for Top 1% of Real-Time Hours



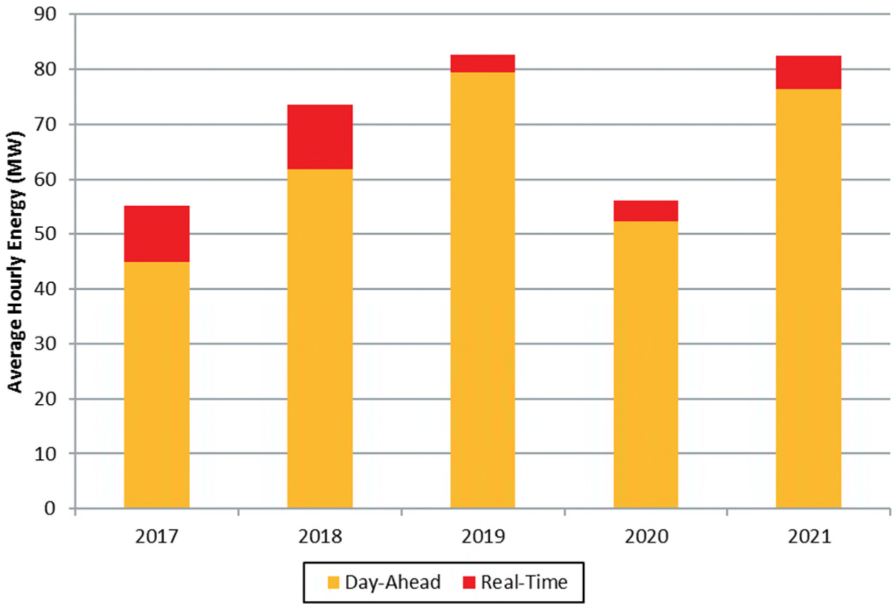
2021 LMPs were lower than those of 2017-2018 but higher than those of 2019-2020 across all ranked observations in top 1% of hourly RT LMPs.

Highest 2021 value:
LMP = $375/MWh

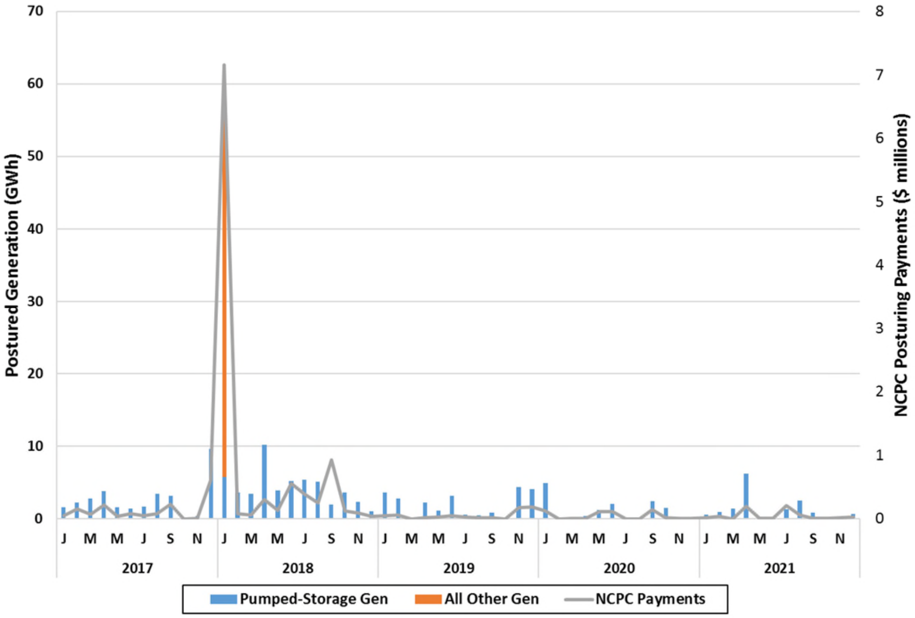
Highest 2020 value:
LMP = $236/MWh

Reliability commitments remain low, no posturing of thermal generation

Avg. Hourly Energy Output from Reliability Commitments during Peak Load Hours



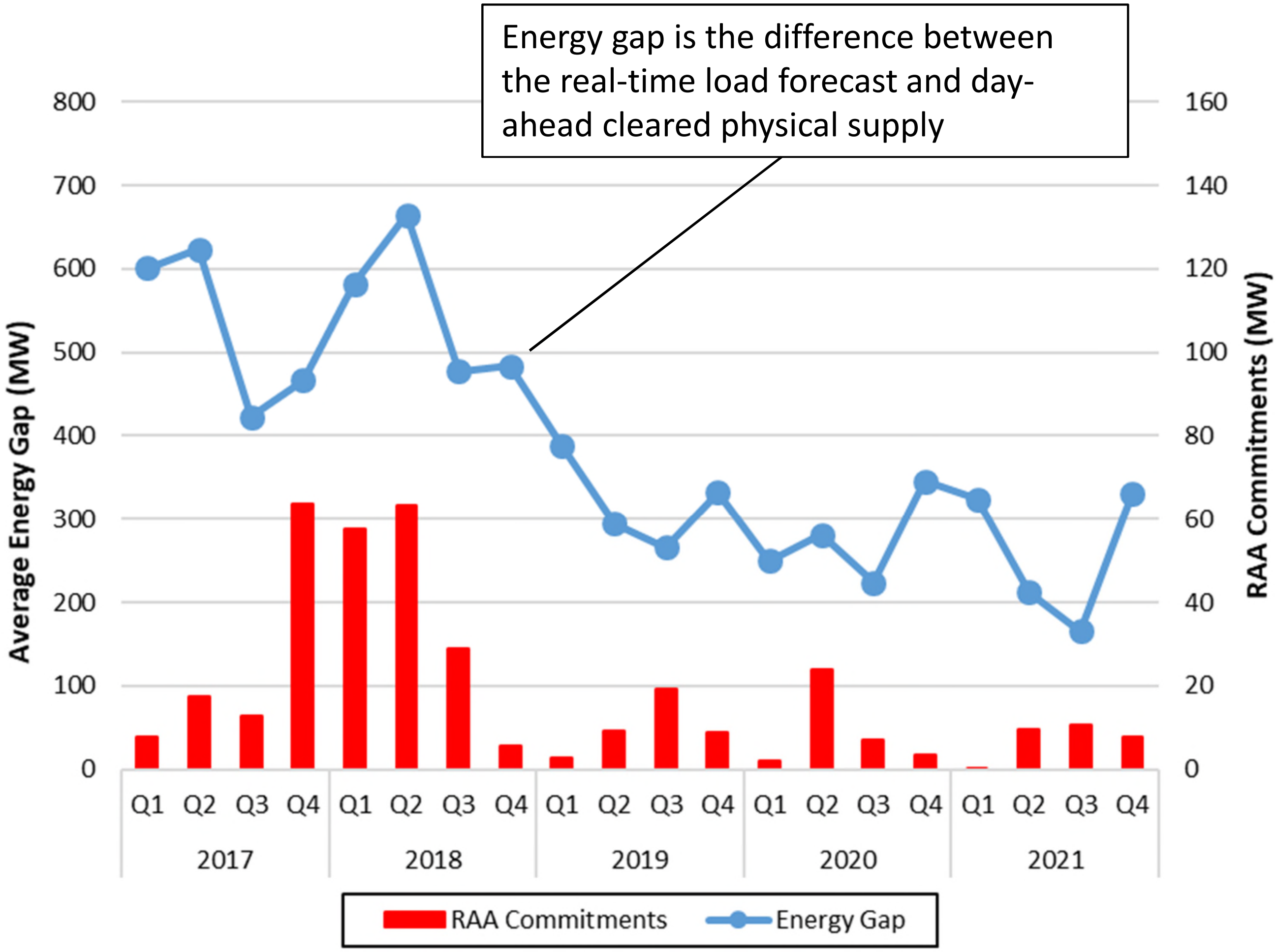
Monthly Postured Energy and NCPC Payments



Increase in reliability commitments due to transmission work related to the NE West-East constraint in December 2021; that month accounted for 31% of the reliability commitment hours in 2021. Most reliability commitments (66%) occurred in Maine and SEMA-RI; the remainder were in NEMA (13%) and New Hampshire (19%).

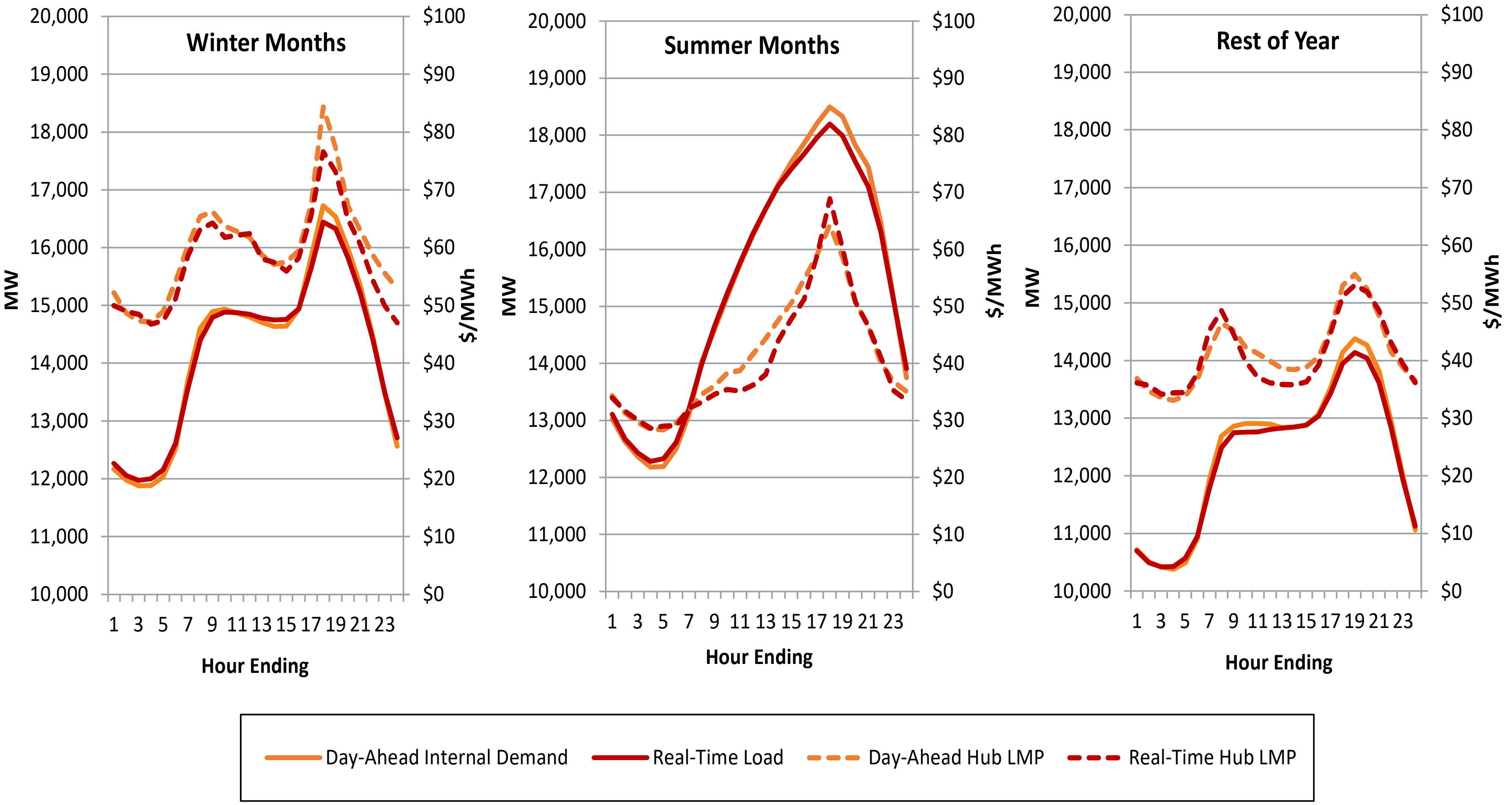
Posturing of in-merit oil generation occurred during January 2018. In 2021, only pumped-storage generators were postured, and posturing levels were relatively low (15 GWh total) compared other years in the review period.

Day-ahead clearing of physical generation resulted in low levels of RAA commitments on average



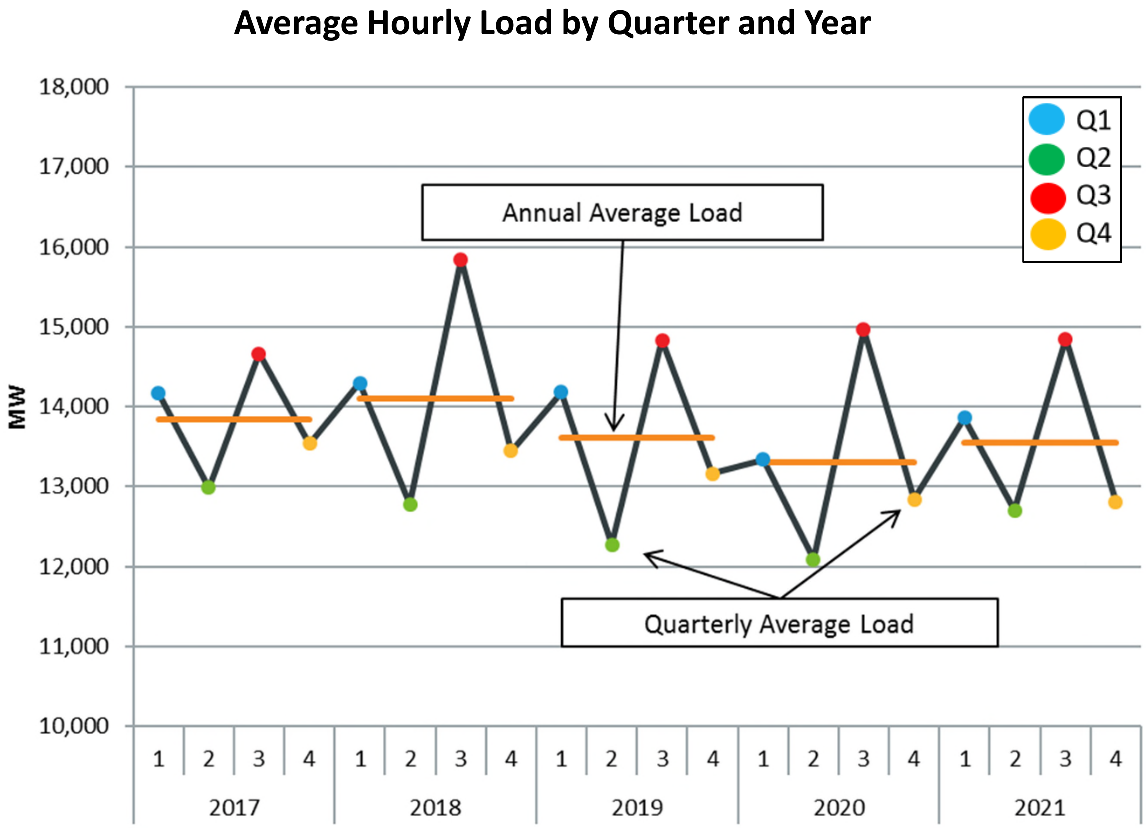
Energy gap is the difference between the real-time load forecast and day-ahead cleared physical supply

Gas and demand impacts on energy price levels vary by season



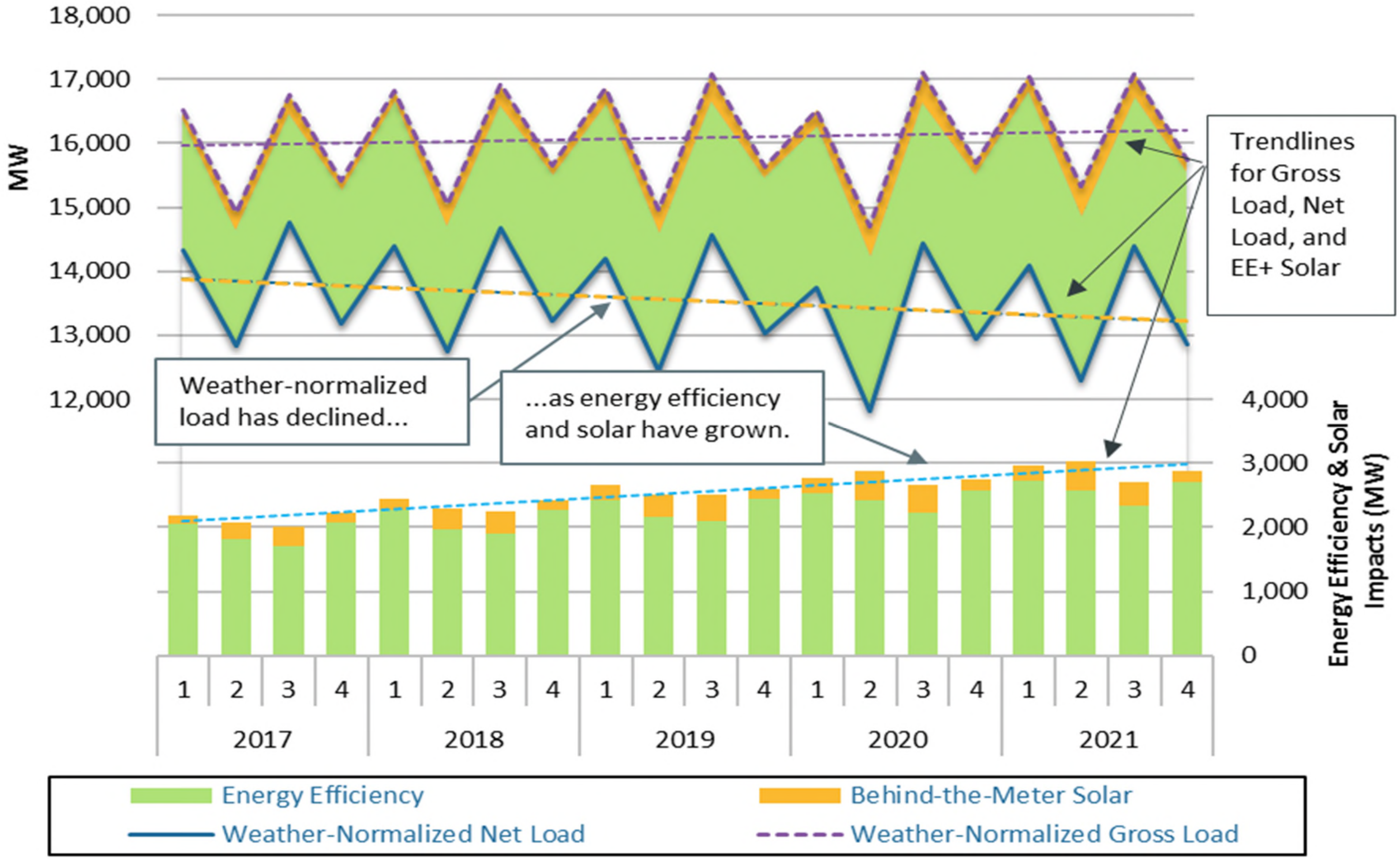
Winter (December, January, February), Summer (June – August) and Rest of Year (March, April, May, September, October, November)

Demand rebounded following COVID-19 pandemic; colder temperatures in Q1

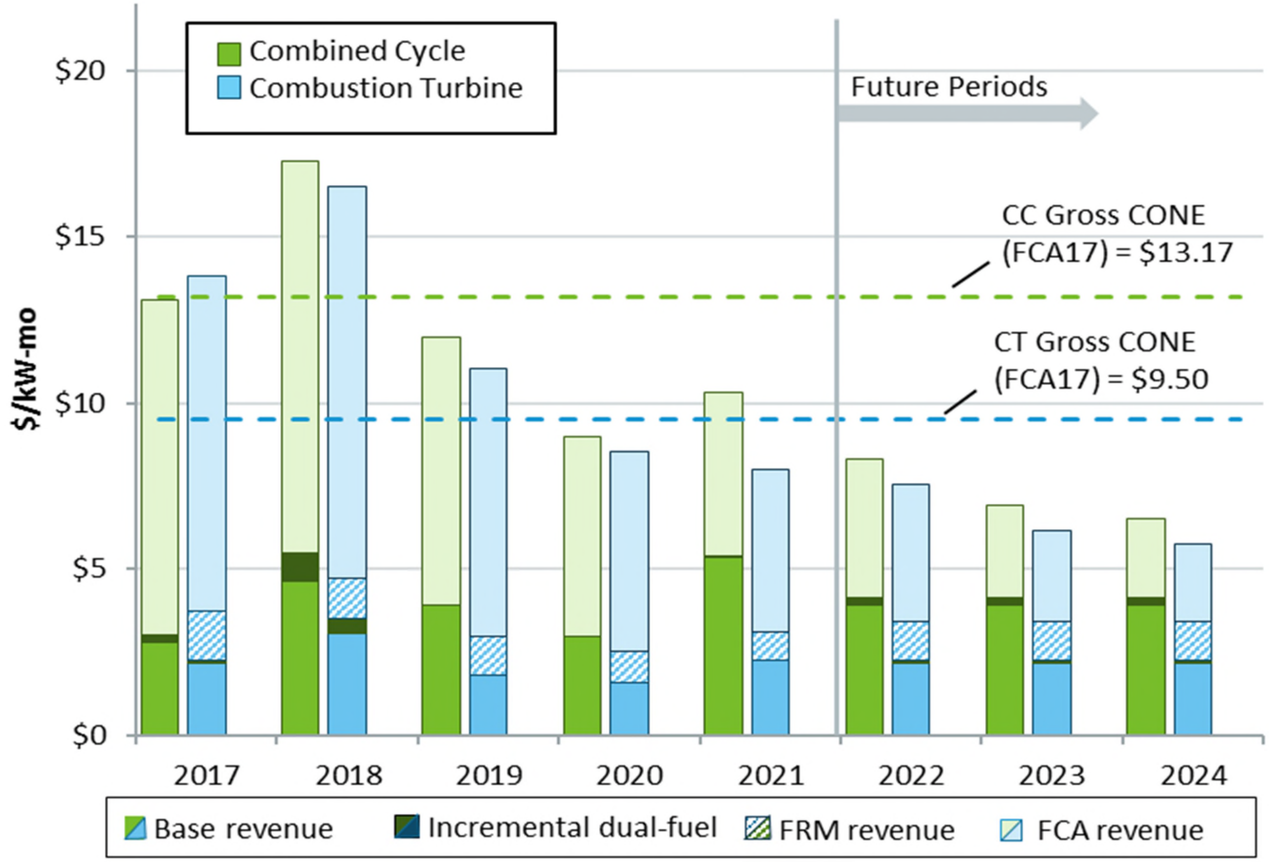


- Average annual demand was up by ~2%, or ~250 MW per hour. Weather-normalized demand increased by 1%.
- A 526 MW per hour (4%) increase in average **Q1** demand largely due to colder temps (down 3°F) compared to 2020.
- During **Q2** 2021, average load increased by 5% (or 609 MW), largely due to low Q2 2020 loads caused by the COVID-19 pandemic.
- Demand in **Q3** and **Q4** 2021 were comparable to 2020.

Trend of declining demand due to growing energy efficiency and BTM solar; expected to reverse from 2022



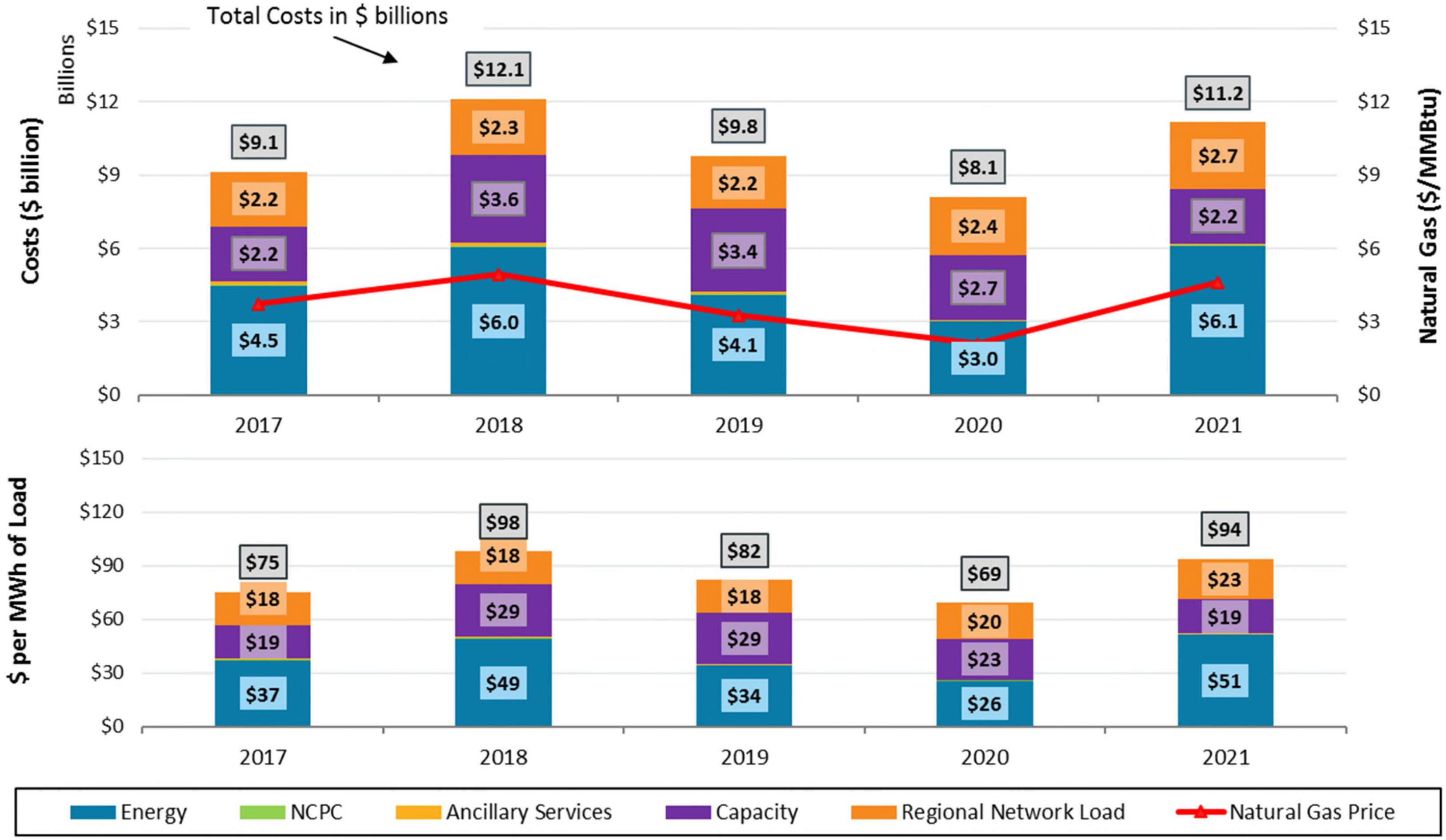
2021 revenues higher for combined cycle but lower for combustion turbine, and falling short of cost of new entry



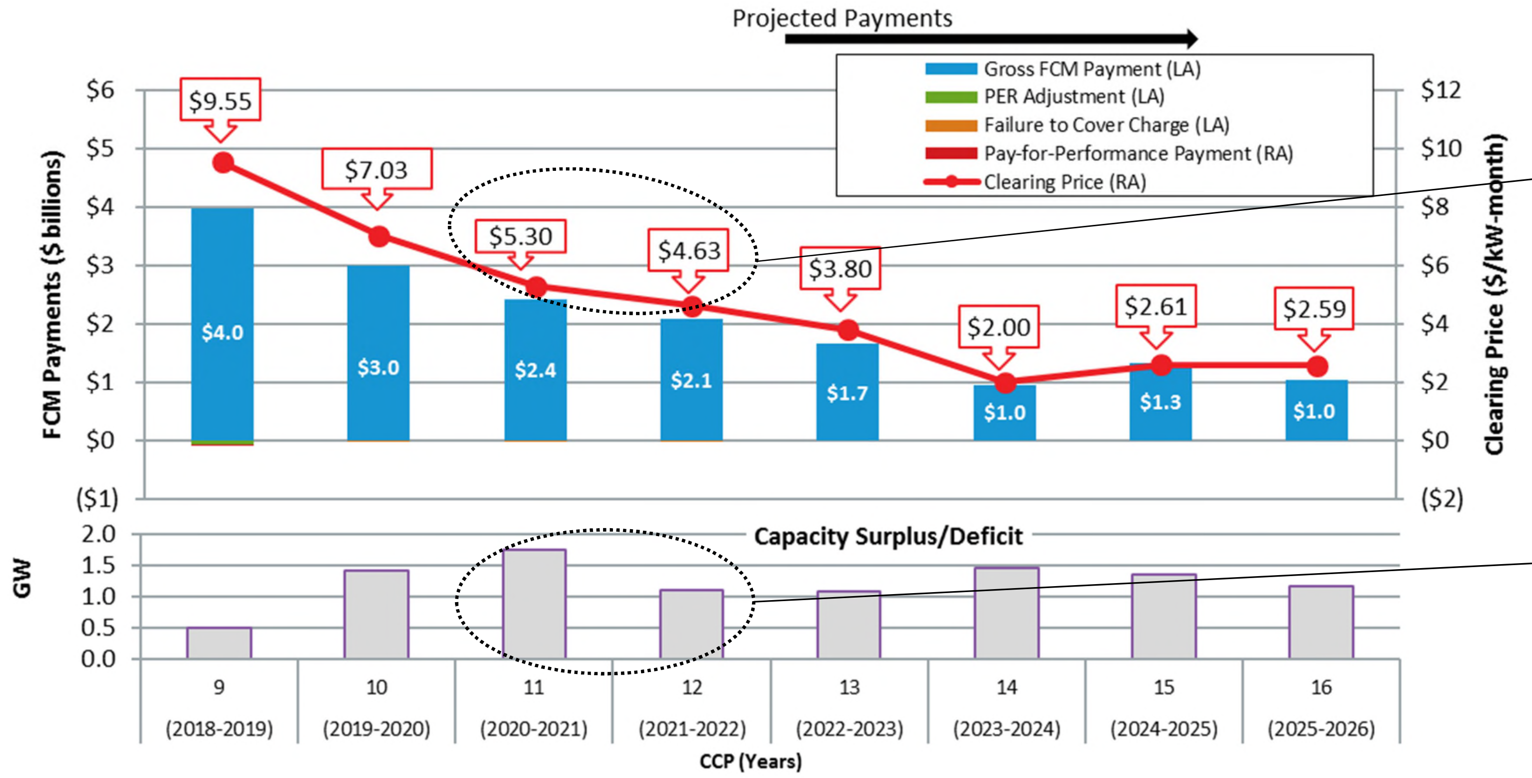
Energy costs comprise a larger share of wholesale costs due to higher natural gas prices and declining capacity costs

- Total wholesale cost of electricity in 2021 was $11.2 billion ($94 per MWh of load served).
  - **Energy costs** were over half ($6.1 billion or 55%) of total costs, up from a 37% share in 2020 due to higher natural gas prices.
  - Lower **capacity costs** made up 20% of total costs ($2.2 billion) and are a function lower clearing prices (avg. of $4.9/kW-mo) and surplus conditions from FCA 11 and 12 (conducted in 2017 and 2018); costs will decline further over next 4 years.
  - Regional network load (**transmission**) costs made up 24% ($2.7 billion), up by 15% due to infrastructure improvement costs.
- Net Commitment Period Compensation (NCPC), or uplift, costs remained relatively low at just $35 million, or 0.6% of total energy payments.
  - Most (75%) uplift was paid to resources committed and dispatched in economic merit order, with the remaining 25% (just $9 million) required to meet the costs of out-of-merit reliability commitments.
  - Consistent with improved price formation in the real-time energy market since the implementation of the fast-start pricing rules in 2017, and with the generally low levels of operator out-of-market or unpriced actions in 2021.

Energy costs drove the overall increase in wholesale costs; lower capacity costs offset by higher transmission (RNL) costs



FCM payments continue on a downward trajectory under capacity surplus conditions



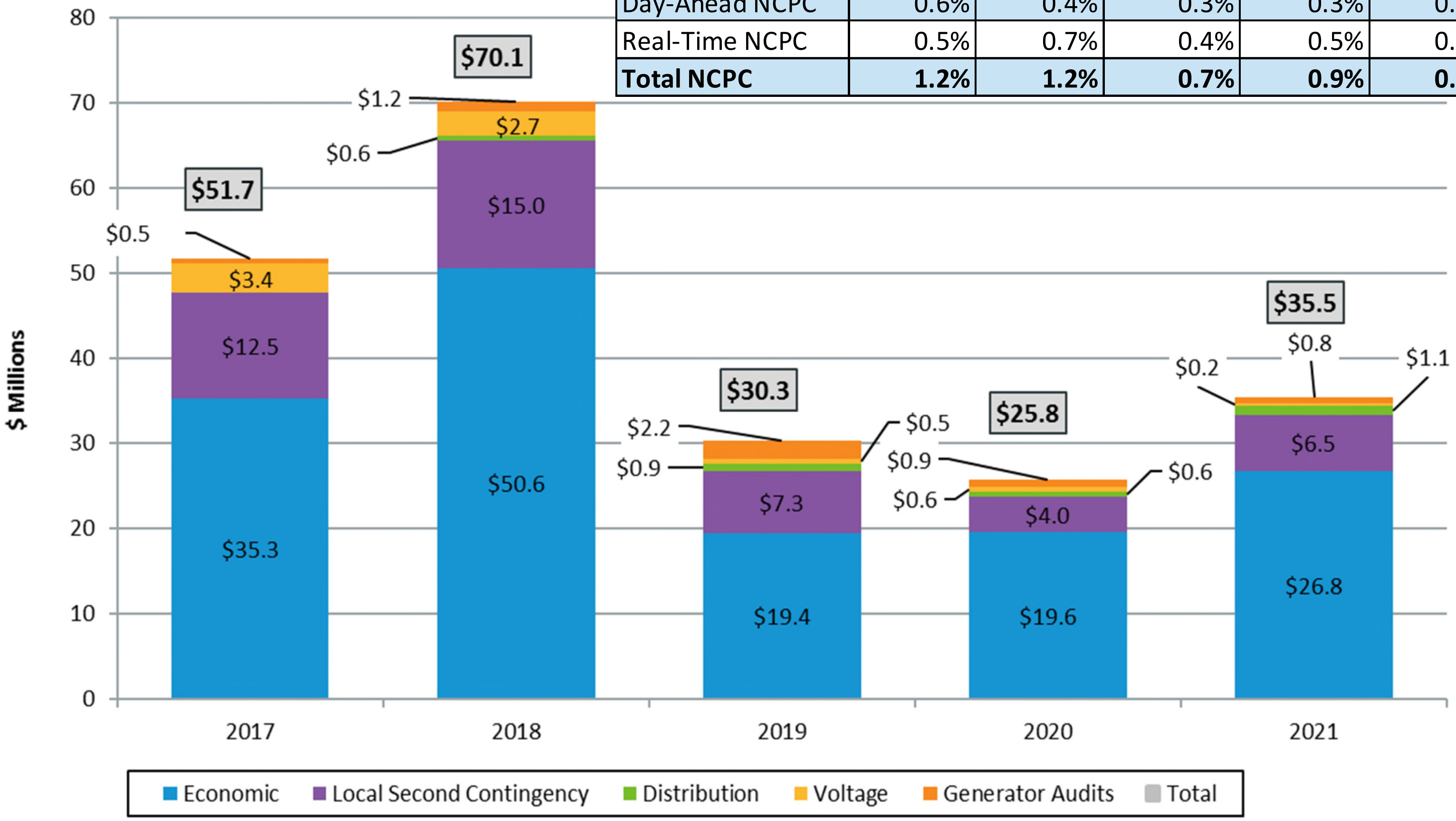
Avg. 2021 capacity price of $4.96/kW-mo (FCA 11 and 12), down 19% from $6.16/kW-mo in 2020 (FCA 10 and 11).

Avg. 2021 surplus of ~1,400 MW (4%) above NICR.

Higher uplift costs due to higher energy prices and a slight increase in local reliability commitments; but comparatively, uplift remained low

Uplift Payments as a Percent of Energy Costs

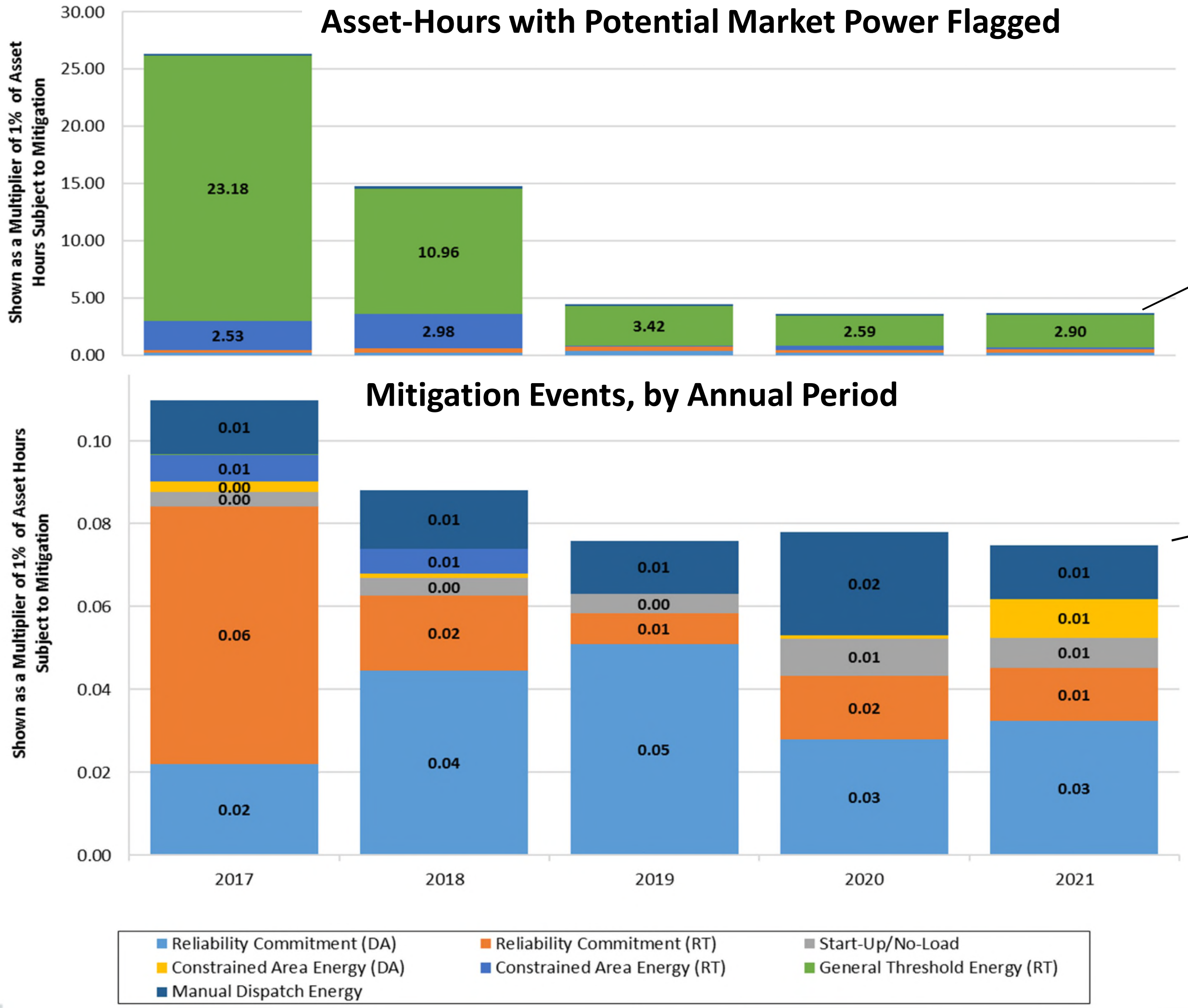
Market	2017	2018	2019	2020	2021
Day-Ahead NCPC	0.6%	0.4%	0.3%	0.3%	0.3%
Real-Time NCPC	0.5%	0.7%	0.4%	0.5%	0.3%
Total NCPC	**1.2%**	**1.2%**	**0.7%**	**0.9%**	**0.6%**



Low level of offer mitigation in the energy market, low levels of structural market power with the exception of the forward reserve market

- 3% of total asset hours flagged for market power of which only 2% were mitigated.
  - 957 asset hours of mitigation of the 44,272 asset-hours flagged.
- Frequency of pivotal suppliers in the real-time energy and reserve market has remained relatively low.
- Wide mitigation thresholds at the system and local level should be revisited, but are not a significant concern under current surplus market conditions.
- Range of industry-standard metrics (price/cost mark-up, output gap) indicate low levels of potential economic withholding in the energy market.
- Regulation market is structurally very competitive.
- Forward reserve market has had modest levels of structural market power but prices have been comparatively low and stable in the past two years (except recent 2022 summer auction).

Energy market mitigation remained low



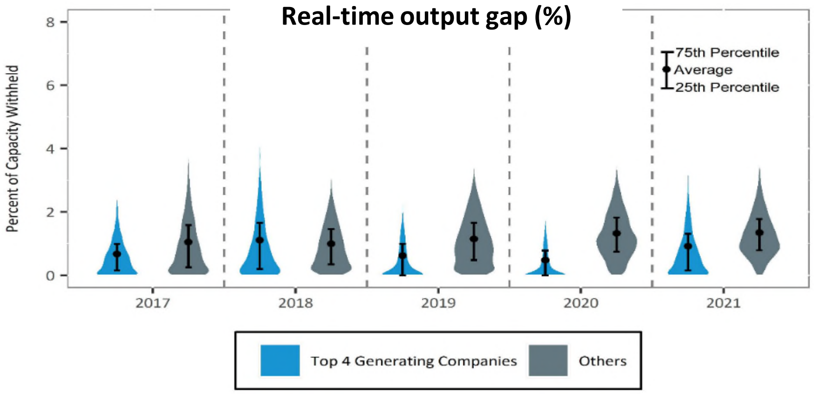
The total unit-hours of committed generation subject to mitigation rules is approximately 1.2 million per year. In 2021, ~44,000 asset-hours (3.4%) were flagged for potential market power.

Of ~44,000 asset-hours that were evaluated for market power, only 957 asset-hours (2%) were deemed as having violated mitigation thresholds and were mitigated. This was less than 0.08% of all asset hours subject to mitigation.

Energy market competitiveness similar to 2020

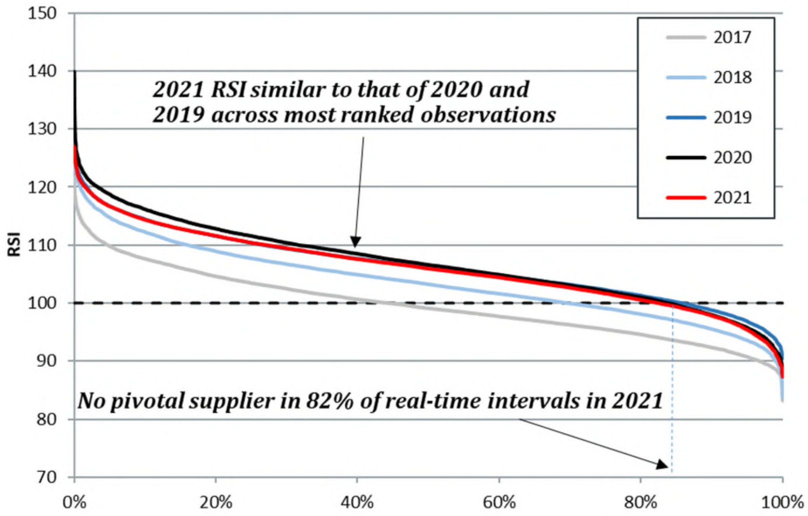
Price-cost markup and output gap metrics within reasonable ranges

Year	Day-Ahead Price-Cost Markup (%)
2017	4.9
2018	4.9
2019	6.6
2020	7.6
2021	8.4



Real-time output gap (%)

Low levels of structural market power in the real-time market; largest supplier required in ~18% of hrs



2021 RSI similar to that of 2020 and 2019 across most ranked observations

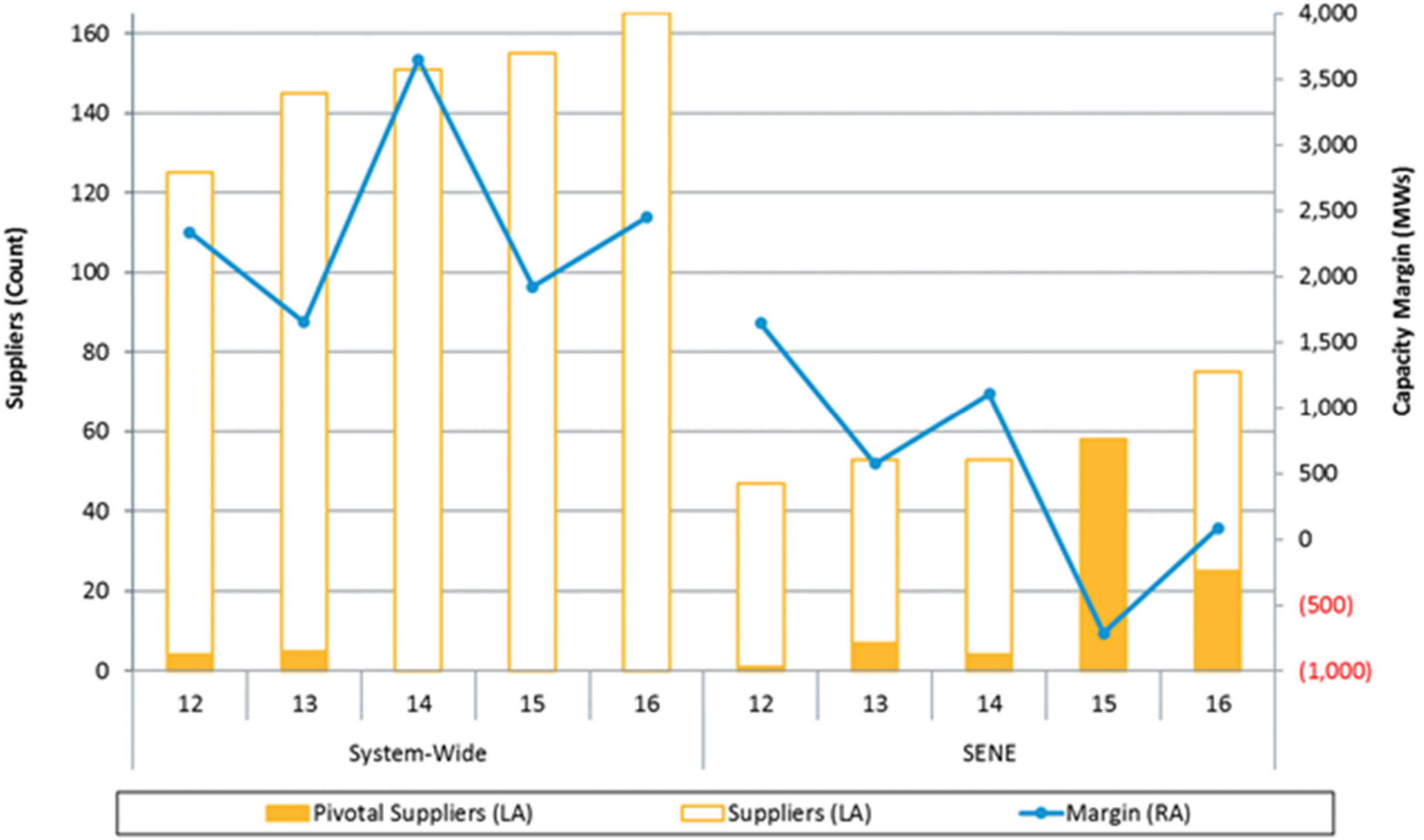
No pivotal supplier in 82% of real-time intervals in 2021

Year	% of Intervals With At Least 1 Pivotal Supplier	RSI
2017	55.7%	99.6
2018	30.7%	103.6
2019	14.7%	106.4
2020	16.6%	106.9
2021	18.0%	106.0

FCM mitigation processes working, but well-known challenges to efficient pricing and capacity procurement

- FCM structurally competitive at a system level in past three auctions; with market power present mostly at a zonal level.
  - Few active de-list bids from pivotal suppliers over past five auctions.
- Primary driver of IMM-mitigated new supply offers has been out-of-market revenues to sponsored policy resources.
- IMM was supportive of the elimination of MOPR, recognizing the over-build inefficiency, but also highlighted the risks to price formation and FCM performance without MOPR.
- Resource capacity accreditation and day-ahead ancillary services are important initiatives that should enhance price formation in the energy and capacity markets.
- Economic merit at a conceptual level to stakeholder proposal on mothballing (re-entry), but more detail on design and assessment of market power aspects needed.

FCA 16 structurally competitive at the system level, but market power in SENE; no static de-list bids from pivotal suppliers



Market Enhancement Recommendations

Table 1-2 in the executive summary provides an update on recommendations included in our quarterly reports and public filings. Notable updates:

- FCM buyer-side mitigation rules: recommendation to exclude “incentive rebuttal” or net benefits test component due to practical implementation challenges. Ultimately, FERC recently approved its inclusion.
- Reconstitution of Regional Network Load for Behind-the-Meter (BTM) Generation: Closed two recommendations to the Transmission Owners (TOs) on the allocation of transmission costs to load with BTM generation. FERC accepted the TOs’ proposal addressing this recommendation.
- Coordinated Transaction Scheduling (CTS) price forecasting accuracy: annual report provides updated analysis and reaffirms the potential impacts and benefits of price forecasting accuracy under the CTS rules.

Highlights Data

Statistic	2017	2018	2019	2020	2021	% Change 2021 to 2020
Demand (MW)						
Real-time Load (average hourly)	13,838	14,095	13,614	13,309	13,556	↑ 2%
Weather-normalized real-time load (average hourly)[a]	13,737	13,725	13,558	13,279	13,410	⇨ 1%
Peak real-time load (MW)	23,968	26,024	24,361	25,121	25,801	↑ 3%
Generation Fuel Costs ($/MWh) [b]						
Natural Gas	29.02	38.61	25.41	16.34	36.07	↑ 121%
Coal	51.57	54.54	40.54	37.83	67.95	↑ 80%
No.6 Oil	94.76	127.80	130.90	89.43	138.30	↑ 55%
Diesel	148.36	187.60	173.54	112.06	184.69	↑ 65%
Hub Electricity Prices - LMPs ($/MWh)						
Day-ahead (simple average)	33.35	44.13	31.22	23.32	45.92	↑ 97%
Real-time (simple average)	33.93	43.54	30.67	23.38	44.84	↑ 92%
Day-ahead (load-weighted average)	35.23	46.88	32.82	24.57	48.30	↑ 97%
Real-time (load-weighted average)	36.15	46.85	32.32	24.79	47.34	↑ 91%
Estimated Wholesale Costs ($ billions)						
Energy	4.5	6.0	4.1	3.0	6.1	↑ 104%
Capacity	2.2	3.6	3.4	2.7	2.2	↓ -16%
Net Commitment Period Compensation	0.05	0.07	0.03	0.03	0.04	↑ 38%
Ancillary Services	0.1	0.1	0.1	0.1	0.1	↑ 3%
Regional Network Load Costs	2.2	2.3	2.2	2.4	2.7	↑ 15%
Total Wholesale Costs	**9.1**	**12.1**	**9.8**	**8.1**	**11.2**	↑ **38%**
Supply Mix [c]						
Natural Gas	40%	40%	39%	42%	45%	↑ 3%
Nuclear	26%	25%	25%	22%	22%	⇨ 1%
Imports	17%	17%	19%	20%	16%	↓ -4%
Hydro	7%	7%	7%	7%	6%	⇨ 0%
Other[d]	5%	5%	5%	5%	5%	⇨ 0%
Wind	3%	3%	3%	3%	3%	⇨ 0%
Solar	1%	1%	1%	2%	2%	⇨ 0.5%
Coal	1%	1%	0%	0%	0.46%	⇨ 0.34%
Oil	1%	1%	0%	0%	0.19%	⇨ 0.05%

Demand increased due to reduced impacts from the COVID-19 pandemic and colder weather in Q1 2021.

Prices of all major fuels increased, rebounding from record lows in 2020.

Simple- and load-weighted avg. LMPs up significantly, but not as much as the increase in gas prices. Offsetting factors included additional nuclear generation due to fewer outages, and increased fixed supply from generators needed to offset the decrease in imports.

Energy comprised 55% of wholesale costs. Increases in all wholesale market cost categories, with the exception of capacity costs. Decreased capacity costs offset by higher transmission (RNL) costs.

Reduction in avg. net imports (by 536 MW per hour), mostly over the NY interfaces due to planned transmission reductions and increased export transactions due to higher NY prices. This shortfall was countered by an increase in native generation, with natural gas generation increasing by 508 MW and nuclear generation increasing by 171 MW.

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[a] Weather-normalized results are those that would have been observed if the weather were the same as the long-term average.

[b] Generation costs are calculated by multiplying the daily fuel price ($/MMBtu) by the average standard efficiency of generators for each fuel (MMBtu/MWh)

[c] Provides a breakdown of total supply, which includes net imports. Note that section 2 provides a breakdown of native supply only.

[d] The "Other" fuel category includes landfill gas, methane, refuse and steam

⇨ denotes change is within a band of +/- 1%

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Questions

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of August 2, 2022

The following activity, as more fully described in the attached litigation report, has occurred since the report dated June 17, 2022 ("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: *FTR Collateral Show Cause Order* (EL22-63)	Jul 28	FERC issues order finding that the ISO-NE Tariff appears to be unjust and unreasonable in the absence of volumetric minimum collateral requirements for FTR Market Participants; ISO-NE response due on or before ***Oct 26, 2022***; interventions due on or before ***Aug 18, 2022***
			Jul 29-Aug 2	DC Energy, NRG intervene
	2	RENEW/ACPA Resource Capacity Accreditation & Operating Reserve Designation Complaint (EL22-42)	Jul 20	ISO-NE requests expeditious action on Complaint
			Aug 1	Complainants answer and provide additional support for ISO-NE's request for expedited action
	3	NMISA Complaint Against PTO AC (Reciprocal TOUT Discount) (EL22-31)	Jul 28	FERC denies NMISA Complaint

II. Rate, ICR, FCA, Cost Recovery Filings

*	8	Essential Power Newington CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER22-2469)	Jul 22	Essential Power Newington requests recovery of $360,261 of incremental medium impact CIP-IROL Costs incurred between Feb 18, 2021 and Jun 30, 2022; comment date ***Aug 12, 2022***
			Jul 26	NESCOE intervenes
*	8	GenConn Middletown CIP IROL (Schedule 17) Cost Recovery Schedule Filing (ER22-2367)	Jul 13	GenConn Energy requests FERC acceptance of a proposed rate schedule to allow GenConn Middletown to begin the recovery period for certain CIP-IROL Costs under Schedule 17 of the ISO-NE Tariff; comment date ***Aug 3, 2022***
			Jul 14-Aug 1	CT PURA, Eversource, National Grid, NESCOE intervene
	9	FCA16 Results Filing (ER22-1417)	Jul 18	FERC accepts FCA16 Results filing, eff. Jul 19, 2022
	9	Constellation Post-Spin Updates to Mystic COS Agreement (ER22-1192)	Jun 23	Settlement Judge issues his first status report
			Jun 28	Second settlement conference held
			Jul 14	Third settlement conference held; parties reach agreement in principle
			Jul 26	Settlement Judge issues his second status report
			Jul 29	Deputy Chief ALJ substitutes ALJ Patricia French for ALJ Glazer (who retired) to conduct settlement judge procedures going forward
	10	Mystic 8/9 COS Agreement First CapEx Info Filing (ER18-1639)	Jun 27	(-017) Mystic request for clarification or reh'g of *Mystic First CapEx Info. Filing Order* denied by operation of law
			Jul 20	(-018) Mystic submits for information revision to Fuel Supply Agreement
*	11	Transmission Rate Annual (2022-23) Update/Informational Filing (ER09-1532; RT04-2)	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

*	12	CSF Revisions (ER22-2546)	Jul 29	ISO-NE and NEPOOL jointly file Market Rule 1 revisions to allow storage facilities incapable of consuming electricity from the grid to participate in the New England Markets as Continuous Storage Facilities; comment deadline ***Aug 19, 2022***
*	12	Info Policy Changes: Cyber Security Exigency Sharing Provisions (ER22-2366)	Jul 13	ISO-NE and NEPOOL jointly file changes to allow ISO-NE to share confidential information with NERC and federal agencies with cyber security responsibilities, without prior, if a cyber-security event occurs’ comment date ***Aug 3, 2022***
			Jul 15-Aug 1	Calpine, Eversource, National Grid intervene
	12	New England’s *Order 2222* Compliance Filing (ER22-983)	Jul 8	AEE, AEMA, PowerOptions, and SEIA file Joint Protest
			Jul 25	ISO-NE answers Joint Protest

IV. OATT Amendments / TOAs / Coordination Agreements

*	13	*Phase I/II HVDC-TF Order 881 Compliance Filing (ER22-2468 and (ER22-2467)*	Jul 22	ISO-NE, Phase I/II HVDC-TF Asset Owners, and the 20A Service Providers submit an *Order 881* compliance filing with changes to the HVDC TOA (ER22-2467) and Schedule 20-Common Attachment M (ER22-2468); comment deadline ***Aug 12, 2022***
*	13	*Order 881* Compliance Filing: New England (ER22-2357)	Jul 12	ISO-NE, NEPOOL, PTO AC, and CSC submit *Order 881* (Transmission Line Ratings) compliance filing
			Jul 21-Aug 1	Eversource, Narragansett Electric, National Grid intervene
*	14	Process Modifications - DER Interconnection/Interconnection Study Coordination (ER22-2226)	Jun 29	ISO-NE, NEPOOL and the PTO AC file Tariff changes to modify the process for interconnection of new distributed energy resources and improve the coordination of interconnection studies
			Jul 15-Jul 26	Calpine, Borrego, Eversource, National Grid, NRG, MA DPU intervene
			Jul 20	AEE, ENGIE, SEIA submit comments supporting changes
	14	Attachment F Corrections & Updates (ER22-2021)	Jun 24	Public Systems intervene
			Aug 1	FERC accepts corrections & updates, eff. Aug 2, 2022

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

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

*	15	Schedule. 20A (Phase I/II HVDC-TF Service Agreement) Reassignm’t Agreements: CMP & UI/ BRTM/ HQUS (ER22-2433/32/31)	Jul 19	Avangrid Networks files 3 Phase I/II HVDC-TF service agreements to transfer the transmission service rights and obligations that Brookfield Renewable Trading & Marketing (BRTM) currently holds under existing TSAs (1 with CMP; 2 with UI) to HQUS
			Jul 28	BRTM and HQUS file comments supporting Agreements
*	15	Schedule. 20A (Phase I/II HVDC-TF Service Agreement) Reassignm’t Agreement: NEP/BRTM/HQUS (ER22-2398)	Jul 18	NEP files a Phase I/II HVDC-TF service agreements to transfer the transmission service rights and obligations that BRTM currently holds under an existing TSA to HQUS;
			Jul 26-27	BRTM, HQUS intervene
			Jul 28	BRTM and HQUS file comments supporting Agreement
	16	Schedule 21-NEP: Revised RI LSAs Compliance Filing (ER22-1918)	Jul 14	FERC accepts Revised RI LSA (TSA-NEP-86), eff. Jan, 1, 2022

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

	18	Capital Projects Report - 2022 Q1 (ER22-1880)	Jul 11	FERC accepts 2022 Q1 Report, eff. Apr 1, 2022
*	18	LFTR Implementation: 55th Quarterly Status Report (ER07-476)	Jul 15	ISO-NE files its 55th quarterly report

IX. Membership Filings

*	19	Aug 2022 Membership Filing (ER22-2568)	Jul 29	NEPOOL requests that the FERC accept (i) the memberships of Concurrent; Leapfrog Power; Old Middleboro Road Solar; and Accelerate Renewables; and (ii) the termination of the Participant status of Chris Anthony; Indeck Energy-Alexandria; Standard Normal; and Borrego Solar Systems; comment deadline ***Aug 22, 2022***
*	20	July 2022 Membership Filing (ER22-2260)	Jun 29	NEPOOL requests that the FERC accept (i) the termination of the Participant status of Liberty Power Holdings; and (ii) the name change of Astral (f/k/a/ Able Grid) Infrastructure Holdings, LLC
	20	Jun 2022 Membership Filing (ER22-1991)	Jul 5	NEPOOL submits corrected transmittal letter
	20	May 2022 Membership Filing (ER22-1738)	Jun 24	FERC accepts (i) the memberships of Altop Energy Trading, Indra Power Business CT, Indra Power Business MA, Leicester Street Solar, and Nexamp Markets; and (ii) Salem Harbor Power Development LP's name change, eff. May 1, 2022

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

	20	NPCC Bylaws Changes (RR22-2)	Jul 8	FERC conditionally approves changes to NPCC Bylaws, eff. Jul 8, 2022; compliance filing due on or before ***Sep 6, 2022***
			Jul 29	NERC/NPCC request 30-day extension of time, to Oct 6, 2022, to submit compliance filing
	21	Rules of Procedure Changes (CMEP Risk-Based Approach Enhancements) (RR21-10)	Jul 18	NERC submits compliance filing reinstating language in its ROP as directed in the FERC's May 19 order; comment date ***Aug 8, 2022***

XI. Misc. - of Regional Interest

*	22	203 Application: Centrica / CPower (EC22-90)	Jul 13	Centrica and CPower request authorization for the sale of 100% of the equity interests in Centrica to CPower; comment deadline ***Aug 3, 2022***
			Jul 14-22	PJM IMM, Public Citizen intervene
*	22	203 Application: Clearway / TotalEnergies (EC22-84)	Jul 1	Clearway requests authorization for, among other things, TotalEnergies acquisition of a 50% percent indirect interest in the Clearway Group
			Jul 13, 27	PJM IMM, PJM (out-of-time) intervene
*	22	203 Application: Waterside Power / KKR (EC22-79)	Jun 22	Applicants request authorization for the sale of 100% of their equity interests to KKR
			Jun 23	Public Citizen intervenes
	22	203 Application: Stonepeak/JERA Americas (EC22-71)	Jun 22	MA AG submits comments, Public Citizen protests filing
			Jul 1	Stonepeak answers protest and comments
*	23	Versant MPD OATT *Order 881* Compliance Filing (ER22-2358)	Jul 12	Versant Power submits compliance filing
			Aug 1	Versant Power corrects requested eff. date (now Jul 12, 2025)
*	23	VTransco Shared Structure Participation Agreements (ER22-2189)	Jun 24	VTransco files two Shared Structure Participation Agreements between VTransco and Green Mountain Power

	23	LGIA: CL&P / EIP Investment (New Britain, CT Fuel Cell) (ER22-1862)	Jul 11	FERC accepts non-conforming LGIA governing the interconnection of EIP's 20 MW fuel cell project, eff. Apr 12, 2022
	24	Maine Power Link Application for Negotiated Rate Authority (ER22-1290)	Jun 22	FERC denies Maine Power Link's request for negotiated rate authority (for failure to show that it has assumed the full market risk for the Project)
	24	Versant Power MPD OATT *Order 676-I* Compliance Filing (ER21-2498)	Jun 29	FERC accepts compliance filing, eff. May 1, 2022
	25	*Orders 864/864-A* (Public Util. Trans. ADIT Rate Changes): New England Compliance Filings (various)	Jul 18	*ER20-2553 (NEP – MECO/Nantucket LSA).* NEP supplements its Jul 30, 2020 compliance filing
			Jul 18	*ER20-2251 (NEP – Sched. 21-NEP and TSA-MEP-22).* NEP supplements its Jul 30, 2020 compliance filing
			Jul 19	*ER20-2219 (NEP – Tariff No. 1).* NEP supplements its Jun 29, 2020 compliance filing

XII. Misc. - Administrative & Rulemaking Proceedings

	26	New England Gas-Electric Winter Forum (AD22-9)	Jul 21	FERC issues supplemental notice of ***Sep 8, 2022*** forum in Burlington, VT, strongly encouraging those interested to promptly register
	26	Joint Federal-State Task Force on Electric Transmission (AD21-15)	Jul 15	FERC issues order listing State Commissioners that will serve on the JFSTF for the Sep 1, 2022 – Aug 31, 2023 term
			Jul 20	FERC convenes fourth JFSTF meeting
	28	Increasing Market and Planning Efficiency Through Improved Software Tech Conf (Jun 21-23, 2022) (AD10-12)	Jun 21-23	FERC holds 13th annual tech conf
			Jul 14	FERC issues second supplemental notice attaching a corrected final agenda and speakers' summaries of their presentations
			Jul 28	Post-tech conf comments filed
*	28	NOPR: Duty of Candor (RM22-20)	Jul 28	FERC issue NOPR 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 and their market monitors, NERC and its Regional Entities, 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; comments and reply comments due **[60 days after publication in the *Fed. Reg.*]**
	29	NOPR: Extreme Weather Vulnerability Assessments (RM22-16; AD21-13)	Jul 1	NOPR published in *Federal Register*; initial comments due ***Aug 30, 2022***
	29	NOPR: Interconnection Reforms (RM22-14)	Jul 5	NOPR published in *Federal Register*; initial comments due ***Oct 13, 2022***; reply comments, ***Nov 14, 2022***
*	31	NOPR: ISO/RTO Credit Information Sharing (RM22-13)	Jul 28	FERC issues NOPR proposing to revise its regulations to permit ISO/RTOs to share among themselves credit-related information regarding market participants; comments and reply comments due **[60 days and 90 days, respectively, after publication in the *Fed. Reg.*]**
	31	NOPR: Transmission System Planning Performance Requirements for Extreme Weather (RM22-10)	Jun 27	NOPR published in *Federal Register*; initial comments due ***Aug 26, 2022***

	33	*Transmission NOPR* (RM21-17)	Jul 8-18	Microgrid Resources Coalition, Smart Electric Power Alliance, Tabors Caramanis submit comments
			Jul 27	GA PSC asked for an additional 30 days for comments and reply comments; absent extension, comments due ***Aug 17, 2022***; reply comments, ***Sep 19, 2022***
	34	NOI: Removing the DR Opt-Out in ISO/RTO Markets (RM21-14)	Jul 1	Voltus submits comments in support of eliminating the DR Opt-Out
			Jul 15-Aug 1	Mississippi PSC, R. Borlick respond to Voltus comments
*	35	NOPR: Acct'ng and Reporting Treatment of Certain Renewable Energy Assets (RM21-11)	Jul 28	FERC issues NOPR proposing reforms to the USofA to account for certain renewable energy assets; comments and reply comments due **[45 days after publication in the *Fed. Reg.*]**

XIII. FERC Enforcement Proceedings

*	38	Salem Harbor (IN18-8)	Jun 27	FERC approves Stipulation and Consent Agreement that resolved OE's investigation into Salem Harbor's receipt of capacity payments for its New Salem Harbor Generating Station project during the 2017-18 Capacity Commitment Period, a period during which the Project had neither been built nor commenced commercial operation; Salem Harbor must (subject to any limitation imposed by its bankruptcy cases) ***disgorge $26.7 million***, and pay a ***$17.1 million civil penalty***
*	40	M3/Utica East/UEOM (IN22-6)	Jun 24	FERC approves Stipulation and Consent Agreement that resolved OE's investigation into M3's and Utica East's failure to submit Utica East's FERC Form No. 6s over a 6-year period; M3 must pay a ***$30,000 civil penalty***
*	39	sPower Development Company (IN22-5)	Jun 24	FERC approves Stipulation and Consent Agreement that resolved OE's investigation into whether sPower violated § 36.2A of the PJM Tariff by submitting inaccurate information to PJM during the interconnection process; sPower must pay a ***$24,000 civil penalty***
	42	Total Gas & Power North America, Inc. et al. (IN12-17)	Jul 1-22	OE and Petitioners submit revised testimony and exhibits
			Jul 5	OE opposes Respondents motion to dismiss or stay proceedings
			Jul 13	Chief Judge denies motion for appointment of special discovery judge

XIV. Natural Gas Proceedings

	43	Northern Access Project (CP15-115)	Jun 29	FERC grants Applicants' request for an additional extension of time; Applicants now have until ***Dec 31, 2024*** to construct and place the Project into service
			Jul 22	Rehearing requested of Jun 29 order

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

	46	*2nd Revised Narragansett LSA Orders* (22-1108, 22-1161) (consol.)	Jul 14	Green Development petitions DC Circuit for review of the FERC's *2nd Rev Narragansett LSA Allegheny Order*
			Jul 15	Court consolidates 2nd Rev Narragansett LSA cases
			Jul 18	Green Development files initial submissions
			Jul 28	FERC files Certified Index to the Record

47	Mystic ROE (21-1198 et al.) (consol.)	Jul 8	CT Parties and ENECOS jointly move to hold these proceedings in abeyance until 30 days after opinion issues in *MISO TOs* (16-1325)
		Jul 12	Constellation opposes abeyance request
		Jul 19	CT Parties and ENECOS reply to Constellation opposition
		Jul 27	Court grants abeyance request
48	CASPR (20-1333, 21-1031) (consolidated)**	Jul 22	Petitioners seek third abeyance of proceedings (until ***Mar 1, 2024***)
		Jul 25	Court grants third abeyance request
50	Algonquin Atlantic Bridge Project Cases (21-1115 et al.)	Jun 30	First Circuit transfers cases 20-1458 and 22-1201 to the DC Circuit, subsequently docketed as cases 22-1146 and 22-1147, and consolidates the cases with its pending Atlantic Bridge Project cases
		Jul 19	Parties file motion to sever cases 22-1146/47, propose a briefing schedule for the severed cases, and ask that the remaining cases continue to be held in abeyance

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: August 2, 2022

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, 2022. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

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

On July 28, 2022, the FERC instituted a Section 206 proceeding finding that the existing tariffs of certain ISO/RTOs, including the ISO-NE Tariff, appear to be unjust and unreasonable.[2] 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 Tariff has in fact become unjust and unreasonable or unduly discriminatory or preferential.[3] Alternatively, if it is so inclined, ISO-NE may propose Tariff revisions on the subject of the *FTR Collateral Show Cause Order* under FPA Section 205 and request that these proceedings be held in abeyance pending disposition of that proceeding.[4]

This 206 order follows PJM's *Green Hat* experience,[5] 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,[6] and a two-day technical conference in February 2021 that discussed principles and best practices for credit risk management in organized wholesale electric markets.[7] In the *FTR Collateral Show Cause Order*, the

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

[3] *Id.* at P 31.

[4] *Id.* at P 32.

[5] *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.

[6] 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 Electric Markets*, Docket No. AD20-6-000 (Dec. 16, 2019).

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

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."[8] ISO-NE has implemented 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, which will be the date of publication of the notice in the *Federal Register* (which has not yet happened). Those interested in participating in this proceeding are required to intervene on or before ***August 18, 2022***. Thus far, doc-less interventions have been filed by DC Energy and NRG. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **RENEW/ACPA Resource Capacity Accreditation & Operating Reserve Designation Complaint (EL22-42)**

As previously reported, RENEW Northeast, Inc. ("RENEW") and the American Clean Power Association ("ACPA") filed a Complaint on March 15, 2022 under Section 206 of the Federal Power Act ("FPA") against ISO-NE seeking a FERC order directing ISO-NE to make changes to its rules for capacity accreditation and operating reserve designations, effective no later than FCA18 with respect to capacity accreditation and promptly with respect to operating reserve designations. RENEW/ACPA asserted that the changes are needed to address undue preferences granted under ISO-NE's rules and procedures to gas-fired generation resources that have neither dual-fuel capability nor dedicated, firm natural gas supply arrangements ("Gas-Only Resources"). Complainants asserted that the undo preferences arise in the context of capacity accreditation through an assumption of 100% fuel availability for Gas-Only Resources, and in the context of operating reserves, through the absence of any pre-dispatch requirements to confirm fuel availability. ISO-NE's response and comments, following a request for extension granted by the FERC, were due on or before April 14, 2022.

On April 14, 2022, ISO-NE responded to the Complaint. Protests and comments on the Complaint were filed by: NEPOOL, AEE, Calpine, EDF, FirstLight, LS Power, NEPGA, NESCOE, Public Interest Orgs,[9] Vistra/LSP Power, State Parties,[10] EPSA, National Hydropower Assoc., and the Solar Energy Industries Association ("SEIA"). On April 29, RENEW/ACPA answered the ISO-NE and NEPOOL motions to dismiss and answered the protests and comments filed in opposition to the Complaint. On May 17, ISO-NE answered the April 29 RENEW/ACPA answer. Interventions only were filed by AEP, Avangrid, Avangrid Renewables, Borrego, Brookfield, Constellation, CPV Towantic, Dominion, ENE, Excelerate, National Grid, NextEra, NH OCA, North East Offshore, NRG, Public Systems,[11] CT PURA, MA DPU, MPUC, Repsol, APPA, EPSA, the Institute for Policy Integrity at New York University School of Law, and Public Citizen. Since the last Report, on July 20, 2022, ISO-NE submitted a letter requested expeditious action on the Complaint (a request NEPOOL supported). Complainant supported the request for expedited action on August 1, 2022 (adding that the FERC "should grant the Complaint and direct ISO-NE to submit a compliance

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[8] 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 ("FAP") 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.

[9] "Public Interest Orgs" are the Sustainable FERC Project, Acadia Center, Conservation Law Foundation ("CLF"), Sierra Club, and Natural Resources Defense Council ("NRDC").

[10] "State Parties" are the Connecticut Department of Energy and Environmental Protection ("CT DEEP"), the Massachusetts Attorney General ("MA AG"), and the Connecticut Attorney General ("CT AG").

[11] "Public Systems" are Connecticut Municipal Electric Energy Cooperative ("CMEEC"), Massachusetts Municipal Wholesale Electric Company ("MMWEC"), New Hampshire Electric Cooperative, Inc. ("NHEC"), and Vermont Public Power Supply Authority ("VPPSA").

filing that timely implements the proposed remedies", and could address the wish for "constructive *ex parte* communications with [FERC] Staff … with an appropriately crafted waiver of the *ex parte* limitations"). No action has yet been taken and this Complaint remains pending before the FERC. If you have any questions concerning this Complaint, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **NMISA Complaint Against PTO AC (Reciprocal TOUT Discount) (EL22-31)**

On July 28, 2022, the FERC denied the Northern Maine Intendent System Administrator's ("NMISA") complaint against the Participating Transmission Owners ("PTOs") Administrative Committee ("PTO AC"), holders of the exclusive Section 205 rights in this matter, for failure to consider and implement a reciprocal discount to the Through and Out ("TOUT") charges applied to transactions between the New England and Northern Maine regions ("TOUT Discount").[12] In denying the Complaint, the FERC found that "NMISA has not demonstrated that the failure of the PTO AC and ISO-NE to offer NMISA reciprocal treatment is unduly discriminatory or preferential".[13] Specifically, the FERC citied its longstanding policy permitting such charges, found for a number of reasons NYISO and NMISA not similarly situated, and noted that NMISA's showing that the proposed approach might be superior for NMISA insufficient to meet its statutory burden. Challenges, if any, to the order denying the Complaint are due on or before August 29, 2022. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **206 Proceeding: ISO-NE Tariff Schedule 25 and Section I.3.10 (EL21-94)**

As previously reported, the FERC instituted on September 7, 2021 a proceeding under FPA Section 206 to consider whether Schedule 25 and Tariff section I.3.10 may be unjust and unreasonable.[14] This proceeding arises out of issues raised in the NECEC Transmission LLC ("NECEC")/Avangrid Complaint Against NextEra/Seabrook (related to the interconnection of the New England Clean Energy Connect transmission project ("NECEC Project")) summarized below (EL21-6). Specifically, the FERC identified a concern that "Schedule 25's definition of Affected Party and Tariff section I.3.10 may be unjust and unreasonable to the extent they may allow generating facilities and their components to be identified as facilities on which adverse impacts must be remedied before an elective transmission upgrade can interconnect to the ISO-NE transmission system, even though generators are not subject to the [FERC]'s open access transmission principles," and could result in upgrades identified on an Affected Party's system without any obligation for the Affected Party to construct the identified upgrades.[15]

Accordingly, the FERC directed ISO-NE to: (1) show cause as to why Schedule 25 and Tariff section I.3.10 remain just and reasonable or (2) explain what changes to Schedule 25 and/or Tariff section I.3.10 it believes would remedy the identified concerns if the FERC were to determine that Schedule 25 and/or Tariff section I.3.10 has become unjust and unreasonable and proceeds to establish a replacement rate. On September 8, 2021, the FERC issued a notice of the proceeding and of the refund effective date, which will be October 13, 2020 (the date the NECEC/Avangrid Complaint Against NextEra/Seabrook was filed). Those interested in participating in this proceeding were required to intervene on or before October 5, 2021.[16] NEPOOL, NESCOE, Brookfield, Calpine, Dominion, Eversource, HQ US, LS Power, MA AG, MMWEC, National Grid, NECEC Transmission, NEPGA, NextEra, NRG, CT DEEP, MA DOER, Pixelle Androscoggin (out-of-time), Vistra (out-of-time), ACPA, EPSA, RENEW, and Public Citizen intervened.

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[12] *Northern Maine Indep. Sys. Administrator, Inc. v. ISO New England Participating Transmission Owners Administrative Comm.*, 180 FERC ¶ 61, 044 (July 28, 2022) (order denying reciprocal TOUT discount complaint).

[13] *Id.* at PP 14-15.

[14] *NECEC Transmission LLC and Avangrid, Inc. v. NextEra Energy Resources, LLC et al. and ISO New England Inc.*, 176 FERC ¶ 61,148 (Sep. 7, 2021) ("*Sep 7 Order*").

[15] *Id.* at P 20.

[16] The *Notice* was published in the *Fed. Reg.* on Sep. 14, 2021 (Vol. 86, No. 175) p. 51,140.

ISO-NE Answer. On November 8, 2021, ISO-NE submitted its answer explaining why Schedule 25 and Tariff section I.3.10 remain just and reasonable. ISO-NE called for the FERC to "assist Affected Parties and Interconnection Customers in resolving any disputes pertaining to upgrades on Affected Systems—such as the dispute between NECEC Transmission and NextEra Energy Seabrook, LLC in Docket No. EL21-6—as quickly as possible." Interested parties had until January 7, 2022 to address whether ISO-NE's existing Tariff remains just and reasonable and if not, what changes to ISO-NE's Tariff should be implemented as a replacement rate.

Comments. Comments were filed by the January 7, 2022 deadline by NEPOOL, NECEC/Avangrid, NEPGA, NextEra. On January 20 NextEra answered the NECEC/Avangrid comments. On January 28, NECEC answered NextEra's January 20 answer and ISO-NE answered NECEC's Jan 7 comments.

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

- **NECEC/Avangrid Complaint Against NextEra/Seabrook (EL21-6)**

Still pending before the FERC is the October 13, 2020 complaint by NECEC and Avangrid Inc. (together, "Avangrid") requesting FERC action "to stop NextEra from unlawfully interfering with the interconnection of the NECEC Project and seeking, among other things, an initial, expedited order that would grant certain relief[17] and direct NextEra to immediately commence engineering, design, planning and procurement activities that are necessary for NextEra to construct the generator owned transmission upgrades during Seabrook Station's Planned 2021 Outage (the "Complaint"). NextEra submitted an answer to the Complaint (requesting the FERC dismiss or deny the Complaint) and National Grid filed comments. Doc-less interventions only were filed by Dominion, Eversource, Calpine, Exelon, HQ US, MA AG, MMWEC, NESCOE, NRG, and Public Citizen. Avangrid answered NextEra's answer and NextEra answered Avangrid's answer ("supplemental answer"), repeating its request that the FERC dismiss or deny the Complaint. Avangrid subsequently answered the supplemental answer.

Amended Complaint. On March 26, 2021, Avangrid amended the Complaint to reflect that aspects of the relief originally requested in the Complaint were no longer feasible within the timeline previously sought. Avangrid continued to seek expeditious FERC action, requesting in its March 26 filing a FERC order on or before May 7, 2021 (which did not occur). On April 15, 2021, NextEra answered the amended Complaint. On April 20, 2021, Avangrid answered NextEra's April 15 answer. On May 6, 2021, ISO-NE submitted a letter to express importance of prompt resolution of these matters. On May 17, Avangrid submitted a letter supporting ISO-NE's May 6, 2021 letter.

Additional Briefing. On September 7, 2021, the FERC issued an order establishing additional briefing in this proceeding and instituted a broader Section 206 proceeding (*see* EL21-94 above).[18] Initial briefs[19] were due on

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[17] Directing NextEra to comply with the ISO-NE OATT, to comply with open access requirements, and to cease and desist unlawful interference with the NECEC Project; and to have the FERC temporarily revoke NextEra's blanket waiver under Part 358 of the FERC's regulations and to initiate an investigation and require NextEra to preserve and provide documents related to the interconnection of the NECEC Project.

[18] *NECEC Transmission LLC and Avangrid, Inc. v. NextEra Energy Resources, LLC et al. and ISO New England Inc.*, 176 FERC ¶ 61,148 (Sep. 7, 2021).

[19] The FERC requested additional briefing from the Parties, as well as from ISO-NE, on the following issues: (i) whether or not Seabrook's breaker is properly identified as a part of Seabrook's generating facility; (ii) if Seabrook's breaker is part of Seabrook's generating facility, under what authority, if any, Seabrook may be subject to the upgrade obligations imposed on Affected Parties under the ISO-NE Tariff; (iii) if Seabrook's breaker is part of Seabrook's generating facility, what obligations, if any, Seabrook has under its LGIA with respect to replacement of the breaker and whether or not ISO New England Operating Documents and Applicable Reliability Standards impose an obligation to replace the breaker. If Seabrook's breaker is appropriately classified as a system protection facility, what obligations Seabrook has to replace the breaker. If the Seabrook LGIA obligates Seabrook to act, a description of the scope of Seabrook's obligation under the LGIA; (iv) whether there exists any solution for the interconnection of the NECEC Project that may be implemented without the replacement of Seabrook's breaker; and (v) If replacement of Seabrook's breaker is necessary for the interconnection of the NECEC Project,

or before October 7, 2021, and were filed by ISO-NE, Avangrid, NextEra, MA AG, NEPGA/EPSA, MA DOER. Reply briefs were due on or before October 22, 2021, and were filed by Avangrid, NextEra, ISO-NE. Avangrid answered NextEra's November 4 answer, NextEra moved to lodge a letter from a Branch Chief of the Nuclear Regulatory Commission ("NRC"), including an Inspection Report for Seabrook Station for the time period from July 1, 2021 through September 30, 2021 (together, the "NRC Seabrook Report"), to directly refute a central claim of Avangrid (that Seabrook should have already replaced the Generation Breaker at issue in this proceeding). Avangrid opposed that motion to lodge (asserting that the NRC Seabrook Report is outside the scope of these proceedings and will not assist the FERC in its decision making). With briefing complete, this matter is again pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **NextEra Energy Seabrook Declaratory Order Petition re: NECEC Elective Upgrade Costs Dispute (EL21-3)**

In a related matter, and also still pending before the FERC, is a Petition for a Declaratory Order filed by NextEra Energy Seabrook, LLC ("Seabrook") a week earlier than the Avangrid Complaint that seeks clarity on the scope of Seabrook's "FERC-jurisdictional regulatory obligations with respect to the project ("NECEC Elective Upgrade"), and to resolve its dispute with NECEC" (the "Seabrook Petition"). Specifically, Seabrook asked the FERC to declare that: (1) Seabrook is not required to incur a financial loss to upgrade, for NECEC's sole benefit, a 24.5 kV generator circuit breaker and ancillary equipment ("Generation Breaker") at Seabrook Station; (2) "Good Utility Practice" for replacement of the nuclear plant Generation Breaker is defined in terms of the practices of the nuclear power industry, such that Seabrook's proposed definition of that term is appropriate for use in a facilities agreement with NECEC; and (3) Seabrook will not be liable for consequential damages for the service it provides to NECEC under a facilities agreement (collectively, the "Requested Declarations"). Alternatively, Seabrook asked that the FERC declare that nothing in ISO-NE's Tariff requires Seabrook to enter into an agreement to replace the Generation Breaker, and therefore, Seabrook and the Joint Owners are entitled to bargain for appropriate terms and conditions to recover their costs, to define Good Utility Practice, and to limit liability associated with providing the service ("Alternative Declaration").

Comments on the Seabrook Petition were filed by Eversource, MMWEC and NEPGA. Avangrid and NECEC Transmission (together, "Avangrid") protested the Seabrook Petition. Doc-less interventions only were filed by Dominion, Eversource, Calpine, Exelon, HQ US, National Grid, NESCOE, NRG, and Public Citizen. NextEra answered Avangrid's protest and Avangrid answered NextEra's answer. On May 6, 2021, ISO-NE submitted a letter in this proceeding, as well as in EL21-6, to express importance of prompt resolution of these matters. NextEra moved to lodge both an August 29, 2021 filing containing an executed Engineering and Procurement Agreement ("E&P Agreement") between Seabrook and NECEC that was filed with the FERC on August 19, 2021 and the NRC Seabrook Report. Avangrid answered that motion, asserting that the NRC Seabrook Report was outside the scope of the proceeding and the motion to lodge should be denied. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **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,[20] set the TOs' Base ROE at 10.57%

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whether there exists any interim solution for the interconnection of the NECEC Project that would allow energization of the NECEC Project prior to the replacement of Seabrook's breaker.

[20] 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*")).

(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*).[21] However, the FERC's orders were challenged, and in *Emera Maine,*[22] 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)[23] and third (EL14-86)[24] 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.[25] 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[26] also went to hearing before an Administrative Law Judge ("ALJ"), Judge Glazer, who issued his initial decision on March 27, 2017.[27] 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

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[21] *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*").

[22] *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).

[23] 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%.

[24] 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.

[25] *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*").

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

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

FPA.[28] 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.[29] 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*[30] (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.[31]

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

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

The FERC provided preliminary analysis of how it would apply the proposed methodology in the Base ROE I Complaint, suggesting that it would affirm its holding that an 11.14% Base ROE is unjust and unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[32] 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

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

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

[30] *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*.

[31] *Id.* at P 19.

[32] *Id.* at P 59.

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[33] 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*[34] 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

- **Essential Power Newington CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER22-2469)**

On July 22, 2022, Essential Power Newington ("EP Newington") requested FERC acceptance of its recovery, pursuant to its Schedule 17 Rate Schedule,[35] of ***$360,261*** in Interconnection Reliability Operating Limits Critical Infrastructure Protection costs ("CIP-IROL Costs") under Schedule 17 of the ISO-NE Tariff for the February 18, 2021 through June 30, 2022 period ("Cost Recovery Period"). Essential Power Newington reported that it completed Schedule 17's pre-filing requirements ("Pre-Filing Review Process"), which included the active participation of NESCOE and one other interested party. A September 21, 2022 effective date for EP Newington's CIP-IROL Cost Recovery was requested. Comments on this filing are due on or before August 12, 2022. Thus far, NESCOE has filed a doc-less intervention. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **GenConn Middletown CIP IROL (Schedule 17) Cost Recovery Schedule Filing (ER22-2367)**

On July 13, 2022, GenConn Energy requested FERC acceptance of a proposed rate schedule to allow GenConn Middletown to begin the recovery period for certain Interconnection Reliability Operating Limits Critical Infrastructure Protection costs ("CIP-IROL Costs") under Schedule 17 of the ISO-NE Tariff. GenConn stated that the rate schedule will provide interested parties notice of GenConn Middletown's intent to recover CIP-IROL Costs for each affiliated facility designated as an IROL-Critical Facility, and an order accepting the rate schedule will provide an effective date after which associated costs incurred can be recovered following completion of the process

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

[34] *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).

[35] *See Essential Power Newington, LLC*, Docket No. ER21-1171 (Mar. 31, 2021) (delegated letter order) (accepting Newington's CIP-IROL Rate Schedule effective Feb. 18, 2021, starting the eligible Cost Recovery Period).

contemplated by Schedule 17 and a subsequent Section 205 filing identifying the specific costs to be recovered. A September 12, 2022 effective date was requested. Comments on this filing are due on or before August 3, 2022. Thus far, Eversource, CT PURA, National Grid, and NESCOE have filed doc-less interventions. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **FCA16 Results Filing (ER22-1417)**

On July 18, 2022, the FERC accepted for filing ISO-NE's results for the sixteenth FCA ("FCA16") held February 7, 2022 for the June 1, 2025-May 31, 2026 Capacity Commitment Period ("CCP").[36] The FCA16 Results were accepted effective July 19, 2022, as requested. In accepting the Results Filing, the FERC noted that "No party has provided evidence that ISO-NE failed to conduct [FCA16] in accordance with its Tariff, and therefore we accept ISO-NE's filing." The FERC found that the protests by No Coal No Gas, SEIA, and Pro Se Commenters raised issues focused on FCM design that were outside the scope of this proceeding and that the Killingly issue was made moot by the DC Circuit's May 10, 2022 decision dismissing NTE's petition for review.[37] Unless the *FCA16 Results Order* is challenged, with any challenges due on or before August 17, 2022, this proceeding will be concluded. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Mystic COS Agreement Updates to Reflect Constellation Spin Transaction[38] (ER22-1192)**

On May 2, the FERC accepted and suspended in part Constellation Mystic Power, LLC's ("Mystic's") changes to its Amended and Restated Cost-of-Service Agreement ("COS Agreement") to reflect Mystic's current upstream ownership.[39] The changes were accepted effective as of Jun 1, 2022, but subject to refund. Specifically, the FERC accepted (i) Mystic's changes throughout the COS Agreement to replace the term "Exelon Generation Company, LLC" with "Constellation Energy Generation, LLC"; and (ii) the addition of language to the true-up methodology that provides that the values included in the true-up methodology exclude costs associated with the Spin Transaction. However, noting that Mystic's contested proposal on the issue of capital structure and cost of debt raises issues of material fact that cannot be resolved based on the record, the FERC accepted and suspended this portion of the COS Agreement for a nominal period, to become effective June 1, 2022, subject to refund and to the outcome of paper hearing procedures. The FERC also directed the appointment of a settlement judge and will hold the paper hearing in abeyance so as to provide the participants an opportunity for settlement discussions.[40]

Settlement Judge Procedures. On May 10, Chief Judge Cintron designated Judge Steven Glazer as the Settlement Judge in this proceeding. Judge Glazer convened three settlement conferences -- on June 2, June 28, and July 14, 2022. In each of his two status reports (June 23 and July 26, 2022), Judge Glazer recommended that, "as the participants continue to engage in good faith efforts to reach settlement, …. that settlement procedures continue." In addition, in his July 26 report, Judge Glazer reported that, "the participants reached an agreement to settle their issues. The participants have moved to documenting the agreement in principle." On July 19, Deputy Chief ALJ Andrew Statten substituted ALJ Patricia M. French for Judge Glazer (who has now retired). Judge French will conduct the ongoing settlement judge procedures going forward.

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[36] *ISO New England Inc.*, 180 FERC ¶ 61,036 (July 18, 2022) ("*FCA16 Results Order*").

[37] *Id.* at P 15.

[38] 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.

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

[40] *Id.* at P 24.

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)**

As previously reported, each of the *July 17 Orders*[41] and the *Mystic ROE Orders,*[42] which addressed in part or in whole the COS Agreement[43] among Mystic, Constellation Energy Generation, LLC[44] ("Constellation") and ISO-NE, have been appealed to, and consolidated before, the DC Circuit (*see* Section XVI below).

(-014) Revised ROE (Sixth) Compliance Filing. Still pending is Mystic's December 20, 2021 filing in response to the requirements of the *Mystic ROE Allegheny Order*. 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.

(-000) First CapEx Info. Filing. On September 15, 2021, Mystic submitted, as required by orders in this proceeding and Sections I.B.1.i. and II.6.of Schedule 3A of the COS Agreement ("Protocols"), its informational filing to provide support for the capital expenditures and related costs that Mystic projects will be collected as an expense between June 1, 2022 to December 31, 2022 ("First CapEx Projects Info. Filing"). Formal challenges to the September 15 filing were submitted by the Eastern New England Customer-Owned Systems ("ENECOS") and NESCOE. Mystic responded to the formal challenges on November 17, 2021 asserting that that the challenges should be rejected without further procedures. ENECOS and NESCOE replied to Mystic's November 17 reply on December 2 and December 6, 2021, respectively.

On April 28, 2022, the FERC issued an order granting in part, and denying in part, ENECOS' and NESCOE's formal challenges, subject to refund, and established hearing and settlement judge procedures.[45] The FERC summarily denied NESCOE's challenge regarding the update to the AFRR and ENECOS' challenge with regard to the improper booking of items. Those items, and challenges to other underlying projected costs, may be challenged in connection with Mystic's Second Informational Filing (where the informal challenge process begins on April 1, 2022 and the formal challenge process begins on September 15, 202).[46] The FERC reiterated that all items except

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[41] The "*July 17 Orders*" are the *July 2018 Rehearing Order, Dec 2018* Rehearing *Order* and the *July 17 Compliance Order*. *Constellation Mystic Power, LLC,* 164 FERC ¶ 61,022 (July 13, 2018) ("*July 2018 Order*"), *clarif. granted in part and denied in part, reh'g denied*, 172 FERC ¶ 61,043 (July 17, 2020) ("*July 2018 Rehearing Order*"); *Constellation Mystic Power, LLC*, 165 FERC ¶ 61,267 (Dec. 20, 2018) ("*Dec 2018 Order*"), *set aside in part, clarification granted in part and clarification denied in part*, 172 FERC ¶ 61,044 (July 17, 2020) ("*Dec 2018* Rehearing *Order*"); *Constellation Mystic Power, LLC*, 172 FERC ¶ 61,045 (July 17, 2020) ("*July 17 Compliance Order*") (order on compliance and directing further compliance).

[42] *Constellation Mystic Power, LLC,* 176 FERC ¶ 61,019 (July 15, 2021) ("*Mystic ROE Order*") (setting the base ROE for the Mystic COS Agreement at 9.33%); *Constellation Mystic Power, LLC*, 177 FERC ¶ 61,106 (Nov. 18, 2021) ("*Mystic ROE First Allegheny Order*") (re-setting Mystic's ROE to 9.19%); *Constellation Mystic Power, LLC*, 177 FERC ¶ 61,106 (Nov. 18, 2021) ("*Mystic ROE Second Allegheny Order*", and together with the *Mystic ROE Order* and the *Mystic ROE Allegheny Order,* the *"Mystic ROE Orders"*) (modifying the discussion in, but sustaining the results of, the *Mystic ROE First Allegheny Order*).

[43] The COS Agreement, submitted on May 16, 2018, is between Mystic, Exelon Generation Company, LLC ("ExGen") and ISO-NE. The COS Agreement is to provide cost-of-service compensation to Mystic for continued operation of Mystic 8 & 9, which ISO-NE has requested be retained to ensure fuel security for the New England region, for the period of June 1, 2022 to May 31, 2024. The COS Agreement provides for recovery of Mystic's fixed and variable costs of operating Mystic 8 & 9 over the 2-year term of the Agreement, which is based on the pro forma cost-of-service agreement contained in Appendix I to Market Rule 1, modified and updated to address Mystic's unique circumstances, including the value placed on continued sourcing of fuel from the Distrigas liquefied natural gas ("LNG") facility.

[44] On Feb. 1, 2022, Exelon Generation Company, LLC was renamed and is now known as Constellation Energy Generation, LLC.

[45] *Constellation Mystic Power, LLC*, 179 FERC ¶ 61,011 (Apr. 28, 2022) ("*Mystic First CapEx Info. Filing Order*").

[46] *Id.* at PP 23-24.

return on equity and depreciation are subject to the true-up process described in Schedule 3A of the COS Agreement, not just projected capital expenditures. However, with respect to NESCOE's and ENECOS' allegations that Mystic failed to support all of its projected capital expenditures, the FERC found that the First CapEx Projects Info. Filing raised issues of material fact that could not be resolved based on the record and would be more appropriately addressed under hearing and settlement judge procedures.[47] Accordingly, the FERC set these matters for a trial-type evidentiary hearing. The FERC encouraged the parties to make every effort to settle their disputes before hearing procedures are commenced, and to that end, will hold the hearing in abeyance pending the appointment of a settlement judge and completion of settlement judge procedures.[48]

(-015) First CapEx Info. Filing Settlement Judge Procedures. On May 4, Chief Judge Cintron designated Judge Andrea McBarnette as the Settlement Judge. A first settlement conference was convened on Wednesday June 15, 2022.

(-017) Request for Clarification or Rehearing of Mystic First CapEx Info. Filing Order Denied by Operation of Law. On May 27, 2022, Mystic requested that the FERC clarify that it did not determine that Mystic's already-litigated historical (pre-2018) rate base is subject to re-litigation as part of any "true-up" process under the Mystic Agreement. ENECOS answered that request on June 10, 2022. On June 27, 2022, the FERC issued a notice that Mystic's request can be deemed to have been denied by operation of law.[49]

(-018) Informational Filing of Revision to Fuel Supply Agreement. On July 20, 2022, Mystic notified the FERC of a change to the Fuel Supply Agreement between Mystic and its affiliate, Constellation LNG, LLC. Mystic stated that the change clarifies that the Fixed O & M/Return on Investment Costs in the Fuel Supply Agreement are subject to update under Schedule 3A of the Mystic COS Agreement (a change ISO-NE agreed is consistent with the spirit of the Mystic COS Agreement). This filing was not noticed for public comment.

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

- **Transmission Rate Annual (2022-23) Update/Informational Filing (ER09-1532; RT04-2)**

On July 29, 2022, 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 2023. 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,[50] the formual rates that will be in effect for 2023 include a billing true up of seven months of 2021 (June-December). The PTO AC states that the annual updates results 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 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 $1.75 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 will not be noticed for public comment.

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[47] *Id.* at P 26.

[48] *Id.* at P 27.

[49] *Constellation Mystic Power, LLC*, 179 FEC ¶ 62,179 (June 27, 2022) (notice that Mystic's request for clarification or rehearing of the *Mystic First CapEx Info. Filing Order* can be deemed denied by operation of law).

[50] 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").

The July 29 filing will be reviewed with the Transmission Committee at its August 16, 2022 summer meeting, with an subsequent August 22, 2022 technical session planned for Interested Parties to seek additional information and clarification. The July 29 filing triggered the commencement of the Information Exchange Period and a Review Period under the Interim Protocols. Interested Parties have until September 15, 2022 to submit information and document requests, and the PTOs are 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 have until November 15, 2022 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, 2022. Interested Parties have until January 31, 2023 to file a Formal Challenge with the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

- **CSF Revisions (ER22-2546)**

On July 29, 2022, ISO-NE and NEPOOL jointly filed changes to Market Rule 1 to allow storage facilities incapable of consuming electricity from the grid to participate in the New England Markets as Continuous Storage Facilities ("CSF"). An October 1, 2022 effective date was requested. The CSF Revisions were supported by the Participants Committee at its June 21-23 Summer Meeting (Agenda Item No. 2A). Comments on the CSF Revisions are due on or before August 19, 2022. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Information Policy Cyber Security Incident Information Sharing Changes (ER22-2366)**

On July 15, 2022, ISO-NE and NEPOOL jointly filed changes to the Information Policy to allow ISO-NE to share confidential information with NERC and federal agencies with cyber security responsibilities, without prior notice to Market Participants and other furnishing entities, if a cyber-security event occurs ("Changes"). A September 12, 2022 effective date was requested. The Changes were supported by the Participants Committee at its June 21-23 Summer Meeting (Consent Agenda Item No. 4). Comments on the Changes are due on or before August 3, 2022. Thus far, doc-less interventions have been filed by Calpine, Eversource and National Grid. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

On February 2, 2022, ISO-NE, NEPOOL and the PTO AC ("Filing Parties") submitted 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.

Comments, following an extension of time granted by the FERC in response to a request by Advanced Energy Management Alliance ("AEMA"), were due on or before April 1, 2022. NEPOOL filed supplemental comments on March 28. Protests and comments were filed by: AEE/PowerOptions/SEIA; Environmental Organizations;[51] MA AG; Voltus; AEMA and 4 New England US Senators.[52] Doc-less interventions were filed by:

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[51] Environmental Organizations are Acadia Center, Conservation Law Foundation ("CLF"), Environmental Defense Fund ("EDF"), Massachusetts Climate Action Network, Natural Resources Defense Council ("NRDC"), Sierra Club, and the Sustainable FERC Project.

[52] Senators Markey (MA), Sanders (VT), Warren (MA), and Whitehouse (RI).

Avangrid (CMP/UI), Calpine, Centrica Business Solutions Optimize (out-of-time), Constellation, ENE, Enerwise, Eversource, FirstLight, MA AG, National Grid, NESCOE, NRG, MA DPU, MPUC (out-of-time), APPA, and EEI. ISO-NE (April 20) and National Grid/Avangrid/Eversource (April 19) filed answers to the protests and adverse comments. Since the last Report, AEE/PowerOptions/SEIA and AEMA answered the ISO-NE and National Grid/Avangrid/ Eversource answers.

(-001) Deficiency Letter. On May 18, 2022, the FERC issued a 25-page deficiency letter directing ISO-NE to provide, on or before June 17, 2022, additional information and clarifications. ISO-NE filed its 39-page response to the deficiency letter on June 17, 2022. Comments in response to ISO-NE's deficiency letter response were due on or before July 8, 2022 and a joint protest was filed by AEE, AEMA, PowerOptions, and SEIA ("Joint Protest"). The Joint Protest, while supportive of certain responses (those regarding the exemption of DERAs from the Small Generator Interconnection Procedures ("SGIP") prior to 2026, locational requirements for DER aggregation, and the role of host utilities in identifying potential conflicts with retail program participation), protested the adequacy of ISO-NE responses regarding proposed metering and telemetering requirements for behind-the-meter ("BTM") DERs. On July 25, 2022, ISO-NE answered the July 8 Joint Protest.

This matter is again pending before the FERC. 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

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

On July 12, 2022, ISO-NE, NEPOOL, the PTO AC, and CSC (the "Filing Parties") filed proposed revisions to the OATT in response to the requirements of *Order 881*[53] ("*Order 881* Compliance Changes"). Specifically, the Filing Parties propose to add a new Attachment Q to the OATT, and to revise OATT Schedules 18 (MTF; MTF Service) and 21 (Local Service - Common). The *Order 881* Compliance Changes (the Attachment Q and Schedule 18 changes) were supported by the Participants Committee at its June 21-23 Summer Meeting (Consent Agenda Item No. 2). An effective date of September 10, 2022 was requested, with changes to Attachment Q and Schedule 21 to become applicable by their own terms in July 2025. Comments on the *Order 881* Compliance Changes are due on or before August 2, 2022. Eversource, Narragansett Electric Company ("Narragansett") and National Grid filed doc-less interventions. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Phase I/II HVDC-TF Order 881*** **Compliance Filing: HVDC TOA (ER22-2467) and Sched. 20-A Common Attachment M (ER22-2468)**

On July 22, 2022, following a requested 10-day extension of time granted by the FERC, a Phase I/II HVDC-TF *Order 881* compliance filing was submitted in two parts ((i) changes to the HVDC TOA and (ii) changes to Schedule 20-Common Attachment M) by: ISO-NE, the Asset Owners,[54] and the Schedule 20A Service Providers.[55] Specifically, the Filing proposed changes to the ***HVDC TOA*** (ER22-2467) to address the Order 881 requirements related to transmission ratings and rating procedures and to ***Schedule 20A-Common*** (ER22-2468) to ensure compliance with Order 881 with respect to transmission rating transparency and transmission

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[53] *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*").

[54] The "Asset Owners" are, collectively, New England Hydro-Transmission Electric Company, New England Hydro-Transmission Corporation, New England Electric Transmission Corporation, and Vermont Electric Transmission Company ("VETCO").

[55] The "Schedule 20A Service Providers" are: Central Maine Power Co. ("CMP"); The Conn. Light and Power Co. and Public Service Co. of NH ("Eversource"); Green Mountain Power Cor. ("GMP"); New England Power Co. ("NEP"); NSTAR Electric Co.; The United Illuminating Co. ("UI"); Vermont Electric Cooperative, Inc. ("VEC"); and Versant Power.

service (together, the "Phase I/II HVDC-TF *Order 881* Compliance Filing"). Comments on the Phase I/II HVDC-TF *Order 881* Compliance Filing are due on or before August 12, 2022. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Process Modifications - DER Interconnection/Interconnection Study Coordination (ER22-2226)**

On June 29, 2022, ISO-NE and NEPOOL jointly filed changes to the Tariff to modify the process for interconnection of new distributed energy resources ("DERs") and improve the coordination of interconnection studies ("DER Interconnection Revisions"). Specifically, the DER Interconnection Revisions (i) provide that all DERs will interconnect through the applicable state interconnection process; and (ii) with respect to the coordination of interconnection studies, establish the order in which interconnection requests are included in the Capacity Network Resource ("CNR") Group Study, and include generation projects that are not participating in ISO-NE's interconnection process, if they meet certain conditions, in the Base Case Data. An August 28, 2022 effective date was requested. The DER Interconnection Revisions were supported by the Participants Committee at its June 21-23 Summer Meeting (Consent Agenda Item No. 1). On July 20, 2022, comments supporting the changes were filed by AEE, ENGIE, SEIA. Calpine, Borrego, Eversource, National Grid, NRG, MA DPU, and SEIA filed doc-less interventions. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Attachment F Corrections & Updates (ER22-2021)**

On August 1, 2022, the FERC accepted proposed revisions to Attachment F of the OATT filed by the PTO AC to (i) correct minor errors in certain worksheets of the "Formula Rate Template" contained in Appendices A and B; and (ii) update the name of Versant Power in Appendices A, B and D.[56] The PTO AC opined that the proposed corrections and updates do not have any impact on transmission rates and they do not alter the substance of the Formula Rate Template. The revisions were accepted effective as of August 2, 2022, as requested. Unless the August 1, 2022 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 676-J* Compliance Filing Part I (CSC-Schedule 18-Attachment Z) (ER22-1168)**

On March 2, 2022, in response to the requirements of *Order 676-J*,[57] ISO-NE and Cross-Sound Cable Company ("CSC") filed revisions to ISO-NE Tariff Schedule 18 Attachment Z to incorporate the new cybersecurity and PFV standards contained in the North American Energy Standards Board ("NAESB") Wholesale Electric Quadrant ("WEQ") Version 003.3 Standards ("Schedule 18 Order 676-J Part I Changes").[58] An effective date as of the date of the FERC order accepting these changes was requested. Comments on this filing were due on or before March 23, 2022; none were filed. Doc-less interventions were filed by CSC and NEPOOL. There was no activity since the last Report and this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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[56] *ISO New England Inc.*, Docket No. ER22-2021 (Aug. 1, 2022) (unpublished letter order).

[57] *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-J, 175 FERC ¶ 61,139 (May 20, 2021) ("*Order 676-J*"). *Order 676-J* revised FERC regulations to incorporate by reference the latest version (Version 003.3) of the Standards for Business Practices and Communication Protocols for Public Utilities adopted by NAESB's Wholesale Electric Quadrant. The WEQ Version 003.3 Standards include, in their entirety, the WEQ-023 Modeling Business Practice Standards contained in the WEQ Version 003.1 Standards, which address the technical issues affecting Available Transfer Capability ("ATC") and Available Flowgate Capability ("AFC") calculation for wholesale electric transmission services, with the addition of certain revisions and corrections. The FERC also revised its regulations to provide that transmission providers must avoid unduly discriminatory and preferential treatment in the calculation of ATC.

[58] Compliance filings for the rest of the WEQ Version 003.3 Standards (Schedule 24 Order 676-J Part II Changes) were due 12 months after implementation of the WEQ Version 003.2 Standards, or no earlier than Oct. 27, 2022.

- ***Order 676-J*** **Compliance Filing Part I (TOs-Schedule 20/21-Common) (ER22-1161)**

Also on March 2, 2022, in response to the requirements of *Order 676-J*, the PTO AC, ISO-NE, and the Schedule 20A Service Providers ("S20SPs") (collectively, the "TOs") filed revisions to ISO-NE Tariff Schedules 20A-Common and 21-Common to incorporate the new cybersecurity and PFV standards contained in NAESB WEQ Version 003.3 Standards ("Schedule 20/21-Common Order 676-J Part I Changes").[58] An effective date as of the date the FERC may determine was requested. Comments on this filing are due on or before March 23, 2022; none were filed. Doc-less interventions were filed by NEPOOL and Eversource. There was no activity since the last Report and this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 676-J*** **Compliance Filing Part I (ISO-NE-Schedule 24) (ER22-1150)**

Again on March 2, 2022, in response to the requirements of *Order 676-J*, ISO-NE filed revisions to ISO-NE Tariff Schedule 24 (Incorporation by Reference of NAESB Standards) to incorporate the new cybersecurity and PFV standards contained in NAESB WEQ Version 003.3 Standards ("Schedule 24 Order 676-J Part I Changes").[58] An effective date no earlier than June 2, 2022 was requested. The Transmission Committee recommended that the Participants Committee support the Schedule 24 Order 676-J Part I Changes at its March 23 meeting, and the Participants Committee supported the changes at the April 7 meeting (Consent Agenda Item # 1). Comments on this filing were due on or before March 23, 2022; none were filed. NEPOOL, Eversource, MA DPU, and National Grid submitted doc-less interventions. There was no activity since the last Report and this matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

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

- **Schedule 20A (Phase I/II HVDC-TF Service Agreement) Reassignment Agreements: CMP & UI/Brookfield/HQUS (ER22-2433/32/31)**

On July 19, 2022, Avangrid Networks, on behalf of CMP and UI, submitted three Phase I/II HVDC-TF service agreements ("Schedule 20A TSAs") to transfer the transmission service rights and obligations that Brookfield Renewable Trading and Marketing LP ("BRTM" or the "Reseller") currently holds under existing Schedule 20A TSAs (one with CMP; two with UI) to H.Q. Energy Services (U.S.) Inc. ("HQUS" or the "Assignee"). The Schedule 20A TSAs were filed and docketed as follows: CMP-BRTM 85 MW TSA (ER22-2433); UI-BRTM 32 MW TSA (ER22-2432); and UI-BRTM 1 MW TSA (ER22-2431). An effective date that is the first day of the month that is at least five business days following the date of a FERC order accepting the Schedule 20 TSAs was requested. Comments on this filing are due on or before August 2, 2022. Thus far, both BRTM and HQUS have intervened and submitted joint comments supporting the Reassignment Agreements. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Schedule 20A (Phase I/II HVDC-TF Service Agreement) Reassignment Agreement: NEP/Brookfield/HQUS (ER22-2398)**

On July 18, 2022, New England Power ("NEP") filed a Phase I/II HVDC-TF service agreements ("Schedule 20A TSAs") to transfer the transmission service rights and obligations that BRTM currently holds under an existing Schedule 20A TSA (TSA-NEP-96) to HQUS. An effective date that is the first day of the month that is at least five business days following the date of a FERC order accepting the Schedule 20 TSA was requested. Comments on this filing were due on or before August 1, 2022. On July 28, 2022, BRTM and HQUS jointly filed comments supporting the Agreement. This matter is pending before the FERC. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Schedule 21-NEP: Revised RI LSAs Compliance Filing (ER22-1918)**

On May 20, 2022, NEP submitted a compliance filing following FERC action on Local Service Agreement ("LSA") filings in ER22-707 (Narragansett LSA) and ER22-927 (BIPCO LSA) to: (i) reflect all changes to the LSAs accepted by the FERC in either docket and (ii) provide executed versions of the conformed LSAs. Comments on the Revised RI LSAs compliance filing were due on or before June 10, 2022; none were filed. On July 14, 2022, the FERC accepted Revised RI LSA TSA-NEP-86 (the LSA among NEP, Narragansett and ISO-NE), effective January 1, 2022.[59] If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-NEP: 2nd Revised Narragansett LSA (ER22-707)**

As previously reported, the FERC accepted on February 18, 2022 a LSA among New England Power, Narragansett and ISO-NE.[60] As previously reported, the LSA reflects the construction of the new Iron Mine Hill Road Substation and related transmission modifications, and the assessment to Narragansett of a Direct Assignment Facilities Charge ("DAF Charge") associated with the facilities. The Iron Mine Hill Road Substation, a new 115 kV/34.5 kV substation (including modifications necessary to loop Narragansett's existing 115 kV H17 transmission line through the new substation) will connect to a new 34.5 kV distribution feeder, which will serve as the point of interconnection for several distributed generation projects being developed by Green Development, LLC ("Green Development"), located in North Smithfield, Rhode Island. The LSA was accepted effective as of January 1, 2022, as requested. The FERC was not persuaded by Green Development's arguments that the revised Narragansett LSA was unjust and unreasonable and should be rejected.[61]

Request for Rehearing Denied by Operation of Law. On March 18, 2022, Green Development requested rehearing of the *2nd Rev Narragansett LSA Order.* On April 18, 2022, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[62] The Notice confirmed that the 60-day period during which a petition for review of the *2nd Rev Narragansett LSA Order* could be filed with an appropriate federal court was triggered when the FERC did not act on Green Development's request for rehearing of the *2nd Rev Narragansett LSA Order*. The Notice also indicated that the FERC would address, as is its right, the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper," (which it did on June 16, 2022, *see* immediately below).

2nd Rev Narragansett LSA Allegheny Order. On June 16, 2022, pursuant to section 313(a) of the FPA, the FERC issued an order that modified the discussion, but reached the same result as, in the *2nd Rev Narragansett LSA Order*.[63] On June 15, 2022, Green Development petitioned the DC Circuit for review of the *2nd Rev Narragansett LSA Order.* On July 19, 2022 Green Development also petitioned the DC Circuit for review of the *2nd Rev Narragansett LSA Allegheny Order*. Developments in those proceedings (now consolidated) will be reported in Section XVI below.

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

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[59] *ISO New England Inc.*, Docket No. ER22-1918 (July 14, 2022) (unpublished letter order).

[60] *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*").

[61] *Id.* at P 55.

[62] *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).

[63] *ISO New England Inc. and New England Power Co. d/b/a National Grid*, 179 FERC ¶ 61,186 (June 16, 2022) ("*2nd Rev Narragansett LSA Allegheny Order*").

- **Schedule 21-VP: 2021 Annual Update Settlement Agreement (ER20-2119-001)**

On March 25, 2022, Versant Power submitted a joint offer of settlement between itself and the MPUC to resolve all issues raised by the MPUC in response to Versant's 2021 annual charges update filed, as previously reported, on June 15, 2021, and as amended on June 20, 2021 and July 8, 2021 (the "Versant 2021 Annual Update Settlement Agreement"). Under Part V of Attachment P-EM to Schedule 21-VP, "Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the [Attachment P-EM] Rate Formula. . . ." and follow a dispute resolution procedure set forth there. In accordance with those provisions, the MPUC identified certain disputes with the 2021 Annual Update, all of which are resolved by the Versant 2021 Annual Update Settlement Agreement. Comments on the Versant 2021 Annual Update Settlement Agreement were due on or before April 14, 2022; none were filed. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-VP: 2020 Annual Update Settlement Agreement (ER15-1434-005)**

On November 19, 2021, Versant Power submitted a joint offer of settlement between itself and the MPUC to resolve all issues raised by the MPUC in response to Versant's 2020 annual charges update filed, as previously reported, on June 15, 2020 (the "Versant 2020 Annual Update Settlement Agreement"). Under Part V of Attachment P-EM to Schedule 21-VP, "Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the [Attachment P-EM] Rate Formula. . . ." and follow a dispute resolution procedure set forth there. In accordance with those provisions, the MPUC identified certain disputes with the 2020 Annual Update, all of which are resolved by the Versant 2020 Annual Update Settlement Agreement. Comments on the Versant 2020 Annual Update Settlement Agreement were due on or before December 9, 2021; reply comments, December 19, 2021; none were filed. There was no activity since the last Report and this matter remains pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

- ***Opinion 531-A* Local Refund Report: FG&E (EL11-66)**

Fitchburg Gas & Electric's ("FG&E") June 29, 2015 refund report for its customers taking local service during *Opinion 531-A's* refund period remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***Opinions 531-A/531-B* Regional Refund Reports (EL11-66)**

The TOs' November 2, 2015 refund report documenting resettlements of regional transmission charges by ISO-NE in compliance with *Opinions No. 531-A*[64] *and 531-B*[65] also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

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

- ***Opinions 531-A/531-B* Local Refund Reports (EL11-66)**

The *Opinions 531-A and 531-B* refund reports filed by the following TOs for their customers taking local service during the refund period also remain pending before the FERC:

- Central Maine Power
- Emera Maine
- Eversource
- National Grid
- NHT
- NSTAR
- United Illuminating
- VTransco

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

- **Capital Projects Report - 2022 Q1 (ER22-1880)**

On July 11, 2022, the FERC accepted ISO-NE's Capital Projects Report and Unamortized Cost Schedule covering the first quarter ("Q1") of calendar year 2022 (the "Report").[66] ISO-NE filed the Report under section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Report highlights included the following new projects: (i) Packet Broker Infrastructure Replacement Project ($839,600); (ii) Amazon Web Services Cloud Foundation ($829,100); (iii) Integrated Market Simulator Phase II ($495,000); and (iv) FCM Non-Commercial Capacity Trading FA ($290,000). Significant changes for Chartered Projects (2022 budget impact in parentheses) were: (i) FCM Cost Allocation & Accelerated Billing ($185,000 increase); (ii) FCM Tracking System Infrastructure Conversion Part III ($398,200 decrease); (iii) Solar DNE Dispatch Phase I ($386,100 decrease); (iv) nGEM Hardware Phase II ($1.15 million decrease); and (v) TranSMART Technical Architecture Update ($135,500 decrease). The 2022 Q1 Report was accepted effective April 1, 2022 as requested. Unless the July 11 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **LFTR Implementation: 55th Quarterly Status Report (ER07-476; RM06-08)**

ISO-NE filed the 55th of its quarterly status reports regarding LFTR implementation on July 15, 2022. ISO-NE reported that it implemented monthly reconfiguration auctions (accepted in ER12-2122) beginning with the month of 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.

- ***Voltus Petition for a FERC Technical Conference on Order 2222* (RM18-9)**

On December 22, 2022, Voltus, Inc. ("Voltus") requested that the FERC convene a technical conference regarding *Order 2222*-related issues sometime in the months of February or March, 2022. Specifically, Voltus requested the technical conference to allow for a collective discussion of key issues arising from the ISO/RTO *Order 2222* compliance proposals, including certain regional variability, roles of industry participants, narrowing perceived knowledge gaps, and subsequent FERC guidance, all of which Voltus asserts supports the request for a technical conference. On January 7, 2022, the FERC issued a notice of Voltus' request, inviting comments on Voltus' request on or before February 7, 2022. Comments supporting Voltus' request were filed by: AEE, AEMA, APPA/NRECA, EEI, ISO-RTO Council, MISO, SPP, Sunrun, Ameren, Camus Energy, Energy Web Foundation, Entegrity Energy Partners, Environmental Law and Policy Center, Fermata LLC, Google, Leapfrog Power, Nuvve Holding, Tesla, U Delaware EV Research and Development Group, and Utilidata. Voltus' request remains pending before the FERC.

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[66] *ISO New England Inc.*, Docket No. ER22-1880 (July 11, 2022) (unpublished letter order).

- **IMM 2021 Annual Markets Report (ZZ22-4)**

On May 26, 2022, the IMM filed its 2021 Annual Markets Report, which covers the 2021 calendar year period.[67] 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 2021. 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. No major reliability issues occurred in 2021, and there were no periods in the Energy Market when a shortage of energy and reserves resulted in very high energy prices or reserve scarcity pricing. The IMM reported that gas and energy prices rebounded from the record low levels seen in 2020. Electricity demand increased year-over-year due to colder weather and increased economic activity. The IMM forecasts that weather-normalized demand will begin to increase from 2022 because of the diminishing impacts of energy efficiency and solar generation and the growth in electrification of transportation and heating. Wholesale costs were at their highest level since 2018 and considerably higher than 2020, driven by higher energy costs. For the eighth consecutive year, the forward capacity auction procured surplus capacity. Other highlights included:

- 2021 total wholesale costs ($11.2 billion) were $3.1 billion higher than 2020, driven by higher energy costs; with the exception of capacity costs, each component of the wholesale cost of electricity increased in 2021.
- 2021 Energy costs totaled $6.1 billion, up 97% from 2020 (Day-Ahead LMPs averaged $45.92/MWh; Real-Time LMPs, $44.84/MW).
- Capacity costs ($2.2 billion) decreased 16%. New entry and limited resource retirements have continued to maintain a system surplus of 4-5% above the capacity requirement, applying downward pressure on prices.
- Transmission and reliability costs in 2021 were $2.7 billion, $357 million (15%) more than 2020 costs. The primary driver was a 12% increase in infrastructure improvements costs.

In light of its review, the IMM, in Section 1.6 (pp. 29-33) of the Report, made a number of recommendations for Market Rule changes and identified areas for additional analysis in 2022. These recommendations will be discussed in more detail at the Participants Committee's August 4 meeting.

IX. Membership Filings

- **August 2022 Membership Filing (ER22-2568)**

On July 29, 2022, NEPOOL requested that the FERC accept (i) the following Applicant's membership in NEPOOL: Concurrent, LLC (Provisional Member); Leapfrog Power (Provisional Member); Old Middleboro Road Solar [Related Person to Agilitas Companies (AR Sector, DG Sub-Sector)]; and Accelerate Renewables [Related Person to ECP Companies (Supplier Sector)]; and (ii) the termination of the Participant status of Chris Anthony; Indeck Energy-Alexandria; Standard Normal; and Borrego Solar Systems. Comments on this filing are due on or before August 22, 2022.

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

- **July 2022 Membership Filing (ER22-2260)**

On June 29, 2022, NEPOOL requested that the FERC accept (i) the termination of the Participant status of Liberty Power Holdings; and (ii) the name change of Astral (f/k/a/ Able Grid) Infrastructure Holdings, LLC. No comments on the filing were submitted. This matter is pending before the FERC.

- **June 2022 Membership Filing (ER22-1991)**

On May 31, 2022, as corrected on July 5, 2022, NEPOOL requested that the FERC accept (i) the following Applicant's membership in NEPOOL: Ebsen LLC and Umber LLC (both in the Supplier Sector); (ii) the termination of the Participant status of Dantzig Energy; Pilot Power Group; and Twin Eagle Resource Management; and (iii) the name change of LS Power Grid Northeast, LLC (f/k/a New England Energy Connection, LLC). No comments on the filing or on the correction were filed. This matter is pending before the FERC.

- **May 2022 Membership Filing (ER22-1738)**

On June 24, 2022, the FERC accepted (i) the following Applicant's membership in NEPOOL: Altop Energy Trading LLC (Supplier Sector); Indra Power Business CT LLC [Related Person to Palmco Power MA, LLC (Supplier Sector)]; Indra Power Business MA LLC [Related Person to Palmco Power MA, LLC (Supplier Sector)]; Leicester Street Solar, LLC [Related Person to Agilitas Companies (AR Sector, DG Sub-Sector)]; and Nexamp Markets, LLC [Related Person to Boston Energy Trading and Marketing (Supplier Sector)]; and (ii) the name change of the following Participant: Salem Harbor Power Development LP (f/k/a Footprint Power Salem Harbor Development LP). The June 24 order was not challenged and is final and unappealable. Reporting on this matter is concluded.

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).

- **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")) on June 15, 2022.[68] Project 2016-02 focuses on modifications to the CIP Reliability Standards to incorporate applicable protections for virtualized environments. A revised schedule for Project 2016-02 calls for final balloting of revised standards in October 2022, NERC Board of Trustees Adoption in November 2022 and filing of the revised standards with the FERC in December 2022.

- **NPCC Bylaws Changes (RR22-2)**

On July 8, 2022, the FERC conditionally approved changes to the NPCC Bylaws (the "Bylaws") filed by NERC and NPCC designed to, among other things: (1) to improve corporate governance; (2) to ensure consistency with the Not-for-Profit Corporation Law of the State of New York ("N-PCL"), pursuant to which NPCC is organized; and (3) to remove extraneous provisions rom the Bylaws, create efficiencies, and reflect changes at NPCC since 2012 (when the last changes to the Bylaws were filed).[69] In accepting the Bylaws Changes, the FERC directed NERC/NPCC to submit in a compliance filing, due on or before September 6, 2022, changes that (i) provide members being terminated for failure to comply with bylaw provisions related to qualifications, obligations, and conditions of membership (a) notice within a reasonable time period of the NPCC Board's membership

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[68] 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.

[69] *N. Am. Elec. Rel. Corp.*, 180 FERC ¶ 61,016 (July 8, 2022).

termination decision and the reason(s) for the action and (b) the option to appeal the membership termination in accordance with the due process requirement in FPA Section 215; and (ii) specifically describe the method of providing public notice of member meetings. The FERC found Public Citizen's protest[70] beyond the scope of the proceeding. The Bylaws changes were accepted effective as of the date of the order, or July 8, 2022, as requested. On July 29, 2022, NERC/NPCC requested a 30-day extension of time to submit the required compliance filing in order to accommodate procedural steps they are required complete before the compliance filing is due.

- **Rules of Procedure Changes (CMEP Risk-Based Approach Enhancements) (RR21-10)**

As previously reported, on May 19, 2022, the FERC approved in part, and denied in part, NERC's proposed revisions to its Rules of Procedure ("ROP") proposed in NERC's September 29, 2021 filing.[71] Specifically, the FERC approved the proposed revisions to the NERC ROP for the Personnel Certification and Credential Maintenance Program in ROP section 600, the Training and Education Program in ROP section 900, and Confidential Information in ROP section 1500. The FERC approved CMEP-related ROP sections 401, 404, 407-409; Appendix 2 (other than the definition of "Self-Logging"); and Appendix 4C sections 5.0, 6.0, 7.0, 8.0, 9.0, and Attachment 1. The FERC rejected certain of the proposed revisions to ROP sections 402, 403, 405, and 406, Appendix 2, and Appendix 4C (concerned that, taken together, those revisions could adversely impact the nature and extent of the ERO's and the FERC's oversight of reliability compliance and enforcement activities). Accordingly, the FERC directed that NERC submit a 60-day compliance filing (on or before July 18, 2022) reinstating language in its ROP. On July 18, 2022, NERC submitted a compliance filing in response to the requirements of the May 19, 2022 order. Comments on that compliance filing are due on or before August 8, 2022.

- **Rules of Procedure Changes (Reliability Standards Development Revisions) (RR21-8)**

On August 18, 2021, NERC filed for approval revisions to sections 300 (Reliability Standards Development), Appendix 3B (Procedure for Election of Members of the Standards Committee) and Appendix 3D (Development of Registered Ballot Body Criteria) of the NERC Rules of Procedure ("ROP"), which are designed to update language, staff titles, and processes; remove unnecessary or duplicative obligations; and clarify roles and responsibilities related to the development of Reliability Standards (the "Reliability Standards Development ROP Revisions"). Comments on this filing were due on or before September 8, 2021; none were filed.

Deficiency Letter, Response & Amendment. On February 24, 2022, the FERC issued a deficiency letter, directing NERC to provide, on or before March 28, 2022, additional information and clarifications. On March 18, NERC provided an amended petition for approval, including revisions to Section 305.3.3 (Review of Segment Criteria) to provide that the qualification guidelines and rules for joining Registered Ballot Body Segments shall be reviewed periodically, instead of every three years. Comments on NERC's amended petition were due on or before April 8, 2022. On April 8, 2022, Public Citizen filed comments (relating to "the absence of balanced stakeholder representation in aspects of NERC's governance"). On April 26, 2022, NERC responded to Public Citizen's comments. This matter is pending before the FERC.

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[70] In its protest, Public Citizen argued that the FERC should require a change to the composition of NPCC's Board of Directors, suggesting that NPCC be compelled to ensure that, of NPCC's eight board sectors and 15 voting members, "household consumer advocates" have two voting seats in Sector 7 (Sub-Regional Reliability Councils, Customers, Other Regional Entities and Interested Entities), and that regulators, reliability coordinators, and end-users compose at least half of the voting seats of the board.

[71] *N. Am. Elec. Rel. Corp.*, 179 FERC ¶ 61,129 (May 19, 2022). In its Sep. 29, 2021 filing, NERC proposed changes to sections 400 (Compliance Monitoring and Enforcement) and 1500 (Confidential Information), Appendix 2 (Definitions) and Appendix 4C (Compliance Monitoring and Enforcement Program) of NERC's ROP. The changes were proposed to further enhance the risk-based approach to the Compliance Monitoring and Enforcement Program ("CMEP") whereby registered entities and the ERO Enterprise focus on the greatest risks to the reliability and security of the Bulk Power System ("BPS").

XI. Misc. - of Regional Interest

- **203 Application: Centrica / CPower (EC22-90)**

On July 12, 2022, Centrica Business Solutions Optimize ("Centrica") requested authorization for the sale of 100% of the equity interests in Centrica to Enerwise Global Technologies, LLC d/b/a CPower ("CPower").[72] Upon consummation, Centrica and CPower will become Related Persons and members of the AR Sector's RG Sub-Sector.[73] Comments on the 203 application are due on or before August 3, 2022. Thus far, doc-less interventions have been filed by PJM's IMM and Public Citizen. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Clearway / TotalEnergies (EC22-84)**

On July 1, 2022, Clearway requested authorization for, among other things, TotalEnergies Renewables USA, LLC's ("TotalEnergies") acquisition of a 50% percent indirect interest in the Clearway Group. Comments on the 203 application were due on or before July 22, 2022; none were filed. The PJM IMM and PJM (out-of-time) doc-lessly intervened. This matter is pending before the FERC. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Waterside Power / KKR (EC22-79)**

On June 22, 2022, Generation Group Seat Member Waterside Power, among others,[74] requested authorization for the sale of 100% of the equity interests in Applicants to Cretaceous Bidco Limited ("Buyer"), a special purpose vehicle indirectly owned by funds, investment vehicles and/or separately managed accounts advised and/or managed by one or more subsidiaries of KKR & Co. Inc. ("KKR & Co." and, together with its subsidiaries, ("KKR")). Comments on the 203 application were due on or before July 13, 2022; none were filed. Public Citizen filed a doc-less intervention. The application is pending before the FERC. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Stonepeak / JERA Americas (EC22-71)**

On June 1, 2022, Stonepeak[75] requested authorization for the sale of 100% of the interests in Canal Power Holdings LLC to a wholly-owned affiliate of JERA Americas Inc. ("JERA Americas").[76] Comments on the 203 application were due on or before June 22, 2022 and were filed by the MA AG (which encouraged the FERC to take the time necessary to comprehensively review the Application based on potential regional and SENE Capacity Zone competition and rate impacts) and Public Citizen (which raised four issues: (i) the potential threat to competition and rates that could be caused by the concentration of power generation ownership by JERA in ISO-NE and NYISO; (ii) the need for additional information to assess impacts on competition and rates as well as potential divestiture requirements to mitigate any threats to competition and rates; (iii) a desire for public disclosure of the purchase price; and (iv) what threats to rates might result from the Related Person relationships to be created and reflected in the NEPOOL stakeholder process). On July 1, 2022, Stonepeak answered the comments and protest. This matter is pending before the FERC. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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[72] JERA Americas Related Persons include Provisional Member Cricket Valley Energy Center, LLC.

[73] CPower is a member of the AR Sector's RG Sub-Sector with its Related Persons Jericho Power and LS Power Grid Northeast, LLC.

[74] In addition to Waterside Power, "Applicants" are: Lea Power Partners, LLC; Badger Creek Limited; Chalk Cliff Limited; Double C Generation Limited Partnership; High Sierra Limited; Kern Front Limited; McKittrick Limited; Bear Mountain Limited; Live Oak Limited; and WGP Redwood Holdings, LLC.

[75] "Stonepeak" includes Canal Power Holdings LLC ("Seller"), and its indirect wholly-owned, public utility subsidiaries, Canal Generating LLC ("Canal Generating"), Canal 3 Generating LLC ("Canal 3"), Bucksport Generation LLC ("Bucksport"), and Stonepeak Kestrel Energy Marketing LLC ("Stonepeak Marketing").

[76] JERA Americas Related Persons include Provisional Member Cricket Valley Energy Center, LLC.

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

- **VTransco Shared Structure Participation Agreements (ER22-2189)**

On June 24, 2022, VTransco filed two Shared Structure Participation Agreements ("ShPA") between VTransco and GMP - the first ShPA relates to the Duxbury 115 kV transmission line (the "Duxbury ShPA"); the second ShPA relates to the Bennington 115 kV transmission line ("Bennington ShPA"). The ShPAs calculate and allocate costs not recovered though the Tariff. The Duxbury ShPA provides for Shared Use Rent;[77] the Bennington ShPA does not. VTransco requested an effective date of January 1, 2022 for both ShPAs. Comments on this filing were due on or before July 15, 2022; 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).

- **IAs: NEP / Narragansett (ER22-2039/2038)**

On June 6, 2022, New England Power (ER22-2038) and Narragansett (ER22-2039) each filed a wires-to-wires interconnection agreement ("IA") to govern the interconnection of the two companies' transmission systems. A May 25, 2022 effective date was requested for both of the IA filings. Comments on these IA filings are due on or before June 27, 2022; none were filed. These filings are pending before the FERC. If you have any questions concerning these filings, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA: CL&P / EIP Investment (New Britain, CT Fuel Cell) (ER22-1862)**

On July 11, 2022, the FERC accepted the non-conforming LGIA between CL&P and EIP Investment ("EIP") governing the interconnection of EIP's 20 MW fuel cell project through Interconnection Facilities that include facilities owned and used by The Farmington River Power Company to serve the Stanley Black & Decker manufacturer campus in New Britain, Connecticut.[78] The LGIA is non-conforming in that it contains limited deviations from the *pro forma* LGIA in Schedule 22 of the ISO-NE OATT that are necessary to reflect unique characteristics of the proposed interconnection, including that the Interconnection Facilities include elements that are not for Interconnection Customer's sole use. The LGIA was accepted effective as of April 12, 2022, as requested. Unless the July 11 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).

- **IA 2nd Amendment: CMP/Sappi (ER22-1612)**

On June 10, 2022, the FERC accepted a second amendment to the interconnection agreement ("IA") between CMP and Sappi North America, Inc. ("Sappi").[79] The Second Amendment, part of a larger transaction in which Sappi will transfer its hydroelectric facilities to Presumpscot Hydro LLC ("Presumpscot Hydro") and will transfer its membership interests in Presumpscot Hydro to an unrelated third-party buyer ("Proposed Transaction"), provides that, for a period of up to two years and 180 days from the closing of the Proposed Transaction, the Presumpscot Hydro facilities may remain interconnected to Sappi's facilities in their current configuration (during which time Presumpscot Hydro will pursue its own physically separate interconnection to the CMP grid. The Second Amended IA was accepted subject to CMP making a compliance filing reflecting the closing date of the Proposed Transaction and filing the executed Second Amended Agreement within 30

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[77] The amount to be paid by GMP for its use of the non-PTF Shared Use Facilities on the Duxbury transmission line.

[78] *ISO New England Inc., and The Conn. Light and Power Co.*, Docket No. ER22-1862 (July 11, 2022) (unpublished letter order).

[79] *Central Maine Power Co.*, Docket No. ER22-1612 (June 10, 2022) (unpublished letter order).

days of the closing date of the Proposed Transaction. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Maine Power Link Application for Negotiated Rate Authority (ER22-1290)**

On June 22, 2022, the FERC denied[80] the application by Maine Power Link, LLC ("MPL") for authority to charge negotiated rates associated with transmission capacity rights on its proposed Northern Maine Line transmission project (the "Project").[81] An applicant for negotiated rate authority must satisfy each of the FERC's four factors established in *Chinook*.[82] In this case, the FERC found that MPL did not meet its burden under the first *Chinook* factor (a showing that the rates to be charged will be just and reasonable). To make this showing, an applicant must show that it has assumed the full market risk of its project (by sufficiently demonstrating that it has no ability to shift risk or pass any costs onto parties or neighboring utilities that are not participating in the project). The FERC found that MPL failed to make that demonstration.[83] Because it did not meet the FERC's first *Chinook* factor, the FERC did not decide whether MPL's application met the second, third, or fourth *Chinook* factors.[84] The FERC stated that its action did not prejudge any terms, rates, and conditions of any TSAs associated with the Northern Maine RFP to be subsequently filed with the FERC. The June 22, 2022 order was not challenged as is final and unappealable. Reporting on this proceeding has concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Versant Power MPD OATT *Order 676-J* Compliance Filing Part I (ER22-1142)**

As previously reported, Versant Power filed revisions to Section 4 of the Versant OATT for the Maine Public District ("MPD OATT") to incorporate the new cybersecurity and PFV standards contained in NAESB WEQ Version 003.3 Standards in response to the requirements of *Order 676-J*, ("Versant MPD OATT *Order 676-J* Part I Changes").[58] A placeholder effective date was submitted. Comments on this filing were due on or before March 23, 2022; none were filed. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Versant Power MPD OATT *Order 676-I* Compliance Filing (ER21-2498)**

On March 7, 2022, the FERC conditionally accepted Versant Power's proposed revisions to Section 4 of the Versant Power Open Access Transmission Tariff for Maine Public District (the "MPD OATT") to incorporate by reference certain of the revisions required by *Order 676-I*, including waiver of certain of those standards that are not applicable to MPD and/or the MPD OATT.[85] In accepting the filing, the FERC directed Versant to revise the MPD OATT to include a citation to the FEC order originally granting the waiver requests to be continued by the *Versant Order 676-I Compliance Filing Order I*. Versant submitted that compliance filing on April 1, 2022. The FERC accepted that compliance filing on June 29, 2022,[86] effective May 1, 2022, as requested. This matter is now concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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[80] *Maine Power Link, LLC*, 179 FERC ¶ 61,215 (June 2, 2022) ("*MPL Order*").

[81] The Project, if selected by the Maine Public Utility Commission ("MPUC") in its request for proposals ("RFP") for renewable energy generation and transmission projects ("Northern Maine RFP"), would be a transmission line to connect renewable energy generation projects in northern Maine to the New England transmission system in southern Maine.

[82] *See Chinook Power Transmission, LLC*, 126 FERC ¶ 61,134 (2009) ("*Chinook*") The four factors are: (1) just and reasonable rates; (2) absence of undue discrimination; (3) absence of undue preference towards of concerns regarding affiliates; and (4) regional reliability and operational efficacy.

[83] *MPL Order* at P 33.

[84] *Id.* at P 35.

[85] *Versant Power*, 178 FERC ¶ 61,159 (Mar. 7, 2022) ("*Versant Order 676-I Compliance Filing Order I*").

[86] *Versant Power*, Docket No. ER21-2498-002 (June 29, 2022) (unpublished letter order).

- ***Orders 864/864-A* (Public Util. Trans. ADIT Rate Changes): *New England Compliance Filings* (various)**

In accordance with *Order 864*[87] and *Order 864-A,*[88] and extensions of time granted, New England's transmission-owning public utilities submitted their *Order 864* compliance filings, with specific dockets and filing dates identified in the following table. The FERC has addressed a number of the compliance filings, with some yet to be acted on, and others submitting further compliance filings (generally to reflect a January 27, 2020 effective date). The *Order 864* compliance proceedings that remain open are as follows:

Docket(s)	Transmission Provider	Date of Last Filing	Date Accepted
ER21-1130 ER20-2572	New England TOs (RNS)	Feb 18, 2022	Pending
ER20-2429	CMP (LNS)	May 6, 2022	Pending
ER21-1702	CMP (Schedule 1 Appendix A Implem. Rule)	Feb 28, 2022	Pending
ER21-1654	CL&P (LNS)	Feb 28, 2022	Pending
ER21-1295	Eversource (CL&P, PSNH, NSTAR) (LNS; Schedule 21-ES)	Feb 23, 2022	Pending
ER21-1154	FG&E (LNS)	Feb 23, 2022	Pending
ER21-1694	Green Mountain Power	Feb 18, 2022	Pending
ER21-1241	NEP (LNS)	Feb 28, 2022	Pending
ER20-2551	NEP (Schedule 21-NEP and TSA-NEP-22 Compliance Revisions)	Jul 18, 2022	Pending
ER20-2219	NEP (Tariff No. 1)	Jul 19, 2022	Pending
ER20-2553	NEP (MECO/Nantucket LSA)	Jul 18, 2022	Pending
ER21-1293	NSTAR (LNS)	Feb 23, 2022	Pending
ER22-1850	UI	May 10, 2022	Pending
ER21-1709	VTransco (LNS)	Feb 22, 2022	Pending
ER20-2133 -001, -002	Versant Power	Nov 22, 2021	Conditionally, Feb 28, 2022

Since the last Report, *Order 864*-related activity included:

♦ ***ER20-2553-001 (NEP – MECO/Nantucket LSA)***. On July 18, 2022, NEP amended its July 30, 2020 *Order 864* compliance filing with further amendments to its LSA with Nantucket Electric Company.

♦ ***ER20-2551-001 (NEP – Schedule 21-NEP and TSA-NEP-22)***. On July 18, 2020, NEP amended its July 30, 2022 *Order 864* compliance filing with further amendments to Schedule 21-NEP and TSA-NEP-22.

♦ ***ER20-2219-001 (NEP – Tariff No. 1)***. On July 19, 2022, NEP amended its June 29, 2020 *Order 864* compliance filing with further amendments to its Tariff No. 1, Schedule III-B.

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[87] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, Order No. 864, 169 FERC ¶ 61,139 (Nov. 21, 2019), *reh'g denied and clarification granted in part,* 171 FERC ¶ 61,033 (Apr. 16, 2020) ("*Order 864*"). *Order 864* requires all public utility transmission providers with transmission rates under an OATT, a transmission owner tariff, or a rate schedule to revise those rates to account for changes caused by the 2017 Tax Cuts and Jobs Act ("2017 Tax Law"). Specifically, for transmission formula rates, *Order 864* requires public utilities (i) to deduct excess Accumulated Deferred Income Taxes ("ADIT") from or add deficient ADIT to their rate bases and adjust their income tax allowances by amortized excess or deficient ADIT; and (ii) to incorporate a new permanent worksheet into their transmission formula rates that will annually track ADIT information ("ADIT Worksheet"). The ***ADIT Worksheet*** must contain the following five specific categories of information: (i) how any ADIT accounts were re-measured and the excess or deficient ADIT contained therein ("***Category 1 Information***"); (ii) is the accounting for any excess or deficient amounts in Accounts 254 (Other Regulatory Liabilities) and 182.3 (Other Regulatory Assets) ("***Category 2 Information***"); (iii) whether the excess or deficient ADIT is protected (and thus subject to the Tax Cuts and Jobs Act's normalization requirements) or unprotected ("***Category 3 Information***"); (iv) the accounts to which the excess or deficient ADIT are amortized ("***Category 4 Information***"); and (v) the amortization period of the excess or deficient ADIT being returned or recovered through the rates ("***Category 5 Information***"). In addition, the FERC stated that it expects public utilities to identify each specific source of the excess and deficient ADIT, classify the excess or deficient ADIT as protected or unprotected, and list the proposed amortization period associated with each classification or source.

[88] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, 171 FERC ¶ 61,033, Order No. 864-A (Apr. 16, 2020) ("*Order 864-A*").

XII. Misc. - Administrative & Rulemaking Proceedings

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

On May 19, 2022, the FERC announced that it will hold a forum, on September 8, 2022 in Burlington, VT, to discuss and achieve a greater understanding among stakeholders in defining the electric and natural gas system challenges in the New England Region. On July 21, the FERC issued a supplemental notice of the forum, announcing that that the forum will be held at the DoubleTree by Hilton, Burlington, VT. Those interested in participating in person were strongly encouraged to register here at their earliest convenience (due to space constraints, seating for the forum will be limited). There is no fee for attendance. Those unable to attend in person will be able to watch via a free webcast.

- **NOI: Dynamic Line Ratings (AD22-5)**

On February 17, 2022, the FERC issued a notice of inquiry ("NOI")[89] seeking comments on (i) whether and how the required use of dynamic line ratings ("DLR") is needed to ensure just and reasonable wholesale rates; (ii) whether the lack of DLR requirements renders current wholesale rates unjust and unreasonable; (iii) potential criteria for DLR requirements; (iv) the benefits, costs, and challenges of implementing DLRs; (v) the nature of potential DLR requirements; and (vi) potential timeframes for implementing DLR requirements. This NOI represents the first step in the FERC's effort to gather more information about the costs and benefits, and potentially mandating the use, of DLRs. A more detailed summary was provided to the Transmission Committee and is posted on the Transmission Committee's webpage.

Initial comments were due ***April 25, 2022*** and filed by: ISO-NE; DC Energy; Eversource; Clean Energy Parties; Potomac Economics; CT DEEP; NERC; US DOE; CAISO; MISO; NYISO; Org of MISO States; PJM, SPP; SPP MMU; AEP; Alliant; APPA; APS; AZ PUC; Clean Energy Entities; Dayton Power; EEI; ELCON; Entergy; IN Util. Reg. Comm.; ITC; LA DPW; MISO TOs; NRECA; NYISO TOs; PPL; R Street Institute; Southern Co.; TAPS; Tri-State; Electricity Canada; Electric Grid Monitoring; Line Vision; Idaho Power.

Reply comments were due on or before ***May 25, 2022***[90] and were filed by: AEP, Clean Energy Entities,[91] EEI, Joint Consumer Advocates, MISO TOs, and the R Street Institute. This matter is pending before the FERC.

- **Improving Generating Units Winter Readiness (AD22-4)**

On April 27-28, 2022, the FERC convened a joint technical conference with NERC and its Regional Entities to discuss how to improve the winter-readiness of generating units, including best practices, lessons learned and increased use of the NERC Guidelines, as recommended in the Joint February 2021 Cold Weather Outages Report.[92] Panels included discussion of (i) cold weather preparedness plans; (ii) planning, engineering and technologies for cold weather preparedness; (iii) implementing cold weather preparedness plans for reliable operations; and (iv) communications, coordination, training, and education for cold weather operations. Speaker materials have been posted in eLibrary.

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

On June 17, 2021, the FERC established a Joint Federal-State Task Force on Electric Transmission ("Transmission Task Force").[93] The Transmission Task Force is comprised of all FERC Commissioners as well as

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[89] *Implementation of Dynamic Line Ratings*, 178 FERC ¶ 61,110 (Feb. 17, 2022) ("*Dynamic Line Ratings NOI*").

[90] The *Dynamic Line Ratings NOI* was published in the Fed. Reg. on Feb. 24, 2022 (Vol. 87, No. 37) pp. 10,349-10,354.

[91] The "Clean Energy Entities" are the Working for Advanced Transmission Technologies Coalition ("WATT"), ACPA, AEE, and SEIA.

[92] *See The February 2021 Cold Weather Outages in Texas and the South Central United States - FERC, NERC and Regional Entity Staff Report* at pp 18, 192 (Nov. 16, 2021), https://www.ferc.gov/news-events/news/final-report-february-2021-freeze-underscores-winterization-recommendations.

[93] *Joint Federal-State Task Force on Electric Transmission*, 175 FERC ¶ 61,224 (June 18, 2021).

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."[94] New England is represented by Commissioners Riley Allen (VT PUC) and Matt Nelson (Chair, MA DPU), each of whom will be serving a second term during the September 1, 2022 – August 31, 2023 term.[95]

Public Meetings.

♦ ***July 20, 2022***. A fourth meeting was held in San Diego, CA, on July 20, 2022. Discussion addressed (i) interregional transmission planning & transmission project development; and (ii) the FERC's *Transmission NOPR*.

♦ ***May 6, 2022***. A third meeting was held virtually on May 16, 2022. Discussion addressed (i) the generator interconnection queue processes and current backlog; and (ii) cost allocation for generator interconnection-related network upgrades, including participant funding. A transcript of this meeting was posted in eLibrary on May 18, 2022. The FERC invited post-meeting comments addressing issues raised during and in the agenda for the May 6 meeting. Those comments were due on June 1, 2022 and were filed by: AEP, Ameren, Clean Energy Coalition, EEI, Invenergy Transmission, MISO, Old Dominion Electric Cooperative, Omaha Power District, PJM, and Xcel Energy.

♦ ***Feb 16, 2022***. A second meeting was held February 16, 2022 in Washington, DC. The agenda included a discussion, for purposes of transmission planning and cost allocation, specific categories and types of transmission benefits that transmission providers should consider and cost allocation principles, methodologies, and decision processes. A transcript of this meeting is posted in eLibrary. Post-meeting comments addressing issues raised during the February 16 meeting and identified in the agenda issued February 2, 2022 were due on or before April 1, 2022 and were filed by AZ PSC, NJ PBU, NARUC, ND PSC, OH PUC Office of the Federal Energy Advocate, VA State Corp. Comm., Americans for a Clean Energy Grid, ITC, PJM, and Sunflower Electric.

♦ ***Nov 10, 2021***. The first Joint Federal-State Task Force meeting, which focused on incorporating state perspectives into regional transmission planning, was convened on November 10, 2021. A transcript of this meeting is posted in eLibrary. Comments on the issues discussed at the first meeting were filed by: AEP, LA PSC, MI PSC, PJM, and Public Citizen.

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

ISO/RTO Reports. On April 21, 2022, the FERC issued an order[96] directing each independent system operator ("ISO") and regional transmission organization ("RTO"), including ISO-NE, to submit on or before ***October 17, 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;

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[94] Topics that the Task Force may consider include: (i) identifying barriers that inhibit planning and development of optimal transmission necessary to achieve federal and state policy goals, as well as potential solutions to those barriers; (ii) exploring potential bases for one or more states to use FERC-jurisdictional transmission planning processes to advance their policy goals, including multi-state goals; (iii) exploring opportunities for states to voluntarily coordinate in order to identify, plan, and develop regional transmission solutions; (iv) reviewing FERC rules and regulations regarding planning and cost allocation of transmission projects and potentially identifying recommendations for reforms; (v) examining barriers to the efficient and expeditious interconnection of new resources through the FERC-jurisdictional interconnection processes, as well as potential solutions to those barriers; and (vi) discussing mechanisms to ensure that transmission investment is cost effective, including approaches to enhance transparency and improve oversight of transmission investment including, potentially, through enhanced federal-state coordination.

[95] *See* Order on Nominations, *Joint Federal-State Task Force on Electric Transmission*, 180 FERC ¶ 61,030 (July 15, 2022).

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

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. Public comments in response to the RTO/ISO reports may be submitted within 60 days following the filing of the reports. The FERC will review the reports and comments to determine whether further action is appropriate.

2021 Technical Conferences. The *Order Directing Reports* follows a series of staff-led technical conferences, convened in 2021 and summarized in previous Reports, addressing ISO/RTO resource adequacy[97] and energy and ancillary services markets.[98]

- **Increasing Market and Planning Efficiency Through Improved Software Tech Conf (Jun 21-23, 2022) (AD10-12)**

On June 21-23, 2022, the FERC held its 13th annual technical conference addressing increasing Real-Time and Day-Ahead market efficiency through improved software. In a second supplemental notice issued on July 14, 2022, the FERC posted final agenda for the technical conference and speakers' summaries of their presentations with minor corrections to the agenda published on May 27, 2022. Panelist materials were posted to eLibrary on July 1, 2022. One set of comments was filed on or before the July 29 comments deadline.

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

On July 28, 2022, the FERC issued a NOPR[99] 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. 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 requirement. Initial comments are due ***[60 days after the date of publication in the Federal Register]***.[100]

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[97] 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: AEE, 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 the American Clean Power Association ("ACPA"), AEP, EPSA, Exelon, Joint Consumer Advocates, LS Power, Old Dominion Electric Cooperative ("ODEC"), PJM Power Providers ("P3"), Public Interest Organizations ("PIOs"), and the Retail Electric Supply Association ("RESA"). Following the May 25 conference, comments were filed by: AEE, Calpine, CT Parties, Dominion, Eversource, MMWEC, NESCOE, NEPGA, NextEra, NRG, Public Interest Orgs, Vistra, AEMA, EPSA, RENEW.

[98] 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.

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

[100] The *Duty of Candor NOPR* has not yet published in the *Fed. Reg*.

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

On June 16, 2022, as corrected on July 12, 2022, the FERC issued a notice[101] proposing to require transmission providers to submit one-time informational reports describing their current or planned policies and processes for conducting extreme weather vulnerability assessments[102] (how they 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). Initial comments are due August 30, 2022.[103]

- **NOPR: Interconnection Reforms (RM22-14)**

On June 16, 2022, the FERC issued a notice of proposed rulemaking ("NOPR"),[104] more than 400 pages long, that proposes 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* Small Generator Interconnection Agreement ("SGIA") to address interconnection queue backlogs, improve certainty, and prevent undue discrimination for new technologies. Initial comments and reply comments are due October 13, 2022 and November 14, 2022, respectively.[105]

The proposed reforms fall into three main categories: (1) reforms to implement a first-ready, first-served cluster study process; (2) reforms to increase the speed of interconnection queue processing; and (3) reforms to incorporate technological advancements to the interconnection process. Within each of these categories, the FERC proposes a wide array of reforms, and requests comment.

To implement the **first-ready, first-served cluster study process**, the FERC proposes to:

- Require transmission providers offer an alternative option for an informational interconnection study that would not require a project enter the interconnection queue;
- Make cluster studies the required interconnection study method under the *pro forma* LGIP;
- Allocate the shared costs of the cluster studies so that 90% of the applicable study costs are allocated to interconnection customers on a pro rate basis based on the requested MWs included in the applicable cluster, and 10% of the applicable study costs are allocated to interconnection customers on a per capita basis based on the number of interconnection requests in the applicable cluster;
- Require transmission providers to allocate network upgrade costs to interconnection customers within a cluster using a proportional impact method, in which the transmission provider will determine the degree to which each generating facility in the cluster contributes to the need for a specific network upgrade;
- Allow interconnection customers in an earlier-in-time cluster to share the costs of network upgrades with interconnection customers who will significantly benefit from those upgrades but would not share the cost of the network upgrades solely by virtue of being in a later cluster;
- Increase study deposits based on the size of the generating facility from $35,000 to $250,000;

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[101] *One-Time Informational Reports on Extreme Weather Vulnerability Assessments; Climate Change, Extreme Weather, and Elec. Sys. Rel.*, 179 FERC ¶ 61,196 (June 16, 2022) ("*Extreme Weather Vulnerability Assessments NOPR*").

[102] "Extreme weather vulnerability assessments" are proposed to be defined as "analyses that identify 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".

[103] The *Extreme Weather Vulnerability Assessments NOPR* was published in the *Fed. Reg.* on July 1, 2022 (Vol. 87, No. 126) pp. 39,414-39,426.

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

[105] The *Interconnection Reforms NOPR* was published in the *Fed. Reg.* on July 5, 2022 (Vol. 87, No. 127) pp. 39,934-40,032.

- Require more stringent site control requirements, and proposes to require an interconnection customer to demonstrate 100% site control for a proposed generating facility when they submit the interconnection request;[106]
- Implement a commercial readiness framework whereby interconnection customers must show demonstrable milestones towards commercial readiness in order to enter the cluster, such as an executed term sheet, reasonable evidence the project was selected in a resource plan, or a provisional LGIA;[107]
- Impose withdrawal penalties when the interconnection customer withdraws from the interconnection queue.[108]

To **increase the speed of the interconnection queue process**, the FERC proposes to:

- Eliminate the "reasonable efforts" standard for transmission providers completing interconnection studies and instead impose firm study deadlines and establish penalties that would apply when transmission providers fail to meet these deadlines. The penalty imposed would be $500 per day that the study is late and would be distributed to interconnection customers on a pro rata basis;
- Add an entirely *pro forma* affected system study process to address the current lack of uniformity in the study of affected systems, which results in late-stage withdrawals, re-studies and increased costs to remaining interconnection customers;
- Establish two new *pro forma* agreements, a *pro forma* Affected System Study Agreement (new Appendix 15) and a *pro forma* Affected Systems Facilities Construction Agreement (new Appendix 16);
- Implement an optional resource solicitation study that can be performed by entities required to conduct a resource plan or solicitation. Under this proposed study process, a resource planning agency (such as a state agency or load-serving entity implementing a state mandate) would facilitate a study to group together interconnection requests associated with the qualifying resource solicitation process, and the resources vying for selection in a qualifying state resource solicitation process would be studied together for the purposes of informational interconnection studies.

Finally, as **technological advances to the interconnection process**, the FERC proposes to:

- Require transmission providers to allow more than one resource to co-locate on a shared site behind a single point of interconnection and share a single interconnection request;
- Change the way in which transmission providers assess an addition of a generating facility to an interconnection request, requiring that transmission providers evaluate a proposed addition as long as the addition does not change the requested interconnection service level;
- Enable customers with unused interconnection capacity share that surplus capacity with other resources as long as the original interconnection customer executes an LGIA or requests filing of an unexecuted LGIA;

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[106] The FERC proposes to limit the option to provide a financial deposit in lieu of site control and would only allow this option when regulatory limitations prohibit the interconnection customer from obtaining site control. In such instances, the interconnection customer would submit a deposit of $10,000 per MW, subject to a floor of $500,000 and a ceiling of $2 million.

[107] *Id.* at P 128.

[108] The proposed withdrawal penalty will increase as the interconnection customer moves through the interconnection queue and proposes a chart demonstrating the possible penalties at P 144.

- Require transmission providers, at the request of the interconnection customer to use operating assumptions for interconnection studies that reflect the proposed operation of an electric storage resource or co-located storage resource; and
- Require transmission providers to evaluate grid-enhancing solutions and file an annual informational report on their use of grid-enhancing technologies.

The FERC proposes to require compliance within 180 days of a final rule in this proceeding. Compliance would require transmission providers to file updates to their *pro forma* LGIA, LGIP, SGIA and SGIP, as applicable. If you have any questions concerning the *Interconnection Reforms NOPR*, please contact Margaret Czepiel (202-218-3906; mczepiel@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

On July 28, 2022, the FERC issued a NOPR[109] proposing to revise its regulations to permit ISO/RTOs to share among themselves[110] credit-related information regarding market participants.[111] The FERC believes that the proposed credit information sharing could improve ISO/RTOs' ability to accurately assess market participants' credit exposure and risks and enable ISO/RTOs to respond to credit events more quickly and effectively (minimizing the overall credit-related risks, including risks of unexpected defaults by market participants, in organized wholesale electric markets). The FERC proposal would not permit the information sharing to be 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 seeks comment on whether ISO/RTOs' credit-related information sharing discretion should be limited in any specific ways or to any specific circumstances. Initial comments are due ***[60 days after the date of publication in the Federal Register]***; reply comments ***[90 days after the date of publication in the Federal Register]***.[112]

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

On June 16, 2022, the FERC issued a notice[113] proposing to require that NERC modify Reliability Standard TPL-001-5.1 (Transmission System Planning Performance Requirements) within one year of the effective date of a final rule in this proceeding to address reliability concerns pertaining to transmission system planning for extreme heat and cold weather events that impact the reliable operations of the Bulk-Power System. Specifically, the FERC proposed modifications to TPL-001-5.1 to require: (i) development of benchmark planning cases; (ii) planning for extreme heat and cold events using steady state and transient stability analyses expanded to cover a range of

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[109] *Credit-Related Information Sharing in Organized Wholesale Electric Markets*, 180 FERC ¶ 61,048 (July 28, 2022) ("*ISO/RTO Credit-Related Info Sharing NOPR*").

[110] The *ISO/RTO Credit-Related Info Sharing NOPR* does propose credit-related information sharing with markets that are not Commission-jurisdictional (i.e. ERCOT, AESO, IESO or commodities and derivative markets that are subject to the jurisdiction of other regulators, including the Commodity Futures Trading Commission).

[111] Revisions would be to 18 CFR § 35.47(h). The changes would "[p]ermit the sharing of market participant credit-related information with, and receipt of market participant credit-related information from, other organized wholesale electric markets for the purpose of credit risk management and mitigation, provided such market participant credit-related information is treated upon receipt as confidential under the terms for the confidential treatment of market participant information set forth in the tariff or other governing document of the receiving organized wholesale electric market; and permit the receiving organized wholesale electric market to use market participant credit-related information received from another organized wholesale electric market to the same extent and for the same purposes that the receiving organized wholesale electric market may use credit-related information collected from its own market participants.

[112] The *ISO/RTO Credit-Related Info Sharing NOPR* has not yet published in the *Fed. Reg*.

[113] *Transmission System Planning Performance Requirements for Extreme Weather*, 179 FERC ¶ 61,195 (June 16, 2022) ("*Extreme Weather Transmission System Planning NOPR*").

extreme weather scenarios; and (iii) corrective action plans that include mitigation for any instances where performance requirements for extreme heat and cold events are not met. Initial comments are due August 26, 2022.[114]

- **NOI: Rate Recovery, Reporting, and Accounting Treatment of Industry Association Dues and Certain Civic, Political, and Related Expenses (RM22-5)**

On December 16, 2021, the FERC issued a notice of inquiry[115] seeking comments on (i) the rate recovery, reporting, and accounting treatment of industry association dues and certain civic, political, and related expenses; (ii) the ratemaking implications of potential accounting and reporting changes; (iii) whether additional transparency or guidance is needed with respect to defining donations for charitable, social, or community welfare purposes; and (iv) a framework for guidance should the FERC determine action is necessary to further define the recoverability of industry association dues charged to utilities and/or utilities' expenses from civic, political, and related activities. Initial comments were due February 22, 2022 and were filed by AGA, APPA, EEI, EPRI, Harvard Electricity Law Institute, INGA, Joint RTO Commenters,[116] MA AG, National Grid, NEI, Nexamp, NRECA, Public Citizen, Public Interest Organizations, Ratepayers, Sunova, and UCS. Reply comments were due on or before March 23, 2022 and were filed by, among others: DTE, MA AG, NECOS, AGA, EEI, INGA, Joint Consumer Advocates, and WIRES. Since the last Report, Joint RTO Commenters replied to NECOS' discussion and characterization of the Initial Joint RTO Comments and a question of First Amendment constitutional law. This matter is pending before the FERC.

- **NOPR: Internal Network Security Monitoring for High and Medium Impact BES Cyber Systems (RM22-3)**

On January 20, 2022, the FERC issued a NOPR[117] proposing to direct NERC to develop and submit for FERC approval new or modified Reliability Standards that require internal network security monitoring ("INSM")[118] within a trusted Critical Infrastructure Protection networked environment for high and medium impact Bulk Electric System ("BES") Cyber Systems. The FERC stated that "including INSM requirements in the CIP Reliability Standards would ensure that responsible entities maintain visibility over communications between networked devices within a trust zone (i.e., within an ESP), not simply monitor communications at the network perimeter access point(s), i.e., at the boundary of an ESP as required by the current CIP requirements. In the event of a compromised ESP, improving visibility within a network would increase the probability of early detection of malicious activities and would allow for quicker mitigation and recovery from an attack."[119]

Comments on the *Internal Network Security Monitoring NOPR* were due on or before March 28, 2022.[120] Comments were filed by: the IRC, NERC, EEI, EPSA, TAPS, Bonneville Power Admin., Consumers Energy, Cynalytica, CA Department of Water Resources, Electricity Canada, Entergy, Idaho Power, Juniper Networks, ITC, Microsoft,

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[114] The *Extreme Weather Transmission System Planning NOPR* was published in the *Fed. Reg.* on June 27, 2022 (Vol. 87, No. 122) pp. 38,021-38,044.

[115] *Rate Recovery, Reporting, and Accounting Treatment of Industry Association Dues and Certain Civic, Political, and Related Expenses*, 177 FERC ¶ 61,180 (Dec. 16, 2021) ("*Dues & Expenses NOI*").

[116] "Joint RTO Commenters" are PJM Interconnection, L.L.C. ("PJM"), California Independent System Operator Corp. ("CAISO"), Midcontinent Independent System Operator, Inc. ("MISO"), and Southwest Power Pool ("SPP").

[117] *Internal Network Security Monitoring for High and Medium Impact Bulk Electric System Cyber Systems*, 178 FERC ¶ 61,038 (Jan. 20, 2022) ("*Internal Network Security Monitoring NOPR*").

[118] INSM is a subset of network security monitoring that is applied within a "trust zone," such as an Electronic Security Perimeter ("ESP"), and is designed to address situations where vendors or individuals with authorized access are considered secure and trustworthy but could still introduce a cybersecurity risk to a high or medium impact BES Cyber System.

[119] *Id.* at P 2.

[120] The *Internal Network Security Monitoring NOPR* was published in the *Fed. Reg.* on Jan. 27, 2022 (Vol. 87, No. 18) pp. 4,173-4,180.

North American Generator Forum, Nozomi Networks, Operational Technology Cybersecurity Coalition, the US Bureau of Reclamation, and T. Conway. This matter is pending before the FERC.

- **NOI: Reactive Power Capability Compensation (RM22-2)**

On November 18, 2021, the FERC issued a notice of inquiry[121] seeking comments on reactive power capability compensation and market design. Specifically, the FERC seeks comments on whether (i) the AEP Methodology remains a just and reasonable approach to determining reactive power revenue requirements in all circumstances; (ii) other potential alternative methodologies not based on the costs of the particular resource(s) at issue in a given proceeding should be considered or better used to develop reactive power capability revenue requirements; and (iii) resources interconnected to a distribution system and participating in wholesale markets are technically capable of providing reactive power to the transmission system in such a way that they should be eligible for reactive power capability compensation through transmission rates. Initial comments were due February 21; Reply Comments, March 23, 2022. Initial comments were filed by over 35 parties. Reply comments were filed by: Ameren, Clean Energy Coalition, DE Shaw, EDF, EEI, EPSA, Joint Customers,[122] MISO TOs, PJM IMM, PSEG, Vistra, and N. Bhushan. This matter is pending before the FERC.

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

Following its ANOPR process,[123] the FERC issued on April 21, 2022 a NOPR[124] 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 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

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[121] *Rate Recovery, Reporting, and Accounting Treatment of Industry Association Dues and Certain Civic, Political, and Related Expenses*, 177 FERC ¶ 61,180 (Dec. 16, 2021) ("*Dues & Expenses NOI*").

[122] "Joint Customers" are Old Dominion Electric Cooperative ("ODEC"), Northern Virginia Electric Cooperative, Inc. ("NOVEC"), and Dominion Energy Services, Inc. on behalf of Virginia Electric and Power Company d/b/a Dominion Energy Virginia ("Dominion").

[123] *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, AEE, 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, AEE, APPA, EEI, ELCON, Environmental and Renewable Energy Advocates, EPSA, Harvard ELI, NRECA, Potomac Economics, and SEIA. Supplemental reply comments were filed by WIRES, and a group of former military leaders and former Department of Defense officials, and ACPA/AEE/SEIA.

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

(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, which will recommend whether NEPOOL should submit comments on the *Transmission NOPR*.

Comment Dates Extended. Following a number of requests for extensions of time, comments on the *Transmission NOPR* are due ***August 17, 2022***; reply comment ***September 19, 2022***. Thus far, the Clean Energy Coalition and Large Public Power Council, Microgrid Resources Coalition, the Smart Electric Power Alliance, and Tabors Caramanis have submitted comments. On July 27, 2022, the Georgia Public Service Commission ("GA PUC") asked for an additional 30 days of time to submit comments and reply comments. That request is 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).

- **NOI: Removing the DR Opt-Out in ISO/RTO Markets (RM21-14)**

On March 18, 2021, the FERC issued a NOI[125] seeking comments on whether to revise its Demand Response ("DR") Opt-Out regulations established in *Orders 719 and 719-A.* Those regulations require an ISO/RTO not to accept bids from an aggregator of retail customers ("ARC") that aggregates DR of the customers of utilities that distributed more than 4 million MWh in the previous fiscal year, where the relevant electric retail regulatory authority prohibits such customers' DR to be bid into ISO/RTO markets by an ARC. The FERC now seek information to help it examine the potential costs/burdens and benefits, both quantitative and qualitative, of removing the DR Opt-Out, as well as other changes relating to DR since the FERC issued *Orders 719 and 719-A*. The FERC is not seeking comment on the Small Utility Opt-In. Comments on the NOI, following an extension, were due on or before July 23, 2021 and were filed by nearly 30 parties, including by AEE, Voltus, AEMA, APPA/NRECA, EEI, and NARUC. Reply comments were due on or before August 23, 2021, and were filed by AEP, Armada Power, Entergy, Southern Pioneer Electric, Voltus, State Commissions from LA/MS, MI, MO, NC, APPA/NRECA, Assoc. of Bus. Advocating Tariff Equity ("ABATE"), and PIOs. On March 28, 2022, the Mississippi PSC moved to lodge its Protest and Response filed in a recent Complaint proceeding initiated and subsequently withdrawn by Voltus (EL21-12), to ensure its pleading is a part of the record of this proceeding. On March 29, 2022, the U.S. House Sustainable Energy and Environment Coalition ("SEEC") Power Sector Task Force urged the FERC to proceed to a NOPR that would eliminate the demand response Opt-Out. Since the last Report, Voltus again submitted comments in support of eliminating the DR Opt-Out, with responses to those comments filed by the Mississippi PSC and R.

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[125] *Participation of Aggregators of Retail Demand Response Customers in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 174 FERC ¶ 61,198 (March 18, 2021) ("*DR Aggregator NOI*").

Borlick (further supplemented on August 1, 2022 by the submission of a copy of the Supreme Court's decision in *FERC v. EPSA*, 577 U.S. 260 (2016)) This matter remains pending before the FERC.

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

On July 28, 2022, the FERC issued a NOPR[126] proposing reforms to the accounting and reporting treatment of certain renewable energy assets. Specifically, the FERC proposes changes to the Uniform System of Accounts ("USofA") and relevant FERC forms to: (i) include new accounts for wind, solar, and other non-hydro renewable assets; (ii) create a new functional class for energy storage accounts; (iii) codify the accounting treatment of renewable energy credits; and (iv) create new accounts within existing functions for hardware, software, and communication equipment. The FERC also seeks comment on whether the Chief Accountant should issue guidance on the accounting for hydrogen. Comments on the *Renewable Energy Assets USofA and Reporting NOPR* are due ***[45 days after the date of publication in the Federal Register]***.[127]

- **NOPR: Cybersecurity Incentives (RM21-3)**

On December 17, 2020, the FERC issued a NOPR[128] proposing to establish rules for incentive-based rate treatment for voluntary cybersecurity investments by a public utility for or in connection with the transmission or sale of electric energy subject to FERC jurisdiction, and rates or practices affecting or pertaining to such rates for the purpose of ensuring the reliability of the BPS.

Comments on the *Cyber security Incentives NOPR* were due on or before April 6, 2021. Comments were filed by: NECPUC, APPA, EEI, EPSA, LPPC, NERC, NRECA, TAPS, Accenture, aDolus Inc. et al.,[129] Alliant, Anterix, Bureau of Reclamation, CA Dept of Water Resources State Water Project/CPUC, George Cotter, FRS, Hitachi ABB Power Grids, IECA, ITC, Joint Consumer Advocates, MI PUC, Org of MISO States, MISO TOs, PJM TOs, and Public Citizen. Reply comments were due May 6, 2021[130] and were filed by APPA/TAPS, EEI, SEIA, California Public Utilities Commission and California Department of Water Resources ("CA PUC/DWR"), and the Office of the Ohio Federal Energy Advocate ("Ohio FEA"). This matter remains pending before the FERC.

- ***Order 881*: Managing Transmission Line Ratings (RM20-16)**

On December 16, 2021, the FERC issued its final rule, *Order 881*, on Managing Transmission Line Ratings.[131] In *Order 881*, the FERC reforms both the *pro forma* OATT and its regulations to improve the accuracy and transparency of transmission line ratings. Specifically, *Order 881* requires:

(vi) transmission providers to implement ambient-adjusted ratings on the transmission lines over which they provide transmission service;

(vii) ISO/RTOSs to establish and implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings at least hourly;

(viii) transmission owners to share transmission line ratings and transmission line rating methodologies with their respective transmission provider(s) and, in ISO/RTOs, with their respective market monitor(s); and

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[126] *Accounting and Reporting Treatment of Certain Renewable Energy Assets*, 180 FERC ¶ 61,050 (July 28, 2022) ("*Renewable Energy Assets USofA and Reporting NOPR*").

[127] The *Renewable Energy Assets USofA and Reporting NOPR* has not yet published in the *Fed. Reg*.

[128] *Cybersecurity Incentives*, 173 FERC ¶ 61,240 (Dec. 17, 2020) ("*Cybersecurity Incentives NOPR*").

[129] These joint comments were filed by aDolus Inc., Fortress Information Security, GMO GlobalSign Inc., Ion Channel, ReFirm Labs and Reliable Energy Analytics LLC.

[130] The *Cybersecurity Incentives NOPR* was published in the *Fed. Reg.* on Feb. 5, 2021 (Vol. 86, No. 23) pp. 8,309-8,325.

[131] *Managing Transmission Line Ratings*, Order No. 881, 177 FERC ¶ 61,179 (Dec. 16, 2021) ("*Order 881*").

(ix) transmission providers to maintain a database of transmission owners' transmission line ratings and transmission line rating methodologies on the transmission provider's Open Access Same-Time Information System ("OASIS") site or other password-protected website.

Order 881 became effective March 14, 2022.[132]

Requests for rehearing and/or clarification. Requests for rehearing and/or clarification of *Order 881* were filed by ATC, EEI, ITC Holdings, MISO IMM, and the MISO TOs on January 18, 2022, but may be deemed denied by operation of law. On February 18, 2022, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[133] The Notice confirmed that the 60-day period during which a petition for review of *Order 881* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of *Order 881*. The Notice also indicated that the FERC would address, as is its right, the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper."

The FERC issued that order on May 19, 2022 ("*Order 881-A*"),[134] modifying the discussion in *Order 881*, granting clarification in part, and continuing to reach the same result as in *Order 881*. Specifically, the FERC:

(i) continued to find that requiring transmission providers to apply the ambient-adjusted ratings ("AAR")[135] requirements set forth in pro forma OATT Attachment M to all transmission lines on which they provide transmission service, subject to certain exceptions, is just and reasonable;

(ii) clarified two aspects of the AAR requirements related to transmission providers' transmission protection relay settings ((1) if a transmission provider establishes higher transmission line ratings, it will have to evaluate or reevaluate its applicable protection systems for that facility and (2) in a majority of situations the relay setting should exceed AAR values);

(iii) continued to require the use of AARs for a 10-day forward period;

(iv) declined to clarify or grant rehearing on the issue of a transmission line rating "floor", which it declined to require in *Order 881*;

(v) did not change its position with respect to the five-degree requirement,[136] the daytime/nighttime ratings requirement,[137] the seasonal line ratings annual update requirement, data storage and sharing requirements, or the proposed implementation schedule (AAR implementation on congested transmission lines within one year from the date of the compliance filing and, for all other transmission lines, implementation within two years from the date of the compliance filing);

(vi) clarified that transmission providers have the discretion to post the required data to their OASIS site or an alternative password-protected website so long as users are able to access the data in a

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[132] *Order 881* was published in the Fed. Reg. on Jan. 13, 2022 (Vol. 87, No. 9) pp. 2,244-2,307.

[133] *Managing Transmission Line Ratings*, 178 FERC ¶ 62,104 (Feb. 18, 2022) ("*Order 881 Notice of Denial of Rehearings by Operation of Law*").

[134] *Managing Transmission Line Ratings*, 179 FERC ¶ 61,125 (May 19, 2022) ("*Order 881-A").*

[135] An ambient-adjusted rating is defined as a transmission line rating that: (1) applies to a time period of not greater than one hour; (2) reflects an up-to-date forecast of ambient air temperature across the time period to which the rating applies; (3) 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; and (4) is calculated at least each hour, if not more frequently. *See* 18 CFR 35.28(b)(12) (2021); Pro Forma OATT attach. M, AAR Definition.

[136] The requirement that transmission providers implement AARs that update at least with every 5°F increment of temperature change, in order to meet the *pro forma* OATT Attachment M requirement that an AAR reflect an up-to-date forecast of ambient air temperature.

[137] The requirement that transmission providers incorporate solar heating into AARs by implementing separate AARs for daytime and nighttime periods, and to update the sunrise and sunset times used to calculate their AARs at least monthly, if not more frequently.

manner that is comparable to if it were posted to OASIS and subject to OASIS access requirements; and

(vii) clarified that *Order 881* did not revise the FERC's existing CEII requirements (and that transmission line ratings and methodologies do not constitute CEII).

As reported in Section IV above, New England's (and the Schedule 21 Providers') *Order 881* compliance filings have been filed. Reporting on this rulemaking proceeding will conclude with this Report.

- **NOPR: Electric Transmission Incentives Policy (RM20-10)**

Supplemental NOPR. In light of comments already received in this proceeding,[138] the FERC issued on April 15, 2021 a *Supplemental NOPR*[139] to propose and seek comment on a revised incentive for transmitting and electric utilities that join Transmission Organizations ("Transmission Organization Incentive"). The Incentive would be reduced from 100 to 50 basis points and would be available only for three years. The FERC sought comment on whether voluntary participation should be a requirement, and if so, how "voluntary" should be determined. In addition, the FERC now proposes to require each utility that has received a Transmission Organization Incentive for three or more years to submit a compliance filing revising its tariff to remove the incentive from its transmission tariff. The *Supplemental NOPR* did not address the other proposals contained in the *March NOPR*.[140] A more detailed summary of the NOPR was distributed to the Transmission Committee and discussed at the TC's March 25, 2020 meeting.

Comments on the *Supplemental NOPR* were due on or before June 25, 2021. Over 60 sets of comments were filed, including by the New England TOs, MMWEC/NHEC/CMMEC, NECOS, NESCOE, Potomac Economics, and CT PURA. Reply comments were due on or before July 26, 2021, with 28 sets of comments received, including by the New England TOs, NECOS, NESCOE, CT PURA/CT DEEP/MA AG, CT AG, and Public Interest Groups.[141] Reply

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[138] Over 80 sets of comments on the *March NOPR* were filed on or before the July 1, 2020 comment date, including comments by: Avangrid, EDF Renewables, EMCOS, Eversource, Exelon, LS Power, MMWEC/NHEC/CMEEC, National Grid, NESOCE, NextEra, UCS, CT PURA, and Potomac Economics. Reply comments were filed by AEP, ITC Holding, the N. California Transmission Agency, and WIRES.

[139] *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, 175 FERC ¶ 61,035 (Apr. 15, 2021) ("*Supplemental NOPR*").

[140] As previously reported, the *March NOPR* proposed revisions to the FERCs existing transmission incentives policy and corresponding regulations, including the following:

- ♦ A shift from risks and challenges to a ***consumers'' benefits test*** that focuses on ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.
- ♦ ***ROEs incentive for Economic Benefits***. A 50-basis-point adder for transmission projects that meet an economic benefit-to-cost ratio in the top 75th percentile of transmission projects examined over a sample period <u>and</u> an additional 50-basis-point adder for transmission projects that demonstrate *ex post* cost savings that fall in the 90th percentile of transmission projects studied over the same sample period, as measured at the end of construction.
- ♦ ***ROE for Reliability Benefits***. A 50-basis-point adder for transmission projects that can demonstrate potential reliability benefits by providing quantitative analysis, where possible, as well as qualitative analysis.
- ♦ ***Abandoned Plant Incentive***. 100 percent of prudently incurred costs of transmission facilities selected in a regional transmission planning process that are cancelled or abandoned due to factors that are beyond the control of the applicant. Recovery from the date that the project is selected in the regional transmission planning process.
- ♦ ***Eliminate Transco Incentives***.
- ♦ ***Transmission Organization Incentive.*** A *50-basis-point increase* for transmitting utilities that turn over their wholesale facilities to a Transmission Organization and *only for the first three years after transferring operational control of its facilities.* The FERC seeks comment as to whether participation must be voluntary to receive the incentive, and if so, how the CFERC should determine whether the decision to join is voluntary.
- ♦ ***Transmission Technologies Incentives***. Eligible for both a stand-alone, 100-basis-point ROE incentive on the costs of the specified transmission technology project and specialized regulatory asset treatment. Pilot programs presumptively eligible (though rebuttable).
- ♦ ***250-Basis-Point Cap***. Total ROE incentives capped at 250 basis points in place of current "zone of reasonableness" limit.
- ♦ ***Updated Date Reporting Processes***. Information to be obtained on a project-by-project basis, information collection expanded, updated reporting process.

[141] "Public Interest Groups" are NRDC, Sierra Club, Sustainable FERC Project, and Western Grid Group.

comments were also posted from New England State Parties,[142] Alliant/Consumers/DTE, AEP, Pacific Gas & Electric, Joint Consumer Advocates, and the American Clean Power Association ("ACPA").

September 10, 2021 Workshop. The FERC convened a workshop on September 10, 2021[143] to discuss certain performance-based ratemaking approaches, particularly shared savings, that may foster deployment of transmission technologies. The notice states that the workshop will explore: the maturity of the modeling approaches for various transmission technologies; the data needed to study the benefits/costs of such technologies; issues pertaining to access to or confidentiality of this data; the time horizons that should be considered for such studies; and other issues related to verifying forecasted benefits. The workshop also discussed whether and how to account for circumstances in which benefits do not materialize as anticipated and may explore other performance-based ratemaking approaches for transmission technologies seeking incentives under FPA section 219, particularly market-based incentives. The FERC issued an agenda for the workshop, which included the final workshop program and expected speakers, on August 23, 2021. The FERC supplemented that notice on September 9, 2021. On October 13, 2021, the FERC posted a transcript of the workshop in eLibrary.

Notice Inviting Post-Workshop Comments. On October 18, 2021, the FERC issued a notice inviting those interested to file post-workshop comments to address the issues raised during the workshop concerning incentives and shared savings. Comments were due on or before January 14, 2022 and were filed by APPA, CAISO, Clean Energy Parties,[144] EDF Renewables, EEI, the Industrial Energy Consumers of America ("IECA"), National Grid, PJM IMM, TAPS.

These matters are pending before the FERC. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- **Salem Harbor (IN18-8)**

On June 27, 2022, the FERC approved a Stipulation and Consent Agreement with Salem Harbor Power Development LP ("Salem Harbor")[145] that resolved OE's Part 1b investigation into Salem Harbor's receipt of capacity payments from ISO-NE for its New Salem Harbor Generating Station project ("Project") during the 2017-18 Capacity Commitment Period, a period during which the Project had neither been built nor commenced commercial operation. OE determined, among other things, that Salem Harbor failed to provide "complete updated version[s] of [its] critical path schedule ("CPS") as required by sections III.13.3.2 and III.13.3.2.1 of the ISO-NE Tariff, that narratives Salem Harbor submitted to ISO-NE made false claims regarding the Project's schedule trajectory and omitted numerous important and relevant details regarding the status of the Project and its construction-related delays, and that its CPS submission violated Salem Harbor's Duty of Candor under the FERC's Market Behavior Rules.[146] Under the Settlement, in which Salem Harbor neither admits nor denies the alleged violations, and subject to limitations of the Bankruptcy Code and in accordance with the treatment afforded to Allowed General Unsecured Claims pursuant to a plan to be approved by the

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[142] "New England State Parties" are CT PURA, CT DEEP and the MA AG.

[143] Notice of Workshop, *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, Docket Nos. RM20-10 and AD19-19 (Apr. 15, 2021).

[144] The "Clean Energy Parties" are: Working for Advanced Transmission Technologies ("WATT Coalition"), ACPA, AEE, American Council on Renewable Energy ("ACORE"), Natural Resources Defense Council ("NRDC"), and the Sustainable FERC Project.

[145] *Salem Harbor Power Development LP*, 179 FERC ¶ 61,228 (June 27, 2022) ("*Salem Harbor Order*").

[146] 18 CFR § 35.41(b) (2022).

Bankruptcy Court in Salem Harbor's ongoing Chapter 11 Cases, Salem Harbor must ***disgorge $26.7 million***,[147] and ***pay a $17.1 million civil penalty*** to the United States Treasury.[148] If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **sPower Development Company (IN22-5)**

On June 24, 2022, the FERC approved a Stipulation and Consent Agreement with sPower Development Company, LLC ("sPower Devco")[149] that resolved OE's investigation into whether sPower Devco violated section 36.2A of the PJM Tariff by submitting inaccurate information to PJM during the interconnection process. Specifically, OE determined that sPower Devco submitted two interconnection study agreements that inaccurately stated that sPower Devco had site control over property for the proposed interconnection of a solar project. Under the Settlement, in which sPower Devco neither admits nor denies the alleged violations, sPower Devco must ***pay a $24,000 civil penalty*** to the United States Treasury. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **PacifiCorp (IN21-6)**

On April 15, 2021, in the FERC's first-ever Show Cause Order addressing alleged violations of NERC Reliability Standards,[150] the FERC directed PacifiCorp to show cause why it should not be found to have violated FPA section 215(b)(1) and section 39.2 of the FERC's regulations by failing to comply with Reliability Standard FAC 009-1 (Establish and Communicate Facility Ratings), Requirement R1, and the successor Reliability Standard FAC-008-3 (Facility Ratings), Requirement R6 (collectively, "FAC-009-1 R1"), which requires a transmission owner to establish and have facility ratings that are consistent with its Facility Ratings Methodology ("FRM"). An Enforcement investigation found that clearance measurements on a majority of PacifiCorp's transmission lines were incorrect under the National Electric Safety Code, which were used to calculate PacifiCorp's facility ratings, thus making PacifiCorp's facility ratings inconsistent with its FRM. Enforcement alleges that PacifiCorp was aware of incorrect clearances on its system since at least 2007 when FAC-009-1 R1 became mandatory, but failed to identify and remedy them in a timely manner, and PacifiCorp's violations began on August 31, 2009, when it implemented its FRM policy, and at least some of the violations continued until August 2017 when PacifiCorp completed remediation of all of its incorrect clearances to make them consistent with its FRM. Enforcement also pointed to the role of the violations in the Wood Hollow, Utah wildfire that lasted from June 23 to July 1, 2012. In light of these alleged violations, the FERC directed PacifiCorp to show cause why it should not be assessed civil penalties in the amount of ***$42 million***.

On July 16, 2021, PacifiCorp answered the PacifiCorp Show Cause Order, denying the alleged violations of FAC-009. Enforcement filed its reply on September 14, 2021. This matter remains pending before the FERC. (Should the FERC choose to pursue a civil penalty against PacifiCorp for the alleged violations, PacifiCorp has already exercised its right to adjudicate these allegations in federal district court.) If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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[147] ISO-NE was directed to distribute the disgorgement *pro rata* to network load, subject to the limitations of the Bankruptcy Code and the order of the Bankruptcy Court.

[148] In recommending the remedies, OE considered the roles that multiple individuals and entities played in ISO-NE not submitting a demand bid on Salem Harbor's behalf into ARA3. Neither the Agreement nor the *Salem Harbor Order* asserted violations by any individual or any entity other than Salem Harbor. However, the FERC reserves its right to make a determination as to the facts or issues of law that might give rise to any violation by any other individual or entity. *Salem Harbor Order* at P 58.

[149] *sPower Development Co., LLC*, 179 FERC ¶ 61,220 (June 24, 2022).

[150] *PacifiCorp,* 175 FERC ¶ 61,039 (Apr. 15, 2021) ("*PacifiCorp Show Cause Order*").

Natural Gas-Related Enforcement Actions

- **M3/Utica East/UEOM (IN22-6)**

On June 24, 2022, the FERC approved a Stipulation and Consent Agreement with M3 Ohio Gathering LLC ("M3") and Utica East Ohio Midstream LLC ("Utica East") and UEOM NGL Pipelines LLC ("UEOM") that resolved OE's investigation into whether M3 and Utica East violated Part I, Section 20(1) of the Interstate Commerce Act and 18 C.F.R. § 357.2(a) when they failed to submit Utica East's FERC Form No. 6 and FERC Form No. 6-Q (collectively, FERC Form No. 6s)[151] over a six-year period from 2013 to 2019.[152] Under the Settlement, in which no party admits or denies the alleged violations, M3 must ***pay a civil penalty of $30,000*** to the United States Treasury and Utica East and UEOM agree to certify and submit all of the outstanding FERC Form No. 6s through the FERC's eForms portal. 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)**

On January 20, 2022, the FERC issued an order establishing a hearing 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.[153]

As previously reported, on March 18, 2021, the FERC issued a show cause order[154] in which it directed Rover Pipeline, LLC ("Rover") and Energy Transfer Partners, L.P. ("ETP" and together with Rover, "Respondents") to show cause why they should not be found to have violated Section 157.5 of the FERC's regulations by misleading the FERC in its Application for Certificate of Public Convenience and Necessity ("CPCN") under NGA section 7(c).[155] The FERC directed Respondents to show cause why they should not be assessed civil penalties in the amount of ***$20.16 million***. On April 5, 2021, the FERC extended by 60 days, to June 18, 2021, the deadline for Respondents' answer. On June 18, 2021, Rover and ETP answered the *Rover/ETP Show CPCN Cause Order*, asserting that the FERC should dismiss this matter and decline to initiate an enforcement action. On July 21, 2021, Enforcement Staff answered Rover/ETP's answer, stating the evidence supports a finding that Rover violated the FERC's Regulations and should be assessed the civil penalty identified in the *Rover/ETP Show Cause Order*. Rover answered the July 21 answer on September 15.

Hearings. As previously reported, ALJ Joel DeJesus will be the presiding judge for hearings in this matter. On March 8, 2022, Chief Judge Cintron issued an order extending the procedural time standards for this proceeding. Based on that order, the deadlines for the commencement of the hearing is now March 6, 2023 and

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[151] FERC regulations require each natural gas pipeline carrier whose annual jurisdictional operating revenues exceed $500,000 to file FERC Form No. 6 and those pipelines that are exempt from filing the entire form to file select pages of the form.

[152] *M3 Ohio Gathering LLC and Utica East Ohio Midstream LLC and UEOM NGL Pipelines LLC*, 179 FERC ¶ 61,221 (June 24, 2022).

[153] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.*, 178 FERC ¶ 61,028 (Jan. 20, 2022) ("*Rover/ETP Hearings Order*").

[154] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 174 FERC ¶ 61,208 (Mar. 18, 2021) ("*Rover/ETP CPCN Show Cause Order*").

[155] Specifically, Rover stated that it was "committed to a solution that results in no adverse effects" to the Stoneman House, an 1843 farmstead located near Rover's largest proposed compressor station. In truth, the OE Staff Report alleges, Rover was simultaneously planning to purchase the house with the intent to demolish it, if necessary, to complete its pipeline. The OE Staff Report alleges that Rover purchased the house in May 2015 and demolished the house in May 2016. The OE Staff Report further finds that despite taking these actions during the year and a half that Rover's application was pending before the FERC, Rover did not notify the FERC that it purchased the Stoneman House, intended to destroy the Stoneman House, and did destroy the Stoneman House. The OE Staff Report therefore concludes that Rover violated section 157.5's requirement for full, complete and forthright applications, through its misrepresentations and omissions, when it decided not to tell FERC that it had purchased the house and was considering demolishing it, and when Rover demolished it in May 2016 without notifying FERC.

the deadline to issue the initial decision is now June 20, 2023. A virtual prehearing conference was also held on March 8, a transcript of which is posted in eLibrary.

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

On December 16, 2021, the FERC issued a show cause order[156] in which it directed Rover and ETP (together, "Respondents") to show cause why they should not be found to have violated NGA section 7(e), FERC Regulations (18 C.F.R. § 157.20); and the FERC's Certificate Order,[157] 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;[158] (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." Also since the last Report, the FERC denied Respondents' request for rehearing of the FERC's January 21, 2022 designation notice.[159] This matter is pending before the FERC.

- **BP (IN13-15)**

On December 17, 2020, the FERC issued *Opinion 549-A*,[160] a 159-page decision addressing arguments raised on rehearing requested of *Opinion 549.*[161] *Opinion 549-A* modifies the discussion in *Opinion 549*, but reaches the same the result (ultimately requiring BP to pay a ***$20.16 million civil penalty (roughly $24.4 million with accrued interest) and disgorge $207,169***). Of note, *Opinion 549-A* denied BP's motion to dismiss this enforcement action as time barred (by the five-year statute of limitations set forth in 28 U.S.C. § 2462), finding BP waived any statute of limitations defense by failing to raise it earlier in this proceeding.[162] Opinion 549-A revised Ordering Paragraph (C) to direct the disgorged profits to non-profits that disburse the Low Income Home Energy Assistance Program of Texas funds, rather than to the Texas Department of Housing.[163]

On December 29, 2020, BP filed a notice that it intends to appeal *Opinion 549-A* to the Fifth Circuit Court of Appeals and paid the civil penalty amount on December 28, 2020, under protest and with full reservation of

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

[157] *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").

[158] 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.

[159] *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.

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

[161] *BP America Inc.*, Opinion No. 549, 156 FERC ¶ 61,031 (July 11, 2016) ("*BP Penalties Order*") (affirming Judge Cintron's Aug. 13, 2015 Initial Decision finding that BP America Inc., BP Corporation North America Inc., BP America Production Company, and BP Energy Company (collectively, "BP") violated Section 1c.1 of the FERC's regulations ("Anti-Manipulation Rule") and NGA Section 4A (*BP America Inc.et al,* 152 FERC ¶ 63,016 (Aug. 13, 2015) ("*BP Initial Decision*")).

[162] *BP Penalties Allegheny Order* at P 1.

[163] *Id*. at P 319.

rights pending the outcome of judicial review of that Opinion. On January 19, BP filed a notice that it disgorged $250,295 ($207,169 principal plus interest), divided equally ($83,431.67) among the following 3 entities identified in the "2016 Comprehensive Energy Assistance Program Subrecipient List": Dallas County Dept. of Health and Human Services (serving Dallas); El Paso Community Action, Project Bravo (Serving El Paso); and Panhandle Community Services (serving Armstrong and numerous other counties), again under protest and with full reservation of rights pending the outcome of judicial review of *Opinion 549/549-A*.

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

On April 28, 2016, the FERC issued a show cause order[164] 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.[165]

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

Hearing Procedures. On July 15, 2021, the FERC issued and order establishing hearing procedures to determine whether Respondents violated the FERC's Anti-Manipulation Rule, and to ascertain certain facts relevant for any application of the FERC's Penalty Guidelines.[166] On July 27, Chief Judge Cintron designated Judge Suzanne Krolikowski as the Presiding ALJ and established an extended Track III Schedule[167] for the proceeding. Judge Krolikowski scheduled and convened on August 26, 2021 a prehearing conference. Judge Krolikowski issued an order confirming her rulings from the August 26 prehearing conference and establishing a procedural schedule that calls for, among other dates, pre-hearing briefs by July 25, 2022, hearings (estimated to take 2-3 weeks) to begin on August 15, 2022, and an initial decision on January 9, 2023. In light of the settlement judge procedures undertaken, Chief Judge Cintron extended the hearing commencement and initial decision deadlines to September 26, 2022, and February 20, 2023, respectively.

Respondents requested reconsideration or in the alternative permission to file an interlocutory appeal of Judge Krolikowski's March 24 order confirming his bench rulings ("Reconsideration Motion"). OE Staff opposed the Motion. On April 25, finding Respondents had not raised any new arguments that would merit reconsideration of his prior rulings, nor had Respondents identified any "exceptional circumstances" requiring

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

[165] 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.

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

[167] The hearing in this proceeding will be convened within 55 weeks (Aug. 15, 2022) and the initial decision issued within 76 weeks (January 9, 2023) of the issuance of the Chief Judge's order.

interlocutory appeal, Judge Krolikowski denied Respondents' Reconsideration Motion. Respondents May 2, 2022 interlocutory appeal was denied on May 9, 2022.[168]

Since the last Report, highlights from the procedural activity in this proceeding have included the submission of revised testimony and exhibits, Enforcement's opposition to Respondents' motion to dismiss or stay the proceedings, and the Chief Judge's denial of a motion for appointment of special discovery judge. Commencement of the hearing and the date for the issuance of an initial decision remain November 15, 2022 and April 27, 2023, respectively.

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.[169] The certificate was conditioned on: (i) Iroquois' completion of construction of the proposed facilities and making them available for service within ***three years*** of the date of the; (ii) Iroquois' compliance with all applicable FERC regulations under the NGA; (iii) Iroquois' compliance with the environmental conditions listed in the appendix to the order; and (iv) Iroquois' filing written statements affirming that it has executed firm service agreements for volumes and service terms equivalent to those in its precedent agreements, prior to commencing construction. The March 25, 2022 order also approved, as modified, Iroquois' proposed incremental recourse rate and incremental fuel retention percentages as the initial rates for transportation on the Enhancement by Compression Project.
  - On April 18, 2022, Iroquois accepted the certificate issued in the *Iroquois Certificate Order*.
  - On June 17, 2022, in accordance with the *Iroquois Certificate Order,* Iroquois submitted its Implementation Plan, documenting how it will comply with the FERC's Certificate conditions.
  - The Project is targeted for a 4th quarter, 2023 in-service date.

Non-New England Pipeline Proceedings

The following pipeline projects could affect ongoing pipeline proceedings in New England and elsewhere:

- **Northern Access Project (CP15-115)**
  - The New York State Department of Environmental Conservation ("NY DEC") and the Sierra Club requested rehearing of the *Northern Access Certificate Rehearing Order* on August 14 and September 5, 2018, respectively. On August 29, National Fuel Gas Supply Corporation and Empire Pipeline ("Applicants") answered the NY DEC's August 14 rehearing request and request for stay. On April 2,

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[168] Notice of Determination by the Chairman, *Total Gas & Power North America, Inc. et al.*, Docket No. IN12-17 (May 9, 2022).

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

2019, the FERC denied the NY DEC and Sierra Club requests for rehearing.[170] Those orders have been challenged on appeal to the US Court of Appeals for the Second Circuit (19-1610).

- As previously reported, the August 6, 2018 *Northern Access Certificate Rehearing Order* dismissed or denied the requests for rehearing of the *Northern Access Certificate Order*.[171] Further, in an interesting twist, the FERC found that a December 5, 2017 "Renewed Motion for Expedited Action" filed by National Fuel Gas Supply Corporation and Empire Pipeline, Inc. (the "Companies"), in which the Companies asserted a separate basis for their claim that the NY DEC waived its authority under section 401 of the Clean Water Act ("CWA") to issue or deny a water quality certification for the Northern Access Project, served as a motion requesting a waiver determination by the FERC,[172] and proceeded to find that the NY DEC was obligated to act on the application within one year, failed to do so, and so waived its authority under section 401 of the CWA.
- The FERC authorized the Companies to construct and operate pipeline, compression, and ancillary facilities in McKean County, Pennsylvania, and Allegany, Cattaraugus, Erie, and Niagara Counties, New York ("Northern Access Project") in an order issued February 3, 2017.[173] The Allegheny Defense Project and Sierra Club (collectively, "Allegheny") requested rehearing of the *Northern Access Certificate Order*.
- Despite the FERC's *Northern Access Certificate Order*, the project remained halted pending the outcome of National Fuel's fight with the NY DEC's April denial of a Clean Water Act permit. NY DEC found National Fuel's application for a water quality certification under Section 401 of the Clean Water Act, as well as for stream and wetlands disturbance permits, failed to comply with water regulations aimed at protecting wetlands and wildlife and that the pipeline failed to explore construction alternatives. National Fuel appealed the NY DEC's decision to the 2nd Circuit on the grounds that the denial was improper.[174] On February 2, 2019, the 2nd Circuit vacated the decision of the NY DEC and remanded the case with instructions for the NY DEC to more clearly articulate its basis for the denial and how that basis is connected to information in the existing administrative record. The matter is again before the NY DEC.
- On November 26, 2018, the Applicants filed a request at FERC for a 3-year extension of time, until February 3, 2022, to complete construction and to place the certificated facilities into service. The Applicants cited the fact that they "do not anticipate commencement of Project construction until early 2021 due to New York's continued legal actions and to time lines required for procurement of necessary pipe and compressor facility materials." The extension request was granted on January 31, 2019.
- On August 8, 2019, the NY DEC again denied Applicants request for a Water Quality Certification, and as directed by the Second Circuit,[175] provided a "more clearly articulate[d] basis for denial."
- On August 27, 2019, Applicants requested an additional order finding on additional grounds that the NY DEC waived its authority over the Northern Access 2016 Project under Section 401 of the CWA,

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[170] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 167 FERC ¶ 61,007 (Apr. 2, 2019).

[171] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 164 FERC ¶ 61,084 (Aug. 6, 2018) ("*Northern Access Rehearing & Waiver Determination Order*"), *reh'g denied*, 167 FERC ¶ 61,007 (Apr. 2, 2019).

[172] The DC Circuit has indicated that project applicants who believe that a state certifying agency has waived its authority under CWA section 401 to act on an application for a water quality certification must present evidence of waiver to the FERC. *Millennium Pipeline Co., L.L.C. v. Seggos*, 860 F.3d 696, 701 (D.C. Cir. 2017).

[173] *Nat'l Fuel Gas Supply Corp.*, 158 FERC ¶ 61,145 (2017) ("*Northern Access Certificate Order*"), *reh'g denied*, 164 FERC ¶ 61,084 (Aug 6, 2018) ("*Northern Access Certificate Rehearing Order*").

[174] *Nat'l Fuel Gas Supply Corp. v. NYSDEC et al*. (2d Cir., Case No. 17-1164).

[175] Summary Order, *Nat'l Fuel Gas Supply Corp. v. N.Y. State Dep't of Envtl. Conservation*, Case 17-1164 (2d. Cir., issued Feb. 5, 2019).

even if the NY DEC and Sierra Club prevail in their currently pending court petitions challenging the basis for the Commission's Waiver Order.[176]

- On October 16, 2020, Applicants requested, due to ongoing legal and regulatory delays, an additional 2-year extension of time, until December 1, 2024, to complete construction of the Project and enter service. More than 50 sets of comments on the requested extension were filed and on December1, 2020, the FERC dismissed, without prejudice, Applicants' request for an extension of time, [177] finding the request premature. The FERC reiterated its encouragement that pipeline applicants requesting extensions "file their requests no more than 120 days before the deadline to complete construction", so that the FERC has the relevant information available to determine whether good cause exists to grant an extension of time and whether the FERC's prior findings remain valid.[178]
- On January 28, 2022, Applicants again requested an additional extension of time, this time until December 31, 2024, to complete construction of the Project and enter service. Comments on that request were due on or before February 16, 2022. Many individual comments and protests were received.
- On June 29, 2022, the FERC granted Applicants' request for an additional extension of time. Applicants now have until December 31, 2024 to construct and place the Project into service.[179] A request for rehearing of the *Northern Access Project Add'l Extension Order* has been filed and is pending before the FERC.

XV. State Proceedings & Federal Legislative Proceedings

- **New England States' Vision Statement**

In October 2020, the six New England states released their "Vision Statement", outlining their vision for "a clean, affordable, and reliable 21st century regional electric grid" and committing to engage in a collaborative and open process, supported by NESCOE, intended to advance the principles discussed in the Vision Statement. As part of that effort, the following series of online technical forums to discuss the issues presented in the Vision Statement were held:

Jan 13, 2021	Wholesale Market Reform
Jan 25, 2021	Wholesale Market Reform
Feb 2, 2021	Transmission Planning
Feb 25, 2021	Governance Reform
Mar 18, 2021	Equity and Environmental Justice

Written comments on the topics and discussions addressed in the on the equity and environmental justice topics and discussions were, following an extension, due by May 13, 2021. Comments submitted are posted on **NewEnglandEnergyVision.com**. Recordings of the technical forums, as well as draft notices, agendas, and additional information on these sessions, are also available on the New England States' Vision Statement website (https://newenglandenergyvision.com/).

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[176] *See Sierra Club v. FERC*, No. 19-01618 (2d Cir. filed May 30, 2019); *NYSDEC v. FERC*, No. 19-1610 (2d. Cir., filed May 28, 2019) (consolidated).

[177] *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 173 FERC ¶ 61,197 (Dec. 1, 2020).

[178] *Id.* at P 10.

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

Report to the Governors. On June 29, 2021, the NESCOE Managers published their Progress Report to the New England Governors Regarding "Advancing the New England Energy Vision". The Report was further discussed at the August 5, 2021 Participants Committee meeting. View Report here.

ISO-NE Board Response. On September 23, 2021, the ISO-NE Board responded to the New England States' Vision Statement and Advancing the Vision Report. A copy of that response was included with the materials for the October 7, 2021 Participants Committee meeting and is posted on the ISO-NE website here.

XVI. Federal Courts

The following are matters of interest, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the federal courts (unless otherwise noted, the cases are before the U.S. Court of Appeals for the District of Columbia Circuit ("DC Circuit")). An "**" following the Case No. indicates that NEPOOL has intervened or is a litigant in the appeal. The remaining matters are appeals as to which NEPOOL has no organizational interest but that may be of interest to Participants. For further information on any of these proceedings, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***2nd Revised Narragansett LSA Orders* (22-1161, 22-1108) (consolidated)**
  Underlying FERC *Proceeding*: ER22-707[180]
  Petitioner: Green Development
  Status: Initial Submissions Submitted and Additional Initial Submissions Scheduled

On June 15, 2022, Green Development petitioned the DC Circuit for review of the FERC's *2nd Revised Narragansett LSA Orders*.[181] On June 17, 2022, the Court directed Green Development to file, and Green Development filed, a Docketing Statement, Statement of Issues, any Procedural Motions, and the underlying decisions from which the appeal arises. The FERC filed the Certified Index to the Record on July 28, 2022.

Since the last Report, Green Development petitioned the DC Circuit for review of the *2nd Rev Narragansett LSA Allegheny Order*[182] (docketed as case 22-1161). The Court, on its own motion, consolidated the new case with case 22-1108 and directed Green Development to file by August 15, 2022, for its appeal in 22-1161, a Docketing Statement Form and a Statement of Issues to be Raised.

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[180] *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*".

[181] The 2nd Revised Narragansett LSA is a Local Service Agreement ("LSA") among New England Power, Narragansett and ISO-NE. The LSA reflects the construction of the new Iron Mine Hill Road Substation and related transmission modifications, and the assessment to Narragansett of a Direct Assignment Facilities Charge ("DAF Charge") associated with the facilities. The Iron Mine Hill Road Substation, a new 115 kV/34.5 kV substation (including modifications necessary to loop Narragansett's existing 115 kV H17 transmission line through the new substation) will connect to a new 34.5 kV distribution feeder, which will serve as the point of interconnection for several distributed generation projects being developed by Green Development, LLC ("Green Development"), located in North Smithfield, Rhode Island.

[182] *ISO New England Inc. and New England Power Co. d/b/a National Grid*, 179 FERC ¶ 61,186 (June 16, 2022) ("*2nd Rev Narragansett LSA Allegheny Order*")

- **Mystic ROE (21-1198; 21-1222, 21-1223, 21-1224, 22-1001, 22-1008, 22-1026) (consolidated)**
  Underlying FERC Proceeding: EL18-1639-010, -011,[183] -013[184]
  Petitioners: Mystic, CT Parties,[185] MA AG, ENECOS
  Status: Being Held in Abeyance (until 30 days after DC Circuit disposition of *MISO Transmission Owners v. FERC*, No. 16-1325)

As previously reported, 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.

Since the last Report, on July 8, 2022, Connecticut Parties and ENECOS jointly moved to hold these proceedings in abeyance until 30 days after the DC Circuit issues an opinion in *MISO Transmission Owners v. FERC*, 16-1325 ("*MISO TOs"*) (*see* below). 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*). Constellation opposed the abeyance request. On July 27, 2022, the Court granted the abeyance request, directing the Parties to file motions to govern future proceedings within 30 days of the court's disposition of MISO TOs.

- **Mystic 8/9 Cost of Service Agreement (20-1343; 20-1361, 20-1362; 20-1365, 20-1368; 21-1067; 21-1070)(consolidated)**
  Underlying FERC Proceeding: EL18-1639[186]
  Petitioners: Mystic (20-1343), NESCOE (20-1361, 21-1067), MA AG (20-1362), CT Parties (20-1365, 20-1368, 21-1070)
  Status: Oral Argument Held May 5, 2022; Awaiting Decision

Mystic, NESCOE, MA AG, and CT Parties have separately petitioned the DC Circuit Court of Appeals for review of the FERC's orders addressing the COS Agreement among Mystic, Constellation and ISO-NE.[187] The cases have been consolidated into Case No. 20-1343. On February 17 and 24, 2021, the Court consolidated with 20-1343 the most recent appeals in cases 21-1067 (NESCOE) and 21-1070 (CT Parties), respectively. On March 25, 2021, the Court issued an order returning this case to its active docket. On March 26, 2021, the Court granted the interventions by MMWEC/NHEC, NESCOE, and ENECOS. Briefing was completed on February 24, 2022. Oral argument was held on May 5, 2022 before Judges Srinivasan, Henderson and Rao.

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[183] *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).

[184] *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).

[185] In this appeal, "CT Parties" are the Connecticut Public Utilities Regulatory Authority ("CT PURA"), Connecticut Department of Energy and Environmental Protection ("CT DEEP"), and the Connecticut Office of Consumer Counsel ("CT OCC").

[186] *July 2018 Order*; *July 2018 Rehearing Order*; *Dec 2018 Order*; *Dec 2018 Rehearing Order; Jul 17 Compliance Order*.

[187] The COS Agreement is to provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024.

Since oral argument, on a related jurisdictional matter, the FERC moved for leave to issue its *May 2, 2022 Order* (described in Section II, ER22-1192 above). The FPA otherwise prevents the FERC, while an appeal is pending, from altering its findings or orders. In the *May 2, 2022 Order*, the FERC agreed with Mystic that, in light of changed circumstances (the spin transaction pursuant to which Exelon Corporation is no longer a Mystic Affiliate), it would be inappropriate to continue basing Mystic's capital structure on that of Exelon and set that part of the filing for hearing.[188] Accordingly, to the extent the *May 2, 2022 Order* constitutes a modification or vacatur of the capital structure ruling in the initial orders in this proceeding, the FERC sought leave to nonetheless issue the order. The FERC's motion was granted on June 10, 2022. This case remains pending before Judges Srinivasan, Henderson and Rao.

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  Underlying FERC Proceeding: ER18-619[189]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF
  Status: Being Held in Abeyance (until March 1, 2024)

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

Petitioners have moved to hold this matter in abeyance three times. The Court has granted each request. The most recent request was submitted on July 22, 2022 (third abeyance request) and moved the Court 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. The Court granted the third abeyance request on July 25, 2022.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[190]
  Petitioners: TOs' (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[191] 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*[192] 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

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[188] *See Constellation Mystic Power, LLC*, 179 FERC ¶ 61,081, PP 24-25 (May 2, 2022).

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

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

[191] 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.

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

pending further order of the court. On April 21, 2021, the FERC filed an unopposed motion for continued abeyance of this case *because* the Commission intends to issue a future order on Petitioners' request for rehearing of the challenged Order Rejecting Compliance Filing, and because the remand proceeding in which the challenged order was issued remains ongoing.

On May 4, 2021, the Court ordered that this case remain in abeyance pending further order of the Court, directing the FERC to file a status report by September 1, 2021 and at 120-day intervals thereafter. The parties were directed to file motions to govern future proceedings in this case within 30 days of the completion of agency proceedings. The FERC's last status report, indicating that the proceedings before the Commission remain ongoing and that this appeal should continue to remain in abeyance, was filed on April 14, 2022. The next status report is due on or before August 12, 2022.

- **ISO-NE's Inventoried Energy Program ("IEP") Proposal (19-1224***; 19-1247; 19-1252; 19-1253)(consolidated); Underlying FERC Proceeding: ER19-1428**[193]
  Petitioners: ENECOS (Belmont et al.) (19-1224); MA AG (19-1247); NH PUC/NH OCA (19-1252); Sierra Club/UCS (19-1253)
  Status: Court Issues Decision Leaving Intact the IEP Except for the Inclusion of Nuclear, Biomass, Coal and Hydroelectric Generators.

On June 17, 2022, the DC Circuit issued a decision[194] leaving intact the FERC's June 2020 *IEP Remand Order*[195] ***except*** for the inclusion of nuclear, biomass, coal, and hydroelectric generators in ISO-NE's IEP, the inclusion of which the Court found arbitrary and capricious (because those resources were unlikely to change their behavior in response to the IEP payments). Because the Court believed "there is not substantial doubt that FERC would have adopted IEP if it had not included these resources in the first place [and] IEP can function sensibly without them", the Court found that it had the authority to sever this portion from the overall program and therefore vacated that portion of IEP from the remainder of the IEP. The Court upheld the remainder of the IEP and remanded the matter to the FERC for further proceedings consistent with its opinion.

Other Federal Court Activity of Interest

- ***Order 872*** **(20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[196]
  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*.[197] Briefing is complete and oral argument was held March 8, 2022 before Judges Nguyen, Miller and Bumatay. This matter is pending before the Court.

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[193] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

[194] *Belmont Mun. Light Dept., et al., v. FERC*, 2022 WL 2182810 (June 17, 2022).

[195] *ISO New England Inc.*, 171 FERC ¶ 61,235 (June 18, 2020) ("*IEP Remand Order*").

[196] *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).

[197] *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.

- **Opinion 569/569-A: FERC's Base ROE Methodology (16-1325, 20-1182, 20-1240, 20-1241, 20-1248, 20-1251, 20-1267, 20-1513) (consol.)**
  Underlying FERC Proceeding: EL14-12; EL15-45[198]
  Petitioners: MISO TOs, Transource Energy, Dec 23 Petitioners et al.
  Status: Oral Argument Held Nov 18, 2021; Awaiting Decision

The MISO TOs, Transource and "Dec 23 Petitioners",[199] among others, have appealed *Opinion 569/569-A*. The MISO TOs' case has been consolidated with previous appeals that had been held in abeyance, with the lead case number assigned as 16-1325. Following completion of briefing, oral argument was held on November 18, 2021 before Judges Srinivasan, Katsas and Walker. This matter is pending before the Court.

- **Algonquin Atlantic Bridge Project Briefing Order (21-1115*, 21-1138, 21-1153, 21-1155, 22-1146, 22-1147) (consol.)**
  Underlying FERC Proceeding: CP16-9-012[200]
  Petitioners: LS Power, Algonquin, INGA
  Status: First Circuit Cases transferred to DC Circuit and consolidated here (22-1146/47); Parties Propose to Sever 22-1146/47 and Hold Remaining Cases in Abeyance Pending Disposition of 22-1146/47

On May 3, 2021, Algonquin petitioned the DC Circuit Court of Appeals 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, 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, the parties filed a proposal that cases 22-1146 and 22-1147 be severed, proposed a revised briefing format and schedule for those cases, and asked the Court to continue to hold the remaining cases in abeyance (asserting that abeyance may avoid the need for briefing and adjudication of the issues that Algonquin and INGAA would press). The Court has not yet rules on the parties' motion.

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[198] *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).

[199] "Dec 23 Petitioners" are: Assoc. of Bus. Advocating Tariff Equity; Coalition of MISO Transmission Customers: IL Industrial Energy Consumers; IN Industrial Energy Consumers, Inc.; MN Large Industrial Group; WI Industrial Energy Group; AMP; Cooperative Energy; Hoosier Energy Rural Elec. Coop.; MS Public Service Comm.; MO Pub. Srvc. Comm.; MO Joint Mun. Electric Utility Comm.; Org. of MISO States, Inc.; Southwestern Elec. Coop., Inc.; and Wabash Valley Power Assoc.

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

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