NEPOOL
NEW ENGLAND POWER POOL

David T. Doot
Secretary

August 25, 2022

VIA ELECTRONIC MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of September 1, 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 September meeting of the Participants Committee will be held **via teleconference on *Thursday*, September 1, 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 September 1 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.

The September meeting, originally scheduled for September 8, was re-scheduled to September 1 so as not to conflict with the FERC's New England Winter Gas-Electric Forum on September 8 in Burlington, VT. If you wish to attend that Forum in person, you must register. Electronic registration with the FERC can be accessed here. Alternatively, you can watch via a free webcast.

Looking ahead, please mark your calendars for the remaining Participants Committee meetings this year. October's meeting is on Thursday, October 6, and November's meeting, which includes modified Sector meetings with the ISO Board and regulators, is on ***Wednesday***, November 2. Both of those meetings are planned to be held in person in Providence, RI at the Renaissance Providence Downtown Hotel, 5 Avenue of the Arts, Providence, RI, 02903-1103. The December meeting is the Participants Committee annual meeting and will be at the Colonnade Hotel, 120 Huntington Ave, Boston, MA 02116. If you are interested in taking advantage of the advanced arrangements to stay at these venues the night before the meetings, we urge you to let Pat Gerity (pmgerity@daypitney.com) know soon, since room availability will be limited.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the draft minutes of the August 4, 2022 Participants Committee meeting. The draft preliminary minutes of that meeting, marked to show changes from the draft circulated with the initial notice, are included with this supplemental notice and posted with the meeting materials.

2. To adopt and approve the actions recommended by the 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. As discussed at the August meeting, the September CEO report will include a discussion of the comments the CEO plans to make at the FERC's September 8 New England Winter Gas-Electric Forum in Burlington, VT. A report will be circulated and posted in advance of the meeting.

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

5. To consider and take action, as appropriate, on NESCOE's fourth 5-Year *pro forma* budget. Background materials and a draft resolution are included and posted with this supplemental notice.

6. To receive a report on the following proposed budgets:

   a. 2023 ISO-NE Operating and Capital Budgets; and

   b. 2023 NESCOE Budget.

   Background materials are included and posted with this supplemental notice.

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

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

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

9. Administrative matters.

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

PRELIMINARY

Pursuant to notice duly given, a teleconference meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Thursday, August 4, 2022. 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. David Doot, Secretary, recorded.

APPROVAL OF APRIL 26, MAY 5, AND JUNE 21-23, 2022 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the April 26, May 5, and June 21-23, 2022 meetings, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of those meetings were unanimously approved as circulated, with an abstention by Mr. Sam Mintz.

CONSENT AGENDA

Mr. Cavanaugh referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved as circulated, with abstentions by BP Energy*, Cross-Sound Cable*, DTE*, EDF, Galt Power*, Harvard*, Icetec Energy Services*, the Maine Office of the Public Advocate, Maple Energy*, Mercuria*, Mr. Mintz, NRDC, PowerOptions*, and VEIC*. Of those abstaining, those identified with an asterisk indicated that their abstention related to concerns with the proposed modifications to the Forward Capacity Market (FCM) parameters recalculation schedule identified in Consent Agenda Item No. 3.

ISO CEO REPORT

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 June 21-23, 2022 Participants Committee Summer Meeting, which had been circulated and posted in advance of the meeting. In response to questions and comments regarding the resolution passed by the Board to document the Board's continuing commitment to review the cost impacts of significant ISO proposals, Mr. van Welie provided additional context, including the relationship of the resolution to the States' recent Vision Statement and the four pillars identified by the ISO as necessary to support a successful clean energy transition. He clarified that the resolution did not signal a change in the ISO's approach to markets, but rather reinforced publicly the fact that consumer costs are considered in the ISO's balancing of social welfare and markets utilization in reliably operating the system. He noted the importance of achieving stakeholder and federal and state regulatory support for any path forward, particularly with respect to ensuring resources to manage through extended periods of severe weather or energy supply constraints.

In response to these observations, some members noted concerns with how the challenges that continue to face the region were being communicated, urged holistic consideration of all market issues and opportunities, and looked forward to in-depth conversations to address the structural, cost and market issues moving forward. Ms. Heather Hunt, NESCOE Executive Director, noted the States' appreciation for the visibility that the Board's resolution offered for consumer cost considerations, emphasized the States' common interest in ensuring revenue sufficiency for resources needed for reliability, and exploring all possible avenues to shore up reliability for winter periods.

Mr. van Welie also referred to two documents that had been received recently by the ISO – a copy of letter from the six New England State governors to the U.S. Department of Energy

(DOE) Secretary, Jennifer Granholm, expressing concerns about Winter 2022-23 and requesting assistance to mitigate those concerns (DOE Letter), and a memo to the ISO from NESCOE thanking the ISO for its Winter 2022-23 analysis and recommendation and expressing continuing concerns with unresolved structural issues contributing to winter reliability challenges (NESCOE Memo). Both documents had been posted and circulated.[**] Addressing the NESCOE Memo, Ms. Hunt highlighted NESCOE's request that the ISO share with the FERC the confidential data underpinning its Winter assessment prior to the September 8, 2022 New England Gas-Electric Forum and reiterated NESCOE's thanks to the ISO and appreciation for its analysis and recommendation.

ISO COO REPORT

Operations Highlights Report

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by referring the Committee to the August COO report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through July 27, 2022, unless otherwise noted. The report highlighted: (i) Energy Market value for July 2022 was \$1.1 billion, up \$380 million from June 2022 and up \$658 million from July 2021; (ii) July 2022 average natural gas prices were 4.1% lower than June average prices; (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for July (\$89.06/MWh) were 24% higher than June averages; (iv) average July 2022 natural gas prices and Real-Time Hub LMPs were up 117% and 149%, respectively, from July 2021 average prices; (v) average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 98.9% during July (up from the 97% reported for June), with the minimum value for April of 95% on July 14; and (vi) Daily Net

[**] The DOE Letter was circulated and posted in advance of the meeting; the NESCOE Memo was added to the posted composite materials during the meeting.

Commitment Period Compensation (NCPC) payments for July totaled $8 million, which were up $5.1 million from June 2022 and up $4.3 million from July 2021. July NCPC payments, which were 0.7% of total Energy Market value, were comprised of: (a) $7.3 million in first contingency payments (up $4.3 million from June 2022, and almost all of which was incurred over the July 19-24 heat wave); (b) $249,000 in second contingency payments (up $222,000 from June); and (c) $495,000 in distribution payments (compared to $0 in June).

Dr. Chadalavada reviewed developments following the ISO's identification of two errors in its calculation of the Installed Capacity Requirement (ICR)-related values for the 2022 Annual Reconfiguration Auctions (ARAs) (ARA3 for the 2022-23 Capacity Commitment Period (CCP) had been run in March; ARA1 for the 2024-25 CCP had been run in June). He said that the errors, discovered during the first week in July, 2022, had been reported to the FERC Office of Enforcement (OE) and discussed with the Reliability Committee. After assessing the actual and projected impacts, reviewing the options for addressing the errors, and considering stakeholder feedback, the ISO determined that the best course of action going forward was to run the remaining ARA (ARA2 for the 2023-24 Capacity Commitment Period) as scheduled in August with values that had been filed with and accepted by the FERC. He outlined the steps the ISO had taken and planned to take to minimize the possibility of similar errors in future ARA values.

Dr. Chadalavada then reported on a heat wave that had occurred from July 19 through July 24. He said that the system was operated reliably in accordance with all NERC and NPCC standards, with energy and reserve pricing reflecting tight system conditions on several days during the heat wave. ISO weather and load forecasts were accurate (less than 1° F weather forecast error and a 1.3% load forecast absolute percent error over all hours). He observed that, while the heat wave was the region's longest in several years, it was not extreme in a historical sense. The highest weighted-average temperature was 94° F and for the week high temperatures ranked 11th and 20th all-time for Boston and Hartford, respectively. He explained that relatively mild dew points, which exceeded 70° F only on one day (July 21), kept the heat index below 100° F throughout the heat wave. Noting the connection between dew point and demand for load, he explained that higher dew points would have resulted in load levels not seen in many years. He reported that peak load, including load served by settlement-only generation, was 24,609 MW, compared to the summer 2022 50/50 load forecast of 24,686 MW. Total energy demand over the heat wave was 2,691 gigawatt hours (GWh), an average of approximately 450 GWh/day. He summarized slides illustrating the contributions from behind-the-meter photovoltaic (BTM PV) resources and contributions from energy sources. He noted that there had been minimal injection of liquefied natural gas to the pipelines during the heat wave, but that six million gallons of fuel oil had been used, with replenishment underway.

In response to questions, Dr. Chadalavada explained that the Capacity Supply Obligation (CSO) numbers in the ISO's Morning Reports capture only generation CSOs, not Energy Efficiency and Demand Response, and are discounted by known forced outages, as compared to the CSO numbers identified in the Forward Capacity Auctions as refined by subsequent ARAs, which do not reflect those factors. He also confirmed that the outages during the heat wave were primarily mechanical (not planned), with a limited percentage of de-ratings due to ambient air capacity reductions for combined-cycle units. He further explained that those outages reduced Ten- and Thirty-Minute Operating Reserves, and thereby triggered redispatch of the system and caused LMP price spikes. LMPs spiked (with the addition of Reserve Constraint Penalty Factors), because system conditions were tight and many of the outages or ambient air reductions during the heat wave occurred during peak hours, cutting into or exceeding the minimum system surplus (approximately 200 MW) that the ISO was trying to maintain. He said that, because the ISO made supplemental commitments of resources located within New England to offset resources lost to mechanical failure, no capacity deficiency was actually experienced. He credited and thanked the operations team for all their efforts successfully juggling and navigating the circumstances presented during the heat wave. Mr. Cavanaugh asked that NEPOOL members' thanks and appreciation be extended to the operations team as well.

Addressing a question asked ahead of the meeting on the modeling of extreme conditions in its winter modeling/analysis, Dr. Chadalavada explained that the ISO planned to update its analysis closer to the winter period, when updated weather forecasts from the National Oceanic and Atmospheric Administration (expected in mid- to late-October) and fuel inventory information from asset owners would be available. He said that the update would be presented at the November Participants Committee meeting and would include baselines for mild, moderate and extreme weather conditions.

IMM 2021~~0~~ ANNUAL MARKETS REPORT

Mr. David Naughton, Director, ISO Market Monitoring, was introduced to present a summary of the Internal Market Monitor (IMM) 2021 Annual Markets Report (IMM 2021 Report). Before doing so, he took the opportunity to detail the functions performed by the IMM, which were to: (1) monitor, on a daily basis, New England Market performance, as well as Market Participant and ISO behavior; (2) review potential Market Rule violations and make referrals to the FERC's Office of Enforcement; (3) administer the market power mitigation rules for the Energy and Capacity Markets; (4) evaluate existing and proposed Market Rules and make recommendations on those rules; and (5) report on the performance of the New England Markets, with the aim to provide transparency and unique insights to stakeholders.

Referring to his presentation that was circulated in advance of the meeting, Mr. Naughton provided an overview of the New England Markets' performance. He showed that high energy prices, driven by high natural gas prices experienced in 2021, caused the Day-Ahead LMP to nearly double since 2020. Referring to a chart, Mr. Naughton highlighted the fluctuation of natural gas prices on a quarterly basis, showing increasingly high natural gas prices during the winters that were driving higher LMPs. He observed that average energy demand had rebounded from the record lows seen in 2020. Mr. Naughton also noted that the system did not experience a shortage event, reflecting a high Reserve surplus on the system.

Next, Mr. Naughton discussed the impact of the CO_2 cap and trade program on energy costs, which he characterized as small but increasing. He specifically noted the IMM's calculation of those costs for 2021 for a typical gas generator to be $4.36/MWh from the Regional Greenhouse Gas Initiative (RGGI), which he reported was about a 50 percent increase from prior RGGI costs, and an additional $3.25/MWh to comply with the Massachusetts Global Warming Solutions Act, which he reported as a five percent increase from prior levels.

Mr. Naughton then noted the large energy surplus on the system, with low reliability commitments in 2021, no posturing of thermal generation resources, and relatively low payments for NCPC. In response to a question regarding the energy opportunity costs adder that was implemented in 2018, he acknowledged that it could be meaningful for generators and may mitigate posturing for energy-limited resources. Mr. Naughton added that the IMM was not seeing many units using that added pricing flexibility. He also noted the impact on demand of energy efficiency and BTM PV resources, observing that energy efficiency contributed the most to reducing load and that the IMM expected net load to begin increasing in 2022.

Mr. Naughton then referred to a chart showing that Reserve Adequacy Analysis (RAA) commitments were falling, corresponding to the decreasing gap between Real-Time load forecast and Day-Ahead cleared physical supply. He clarified in response to a question that the data summarized did not include days when the Day-Ahead cleared physical supply exceeded the Real-Time load and reserve requirement and that the average of the energy gap would have been even lower if such data had been included.

Next, Mr. Naughton referred to a chart showing the IMM's calculations of generator profitability, showing that revenues for both combined cycle and combustion turbine generators fell short of their respective calculated cost of new entry. Consequently, he explained, wholesale markets were not providing enough revenues to make it profitable for a new gas-fired generator in the region.

In the final portion of his presentation, Mr. Naughton provided the IMM's analysis of the competitiveness of the Markets. He noted that Energy costs composed a large share of the wholesale energy costs due to higher natural gas prices and declining capacity costs. Mr. Naughton added a summary of mitigation measures taken in 2021, highlighting very low levels of offer mitigation in the Energy Market, with about three percent of total asset hours flagged for market power, of which only two percent were mitigated. Mr. Naughton also indicated that there were low levels of structural market power, with the exception in the Forward Reserve Market. Similarly, the IMM's analysis concluded that the Energy Market mitigation remained low, with most mitigation taking place at the local level.

Mr. Naughton opined that, in 2021, the FCM was structurally competitive at a system level, with market power mostly found at a zonal level. He added that the Resource Capacity Accreditation and Day-Ahead Ancillary Services improvement projects were important initiatives to enhance price formation and align compensation with a resource's contribution to system reliability. Mr. Naughton also looked forward to discussions regarding the "mothballing" stakeholder proposal. He then reviewed some IMM-recommended proposals that were closed out in 2021.

After concluding his presentation, Mr. Naughton was asked to provide his thoughts in a future report on the External Market Monitor's recommendation to shift the FCM from a forward market to a prompt market. Mr. Naughton stated that there were compelling reasons supporting the recommendation and that the IMM would consider the recommendation and offer input in the future.

LITIGATION REPORT

Mr. David Doot referred the Committee to the August 2 Litigation Report that had been circulated and posted before the meeting. He highlighted the following litigation-related developments included in the August 2 Report:

(i) the FERC's September 8 New England Winter Gas-Electric Forum to be held in Burlington, VT, encouraging all those interested in attending in person to register promptly;

(ii) the FERC's Show Cause Order regarding FTR collateral requirements (FTR Collateral Show Cause Order). Though the ISO's response was due October 26, interventions were due by August 18. The ISO's response would be discussed with the Budget & Finance Subcommittee (B&F), with the first opportunity for discussion on August 23;

(iii) pleadings in the Capacity Accreditation Complaint proceeding expressing a desire to resolve that proceeding so as to permit FERC staff to participate in upcoming regional discussions on capacity accreditation;

(iv) the FERC's order denying the Northern Maine Independent System Administrator's complaint against the Participating Transmission Owners Administrative Committee for failing to consider and implement a reciprocal discount to the Through and Out charges applied to transactions between the New England and Northern Maine regions;

(v) the FERC's order accepting the FCA16 results filing;

(vi) the Transmission Owners' annual transmission rate update/informational filing (2022 RNS Rate Filing), which would be reviewed with the Transmission Committee and would be reviewed in a technical session for all interested parties;

(vii) pleadings related to the ISO's response to the FERC's deficiency letter in New England's Order 2222 compliance proceeding;

(viii) the FERC's Notice of Proposed Rulemaking (NOPR) that would allow ISO/RTOs to share among themselves credit-related information regarding Market Participants. The NOPR was largely responsive to NEPOOL's comments submitted in an earlier, related administrative proceeding on this topic that requested that any Tariff changes be reviewed first through the NEPOOL Participant Processes. The NOPR would be considered by members of the Markets Committee and the B&F Subcommittee, with specific committee dates and assignments for that consideration to be determined and then communicated to members; and

(ix) the FERC's approval of a Stipulation and Consent Agreement with Salem Harbor Power Development LP (Salem Harbor) that resolved OE's investigation into Salem Harbor's receipt of capacity payments from the ISO for its new Salem Harbor Generating Station project during the 2017-18 Capacity Commitment Period, noting the investigation into the ISO's role in the matter was ongoing. Members, noting the ongoing constraints given the continuing proceedings, expressed concerns with the circumstances underlying the investigation and looked forward to an opportunity, when appropriate, to fully de-brief and consider lessons learned from this matter. Dr. Chadalavada expressed the ISO's support for those discussions, in person, at the appropriate time.

COMMITTEE REPORTS

Markets Committee (MC). Mr. William Fowler, the MC Vice-Chair, reported that the MC would meet in person on August 9-10 in Westborough. He highlighted that discussion on Capacity Accreditation was planned for the first day. He encouraged those who had not yet registered on-line but were planning to attend in person to do so as soon as possible.

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that the next RC meeting would take place as part of the August 16-17 Joint RC/TC Summer meeting in Stowe, Vermont. The RC would begin its work on the next load forecast cycle.

Transmission Committee (TC). Mr. José Rotger, the TC Vice-Chair, reported that the next TC meeting would also be part of the August 16-17 Joint RC/TC Summer meeting. He highlighted TC votes on proposed Tariff changes associated with the storage as a transmission-only asset (SATOA) project, as well as a review of the 2022 RNS Rate Filing just made by the Transmission Owners described earlier during the Litigation Report (which he noted would result in a decrease to the Regional Network Service (RNS) rate).

B&F Subcommittee. Mr. Thomas Kaslow, Subcommittee Chair, reported that B&F was scheduled to hold two meetings in August -- one on August 11 to discuss NESCOE's next 5-year *pro forma* budget, the 2023 ISO and NESCOE budgets, the ISO's 2022 second quarter capital projects filing, and other periodic financial reports, and one on August 23 to review a Participant-initiated proposal and, as noted earlier, to hear the ISO's preliminary thoughts on its response to the FTR Collateral Show Cause Order and potentially on the Credit Information Sharing NOPR.

Membership Subcommittee. Mr. Patrick Gerity, counsel to the Subcommittee, reported that the next Membership Subcommittee meeting was scheduled for August 15 and encouraged all those interested to join.

ADMINISTRATIVE MATTERS

Mr. Doot noted that the next Participants Committee, re-scheduled to September 1 so as not to conflict with the FERC's New England Winter Gas-Electric Forum on September 8, was likely to be held virtually, but if in person, would be in Boston. Looking ahead, he said that the October 6 and November 2 meetings were scheduled to be held in Providence and the December 1 Annual Meeting in Boston. He encouraged members with questions on the locations to reach out to Mr. Gerity and to follow the NEPOOL calendar to know where and when to be for Participants Committee meetings for the remainder of the year.

There being no further business, the meeting adjourned at 12:50 p.m.

Respectfully submitted,

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David Doot, Secretary

**PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN AUGUST 4, 2022 TELECONFERENCE MEETING**

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Advanced Energy Economy (AEE)	Associate Non-Voting	Caitlin Marquis		
Ampersand Energy Partners LLC	Supplier			Hannah Braun
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell		
Associated Industries of Massachusetts (AIM)	End User			Mary Smith
AVANGRID: CMP/UI	Transmission	Alan Trotta		Alexander Novicki
Avangrid Renewables	Transmission	Kevin Kilgallen		
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		
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Central Rivers Power	AR-RG		Dan Allegretti	
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
CleaResult Consulting, Inc.	AR-DG	Tamera Oldfield		
Clearway Power Marketing LLC	Supplier			Pete Fuller
Competitive Energy Services, LLC	Supplier		Eben Perkins	
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw		
Connecticut Office of Consumer Counsel	End User	Claire Coleman		JR Viglione; Victor Owusu-Nantwi
Conservation Law Foundation (CLF)	End User	Phelps Turner		
Consolidated Edison Energy, Inc.	Supplier	Grant Flagler		
Constellation Energy Generation	Supplier	Steve Kirk	Bill Fowler	
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
DC Energy, LLC	Supplier	Bruce Bleiweis		
Dominion Energy Generation Marketing, Inc.	Generation		Weezie Nuara	
DTE Energy Trading, Inc.	Supplier			José Rotger
Durgin and Crowell Lumber Co.	End User			Bill Short
Dynegy Marketing and Trade, LLC	Supplier			Bill Fowler
ECP Companies - Calpine Energy Services, Accelerate Renewables	Supplier	Brett Kruse Liz Delaney		Bill Fowler
Elektrisola, Inc.	End User			Bill Short
Emera Energy Services	Supplier			Bill Fowler
Environmental Defense Fund	End User	Jolette Westbrook		
Eversource Energy	Transmission	James Daly	Dave Burnham	Vandan Divatia
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger		
Garland Manufacturing Company	End User			Bill Short
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Granite Shore Power Companies	Generation			Bob Stein
Great River Hydro	AR-RG			Bill Fowler
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	Louis Guilbault	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	
Icetec Energy Services, Inc.	AR-LR	Doug Hurley		
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths	Nancy Chafetz	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN AUGUST 4, 2022 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
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	
Long Island Lighting Company (LIPA)	Supplier		Bill Kilgoar	
Maine Public Advocate’s Office	End User	Drew Landry		
Maple Energy LLC	AR-LR			Doug Hurley
Mass. Attorney General’s Office (MA AG)	End User	Tina Belew	Jamie Donovan	
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	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Mintz, Sam	End User	Sam Mintz		
Moore Company	End User			Bill Short
Narragansett Electric Co.	Transmission	Brian Thomson		
National Grid	Transmission		Tim Martin	
Natural Resources Defense Council (NRDC)	End User	Bruce Ho		
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski		Brian Forshaw
New Hampshire Office of Consumer Advocate	End User		Jason Frost	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson		
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	
PowerOptions, Inc.	End User			Jason Frost
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Saint Anselm College	End User			Bill Short
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Peter Fuller
SYSO LLC	AR-LR	Dan Curran		
Taunton Municipal Lighting Plant	Publicly Owned Entity	Devon Tremont	Dave Cavanaugh	
Tenaska Power Services Co.	Supplier		Eric Stallings	
The Energy Consortium	End User		Mary Smith	
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny		
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori	Karin Stamy	
Vermont Energy Investment Corp. (VEIC)	AR-LR		Doug Hurley	Jason Frost
Vermont Public Power Supply Authority	Publicly Owned			Brian Forshaw
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity		Dave Cavanaugh	
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	
Z-TECH, LLC	End User			Bill Short

CONSENT AGENDA

Reliability Committee (RC)

From the previously-circulated notice of actions of the RC at the August 16-17 Joint RC/TC Summer Meeting, 2022 meeting, dated August 17, 2022.[1]

1. **Changes to OP-14 Appendix B (Periodic Updates)**

   Support the revisions to Appendix B (Generator and Asset Related Demand Reactive Data Explanation of Terms and Instructions for Data Preparation for ISO Form NX-12D) to ISO New England Operating Procedure (OP) No. 14 (Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources), including changes to (i) clarify the responsibility for the provision of voltage schedules; and (ii) implement editorial clean-up changes, all as recommended by the RC at the August 16-17, 2022 Joint RC/TC Summer 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-17 and OP-17 Appendices B-C (Periodic Updates)**

   Support the revisions to OP-17 (Load Power Factor and System Assessment) and OP-17 Appendices B-C (Methodology for Developing Load Power Factor Limits; Instructions for the ISO Power Factor Survey), including changes to (i) clarify the term "Operating Issue"; (ii) update "TO/Transmission Customer" to "Transmission Load Customer (TLC)"; (iii) update the process for the handling of a non-compliance with the Load Power Factor Standard by issuing a letter to all FLC contacts within the LPF area that violated its standard(s); (iv) swap the content of Sections I.C.1 and I.C.2; and (v) make editorial changes, all as recommended by the RC at the August 16-17, 2022 Joint RC/TC Summer 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.

3. **OP-23 Appendix D Retirement**

   Support the retirement of Appendix D (Monthly Price Data Form for Settlement Only Generators (SOG)) to OP-23 (Resource Auditing), as recommended by the RC at the August 16-17, 2022 Joint RC/TC Summer 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.

[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.

Transmission Committee (TC)

From the previously-circulated notice of actions of the TC at the August 16-17 Joint RC/TC Summer Meeting, 2022 meeting, dated August 18, 2022.[2]

4. Changes to OATT Schedules 18 & 24 (Order 676-J Compliance)

Support the revisions to Schedules 18 (MTF; MTF Service) and 24 (Incorporation by Reference of NAESB Standards) of the ISO-NE England Open Access Transmission Tariff (OATT) to incorporate references to the Wholesale Electric Quadrant (WEQ) version 003.3 standards of North American Energy Standards Board (NAESB), as recommended by the RC at the August 16-17, 2022 Joint RC/TC Summer 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 August 9-10, 2022 meeting, dated August 10, 2022.[3]

5. Changes to Tariff §§ III.13.1.1, III.13.1.2, III.13.1.4, III.13.1.10 and III.13.8 (FCA18 Schedule Modifications)

Support the revisions to Market Rule 1 Sections III.13.1.1, III.13.1.2, III.13.1.4, III.13.1.10 and III.13.8 to modify the FCA18 schedule to maintain the FCA18 start date given the changes made to the schedule for FCA17, as recommended by the MC at its August 9-10, 2022 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.

6. Changes to Tariff §§ III.1.11.3 and III.1.11.5; Manual M-11 § 2.2.3.1(15)(b)(ii) (Incorporate Solar Into DNE Dispatch)

Support the revisions to Market Rule 1 Sections III.1.11.3 and III.1.11.5 and Section 2.2.3.1(15)(b)(ii) of Manual 11 () to extend Do-Not-Exceed (DNE) dispatch to front-of-meter solar Generation Assets that are not Settlement Only, as recommended by the MC at its August 9-10, 2022 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.

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

[3] 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

September 1, 2022 Participants Committee Meeting

Since the last update, the Markets Committee, the Audit and Finance Committee, and the Board of Directors each met on August 18. All of the meetings were held by videoconference.

The Markets Committee discussed management's responses to the recommendations included in the Market Monitors' annual reports. In addition, the Committee was provided with an overview of the market projects prioritization process, how it interacts with stakeholder and other external requests, and how the multi-year and annual work plans are developed and updated. In executive session, the Committee considered the appointment of an internal market monitor.

The Audit and Finance Committee received an update regarding the development of the 2023 operating and capital budgets, including a review of the capital structure, and an update on budget discussions with stakeholders. The Committee also received an update on the 2022 budget and approved the second quarter unaudited financial statements after management confirmed that all relevant disclosures from managers were included in the financial statements. Throughout the budget discussions, the Committee considered the impact of inflation, and the difficulty in hiring and retaining a qualified workforce. With reference to a report on New England wholesale electricity costs and retail electricity rates, the Committee also considered the impact of increasing costs on consumers. Next, the Committee conducted its annual review of the Company's liability insurance coverage, and reviewed a summary of external audit services proposals, after which it approved a three-year appointment of KPMG to conduct SSAE 18 engagements and annual audits of the Company's financial statements. The Committee also received an update on internal audit activities, as well as highlights of recent external audits. Finally, in regular session, the Committee received an overview of the funding status of the Company's benefit and post retirement plans. During executive session, the Committee met with the Company's internal auditors and then reviewed the results of its self-evaluation.

The Board of Directors met to discuss winter reliability topics, and reviewed an assessment from management with recommendations specific to winter 2022-2023. The Board discussed the operational analysis, including information that was obtained from recent fuel surveys and from discussions with resource owners about expected fuel inventories and replenishment strategies for facilities with stored fuel capabilities. The Board noted the criticality of the Everett

LNG terminal and Mystic in ensuring reliability for the upcoming winter, and also discussed scenario modeling that was completed in order to evaluate regional energy adequacy under various operating conditions and assumptions. Regarding the steps the Company has taken to enhance regional energy adequacy, the Board discussed the 21-day forecast and gas tools, as well as the markets improvements that will give generators more flexibility in making and reflecting fuel arrangements in the markets. Last, the Board agreed that members of the Board should meet with the Consumer Liaison Group Coordinating Committee. The Board went into executive session and considered the appointment of an internal market monitor, among other topics.

Gordon van Welie
President and Chief Executive Officer

August 29, 2022

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

Dear Secretary Granholm,

I write regarding the letter that you received from the six New England Governors dated July 27, and echo the importance of fuel supplies to the reliability of New England's electric grid during the winter season. I want to call your attention to both short-term and long-term efforts to address energy security concerns in the region.

As you know, the New England region is committed to aggressive action to mitigate the impact of the electric sector on climate change, as embodied in the decarbonization targets established by law in five of the six New England states. ISO New England is both supporting and enabling these actions by planning and executing changes to both the wholesale electricity markets and the transmission grid, in conjunction with the New England states and our stakeholders. The ISO has adopted a vision to harness the power of competition and advanced technologies to reliably plan and operate the grid as the region transitions to clean energy. We view the region's energy security needs in the context of making this transition to clean energy. Furthermore, we recognize that action on climate change is a top priority for the Biden Administration.

Even with the successful development of extensive offshore and onshore wind as well as solar generation in New England, the region will continue to be dependent on resources with the operating flexibility to balance and backstop this variable renewable generation to sustain reliability. Today, natural gas generation provides this flexibility and in the future, this could include non-carbon-emitting energy storage technologies. The region's expected dependence on natural gas in the near future is especially true since policymakers are looking for the electric grid to serve substantially higher demands given their priorities for electrification of transportation and heating in the region. Our expectation of this continuing challenge, beyond the specific issues for which we are preparing this winter, underlies the issues about which we are writing you.

During the coldest days of the year, New England does not have sufficient pipeline infrastructure to meet the region's demand for natural gas for both home heating and power generation. For years, the region has relied heavily on foreign liquefied natural gas (LNG) shipments into import facilities near Boston (Everett) and New Brunswick, Canada to ensure reliable grid operations when pipeline gas is not available in sufficient quantities to support the generation sector. The current uncertainty surrounding the global market for LNG has the potential to stress electric grid reliability this upcoming winter under certain weather scenarios; however, beyond this winter, the ability to import sufficient quantities of LNG will be essential for New England to meet its reliability, electrification, and clean energy goals for many years to come.

Preparation for September 8 Technical Conference

Earlier this year, the Federal Energy Regulatory Commission (FERC) announced that it will hold a winter gas-electric forum in New England on September 8 to "to achieve greater consensus or agreement among stakeholders in defining the electric and natural gas system challenges in New England and identify what, if any, steps are needed to better understand those challenges before identifying solutions." In preparation for that meeting, ISO New England, in collaboration with the regional utilities, has created (and attached for your information) a *Draft Problem Statement and Call for Action* that I hope will aid in reaching consensus on the problem so the region and its federal partners can focus on finding durable solutions.

The *Statement* highlights that New England can meet both its long-term reliability and public policy needs through a variety of investments in physical infrastructure. However, it has been difficult to site and permit various forms of energy infrastructure, and further, the region has been unable to develop sufficient consensus on whether to mitigate the risk of low probability extreme weather events, and the regulatory path to pay for solutions to cover this risk. In the near-term, the *Statement* emphasizes the critical importance of the Everett LNG facility to the reliability of the entire New England region – an importance that will remain after the existing agreement to maintain operations at the Mystic Generating Station ends in June 2024. In short, the ISO believes that continued operations at the Everett LNG facility are vital as the region continues to evolve towards a cleaner, more renewable energy focused electric grid. At the same time, the region also must expeditiously move forward with practical and feasible short-term actions while studying long-term solutions.

Actions to Support Reliability this Winter

The upcoming FERC forum focuses on electricity and natural gas challenges in New England. I would like to highlight several important actions the ISO has already taken over the past several years that aid New England significantly in preparation for this coming winter, given the region's circumstances.

First, the ISO secured FERC approval to retain a natural gas-fired generator with critical LNG import capability that bolsters the region's access to fuel when pipeline gas is constrained. Second, the ISO has developed a tool to forecast the risk of potential energy shortfalls in New England over a 21-day (three week) period. This tool is designed to provide clear signals to suppliers in the wholesale marketplace of the need to secure additional fuel supplies and provides up to a 21-day period to communicate with the public and seek conservation to mitigate the risk of an energy shortfall. Finally, the ISO is working closely with the region's transmission owners and electric distribution companies to coordinate the implementation of emergency actions, should the need arise, to minimize the potential impacts on electric consumers in the region. Based on these actions, and the results of our winter assessment to date, the ISO expects to be able to operate the system reliably in a mild to moderate winter (using established operational procedures to manage capacity deficiencies). However, concerns remain should the region experience an extreme winter, similar to the winter of 2013-14.

Over a Decade of Analysis and Efforts to Mitigate Energy Security Challenges
ISO New England has been active in expressing its concerns and taking action to mitigate the risks associated with the availability of sufficient quantities of fuel to serve the electric generation fleet during the winter. The ISO has published a detailed timeline for the diagnosis and analysis of the region's energy security challenges, as well as the numerous ways in which ISO New England and the region have sought to address these challenges[1]; however, I wanted to highlight a few examples of the ISO's efforts.

In 2012, FERC held a series of technical conferences (including a session in New England), in which ISO New England raised concerns and stressed the importance of enhanced coordination between the electric and natural gas industries. In 2013, the ISO designed and implemented (and FERC approved) a program to provide economic incentives for generators to physically store sufficient quantities of oil and subsequently, LNG and demand response resources during five consecutive winters. In 2014, the ISO filed substantial changes to its Forward Capacity Market with FERC (approved in May 2014) to provide stronger incentives—known as "Pay-for-Performance"— for resources to undertake investments that ensure they can perform during stressed system conditions. Also in 2014, the New England states formally requested that the ISO support a proposal to flow the "cost of firm natural gas pipeline capacity" through the ISO's tariff, recovering the cost of the additional pipeline capacity through Regional Network Service rates. This concept met significant resistance.

The ISO stressed the region's fuel security challenges in comments to DOE during the most recent *Quadrennial Energy Review* (QER) processes, and DOE highlighted the importance of natural gas to New England's electric grid in its 2015 and 2017 *QER*.

Over the last decade, we have taken steps to improve information sharing capabilities with natural gas pipeline operators and began publishing regular reports on fuel inventory. In 2018, the ISO published its *Operational Fuel Security Analysis (OFSA)*, which quantified the region's energy-security risk, specifically "the possibility that power plants won't have or be able to get the fuel they need" to meet demand and maintain reliability. Soon after the *OFSA* was published, the ISO filed at FERC (in response to FERC's January 2018 resilience order) detailing the scope and depth of the fuel-security challenge facing New England. The ISO specified that it "recognizes that fuel security is just one aspect of the bulk power system's resilience; however, it is the most significant challenge for the New England bulk power system's resilience, and it currently has no defined in-market long-term solution."

As I mentioned, in 2018, the ISO took action to postpone the retirement of the Mystic Generating Station (including the Everett LNG facility) outside of Boston, MA for two years to give New England time to implement transmission and market solutions. While the transmission solution is progressing, in October 2020 the FERC rejected the proposed market changes known as the Energy Security Initiative. In the meantime, the retention of the Mystic Generating Station/Everett LNG facility has turned out to be crucial to ensuring that the region has sufficient certainty on LNG supplies to cover the risks of moderate weather patterns in the coming winter.

[1] Timeline: Historical Efforts to Address Fuel Security Issues in New England, ISO New England; https://www.iso-ne.com/about/what-we-do/in-depth/efforts-to-address-fuel-security-in-new-england

ISO Urges Strong Consideration of the Initiatives Identified by the New England Governors
First, the ISO would like to lend its support to the states' call for the specific solutions to the region's fuel challenges as outlined in the July 27 letter from the New England Governors. In the absence of sufficient pipeline infrastructure, the ISO would welcome the ability for domestic natural gas to be brought to New England via tanker at the Everett facility.[2] As has been well documented, LNG – from any source – is of tremendous value to New England during the winter months.

We urge the Department of Energy to stand ready to support targeted requests for exemptions to the Jones Act to allow New England to access domestic LNG by tanker if emergency conditions develop this winter or in the future.

Second, the states raise the notion of a regional energy reserve for power generation, a valuable concept that the federal government already supports through the Northeast Home Heating Oil Reserve. The ISO would be pleased to explore and collaborate on further ideas for an energy reserve to support electricity production. We believe that such a concept will be critical to mitigating low probability extreme weather risks, correlated contingencies and supply chain risks.

We urge you to use the Department of Energy's convening authority and leadership to support the states' and the ISO's suggestion to develop an energy reserve in New England.

Moreover, we urge you to consider the consequence of these issues for New England as you administer the Department's authorities under the 2022 Inflation Reduction Act and the 2021 Bipartisan Infrastructure Framework. This could include identifying opportunities for investment in energy infrastructure in New England, identifying congested transmission corridors, supporting research into low-carbon balancing fuels such as hydrogen, and continuing to support the importance of electric-system reliability to ensure the success of the clean energy transition.

On the states' final point, the ISO enthusiastically supports collaboration between the states, the federal government, regional stakeholders, and ISO New England on electric reliability during the winter as well as the region's clean energy transition more broadly. Finally, I would like to emphasize, that while the industry has traditionally viewed the gas and electric systems as separate, with separate regulatory processes, it has become clear that we should view them holistically as one inter-dependent regional energy system, particularly in the context of the transition to clean energy that seeks to lower carbon emissions in the entire system.

[2] The ISO appreciates that the U.S. Department of Energy is not the federal agency ultimately charged with approving or denying requested waivers to the Jones Act, and that ISO New England would not be the direct applicant of a waiver request. Nevertheless, the ISO will continue to work with the states, resource owners and appropriate federal agencies on the feasibility of a Jones Act waiver should the need arise.

I hope you find the attached *Statement* informative. I know that the U.S. Department of Energy, the New England states, and ISO New England have been in close communications on reliability issues, and will continue to be moving forward. However, I would be pleased to speak with you about any of the issues affecting bulk power system reliability in New England, either prior to or following the September 8 technical conference.

Sincerely,

Gordon van Welie
President & Chief Executive Officer

CC: The New England Governors
FERC Commissioners
New England Congressional Delegation

Draft ISO/EDC/LDC Problem Statement and Call to Action on LNG and Energy Adequacy
Federal Energy Regulatory Commission New England Winter Gas-Electric Forum, September 8, 2022

ISO New England and the New England gas and electric distribution companies agree that, as the region transitions to a clean energy future, there is a need to develop and execute a plan to reduce dependence on ***imported*** LNG. This plan could include accelerated development of clean energy resources, additional transmission to access electrical energy, increased in-region liquefaction and dual-fuel resources, long duration storage, and green fuels.

In the meantime, the region needs to secure and stabilize the imported LNG supply chain to supply customers of natural gas. Most immediately, ***the region must ensure the continued operation of the Everett LNG Facility to maintain reliable electric and natural gas service for New England consumers.*** The need for the Everett LNG Facility will extend for a finite period beyond June 2024, when ISO New England's retention of the related Mystic Generating Station expires, and until the required infrastructure investments are made to reliably enable the envisioned clean energy future.

Everett Facilitates the Initial Stage of the Clean Energy Transition

Ultimately, renewable resources will provide electricity to meet both current needs and additional future demand related to home heating and transportation. The region will also develop the clean, long duration resources needed to balance renewables' variable production characteristics.

Until that time, however, the region will depend on gas to ensure the reliable provision of heat and electricity. Specifically, on the electricity side, we will continue to need natural gas to fuel the current gas-fired generation fleet until sufficient clean energy resources and alternative forms of long duration energy storage are built. Regarding the gas infrastructure, LNG is needed to meet home heating needs and, more fundamentally, to maintain pressure on the gas pipeline system.

In sum, we believe that, ***for the clean energy transition to be successful, the region must continue to have reliable supplies of gas for home heating and electricity***. Without adequate gas, the region may not be able to meet the demand for home heating and electricity – and, when reliability suffers, the clean energy transition suffers. We have seen that story play out in Europe, Australia and, closer to home, in California and Texas. In sum, it is critical to the region's decarbonization goals that the lights and heat stay on in New England – and, for the foreseeable future, that requires gas.

Everett Provides Critical Gas Supply

The natural gas pipelines that serve New England operate at maximum capacity during the winter. During very cold weather, and for extended periods, the pipelines cannot fully supply heating demand or provide enough fuel to power gas generators without significant injections of LNG on the eastern and northern parts of the New England gas system. Because New England is at the end of the interstate pipeline system and lacks large scale, long duration energy or fuel storage, both the gas distribution system and the electric power system have a dependence on imported LNG, and this reality will persist until the region invests in access to alternative long duration energy storage infrastructure.[1]

The only LNG import facility in regular use in New England is Everett.[2] Everett has LNG storage capacity equivalent to 3.4 billion cubic feet of natural gas and includes equipment for the import, storage, local transportation and regasification of LNG that is delivered to the facility by ship. Everett has the capacity to make firm gas deliveries of up to 435 million cubic feet per day[3] to two of the five interstate natural gas pipelines in New England for use by generators and gas utilities.[4] These injections from Everett help maintain pipeline pressures on high demand gas days.

The Current Lack of a Regional Plan to Ensure Energy Adequacy, including the Absence of a State or Federal Regulatory Solution, Endangers the Reliability of the Electric Power System

While the reliability of New England's electric power system is dependent on a reliable gas system, the regulatory oversight of the two systems is not fully compatible. Specifically, the electricity markets are not designed to spur investments in supporting infrastructure needed to ensure a reliable clean energy transition. While the region is in the process of developing a plan and cost allocation methodology for assuring investments in the transmission infrastructure required to integrate renewable resources, there is no comparable plan to ensure the region has sufficiently robust, long duration, sources of balancing energy (including for the meantime, sufficient supplies of natural gas). In essence, the prevailing assumption is that the fuel markets will ensure sufficient fuel supply in response to high prices in the electricity markets. For a variety of reasons, this assumption is proving to be flawed.

Fuel suppliers, including LNG providers, will not maintain and invest in infrastructure and fuel supplies without a long-term financial commitment. However, the counter-party for such a long-term commitment does not exist in New England, particularly for fuel to supply electric generators. Specifically, the majority of wholesale and retail buyers of electricity in New England generally have a short position in the market and are not making long-term commitments to electric energy suppliers, nor do these suppliers have a "firm fuel" obligation under the ISO's FERC-regulated Tariff.

The result of this structure is that fossil-fired electric generators do not have sufficient guaranteed long-term incomes on which to rely when making fuel arrangements. As a result, they will, at best, engage in seasonal contracting for fuel to cover their expected supply obligations and rely on spot fuel markets for the additional supplies to cover unexpected events. Pipelines or suppliers of imported LNG cannot rely on this limited contracting to invest in infrastructure, or ensure stable supplies of LNG.

In 2014, some of the New England states and the Electric Distribution Companies (EDCs), recognizing the risks of this structure, considered requiring the EDCs to become the contracting counterparty to stabilize regional gas supplies for gas generators, but that path was stymied when the Massachusetts Supreme Judicial Court ruled that the Massachusetts Department of Public Utilities did not have the authority to

[1] Given the growing uncertainties in the global LNG markets as a result of the war in Ukraine, this dependence is increasingly fraught.
[2] The region also depends on regular LNG injections from the St John facility located in New Brunswick, Canada, which is outside of U.S. jurisdiction.
[3] This translates to about 2,700 MW per day of capacity.
[4] Everett also has the capability to deliver 100,000 MMBtu per day by truck, which supports local storage refills for gas utilities throughout the region.

approve this proposal. In short, there is a structural problem that encompasses the gas and electric systems and there is a bifurcated state and federal regulatory system for addressing it.

As the clean energy transition progresses, this reliability and regulatory dilemma will become more pronounced. In simple terms, renewables will displace fossil fuels, but the need for balancing energy (and in particular the long duration, peaking requirement for balancing energy) will increase. The recent Future Grid Reliability Study, which was a product of a collaborative effort between the ISO, the states and NEPOOL, illustrates the issue.[5] Cost recovery for the infrastructure that provides this balancing energy will be difficult, especially if it is only used intermittently, and it is unlikely that these costs can be recovered through an electricity market structure that drives electricity suppliers to short-run marginal costs. This problem currently applies to fossil fuel providers, but it will also likely apply to clean, long-duration balancing energy providers with high capital and/or carrying costs (*e.g.,* providers of clean hydrogen or long duration batteries).

Solving the Energy Adequacy Problem Is a Critical Element of a Clean and Reliable Energy Future

While the region has been discussing and attempting to mitigate energy adequacy concerns for many years, ISO New England and the New England gas and electric distribution companies believe we are at a critical juncture given the impending retirement of a key piece of shared fuel infrastructure. The need to find a solution to this issue is vitally important to a reliable and clean energy future.

As the region seeks to decarbonize its economy, a robust solution should move the region toward a reliable and clean energy future by increasing the amounts of clean energy on the system, developing the transmission to interconnect and deliver those resources, maintaining the balancing resources to manage the variability of those resources, and ensuring energy adequacy through an energy reserve to manage through extended periods of severe weather or energy supply constraints.

An energy reserve would cover unusual events, including combinations of major contingencies, or extreme weather, or both. It does not refer to the daily balancing energy requirement to maintain short-term reliability of the bulk power system, but rather to provide a supplementary, "stand-by" quantity of energy to fill in when input energy supply chains are disrupted. In essence, "energy adequacy" or an "energy reserve" can be viewed as regional insurance to cover relatively low probability risks. The ISO is presently working with the Electric Power Research Institute to study and quantify extreme weather risks. Results from this study should be available in early 2023 and will inform the discussion on the magnitude of the risks, and potentially, how best to solve for these risks.

Preliminarily, an energy reserve could be achieved through some or all of the following:

- State regulated cost-of-service infrastructure investments coupled with contracting for the necessary energy

[5] The study shows that approximately 73-90 GW of wind, solar and storage will be needed in 2040 for reliability depending on the amount of available dispatchable resources. https://www.iso-ne.com/static-assets/documents/2022/07/2021_economic_study_future_grid_reliability_study_phase_1_report.pdf at page 3.

- FERC regulated cost-of-service rates for recovering investments in infrastructure and forward energy supply chain arrangements
- FERC regulated wholesale electric market tariffs that rely on uniform clearing price mechanisms to incent investments in infrastructure and forward energy supply chain arrangements

At this stage, given the region's experience over the past two decades, the region needs to determine how much insurance to buy, and which options, or combinations of options, will be the most effective and efficient. Defining and quantifying the risk/cost tradeoff will in turn depend on the potential solutions and we recognize this is an important step to achieving regulatory approval in either, or both, regulatory venues.

It is clear that the New England Governors are concerned about these issues, as indicated in their recent letter to Secretary Granholm. The New England states have a major role in determining the nature and extent of any regional risk mitigation solution, since they represent the end consumers who will have to pay for the insurance, and further, control the siting and permitting of the necessary infrastructure.

To this end, ***the region should undertake a comprehensive study of both the energy adequacy problem and the potential solutions for addressing the problem***. Any solution that involves the ISO and revisions to its Tariff will require deliberation in the appropriate NEPOOL forum and ultimately, approval by the FERC.

Due to the urgency of this issue, we believe it is incumbent upon the region to expeditiously move forward with practical and feasible short-term actions while studying long-term solutions. Therefore, the ISO will work with the New England states and stakeholders to accelerate actions that will help reduce the region's long-term dependency on Everett and imported LNG, mitigate the energy adequacy problem, and continue the transition to a clean energy future. Such short-term actions include identifying expedient investments in transmission and ISO tariff-based or market-based solutions. Clear guidance from the FERC and the states will be critical to finding a feasible solution.

We hope that this problem statement will help inform the discussions at the September 8th FERC Winter Gas-Electric Forum and subsequent discussions with the New England states and NEPOOL.

The Secretary of Energy
Washington, DC 20585

August 18, 2022

The Honorable Ned Lamont
Governor of Connecticut
State Capitol
210 Capitol Avenue
Hartford, Connecticut 06106

Dear Governor Lamont:

Thank you for your July 27 letter regarding the Department of Energy's (DOE) preparations to mitigate potential energy shortfalls in New England this winter. At DOE and across the Biden Administration, we recognize that the New England states face unique energy challenges, and your letter raises important areas for continued coordination and new collaboration with the Administration. As discussed below, we are prepared to work with you on these challenges throughout the winter fuels season.

Over the past few months, DOE's Office of Cybersecurity, Energy Security, and Emergency Response (CESER) has met with state energy officials and governors' homeland security advisors across the country, including State Energy Office Directors from six New England states, to discuss generation capacity issues, liquid fuels and inventories, and state-federal coordination.

Recent data shows, U.S. natural gas storage levels were at 2,501 billion cubic feet, 12% below the 5-year average, but within the 5-year range. Though levels remain within the 5-year range, these trends could indicate a continued tight market nationwide through the winter fuels season, which may impact prices.

In addition to winter fuel concerns, the Northeast region faces additional risks, given low inventories of gasoline and distillates as we approach peak hurricane season. According to U.S. Energy Information Administration data, commercial distillate inventories in three of the five Petroleum Administration for Defense Districts (PADDs) are below their 5-year averages. This is especially true along the East Coast where inventories are 20% below the seasonal 5-year average for gasoline and 47% below the seasonal 5-year average for distillates. In New England, the situation is even more severe, with diesel inventories 63% below their 5-year average.

With peak hurricane season upon us, these data points raise concerns about the impact of any physical disruption of supply and require that both states and the Federal Government are prepared to use all the tools in our toolkit to improve preparedness and respond if needed.

For my part, I have been meeting with domestic energy producers and refiners to discuss inventory levels and hurricane preparedness. DOE has also called on oil and natural gas industry partners to ensure they can safely meet their obligations to their consumers, the American people, by addressing the low product inventory levels across the country. We also continue to shore up energy supplies by taking historic action to ensure crude oil supply is uninterrupted for refiners by releasing from the Strategic Petroleum Reserve, consistent with President Biden's order this past spring to draw down one million barrels per day.

Additionally, I have directed my team to continue to proactively monitor these inventory levels and markets to inform engagement with industry, interagency, and state partners to assess issues affecting the energy sector, discuss preparedness efforts and potential options for mitigation, and provide coordination as needed to ensure preparedness for potential constraints.

In the spirit of continued collaboration, I ask that you and the other governors from the region join me in a convening to align on our response to this situation, as well as other challenges that may arise this winter.

And, ahead of that meeting, I urge you to consider what additional steps you can take in the coming weeks to improve preparedness, including using any legislative or executive tools at your disposal, working with responsible state agencies to require increased storage levels, and encouraging industry to voluntarily prioritize increasing gasoline and distillate inventories at this pivotal period of heightened risk. I will continue to engage with industry on this issue as well.

With respect to winter fuels supply, your letter raises three points – fuel supplies to New England, Strategic Energy Reserves, and coordination. On the first point, my team is tracking the natural gas markets closely. We understand the New England states already coordinate with each other and with industry partners. We encourage you to continue those efforts at the regional level to address energy security needs, and we are ready at the Federal level to address supply interruptions as needed. With regard to the Jones Act, the Department of Homeland Security (DHS), which reviews waiver requests under the Jones Act, has a process in place to expeditiously review any requests for waivers, and the Secretary of Homeland Security will make a determination for each request consistent with the requirements of 46 U.S.C. § 501. While the law does not enable DHS to issue pre-emptive blanket waivers, DHS will expeditiously consider each individual waiver request to determine if the waiver is necessary in the interest of national defense. DOE is a consulting agency for Jones Act waiver requests related to energy, and the Department works closely with DHS to provide input into how energy supplies impact national defense interests, as appropriate.

On the other points, we welcome your thoughts on how to modernize our strategic reserves given recent volatility in the energy markets and seek to coordinate closely with you and fellow governors in the region to ensure the reliability of energy supplies this winter. We also call on states to work with us to encourage increases in both liquid fuel inventories and natural gas procurement ahead of the winter season, and – in these unprecedented times – consider if a minimum fuel stock holding requirement for liquid fuels is a necessity moving forward.

I know DOE's CESER recently met with New England State Energy Directors to ensure close coordination and response in the event these tools are called upon. We look forward to these engagements continuing on a regular basis.

As we navigate hurricane season, and approach the fall and winter heating season, DOE will continue active monitoring of the refined product market, including the home heating oil market, as well as the gasoline and natural gas market.

By working together, we will be best prepared for a range of challenging scenarios. We look forward to seeing you in the next several weeks to discuss these matters.

Again, we appreciate your concerns and stand ready to partner on solutions. If you have further questions, please contact Dr. Ali Nouri, Assistant Secretary for Congressional and Intergovernmental, at Ali.Nouri@hq.doe.gov or (202) 586-5450.

Sincerely,

Jennifer Granholm

NEPOOL Participants Committee Report

September 2022

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

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Regular Operations Report - Highlights

Data is through August 24th unless otherwise noted.

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: July 2022 Energy Market value totaled $1.3B
  - August Energy market value was $1.1B, down $184M from July 2022 and up $418M from August 2021
    - August 2022 natural gas prices over the period were 17% higher than July 2022 average values
    - Average RT Hub Locational Marginal Prices ($97.33/MWh) over the period were 7.3% higher than July 2022 averages
      - DA Hub: $101.02/MWh
    - Average August 2022 natural gas prices and RT Hub LMPs over the period were up 109% and 99%, respectively, from August 2021 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 102.8% during August, up from 99.1% during July*
    - The minimum value for the month was 97.7% on Saturday, August 6th

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

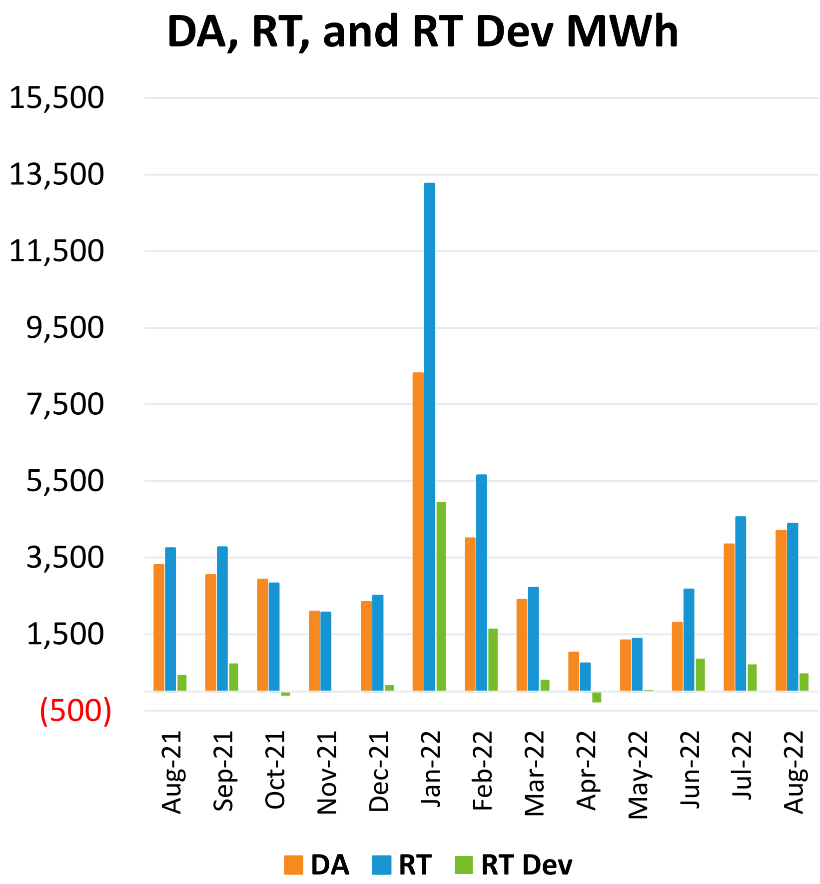
Underlying natural gas data furnished by: ice Global markets in clear view

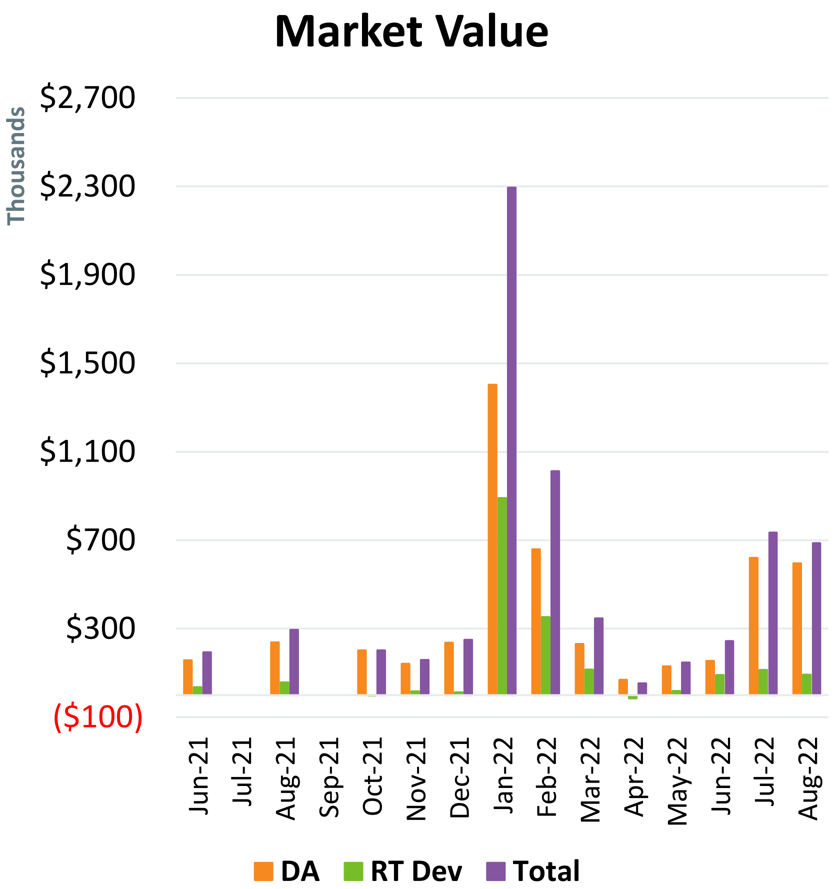
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - August 2022 NCPC payments totaled $5.4M over the period, down $3.7M from July 2022 and up $2M from August 2021
    - First Contingency payments totaled $4.9M, down $3.3M from July
      - $4.8M paid to internal resources, down $3M from July
        - » $1.5M charged to DALO, $2.2M to RT Deviations, $1.1M to RTLO*
      - $180K paid to resources at external locations, down $378K from July
        - » $167K charged to DALO at external locations, $13K to RT Deviations
    - Distribution payments totaled $402K, down $192K from July
  - NCPC payments over the period as percent of Energy Market value were 0.5%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $515K; Rapid Response Pricing (RRP) Opportunity Cost - $616K; 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 conducted 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) was 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

Summary of Operations, August 4th – 9th, 2022

Highlights

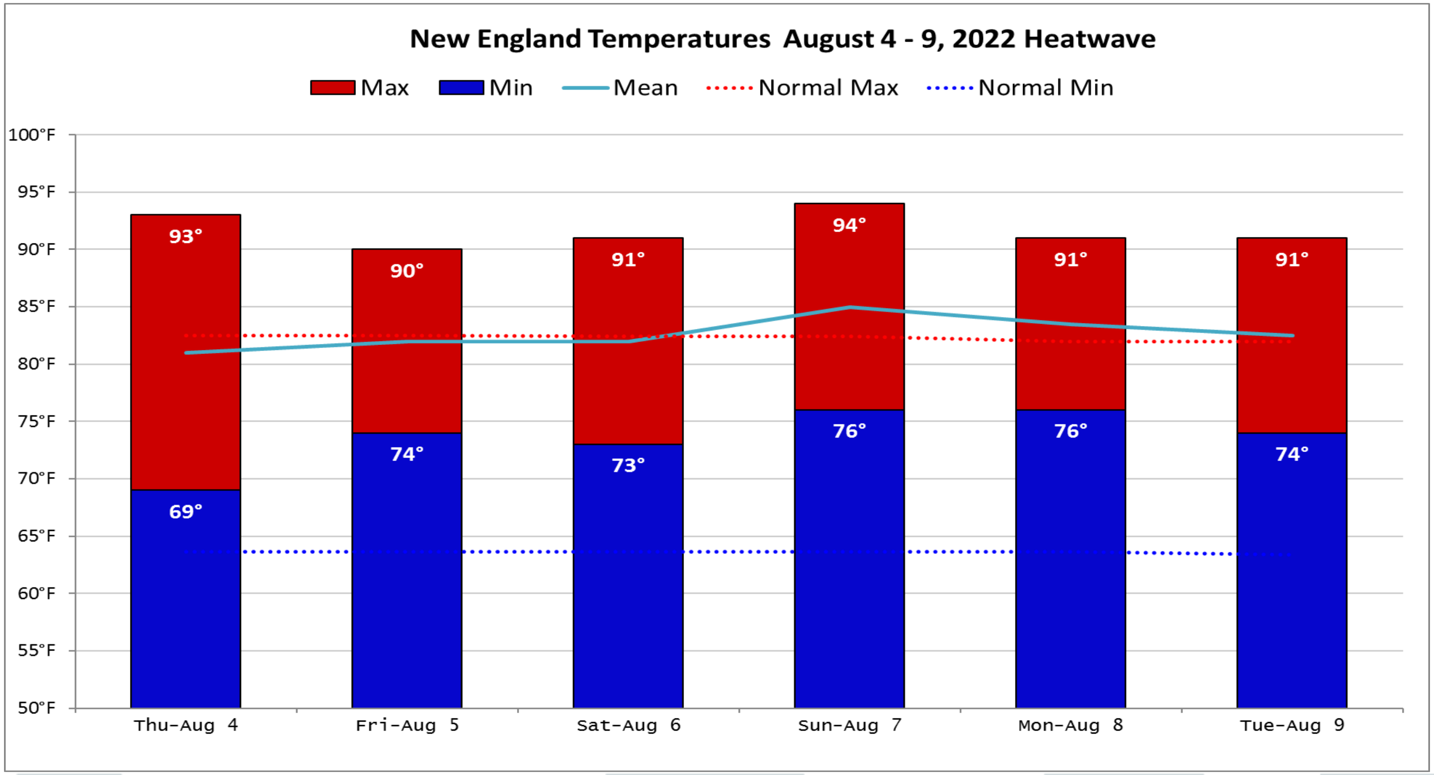
- The August 4 – 9 heat wave was very similar to the July 19 – 24 heat wave in terms of regional weather, loads, and energy demand; one key difference was that fewer unplanned outages of generating resources occurred during this most recent heat wave
- On average, temperatures in the region were well above normal during the six-day heat wave
- Once again during this heat wave, weather and load forecasts were highly accurate
- Significantly less fuel oil was utilized during this heat wave as compared to the July heat wave; this was primarily due to increased energy supplied by natural gas-fired resources
- Despite some unplanned outages, New England’s transmission system and resource fleet performed well
- System energy and reserve pricing properly reflected system conditions during the heat wave

Preparation Activities

- Beginning on Wednesday, 8/3, and periodically throughout the week, ISO Operations staff held conference calls and meetings with neighboring NPCC area and Local Control Center management staff
- Due to the forecasted system conditions and expectations for reduced capacity, ISO declared M/LCC-2, Abnormal Conditions Alert, on 8/4 from 1600 – 2200 and on 8/8 from 0930 – 2200

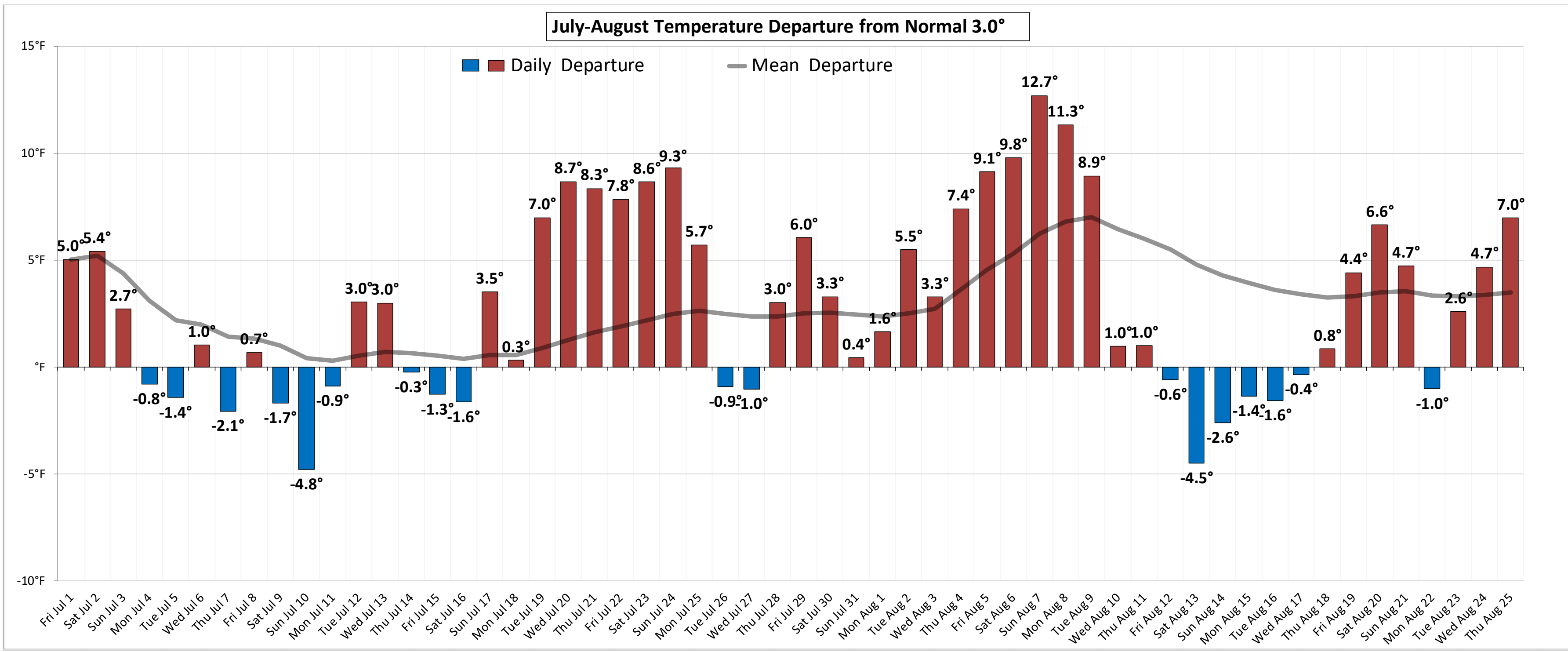
For the Second Time This Summer, New England Temps Reached 90°F For Six Consecutive Days

- The 8-city weighted-avg. high temperature reached 93.8°F, slightly higher than the 92.9°F avg. during the July heat wave; the highest single day 8-city weighted-avg. temperature of 94°F occurred on Sunday, 8/7
- Boston's week-long high temps ranked 6th all-time, reaching a high of 98°F on 4 days during the heat wave (8/4 and 8/7 through 8/9)



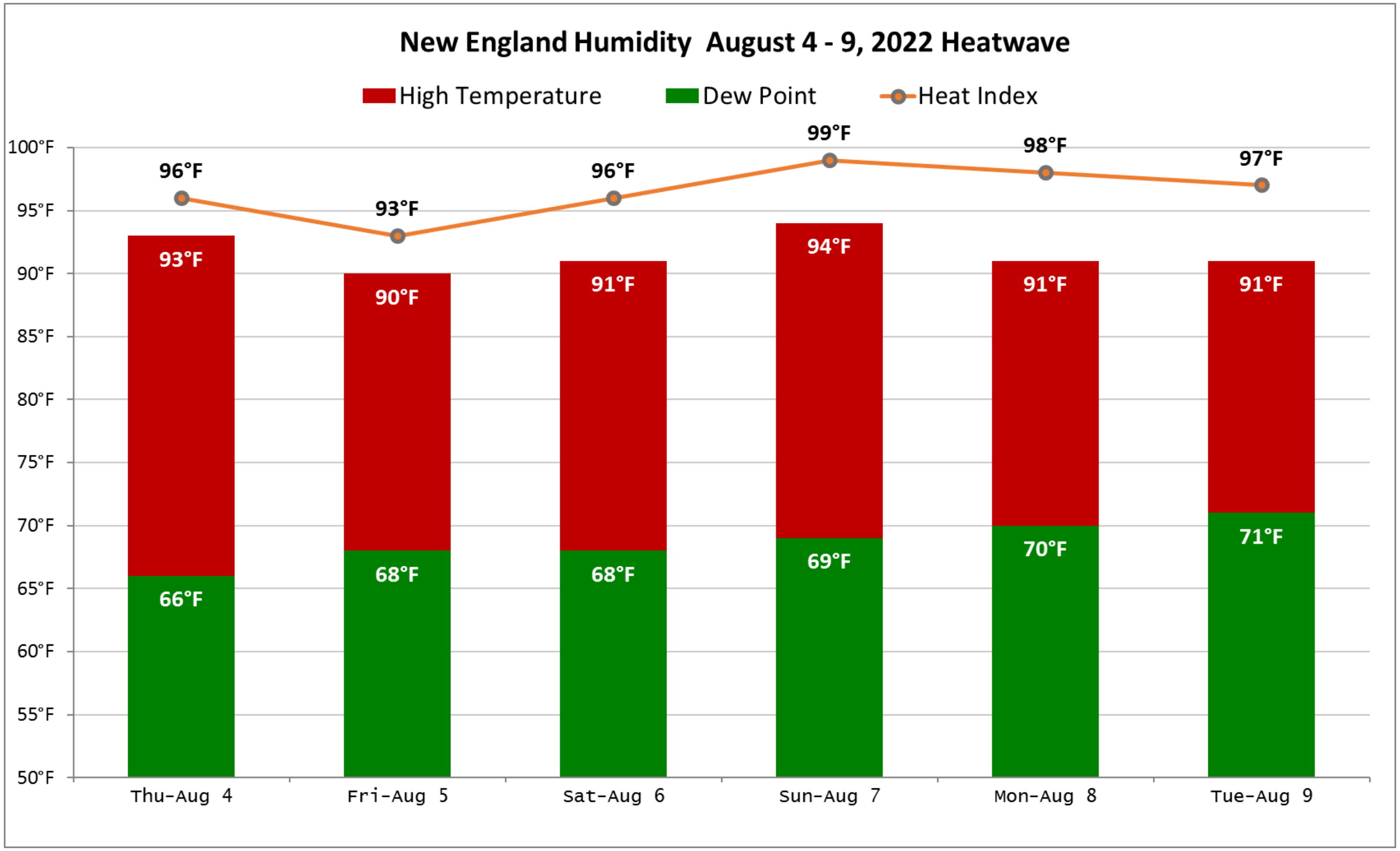
Average Temperatures Continue to Trend Significantly Above Normal

- Since mid-July temperatures have mostly been above normal; during the August heat wave temperatures were well above normal



New England Dew Points Were Not Excessive

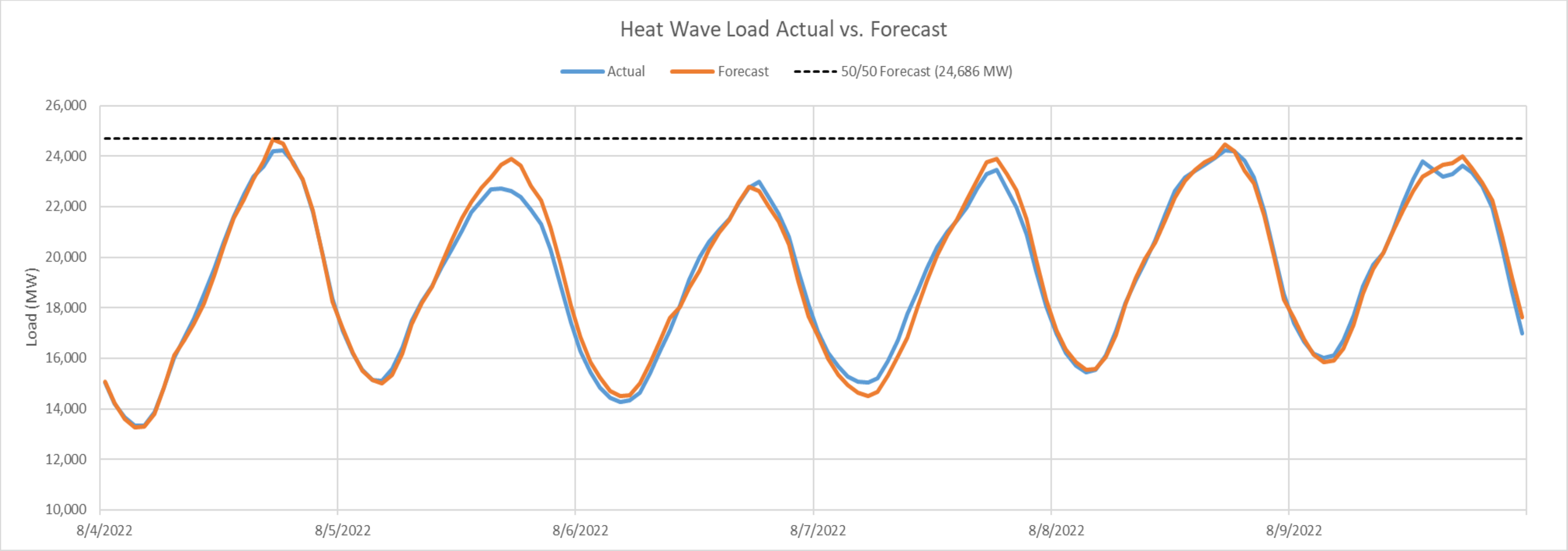
- Similar to the July heat wave, regional dew points were not excessive, resulting in a heat index below 100°F throughout the heat wave



Regional Load and Energy Demand Were Similar to the July Heat Wave

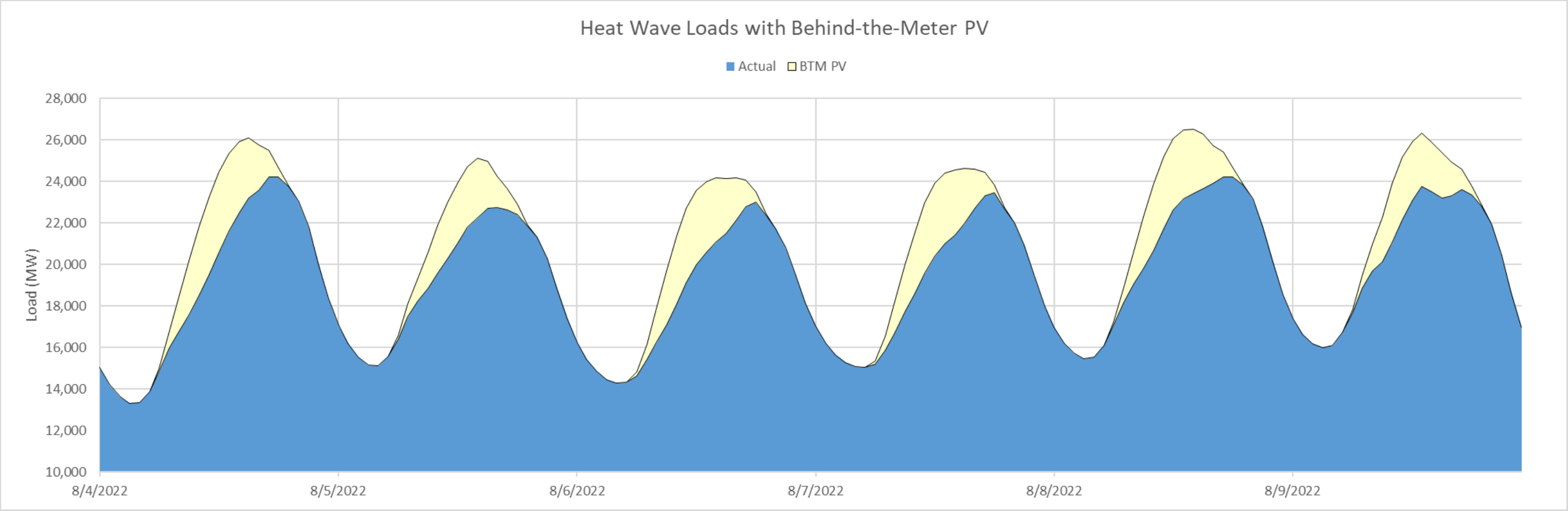
Weather Forecasts and ISO's Load Forecast Were Accurate

- Peak integrated load of 24,226 MW occurred on Thursday, 8/4; peak hourly integrated load, including load served by settlement only generators, was 24,775 MW
- Total energy demand over the 6 days was approximately 2,780 GWh; avg. ~ 465 GWh/day
- Weather forecasts used by ISO to forecast load averaged less than 1.2°F error over all hours



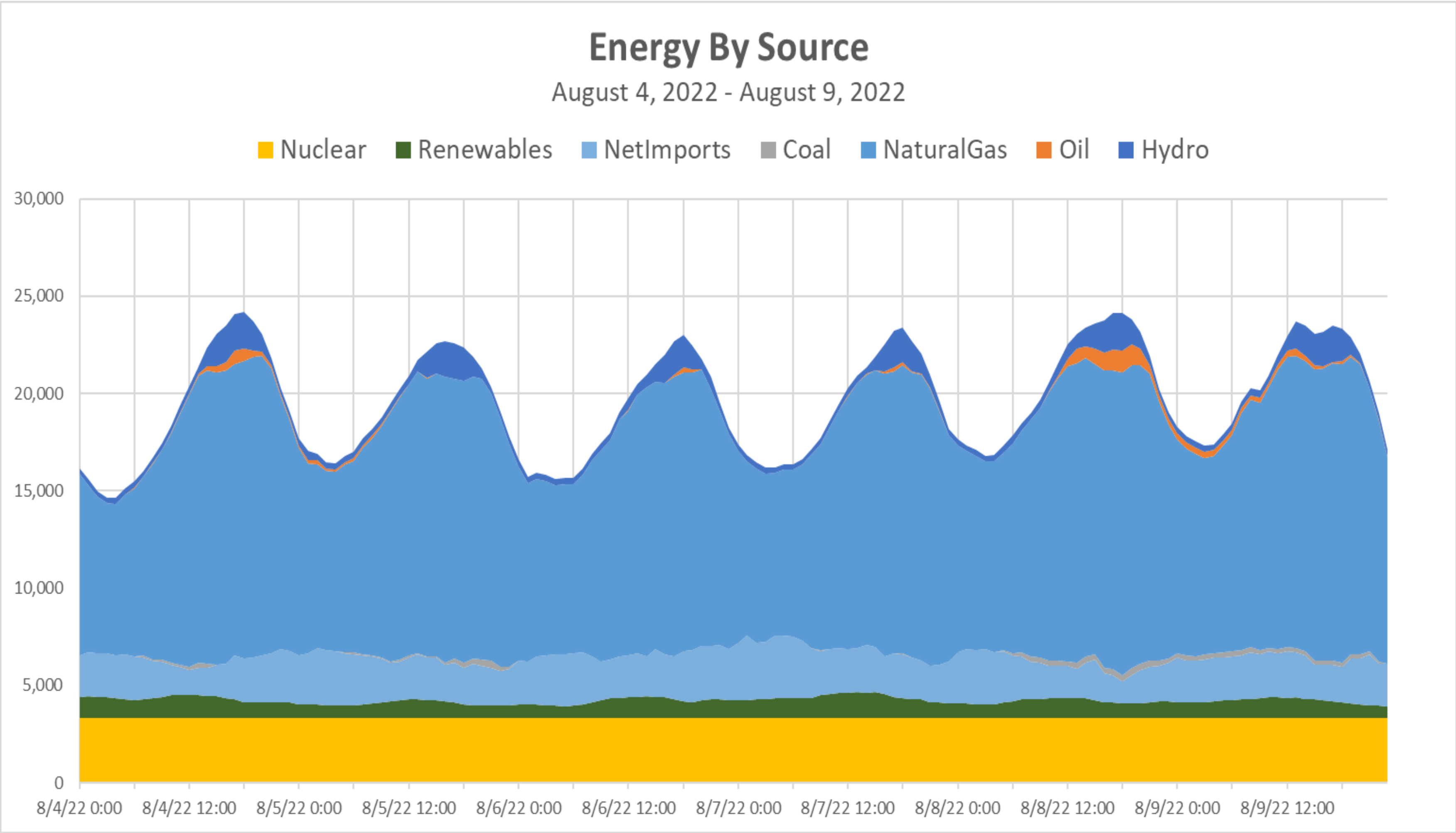
Energy Contributions From Behind-the-Meter PV Was Significant

- The peak contribution from behind-the-meter (BTM) PV during the six-day heat wave was approx. 3,950 MW on 8/4; BTM PV contributions were significantly lower during peak hours



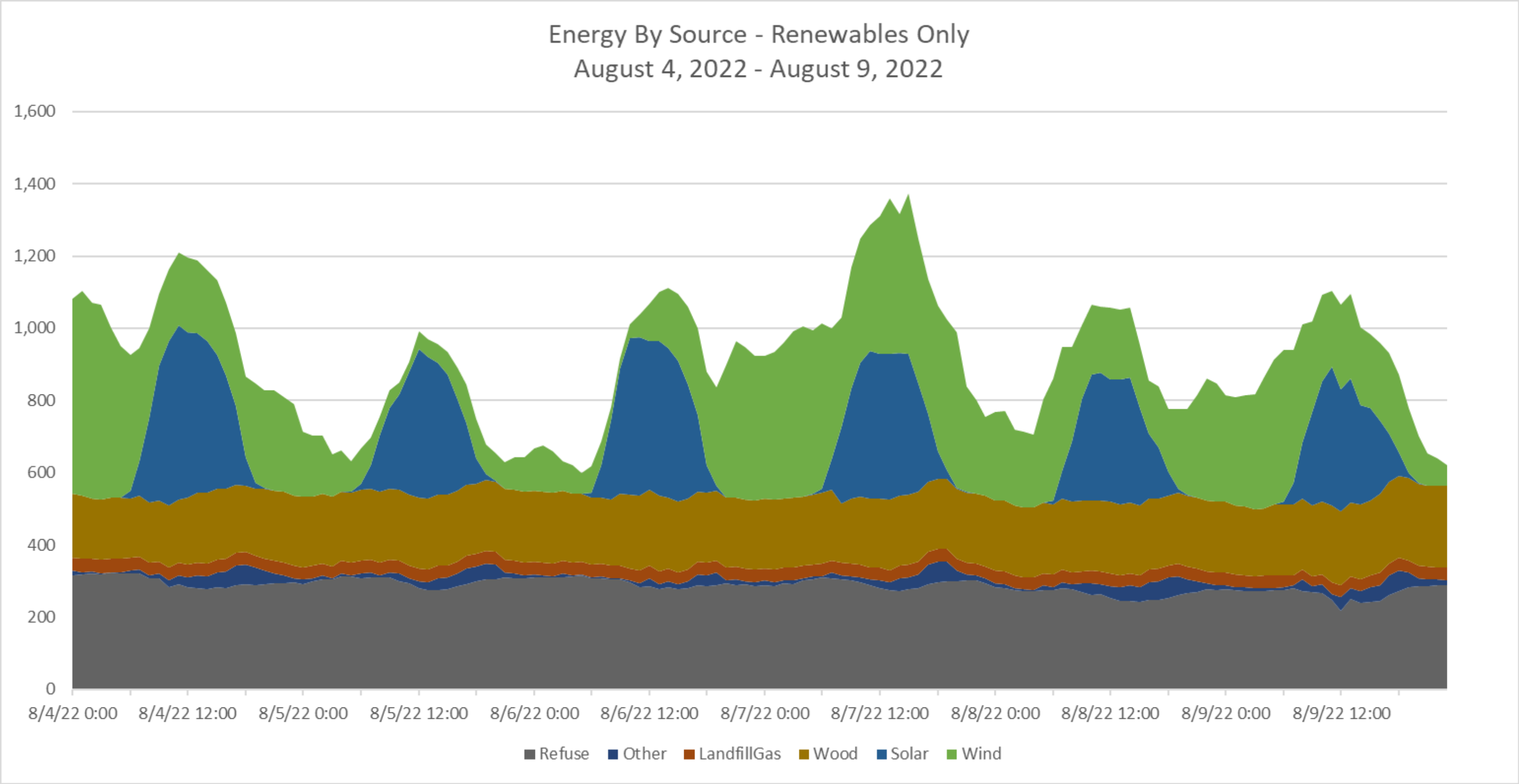
In the figure above, load served behind-the-meter is added to load served by the power grid to show total New England demand during the heat wave

Energy Sources During the Heat Wave

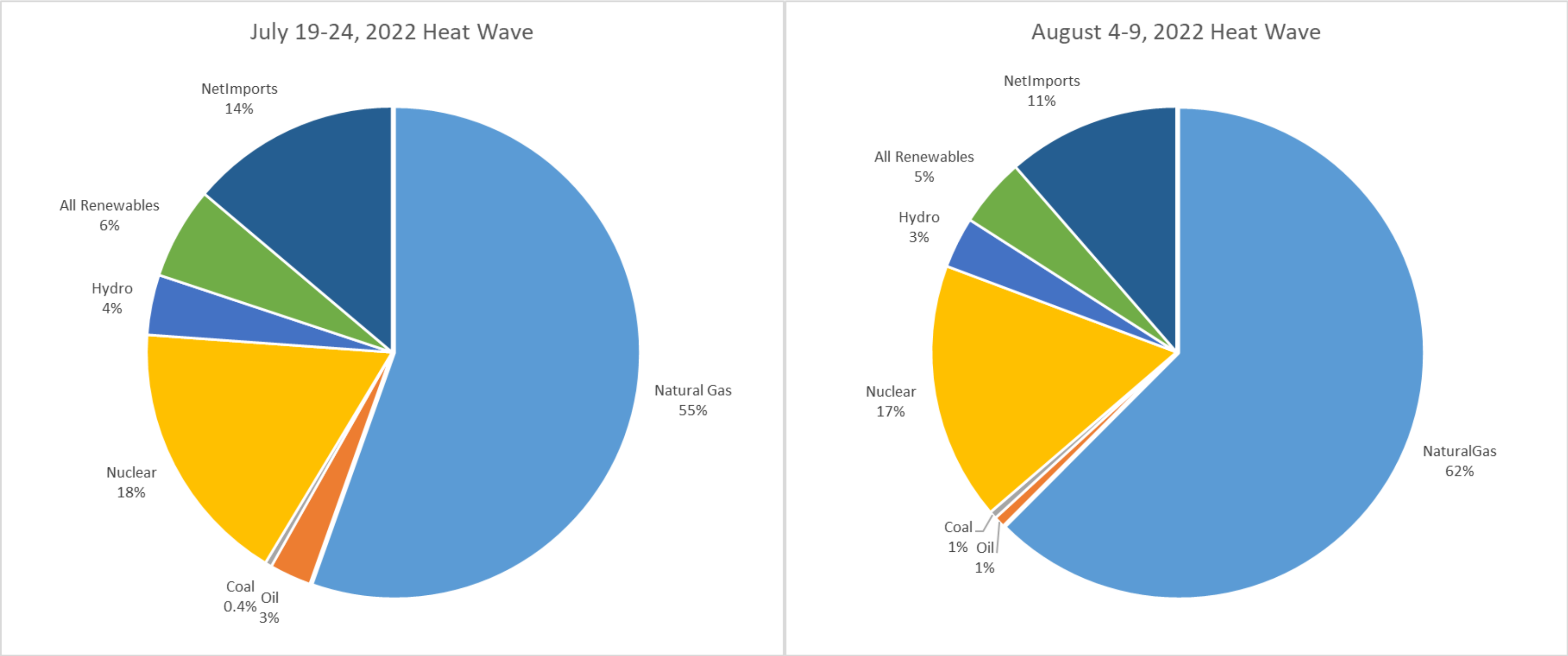


Energy Sources During the Heat Wave – Renewables Only

- Aggregate contributions from wind energy peaked in HE02 on 8/4, and averaged ~240MW/hr during the six-day period which was down from ~450MW/hr in the July heat wave



Energy Sources – Comparison of August and July 2022 Heat Waves



Stored Fuel Usage During the Heat Wave

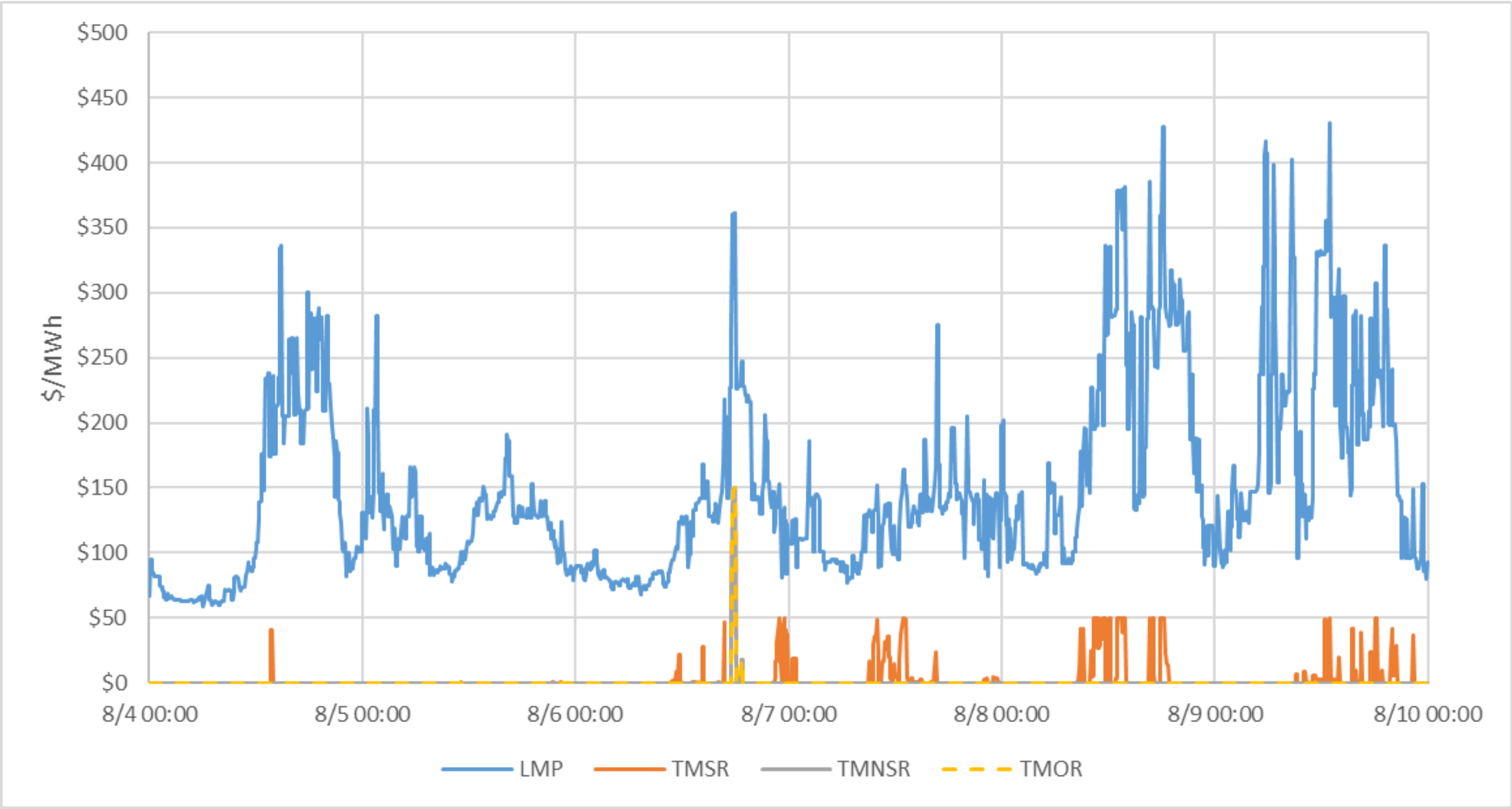
- Injection of LNG to pipelines for use by generators was minimal
- Fuel-oil usage was lower than the amount used during the July heat wave (~6M gallons); according to generator survey responses, during the two-week span of 7/27 to 8/9;
  - Approx. 1.5M gallons of fuel-oil was consumed by generators; a majority of fuel-oil consumption 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 prior to this winter

New England's Transmission System and Resource Fleet Performed Well

- Unplanned transmission outages were minimal
- Unplanned resource outages and reductions occurred at times throughout the heat wave, averaging ~750 MW/day; this was a reduction from ~1,500 MW/day of outages and reductions during the July heat wave
  - Unplanned outages and reductions occurring on the peak load day of 8/4, totaled ~1,050 MW
- Supplemental commitment of resources occurred on each day of the heat wave, averaging ~700 MW/day

System Energy and Reserve Pricing

- System LMPs averaged ~ $148/MWh during the six-day heat wave; non-zero system reserve prices occurred periodically, with TMOR and TMNSR pricing occurring only on 8/6



SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (3.5°F) Max: 98°F, Min: 63°F Precipitation: 1.14" – Below Normal Normal: 2.94"	Hartford	Temperature: Above Normal (3.9°F) Max: 96°F, Min: 54°F Precipitation: 4.69" - Above Normal Normal: 3.86"

Peak Load:	24,226 MW	August 4, 2022	19:00 (ending)

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

Procedure	Declared	Cancelled	Note
M/LCC 2	8/4 16:00	8/4 22:00	Capacity
M/LCC 2	8/8 09:30	8/8 22:00	Capacity

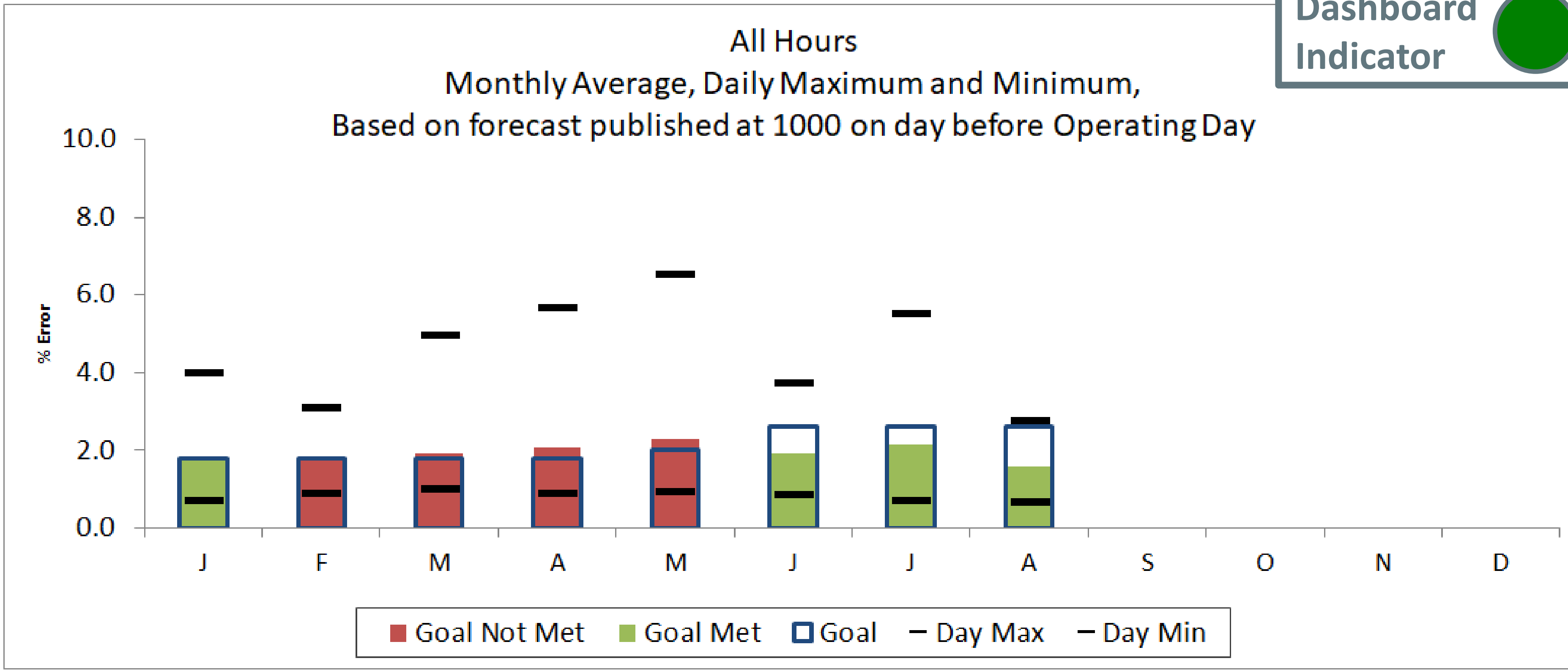
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
8/2/2022	NBPSO	617
8/4/2022	NYISO	1100
8/8/2022	NYISO	550
8/8/2022	NYISO	750

2022 System Operations - Load Forecast Accuracy

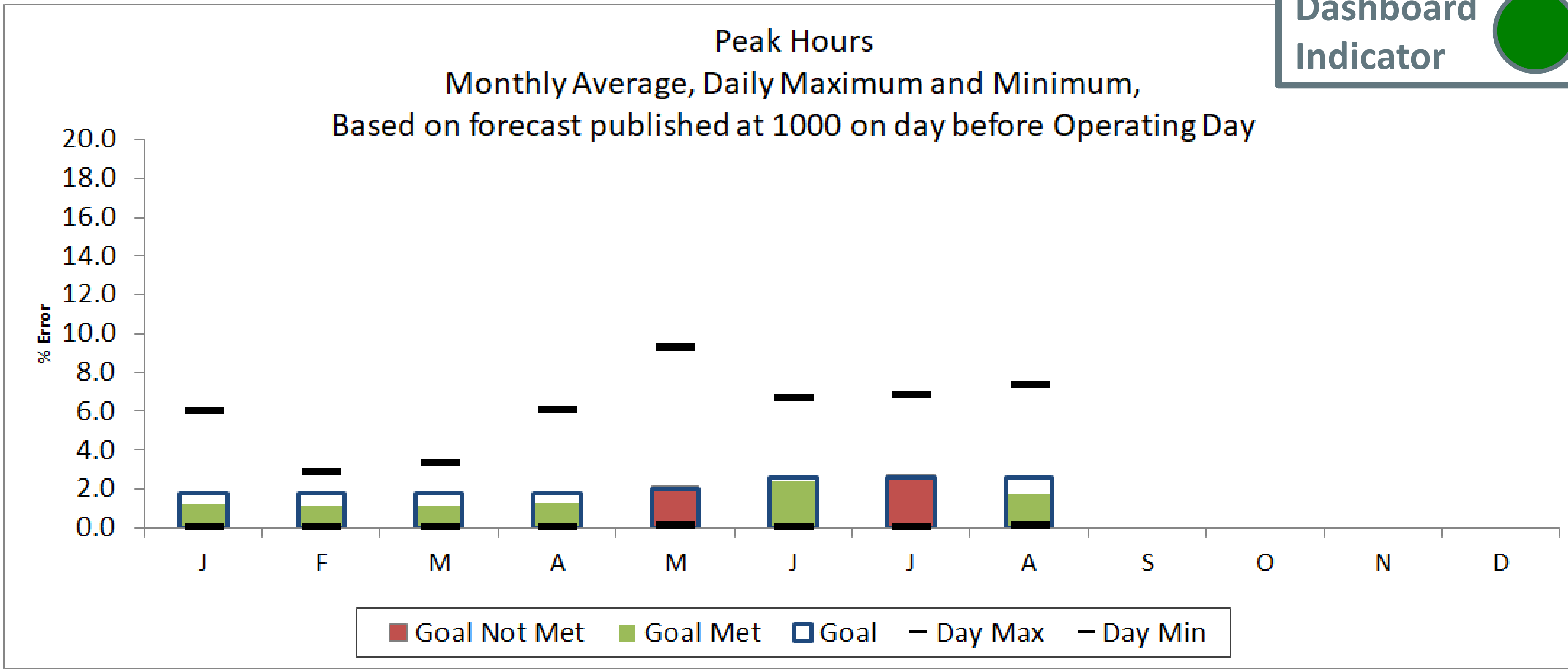
Dashboard Indicator



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	2.74					6.52
Day Min	0.69	0.87	0.97	0.85	0.91	0.83	0.69	0.66					0.66
MAPE	1.79	1.81	1.93	2.05	2.30	1.92	2.13	1.59					1.94
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60					

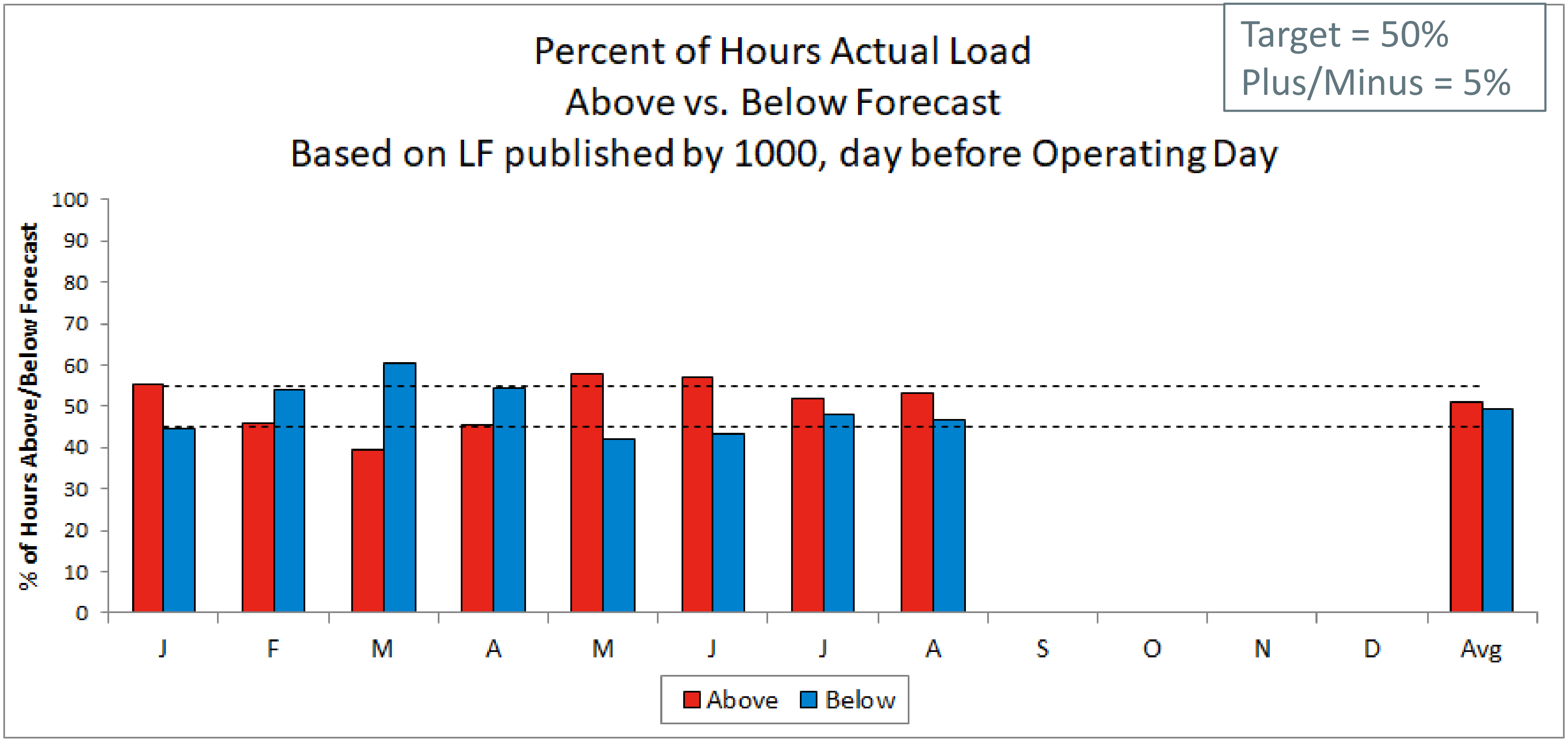
2022 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



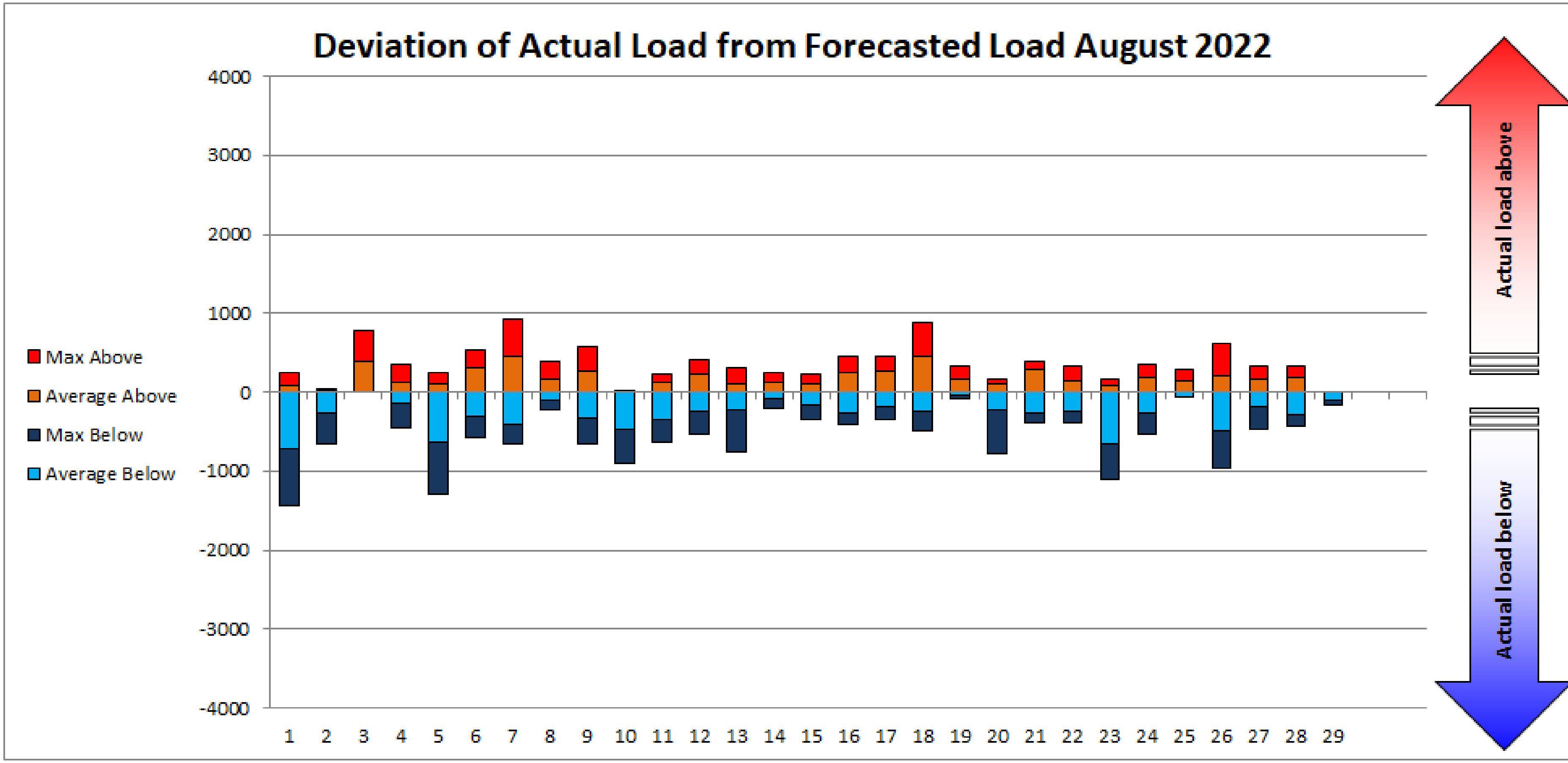
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	6.01	2.85	3.32	6.08	9.27	6.70	6.85	7.31					9.27
Day Min	0.02	0.03	0.04	0.00	0.06	0.01	0.02	0.08					0.00
MAPE	1.25	1.11	1.13	1.29	2.14	2.43	2.73	1.77					1.74
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60					

2022 System Operations - Load Forecast Accuracy cont.

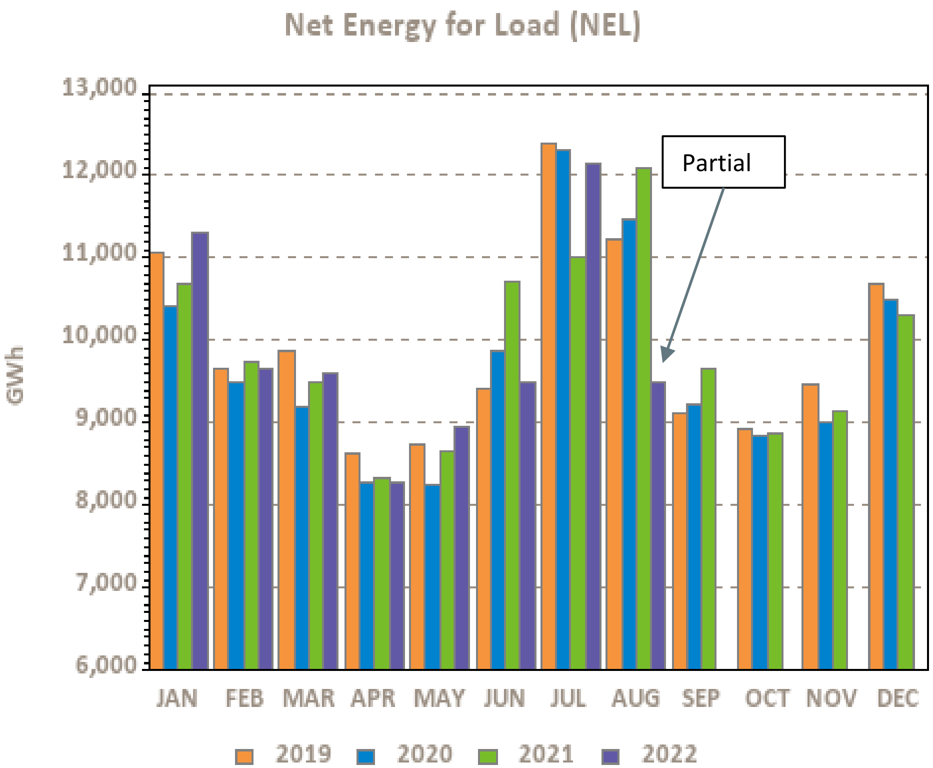


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	55.2	46	39.7	45.6	57.8	56.8	51.9	53.1					51
Below %	44.8	54	60.3	54.4	42.2	43.2	48.1	46.9					49
Avg Above	219.5	245.7	175.9	180	217.2	209.6	268.3	170.3					268
Avg Below	-223.1	-207.6	-240.0	-191.5	-192.2	-215.9	-295.8	-256.9					-296
Avg All	22	6	-78	-18	30	23	5	-37					-6

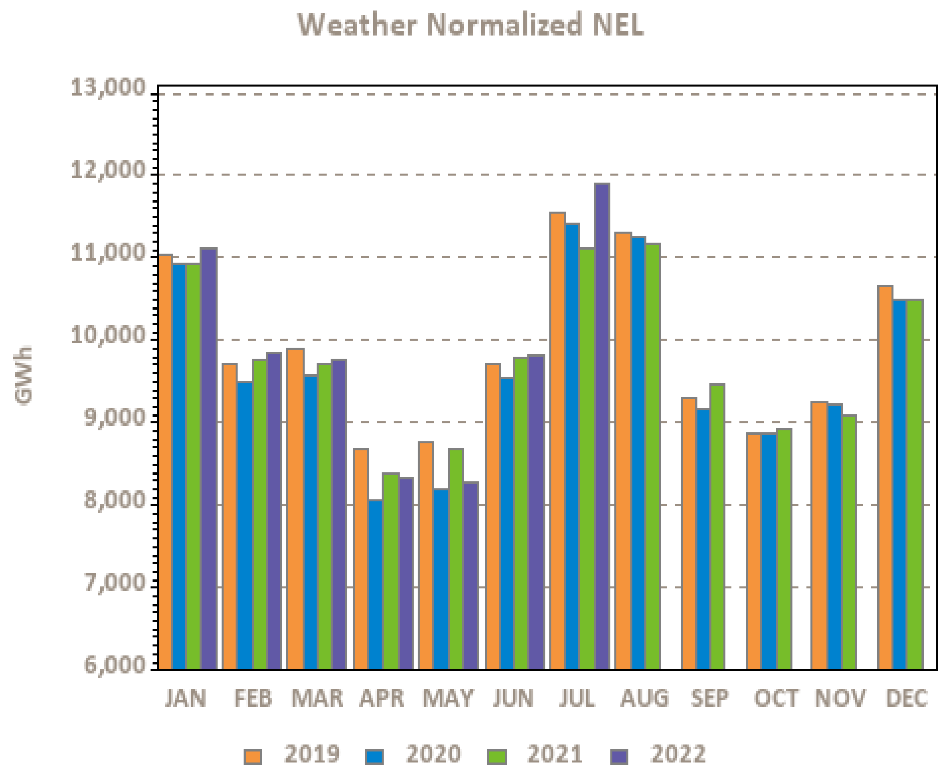
2022 System Operations - Load Forecast Accuracy cont.



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



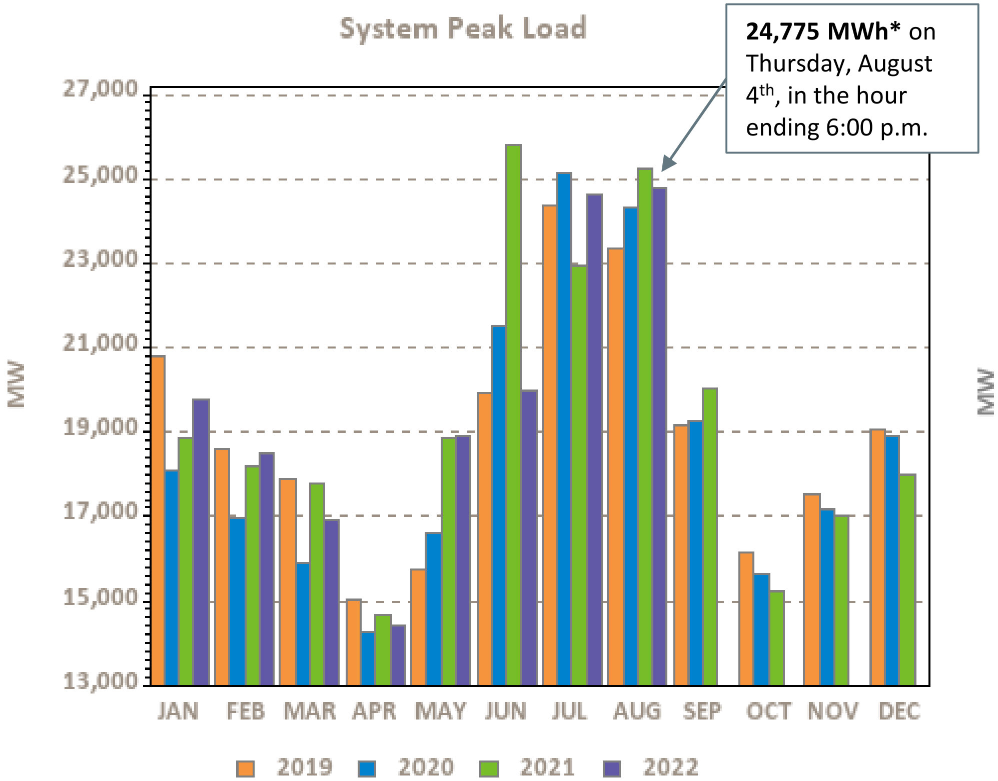
Ann Tot (TWh): 119.2 116.9 118.8 78.9



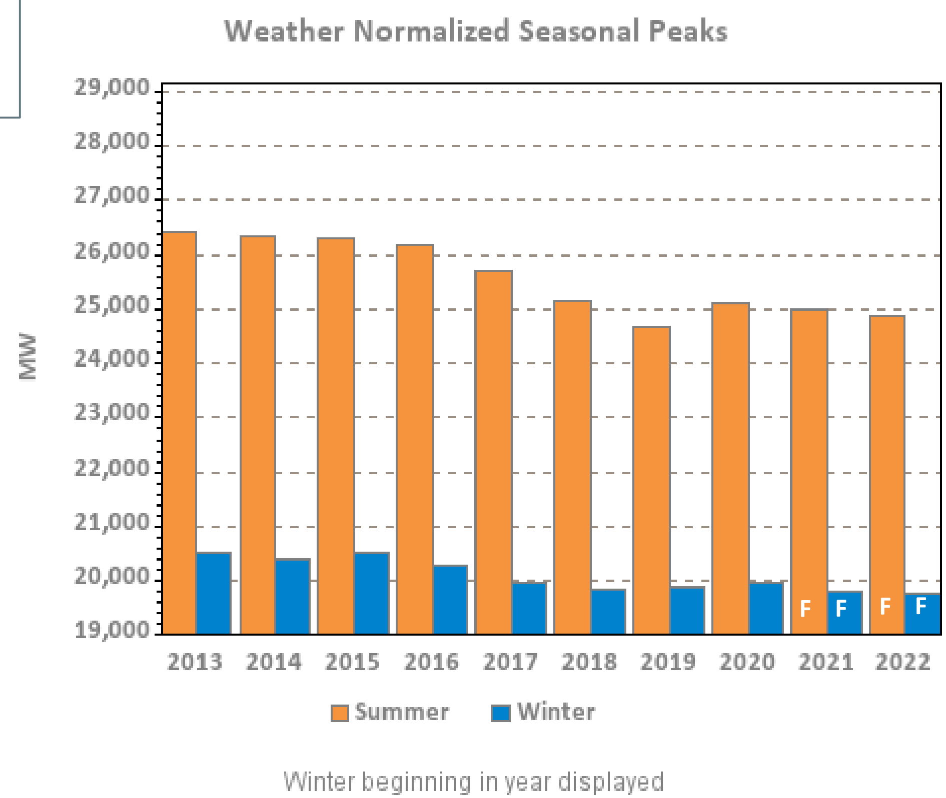
Ann Tot (TWh): 118.8 116.3 117.6 69.1

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

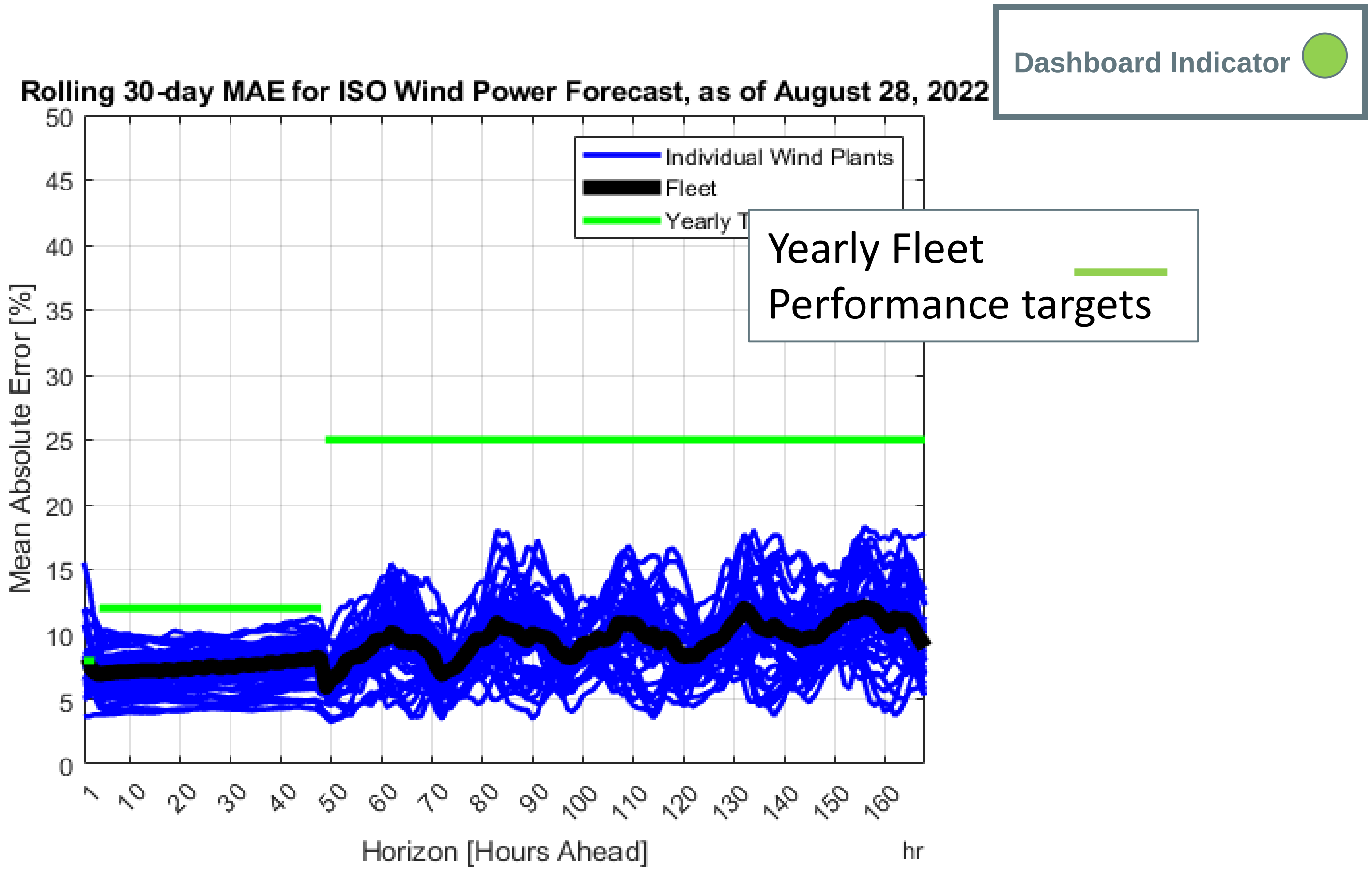


*Revenue quality metered value



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

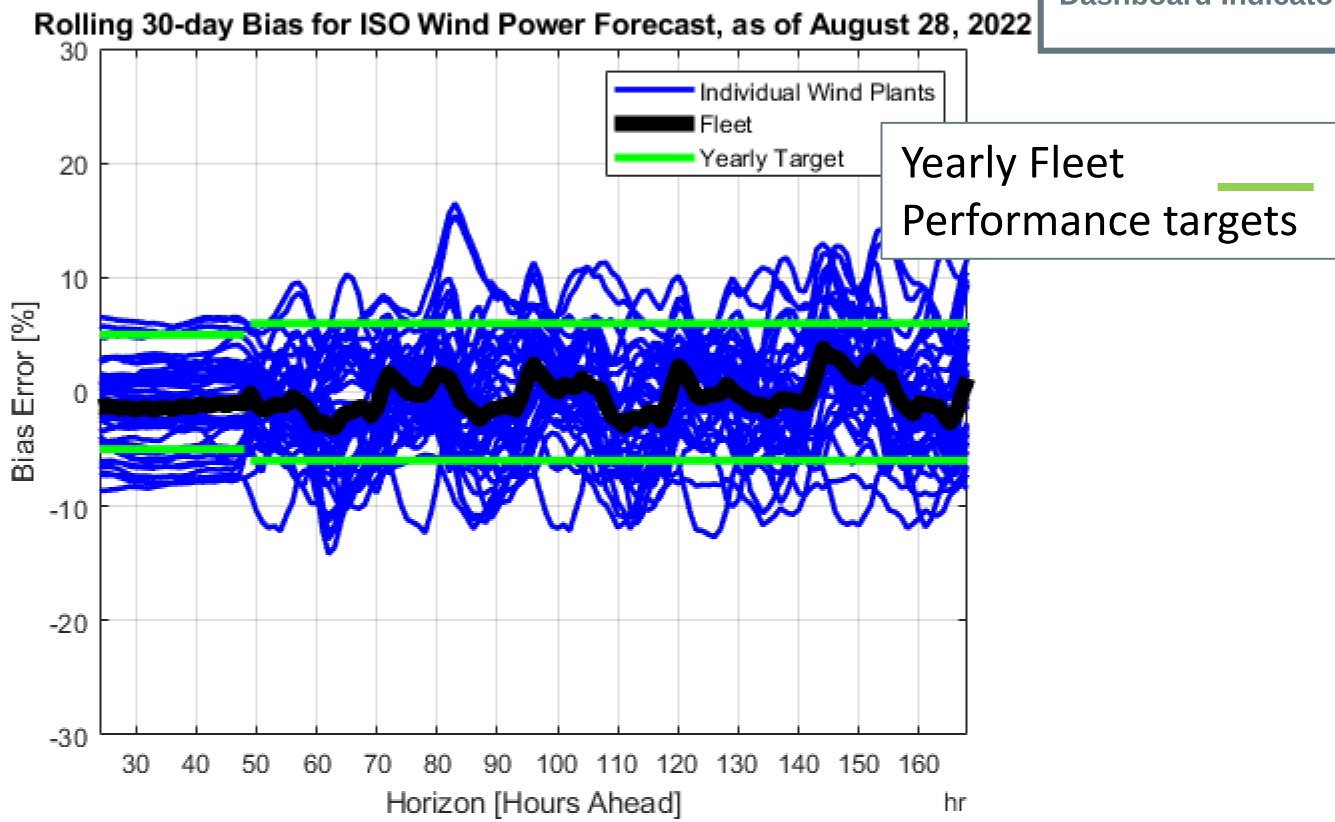
Wind Power Forecast Error Statistics: Medium and Long Term Forecasts MAE



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

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

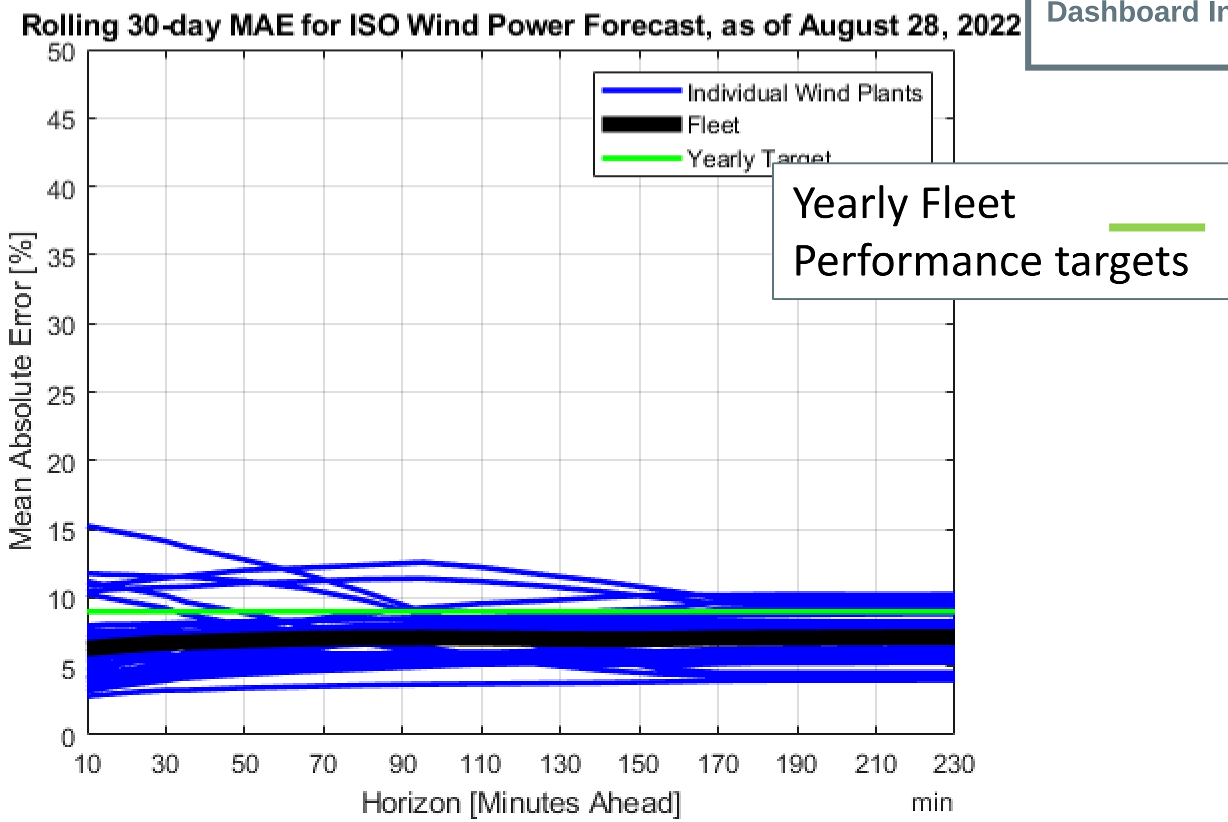
Dashboard Indicator



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

Wind Power Forecast Error Statistics: Short Term Forecast MAE

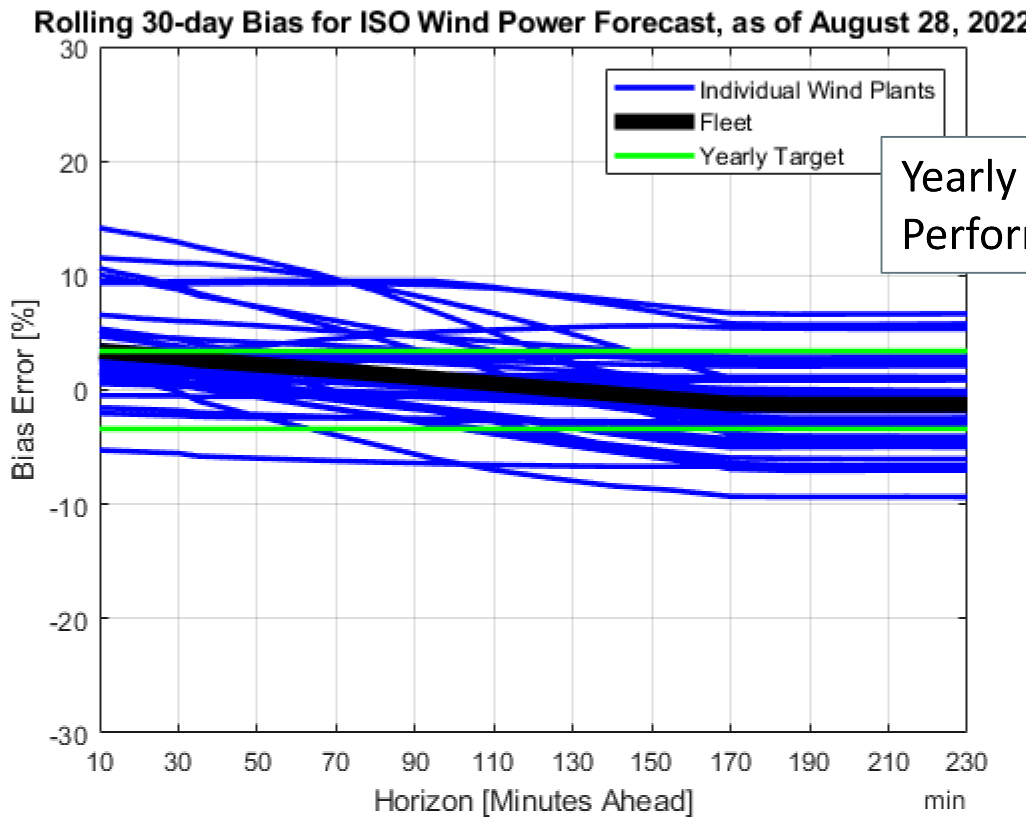
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the 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: Short Term Forecast Bias

Dashboard Indicator

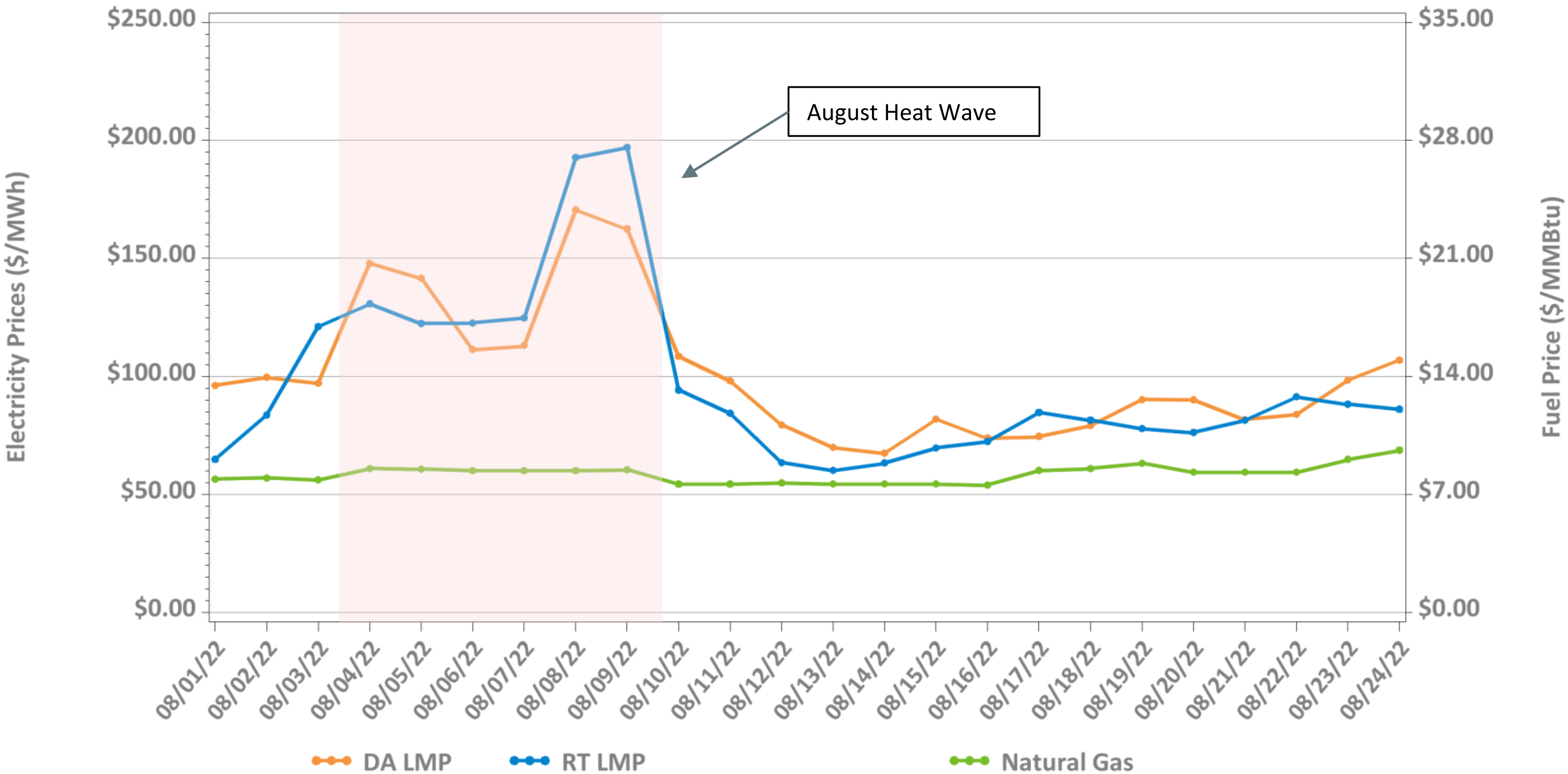


Yearly Fleet Performance targets

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: August 1-24, 2022

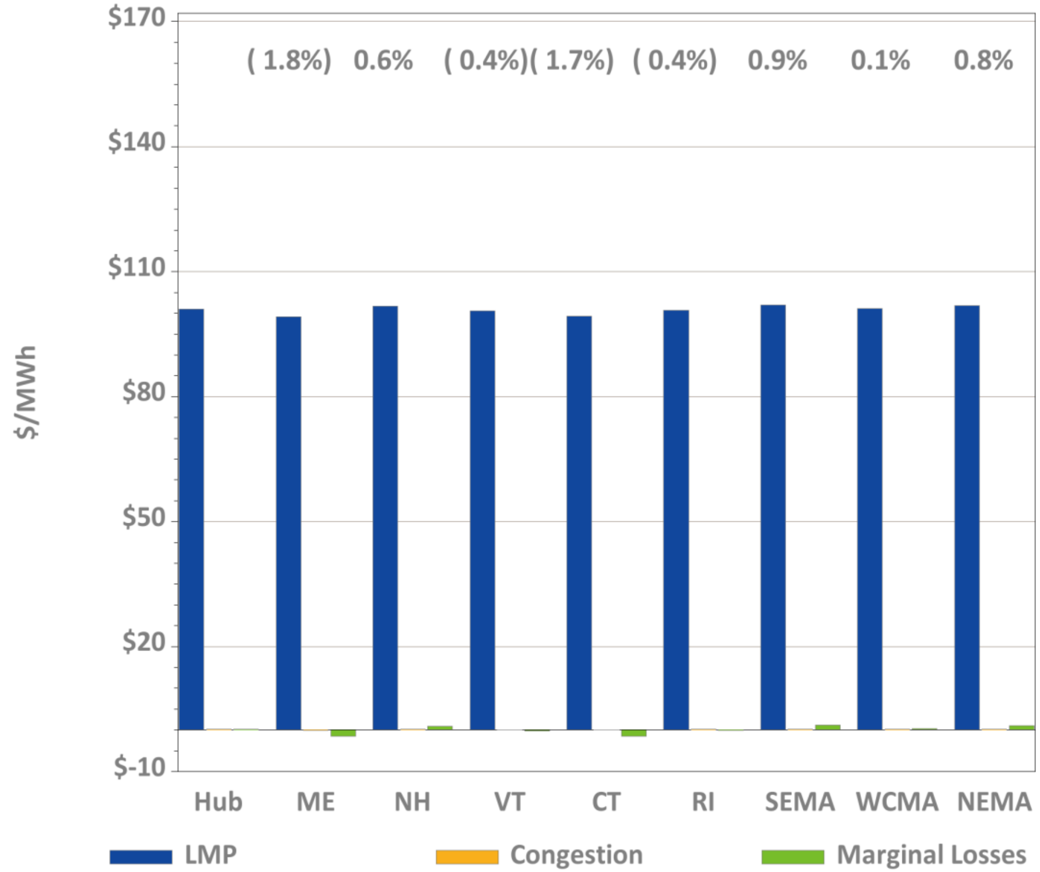


Underlying natural gas data furnished by:

ICE Global markets in clear view

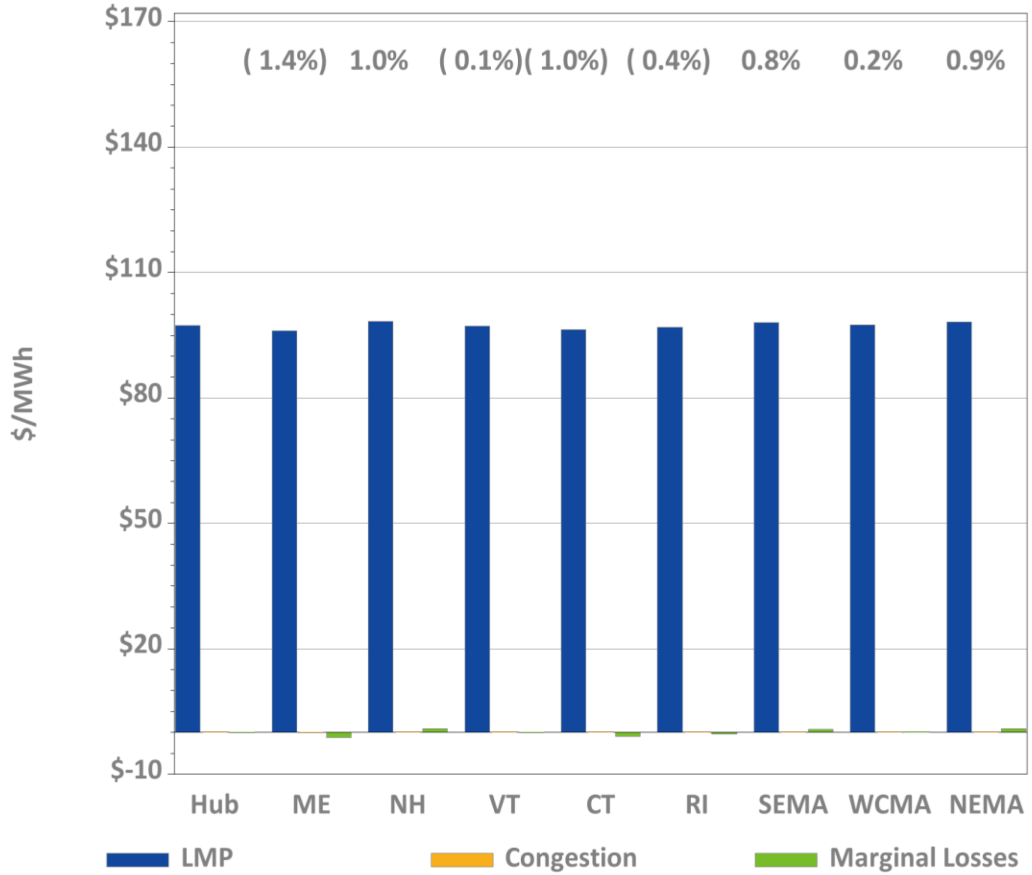
Average price difference over this period (DA-RT): $3.70
Average price difference over this period ABS(DA-RT): $14.01
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 14%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, August 2022



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

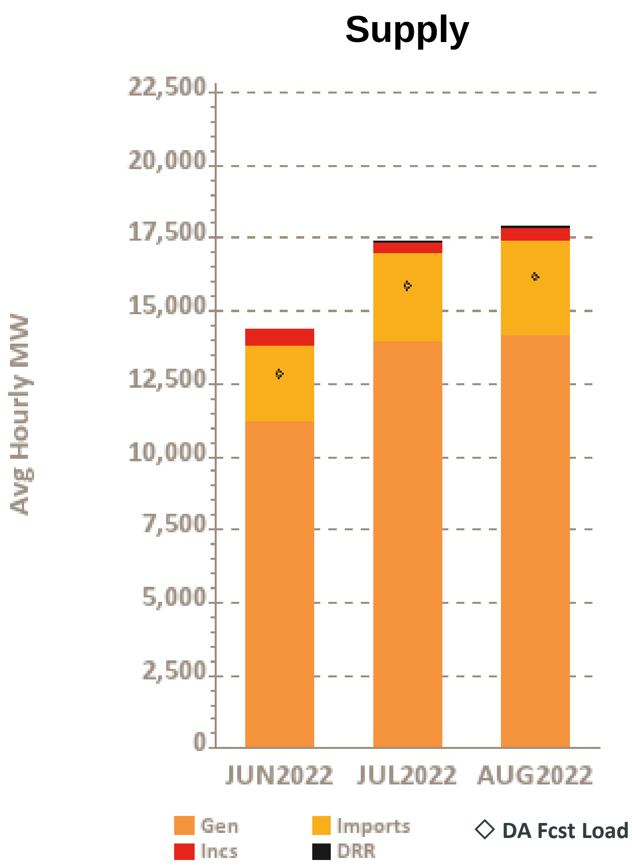
RT LMPs Average by Zone & Hub, August 2022

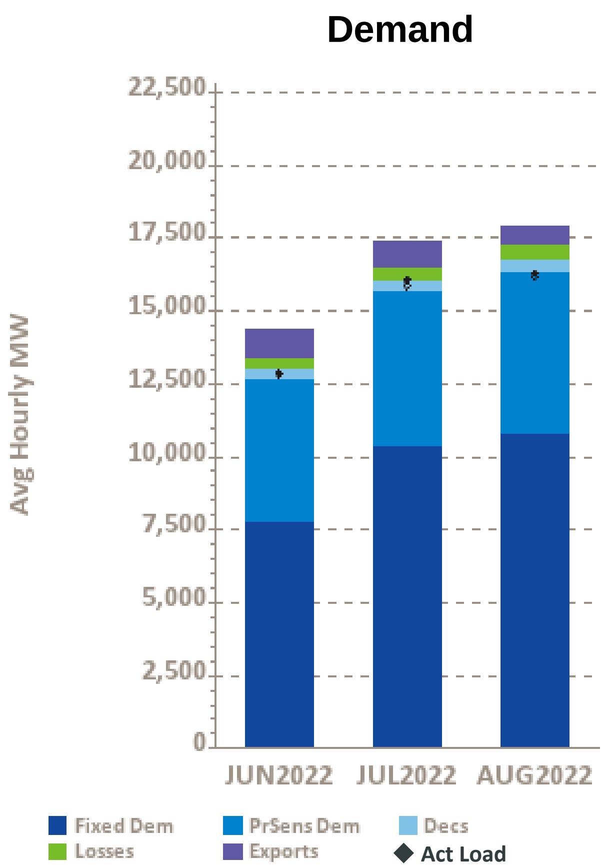


Definitions

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

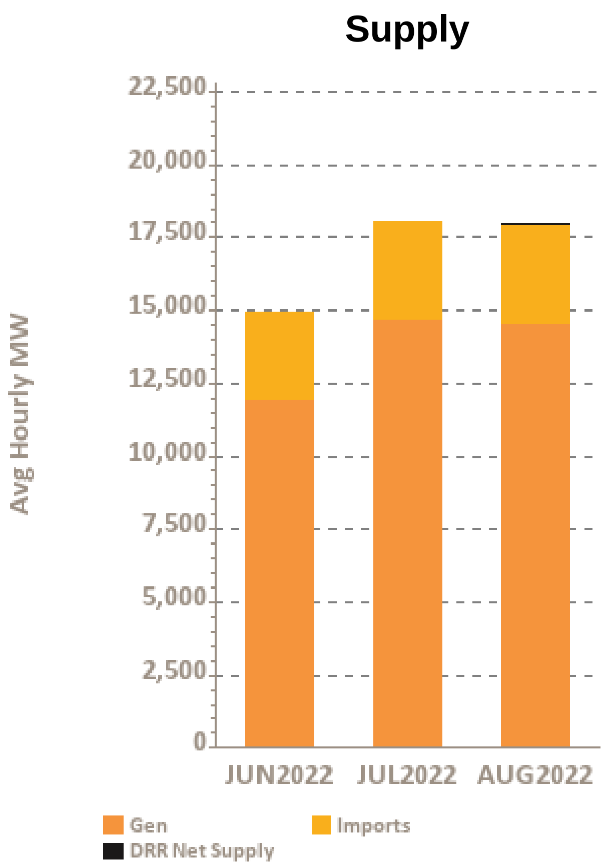


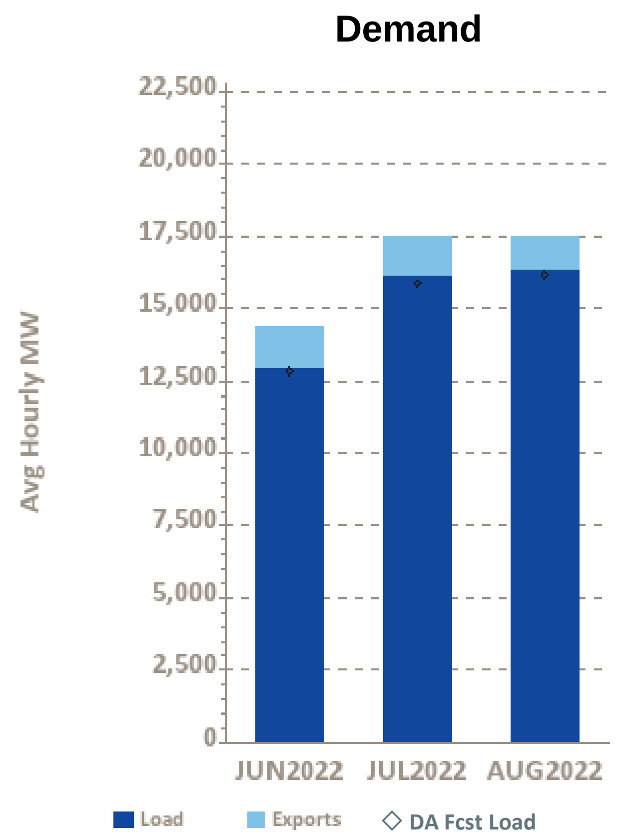


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

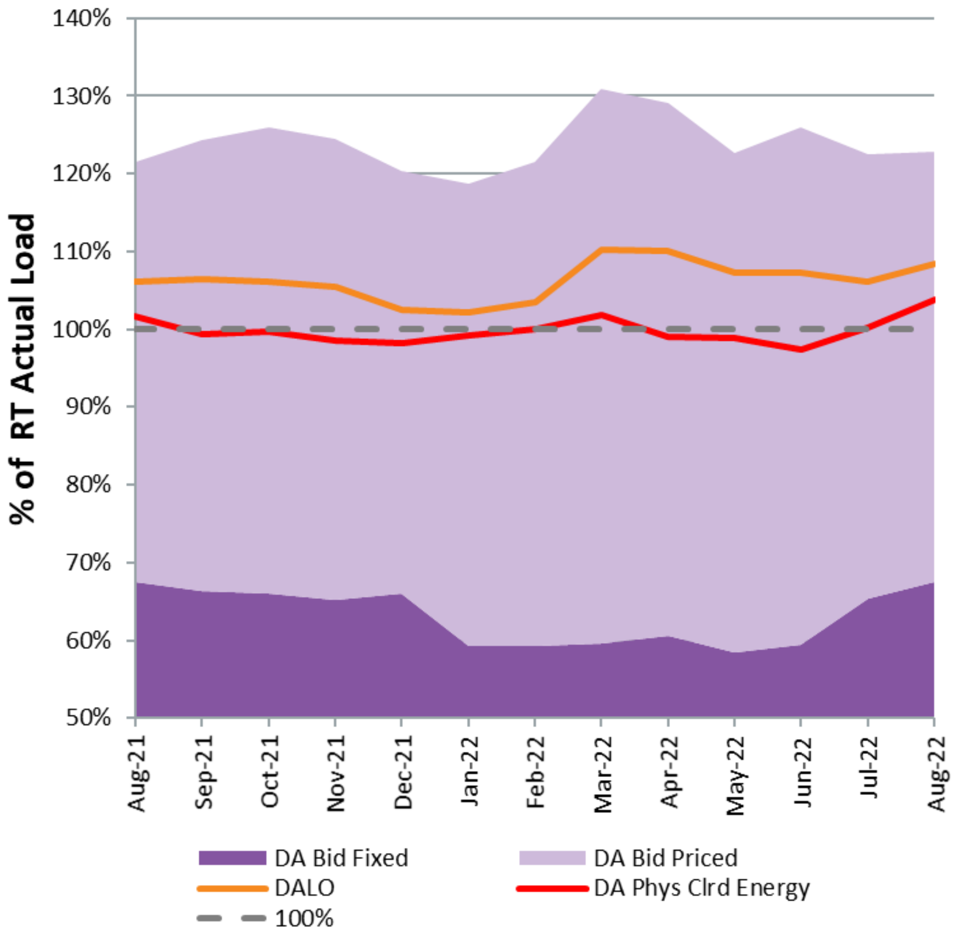
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

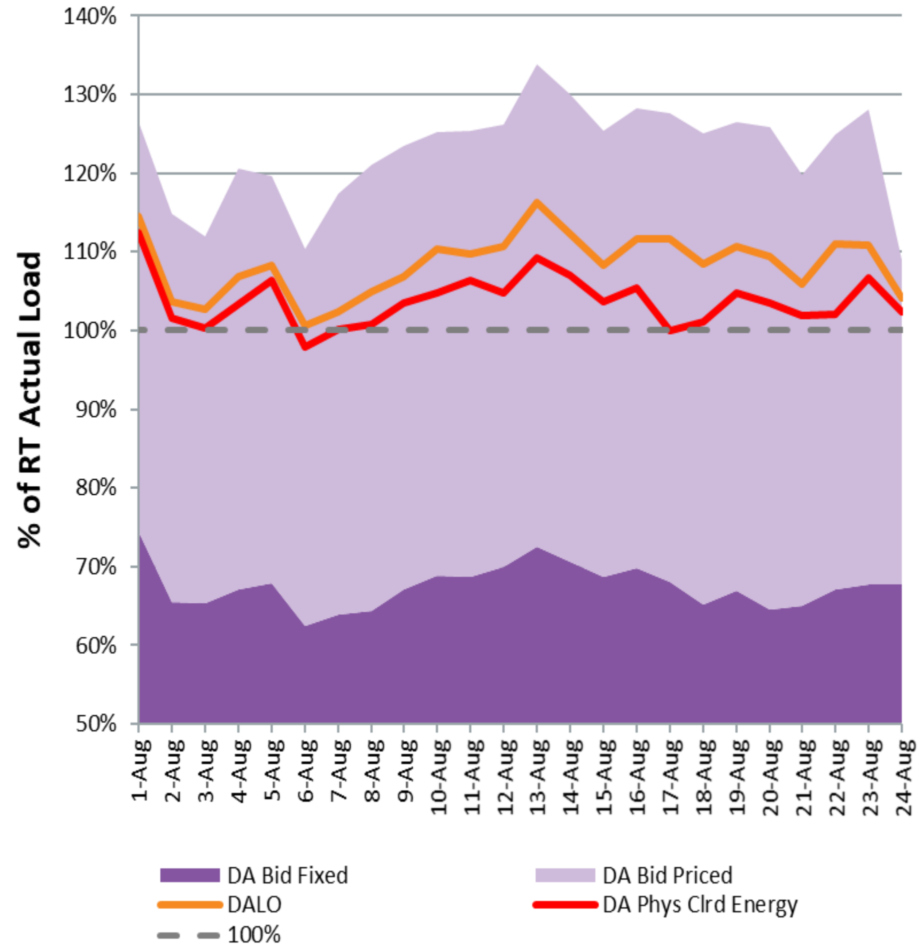
Components of RT Supply and Demand – Last Three Months





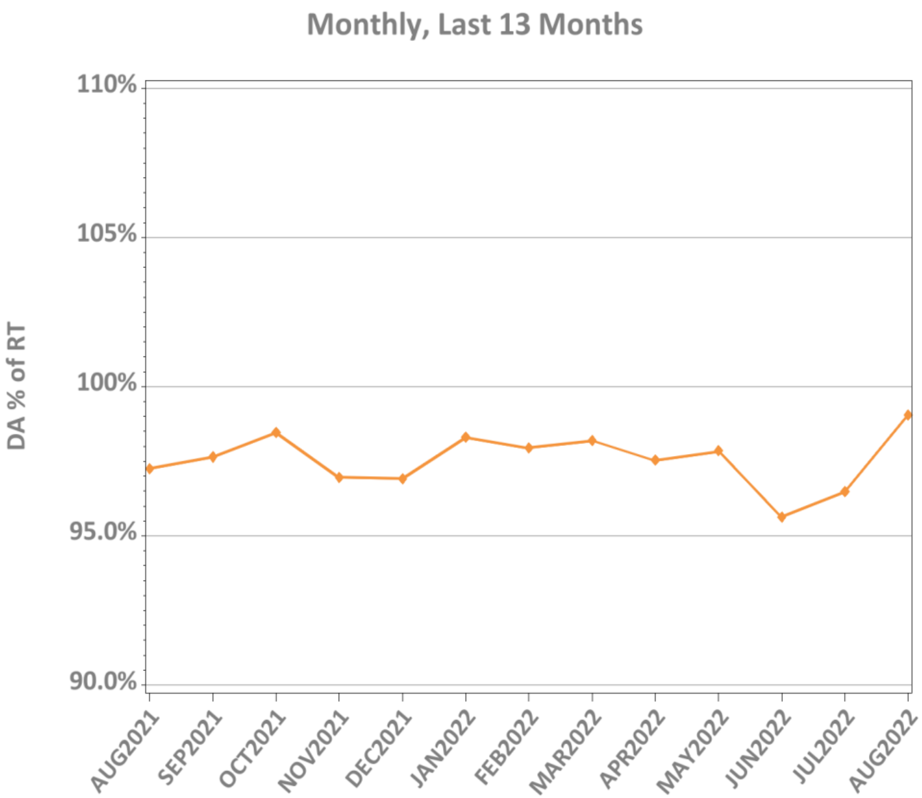
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

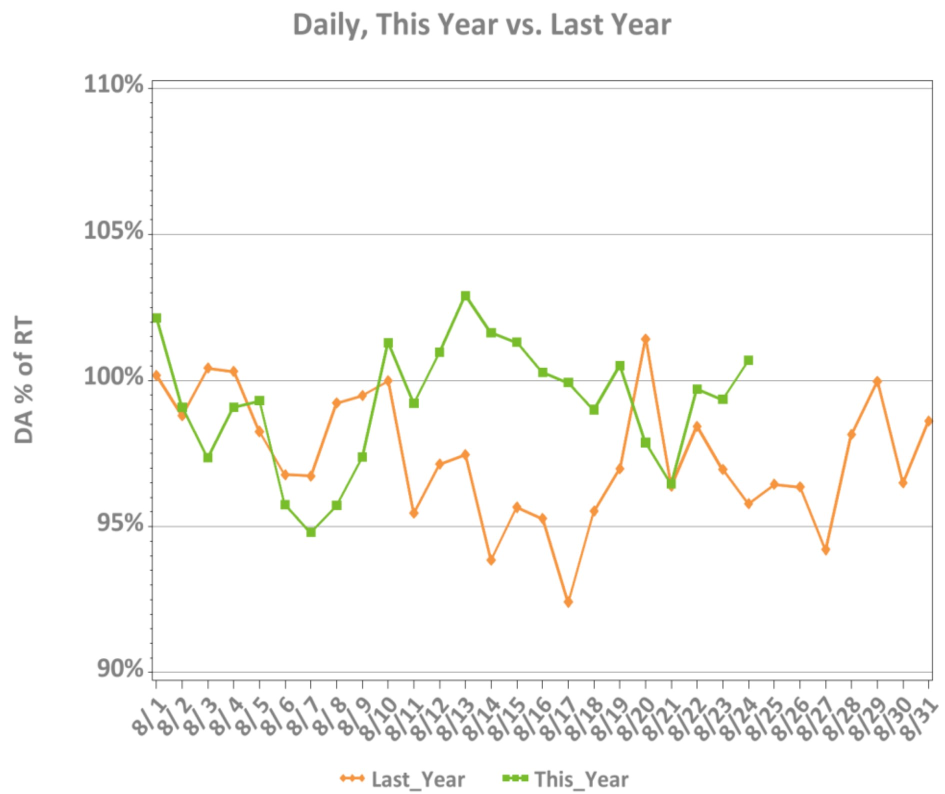




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

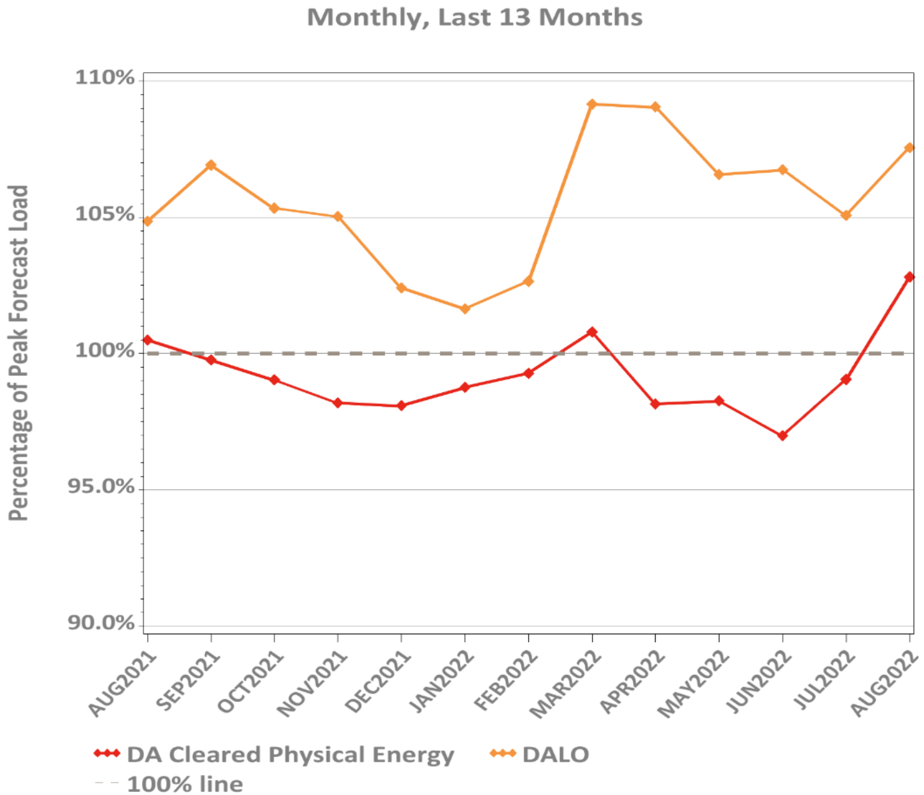
DA vs. RT Load Obligation: August, This Year vs. Last Year

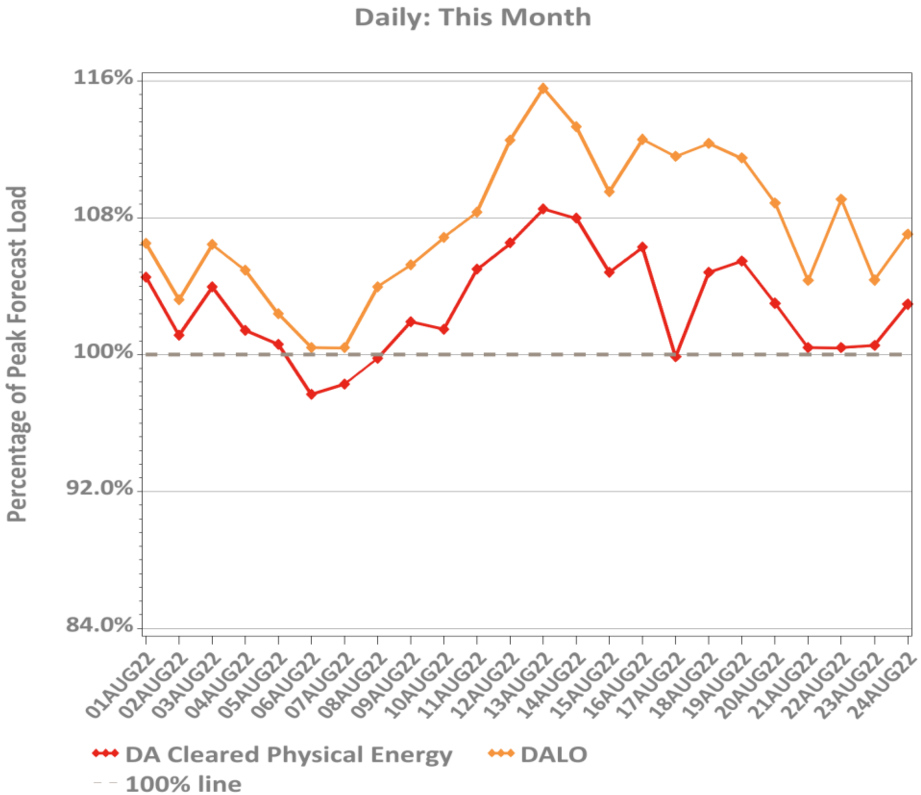




*Hourly average values

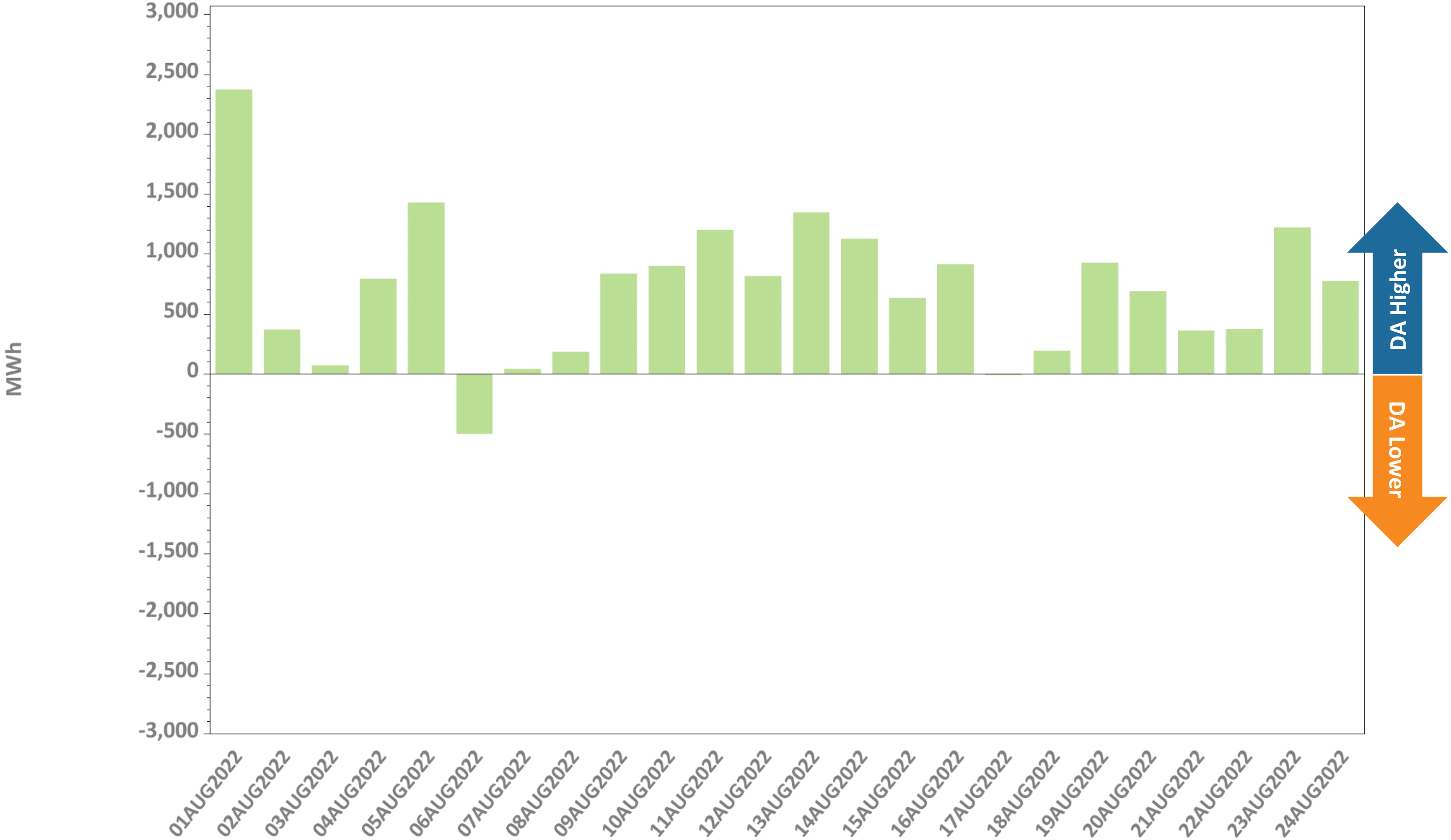
DA Volumes as % of Forecast in Peak Hour





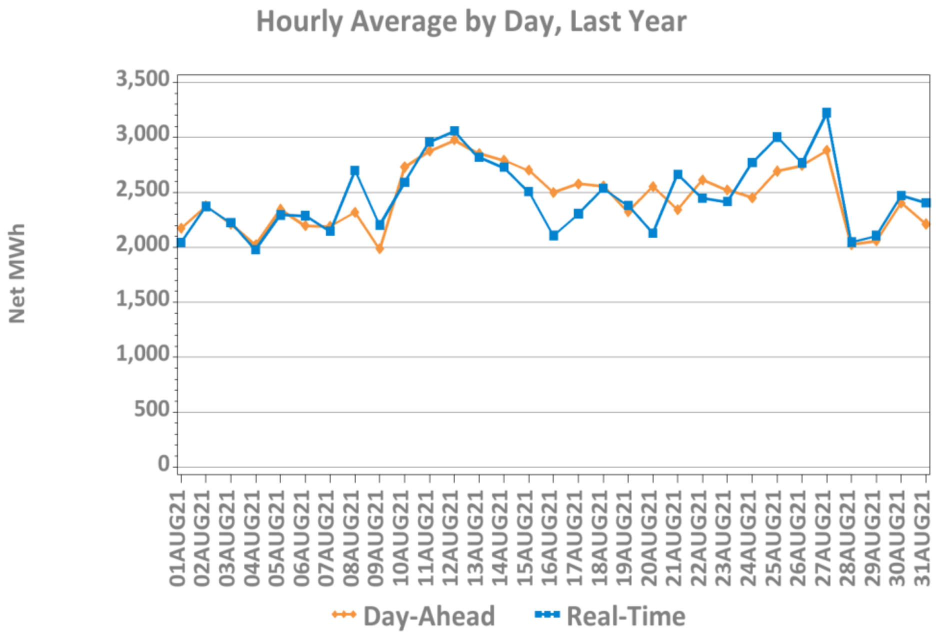
Note: There were three system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month. These occurred on August 6th, 7th and 8th

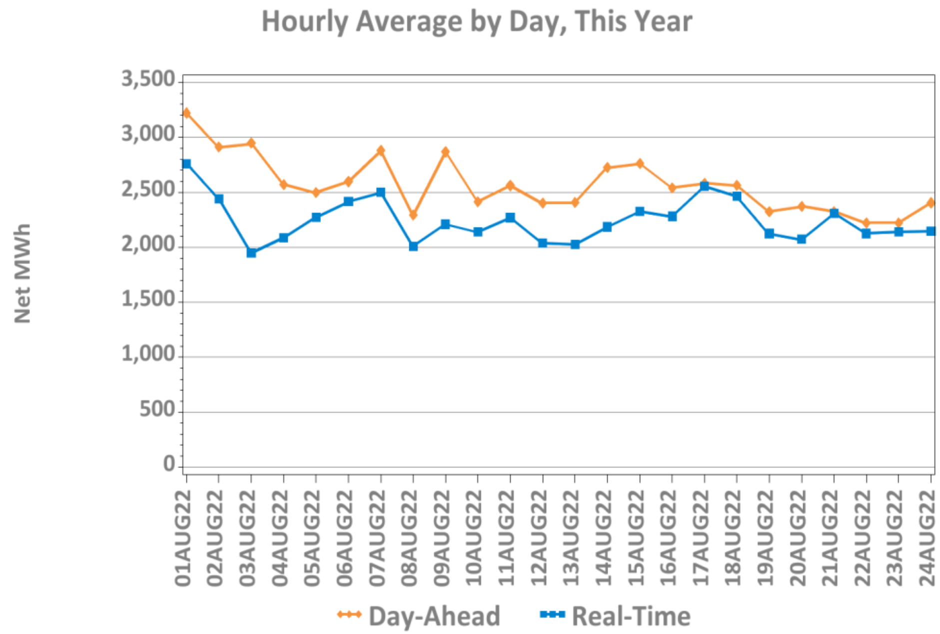
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



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

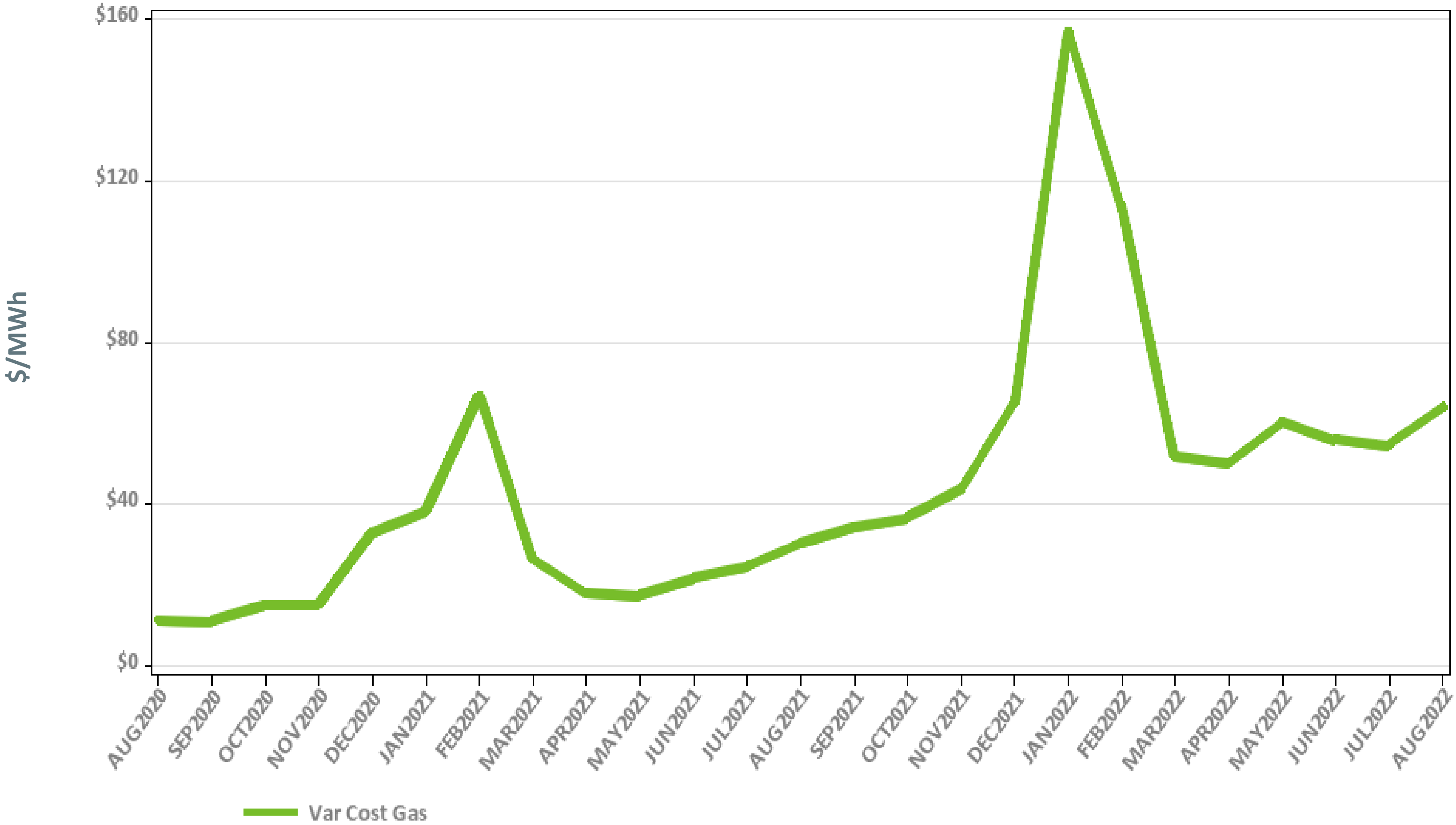
DA vs. RT Net Interchange August 2021 vs. August 2022





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

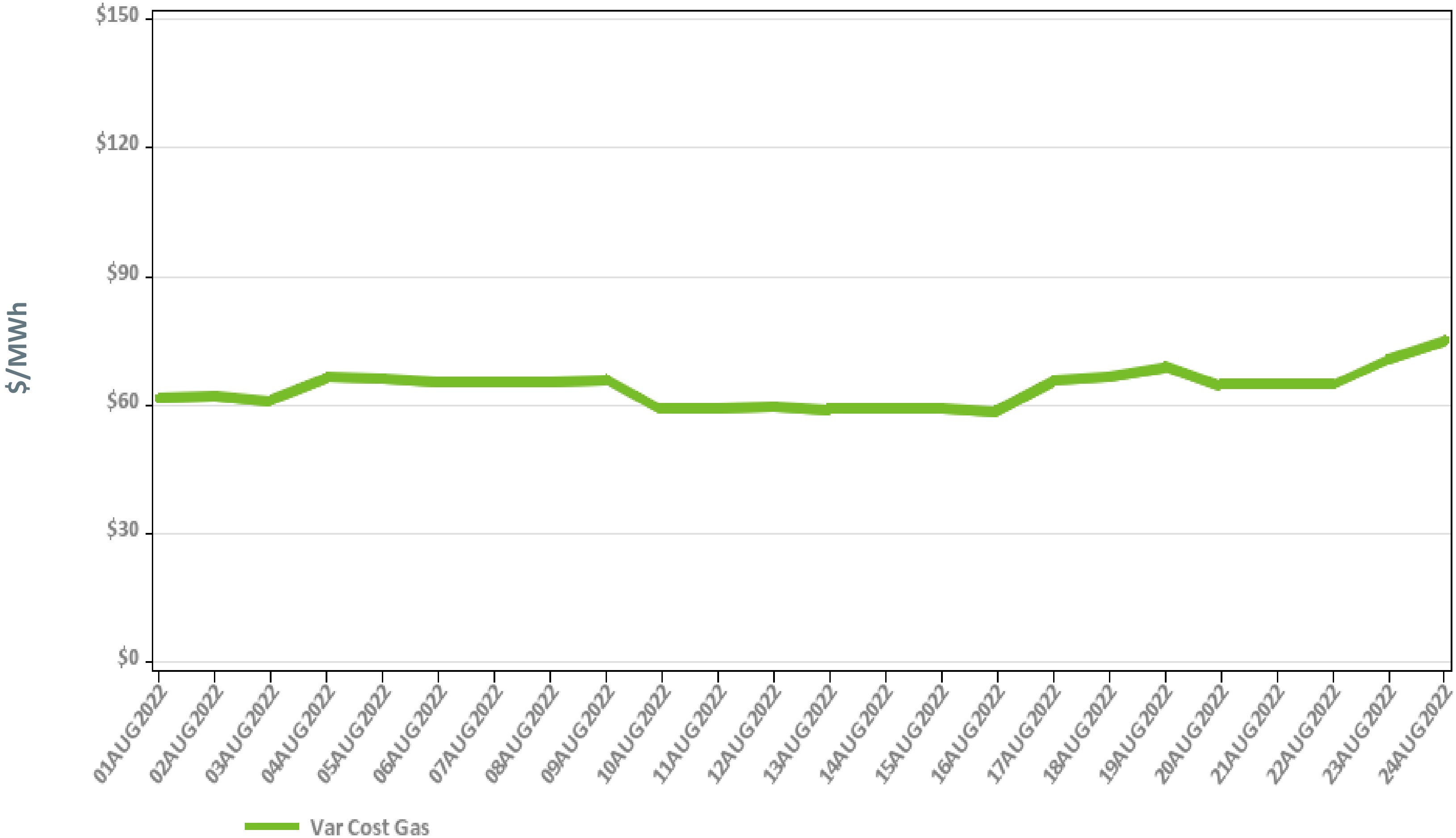


Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Underlying natural gas data furnished by:

ICE Global markets in clear view

Variable Production Cost of Natural Gas: Daily

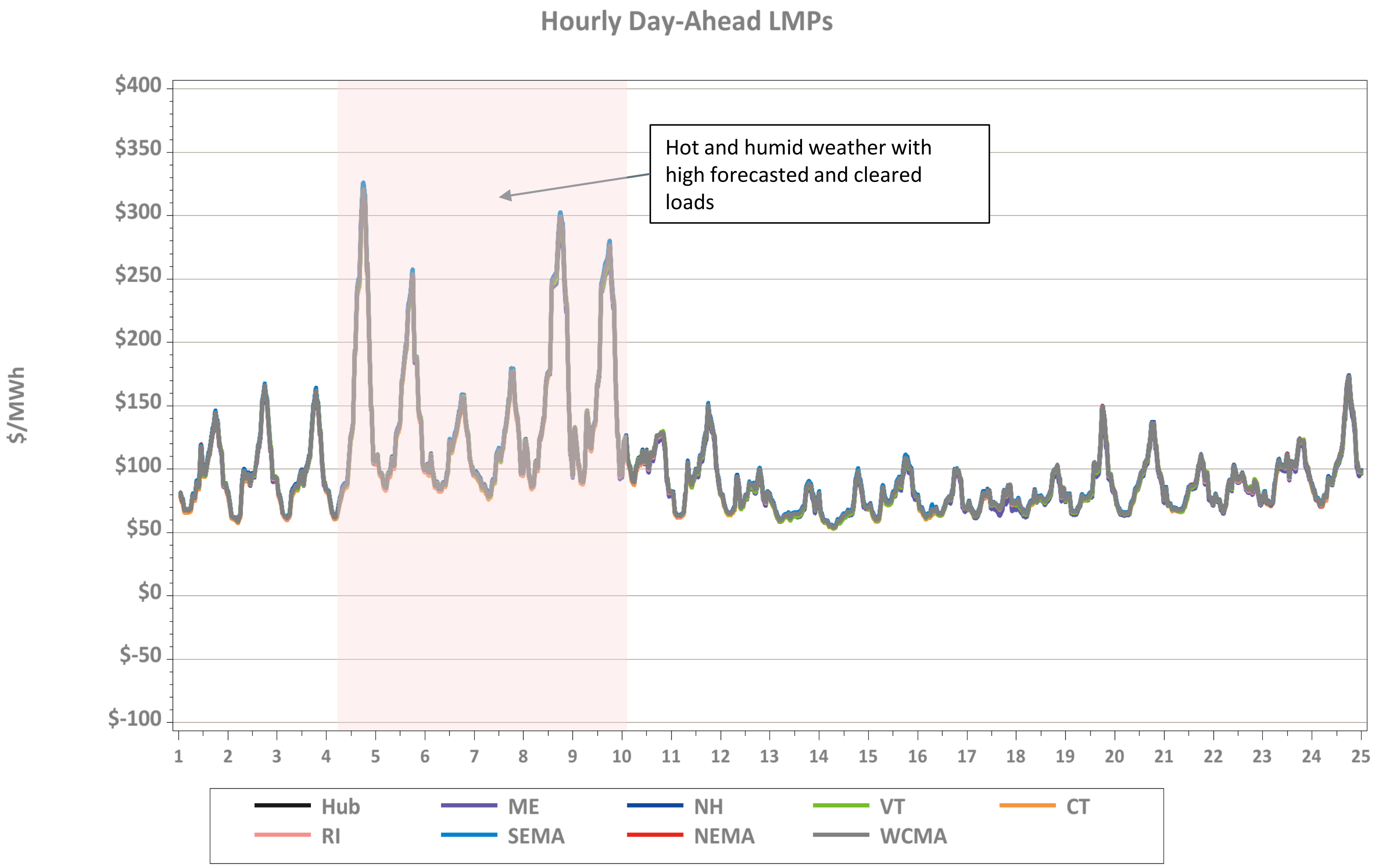


Underlying natural gas data furnished by:

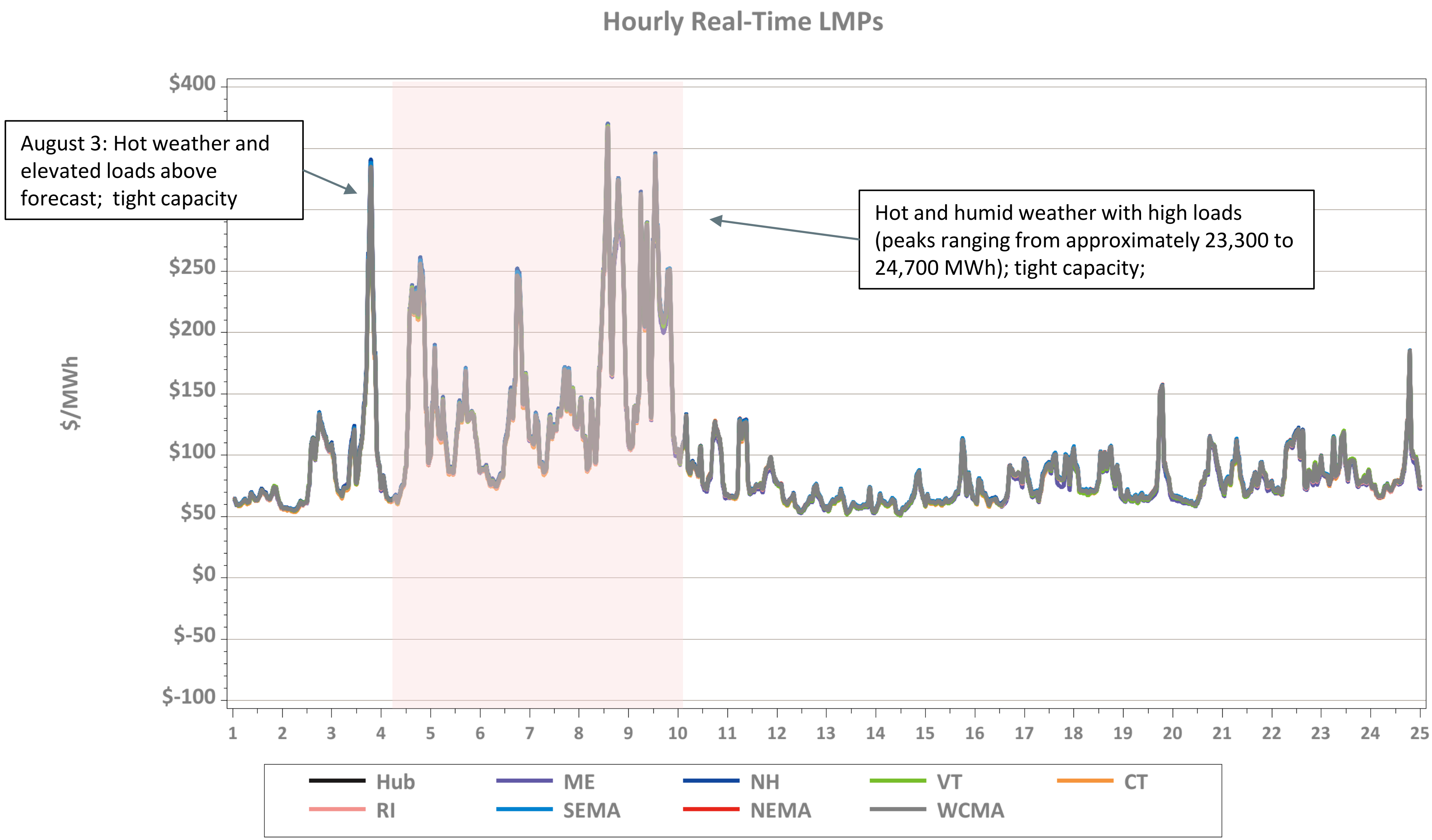
ICE Global markets in clear view

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

Hourly DA LMPs, August 1-24, 2022

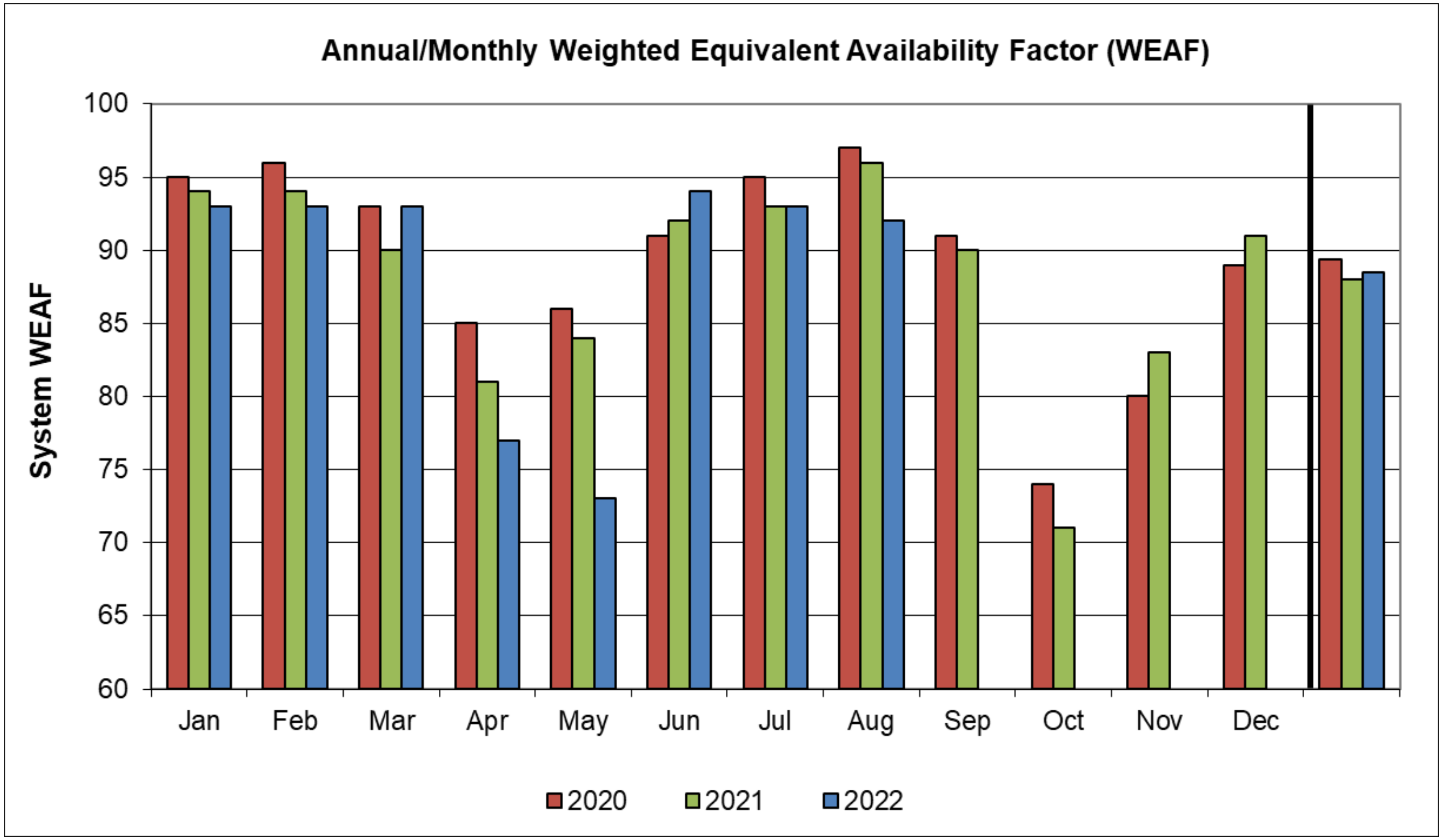


Hourly RT LMPs, August 1-24, 2022



* Revenue quality metered values reflected

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2022	93	93	93	77	73	94	93	92					89
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 8/24/2022

BACK-UP DETAIL

DEMAND RESPONSE

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

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	91.1	213.0	0.0	304.0
NH	42.7	169.4	0.0	212.1
VT	41.7	133.7	0.0	175.4
CT	138.4	232.3	630.2	1,000.9
RI	40.4	346.2	0.0	386.5
SEMA	40.9	532.5	0.0	573.4
WCMA	86.5	558.5	35.2	680.1
NEMA	73.0	879.5	0.0	952.5
Total	**554.5**	**3,065.0**	**665.4**	**4,285.0**

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

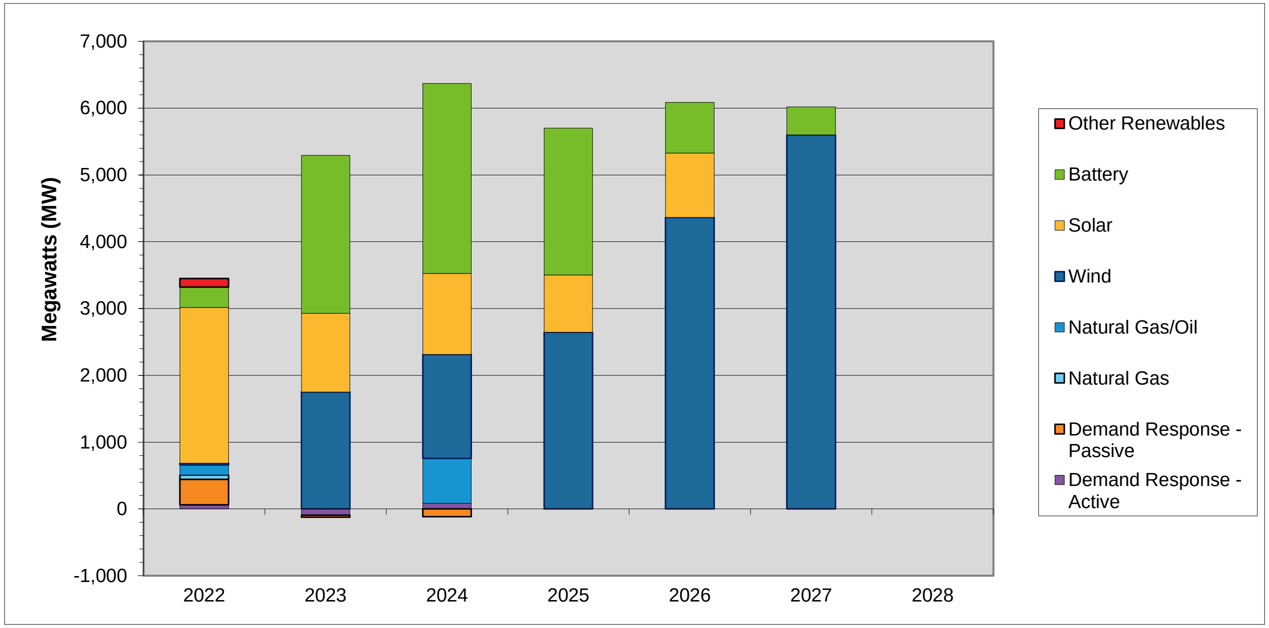
NEW GENERATION

New Generation Update
Based on Queue as of 08/26/22

- Six projects totaling 1,842 MW were added to the interconnection queue since the last update
  - Two solar projects, two battery projects, one solar with battery project and one wind project with in-service dates of 2025 to 2029
- Seven projects were withdrawn
- In total, 353 generation projects are currently being tracked by the ISO, totaling approximately 34,789 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



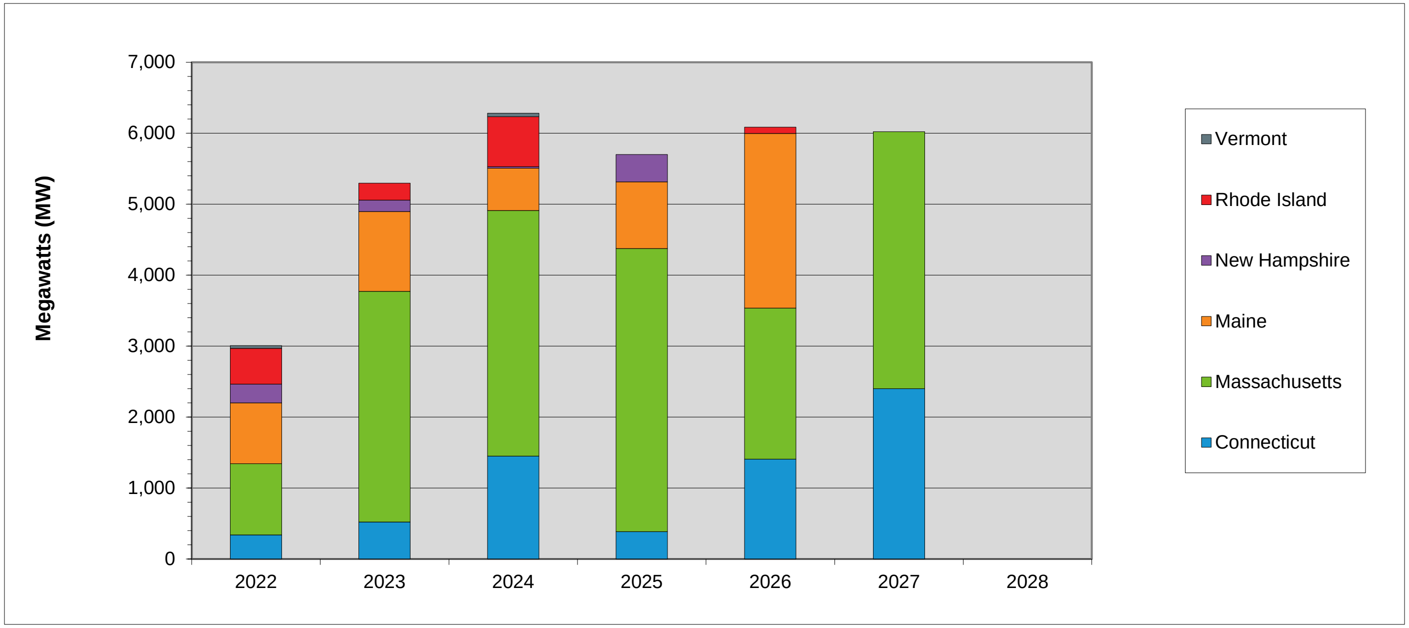
	2022	2023	2024	2025	2026	2027	2028	Total MW	% of Total[1]
Other Renewables	129	0	0	0	0	0	0	129	0.4
Battery	305	2,367	2,841	2,196	759	421	0	8,889	27.2
Solar[2]	2,331	1,175	1,213	859	964	0	0	6,542	20.0
Wind	24	1,752	1,556	2,645	4,363	5,599	0	15,939	48.8
Natural Gas/Oil[3]	151	0	672	0	0	0	0	823	2.5
Natural 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	**3,449**	**5,172**	**6,254**	**5,700**	**6,086**	**6,020**	**0**	**32,681**	**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	858	1,123	597	942	2,461	0	0	5,981	18.5
Massachusetts	1,001	3,251	3,462	3,989	2,126	3,620	0	17,449	53.9
Connecticut	340	520	1,449	384	1,408	2,400	0	6,501	20.1
Totals	**3,007**	**5,294**	**6,282**	**5,700**	**6,086**	**6,020**	**0**	**32,389**	**100.0**

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

New Generation Projection

By Fuel Type

Unit Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	58	8,889	0	0	58	8,889
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	251	6,542	23	242	228	6,300
Wind	27	18,339	1	20	26	18,319
Total	353	34,789	27	395	326	34,394

- 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

Operating Type	Total		Green		Yellow	
	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	315	16,776	25	370	290	16,406
Wind Turbine	26	17,139	1	20	25	17,119
Total	353	34,789	27	395	326	34,394

- 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	58	8,889	0	0	0	0	58	8,889	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	251	6,542	0	0	0	0	251	6,542	0	0
Wind	27	18,339	0	0	0	0	1	1,200	26	17,139
Total	353	34,789	5	70	7	804	315	16,776	26	17,139

- 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						
Demand	*Passive Demand*	2,557.256						
Demand Total		**3,322.606**						
Generator	*Non-Intermittent*	26,805.003						
Generator	*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

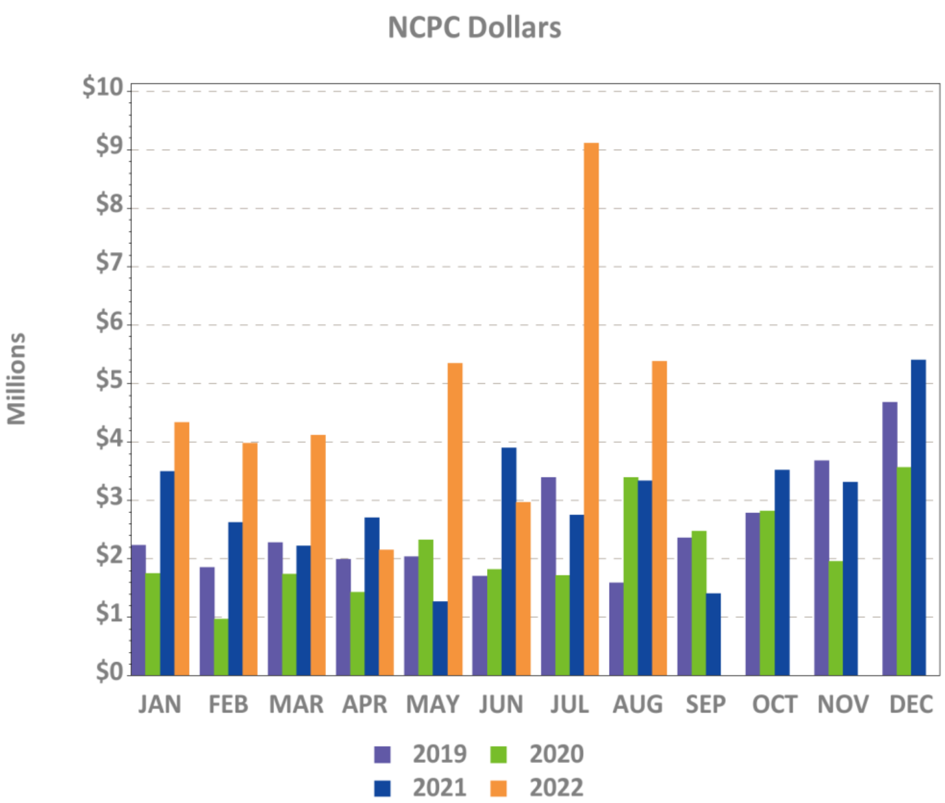
Definitions

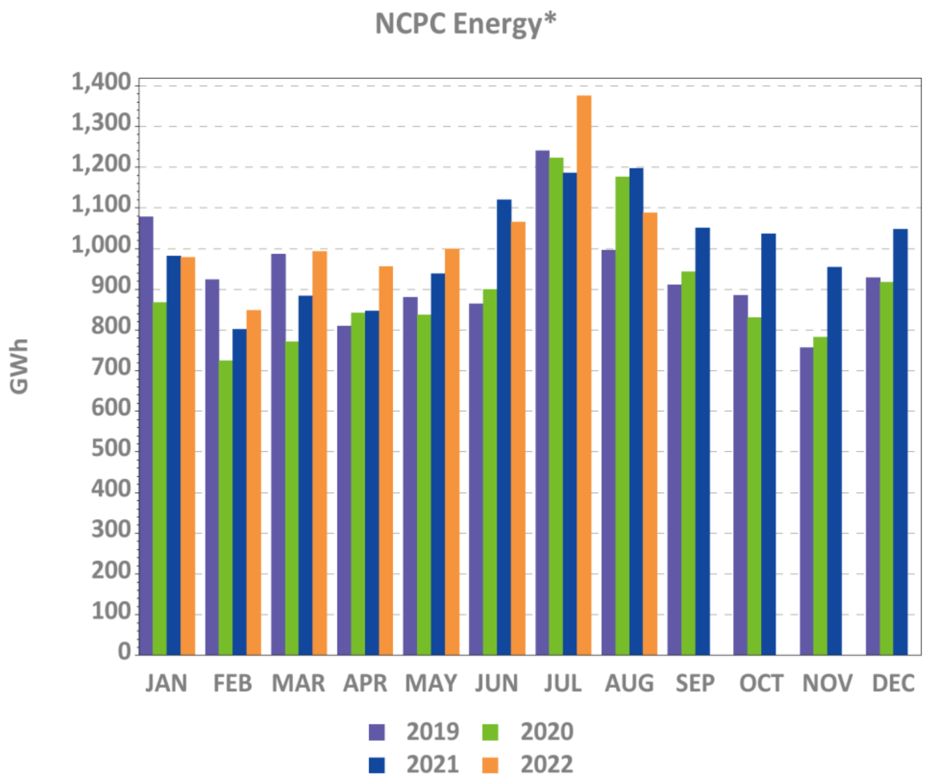
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

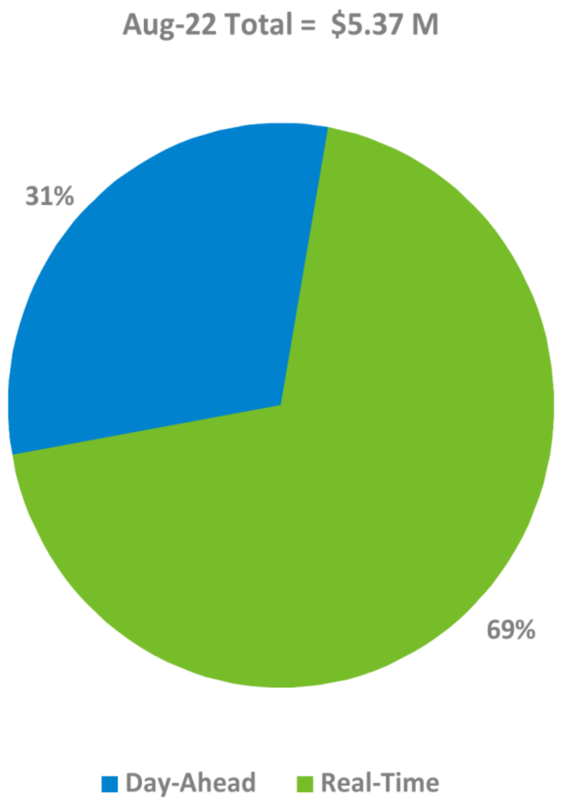
Year-Over-Year Total NCPC Dollars and Energy

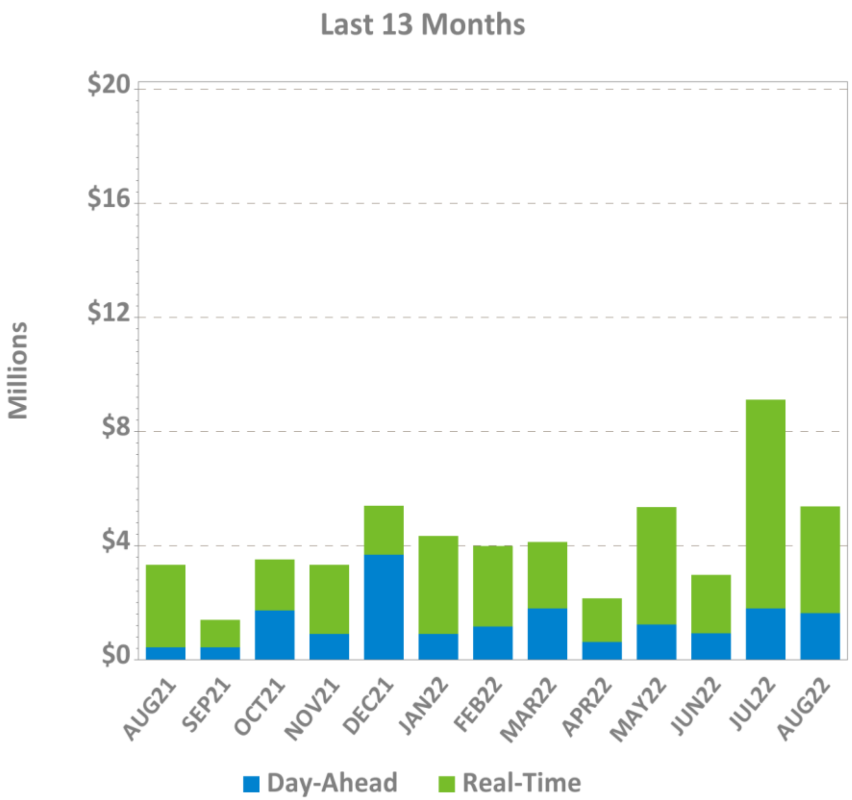




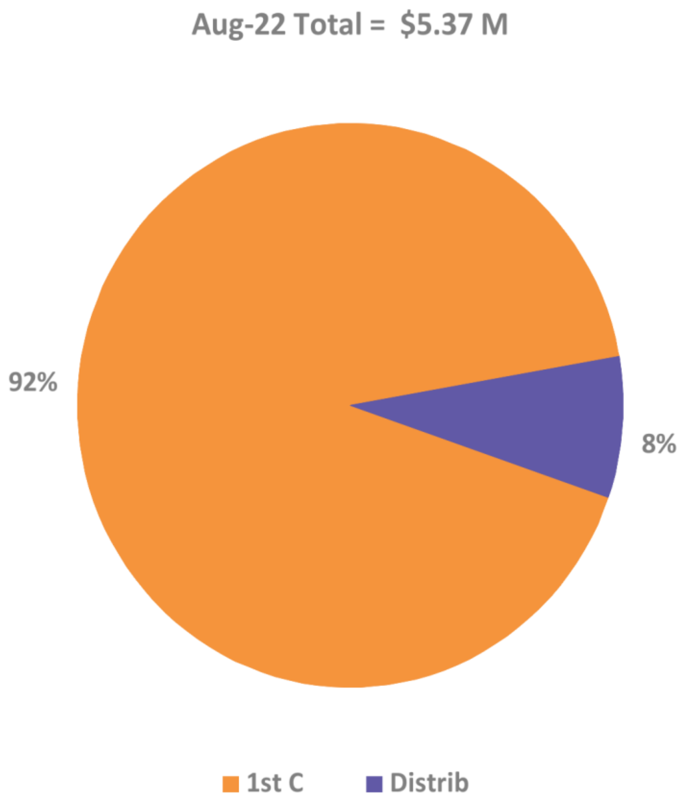
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

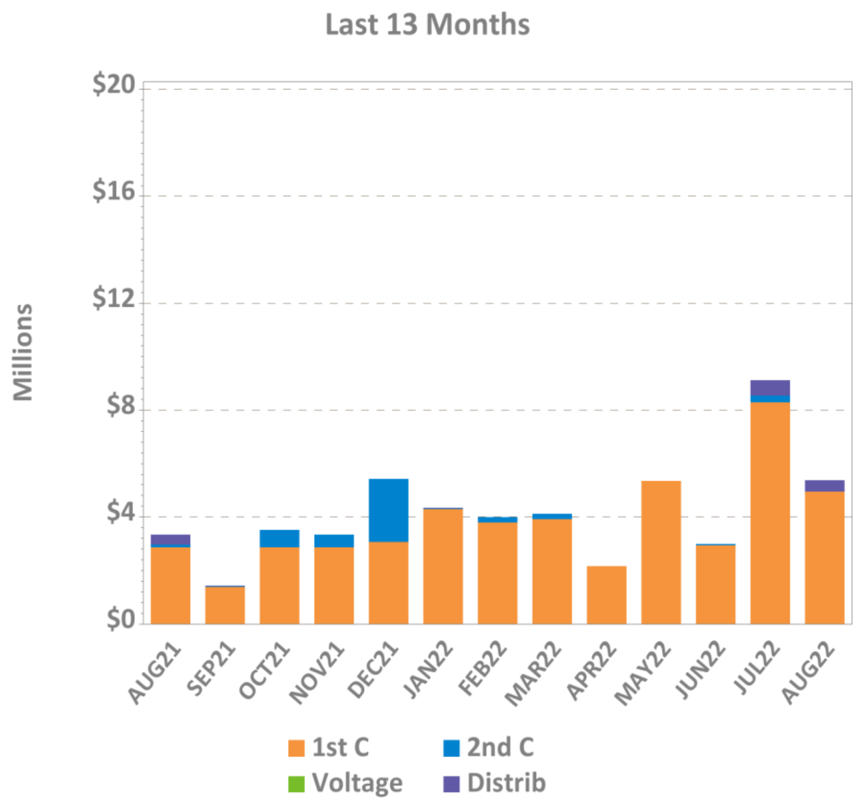
DA and RT NCPC Charges





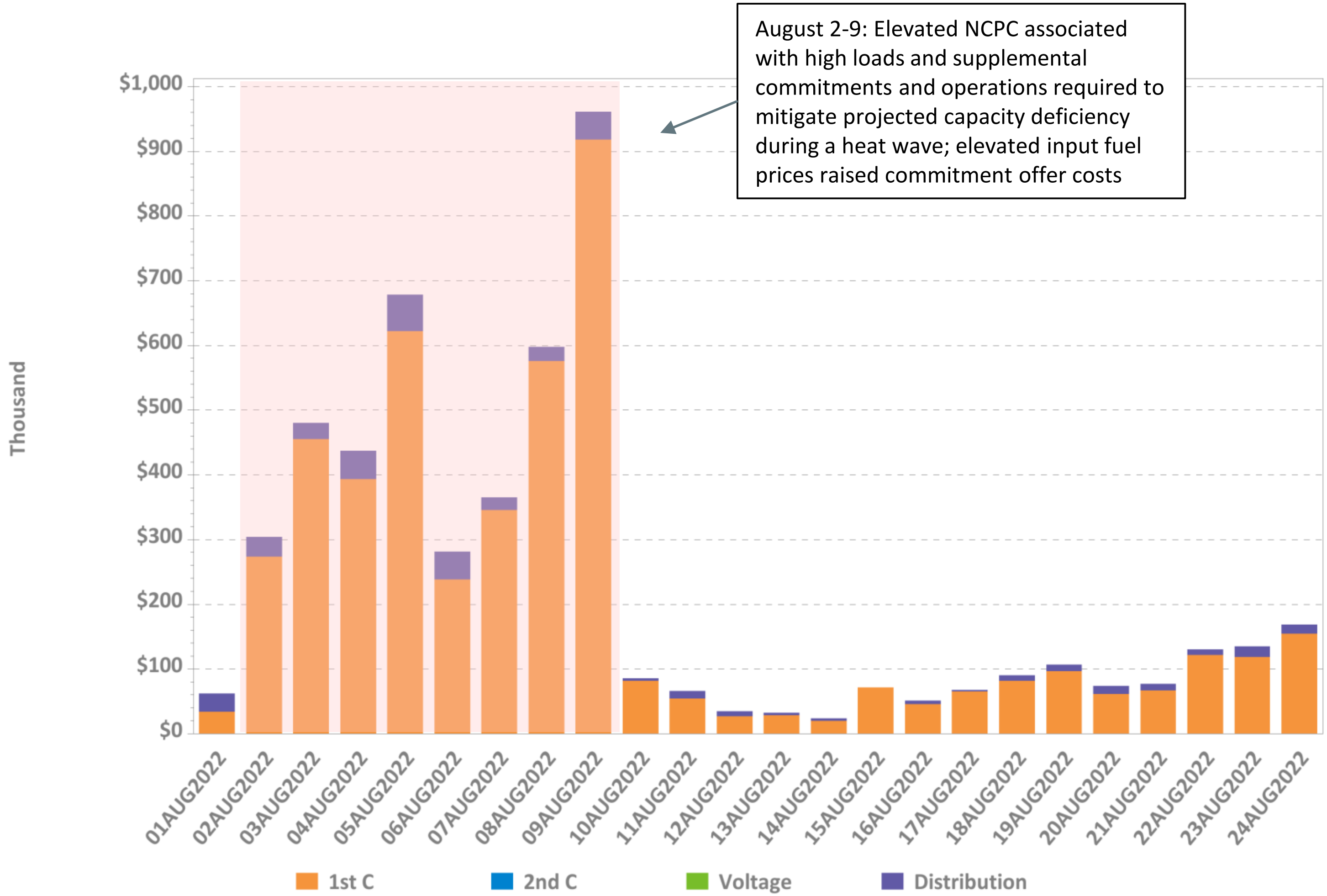
NCPC Charges by Type



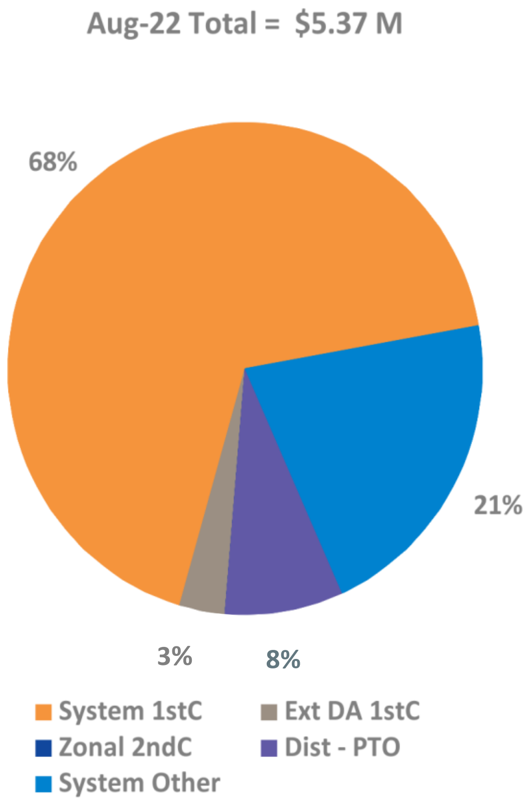


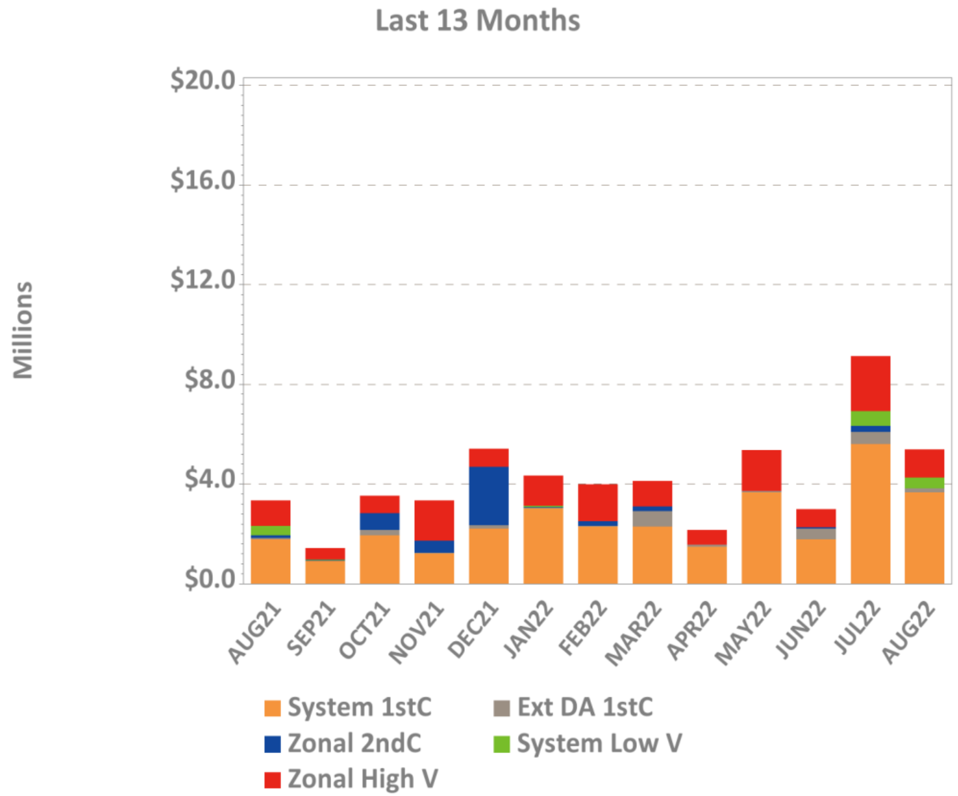
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



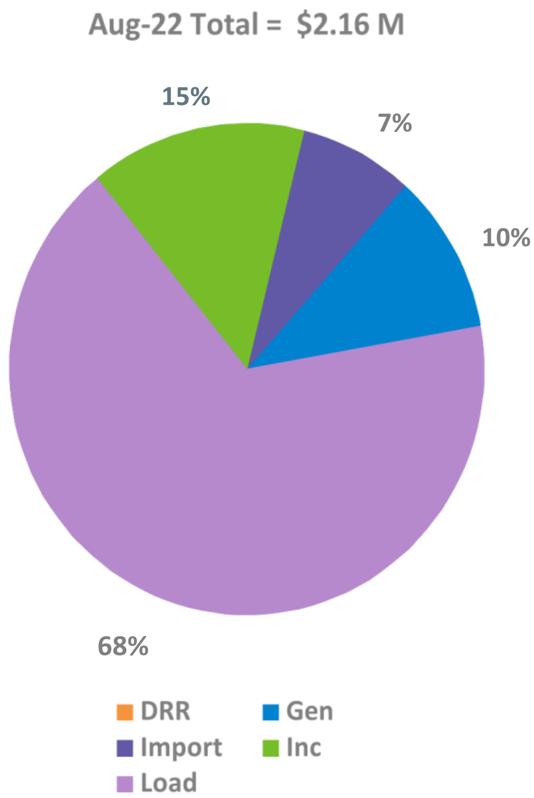
NCPC Charges by Allocation

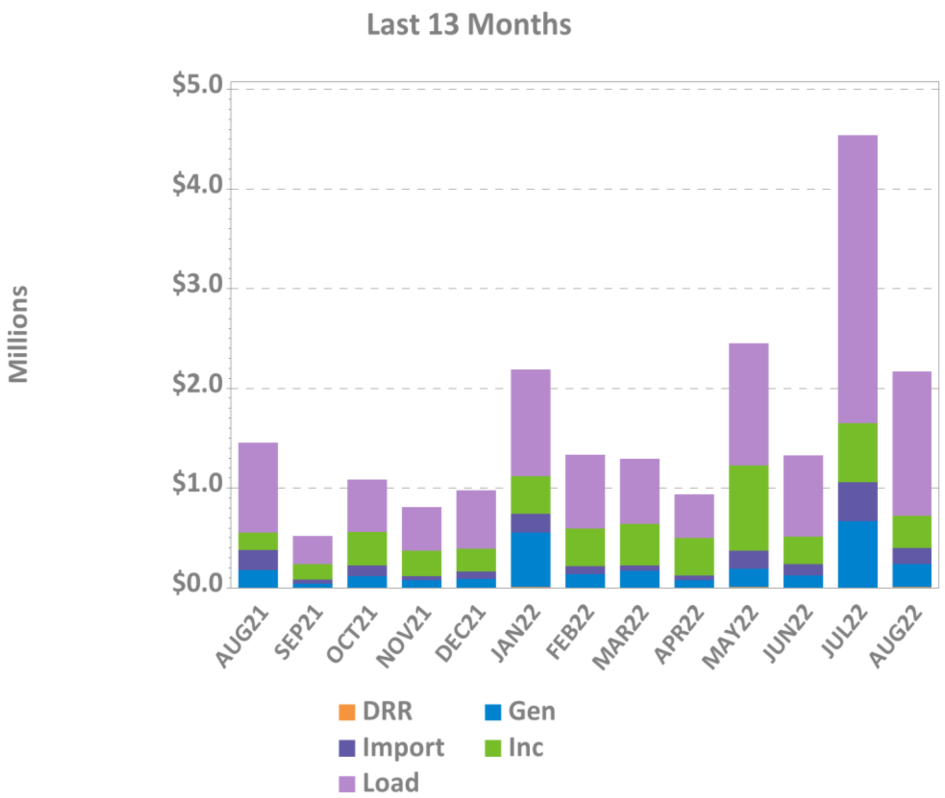




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

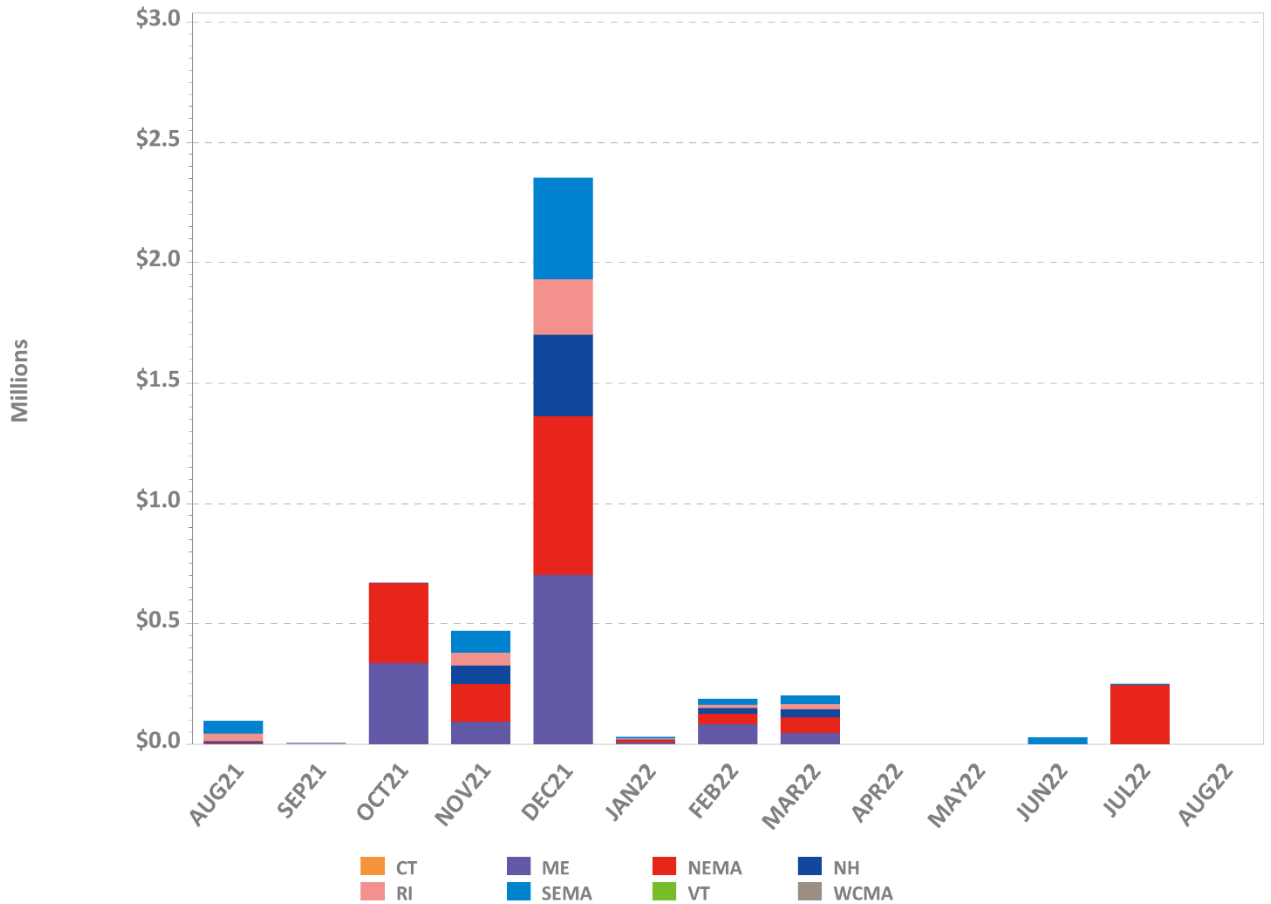
RT First Contingency Charges by Deviation Type





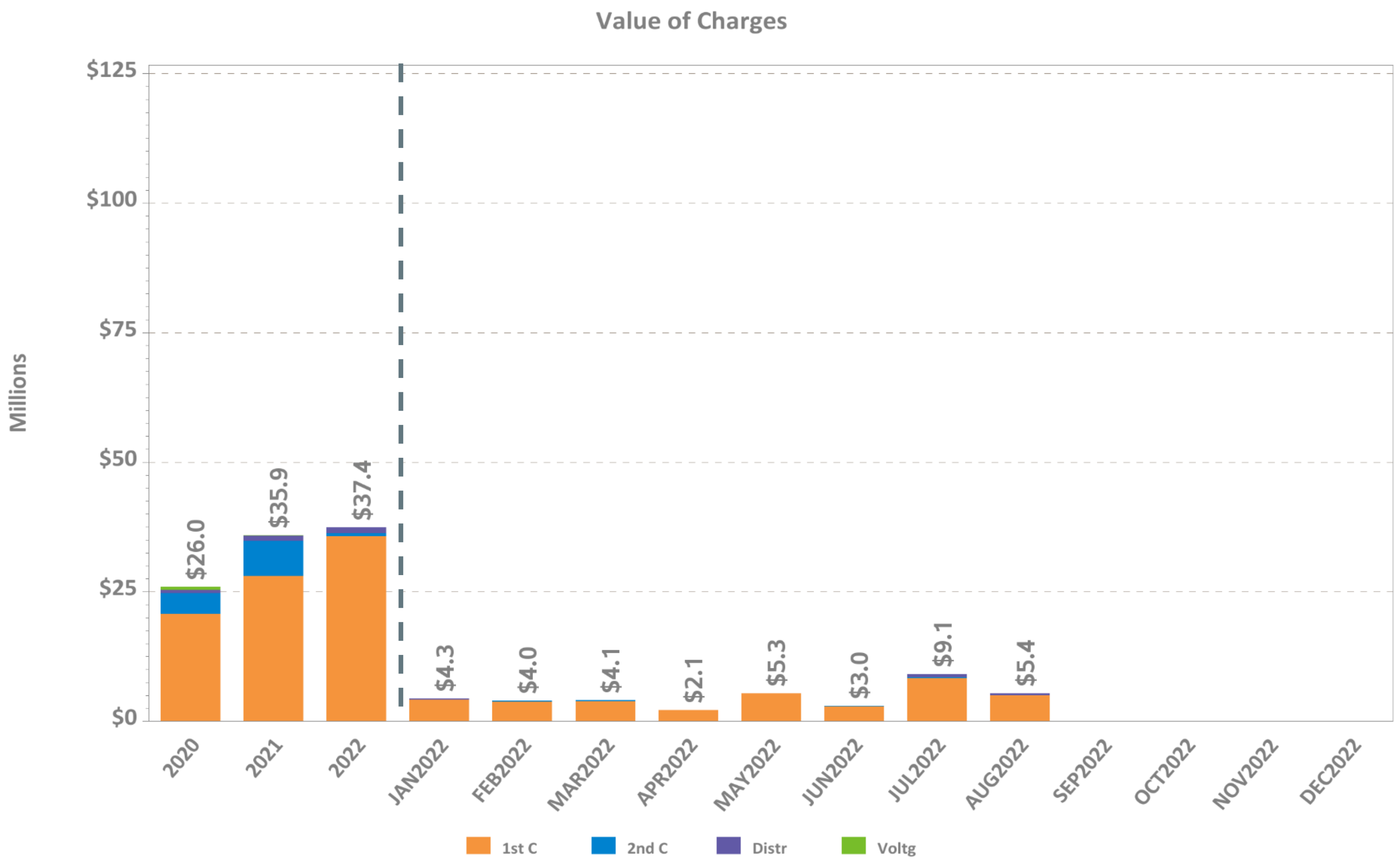
DRR – Demand Response Resource deviations
Gen – Generator deviations
Inc – Increment Offer deviations
Import – Import deviations
Load – Load obligation deviations

LSCPR Charges by Reliability Region

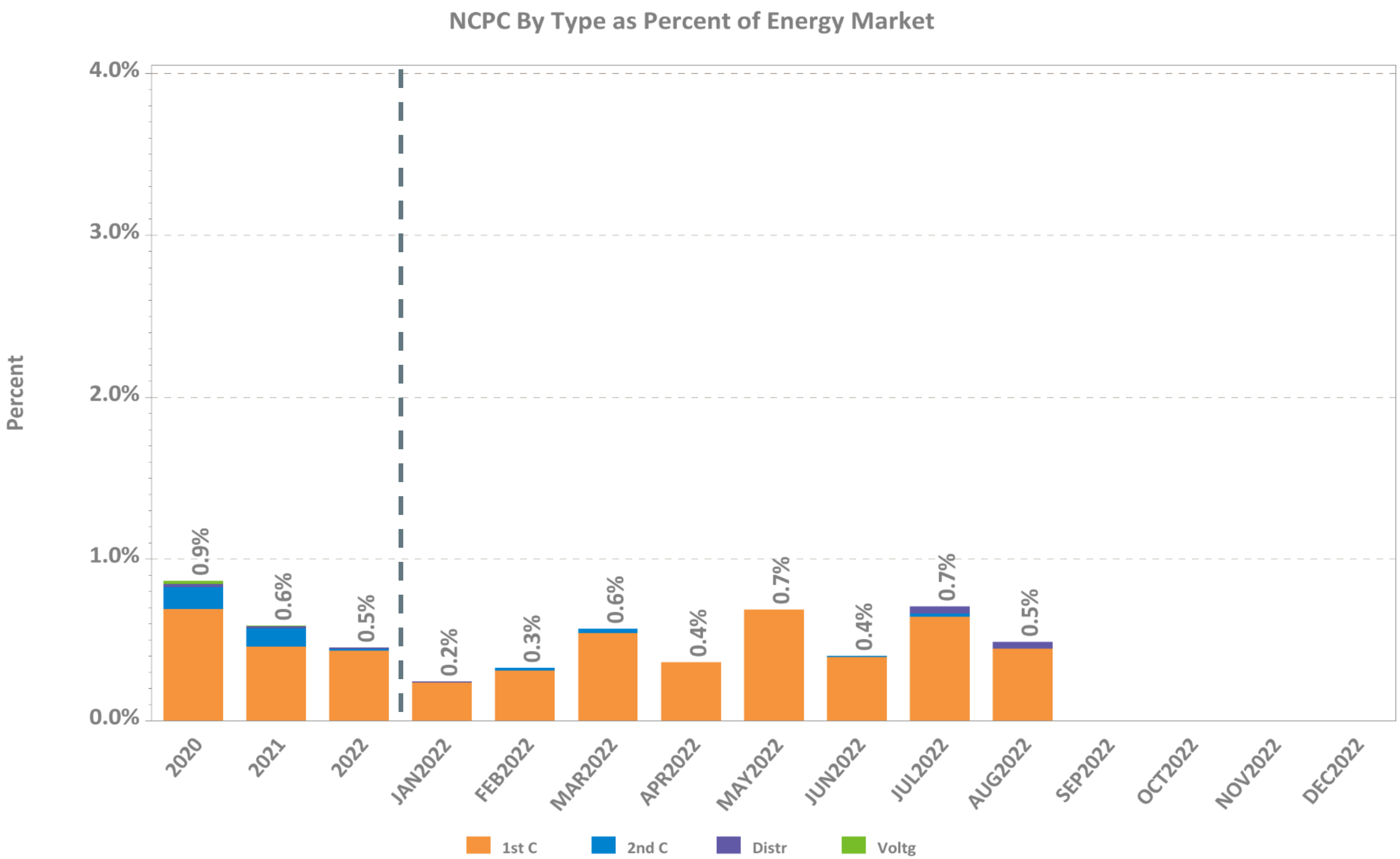


CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region
SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region

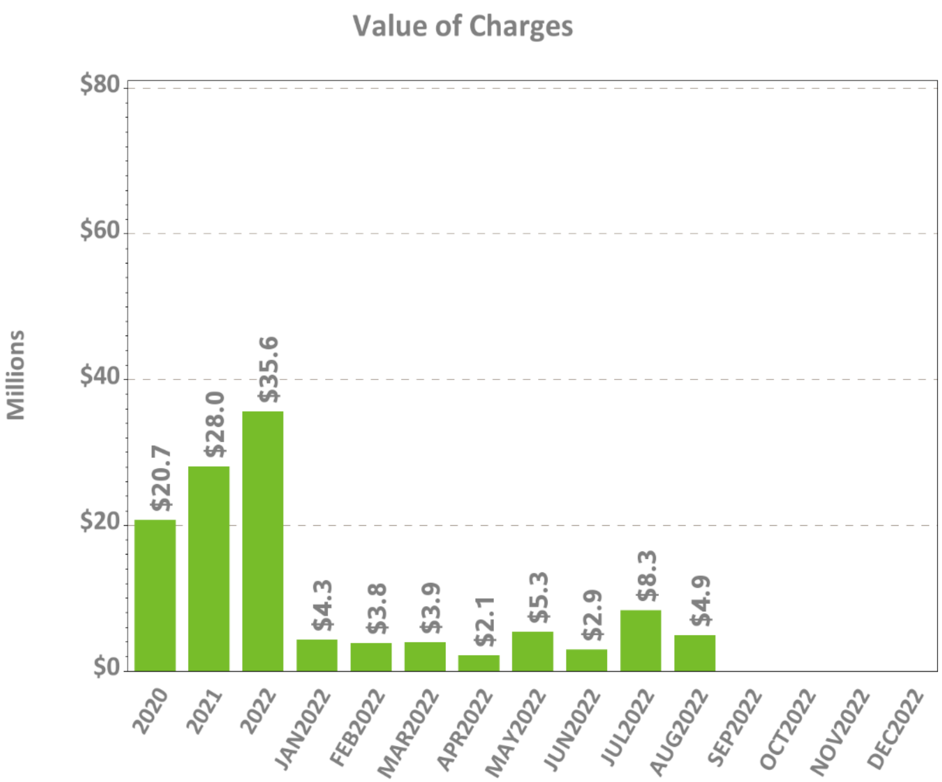
NCPC Charges by Type

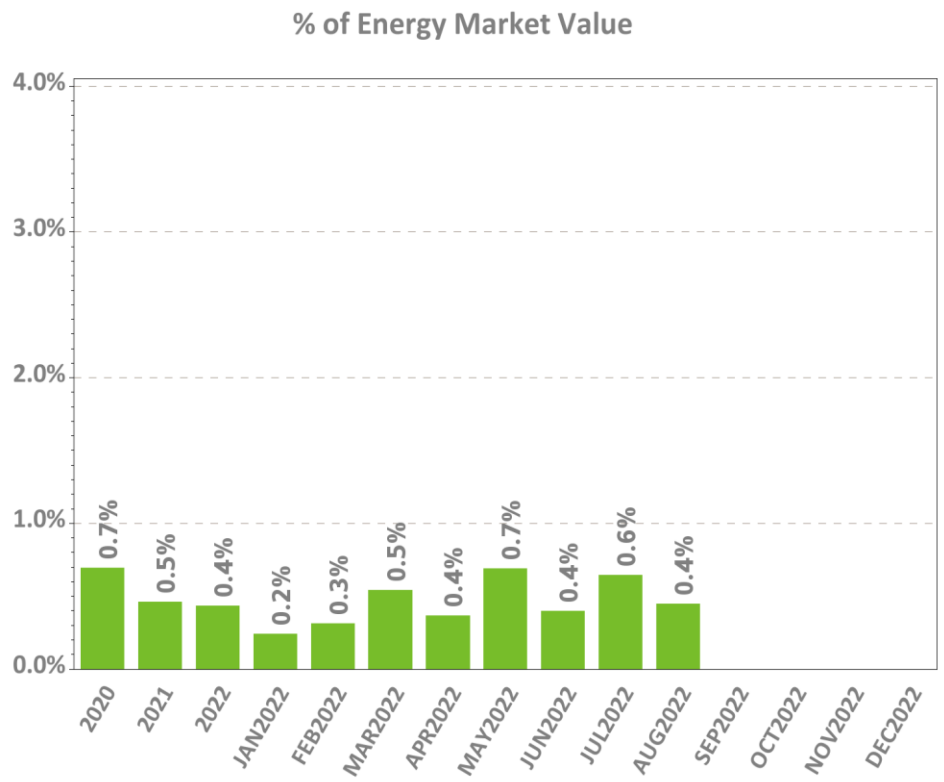


NCPC Charges as Percent of Energy Market



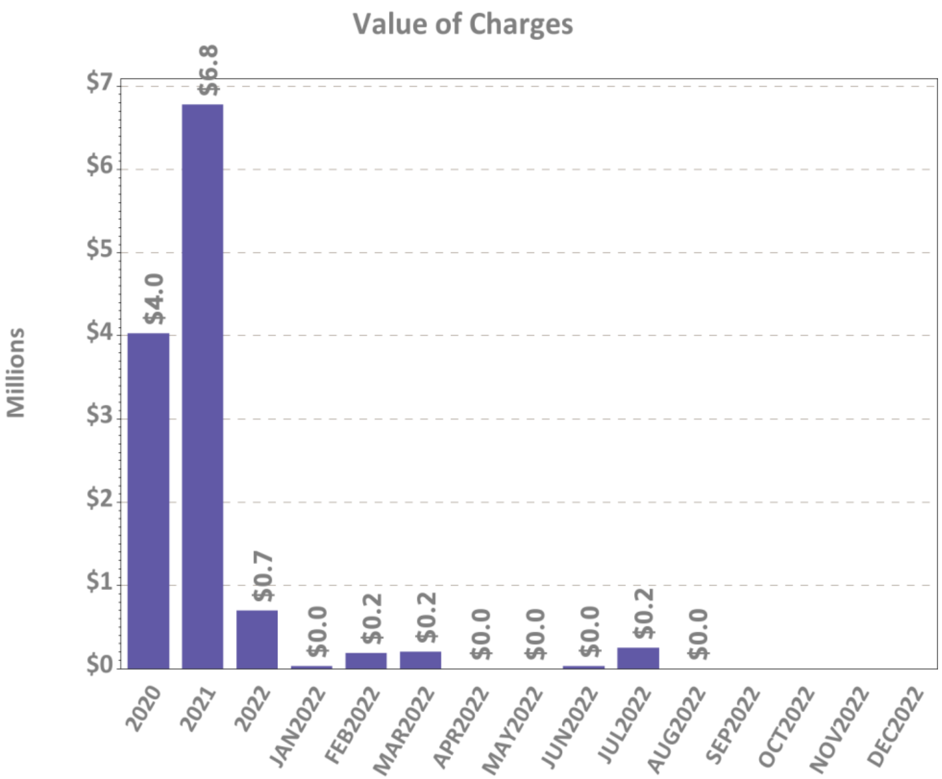
First Contingency NCPC Charges

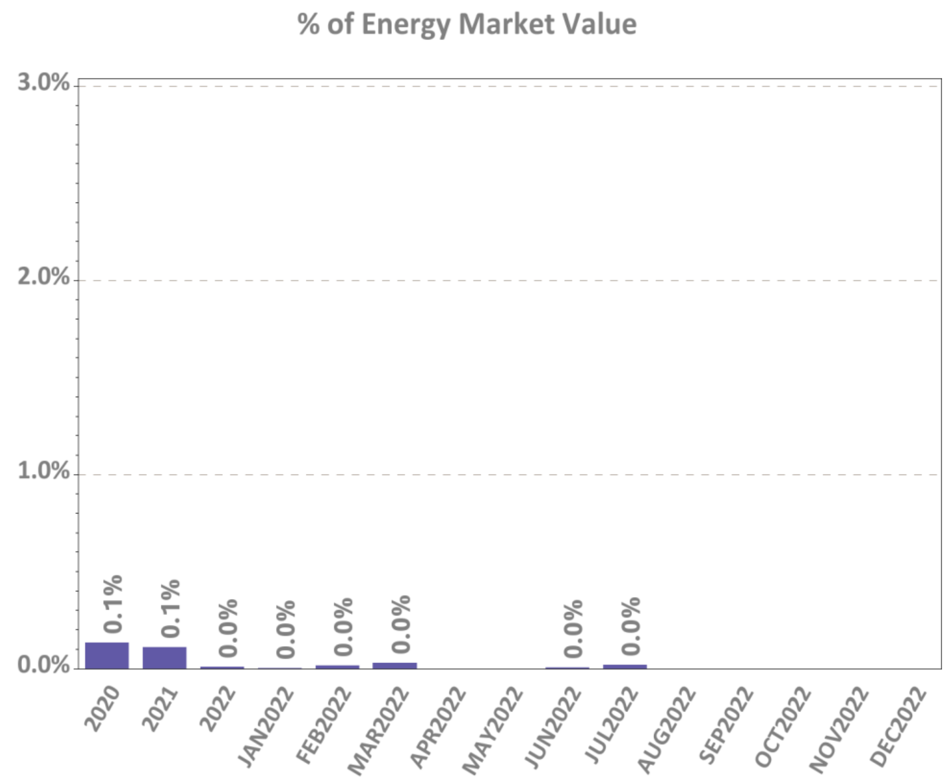




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

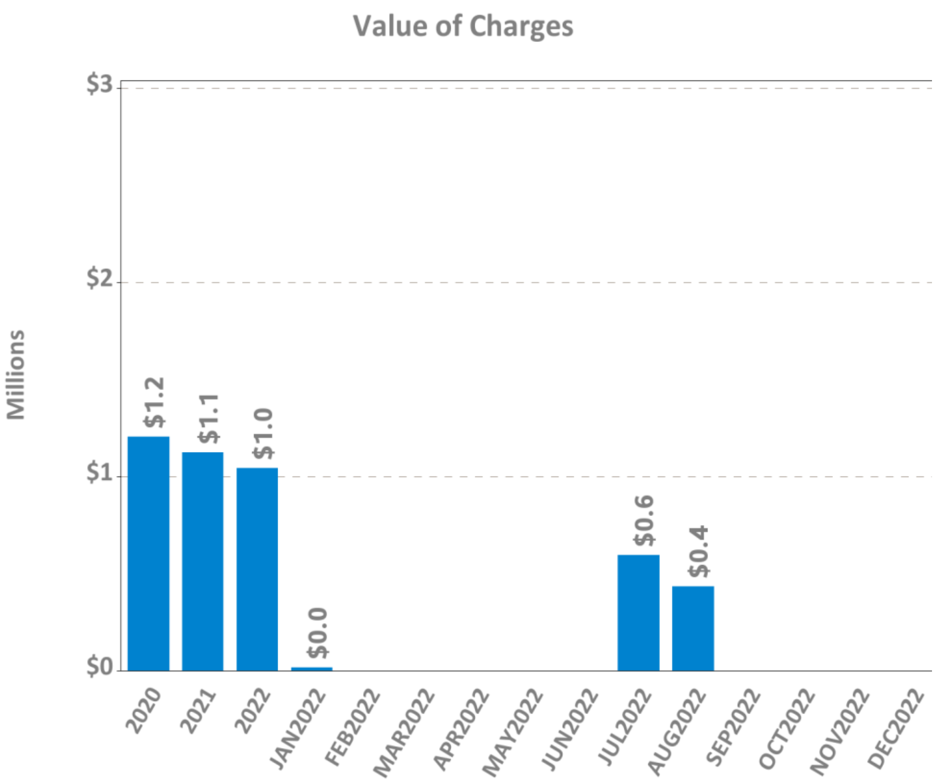
Second Contingency NCPC Charges

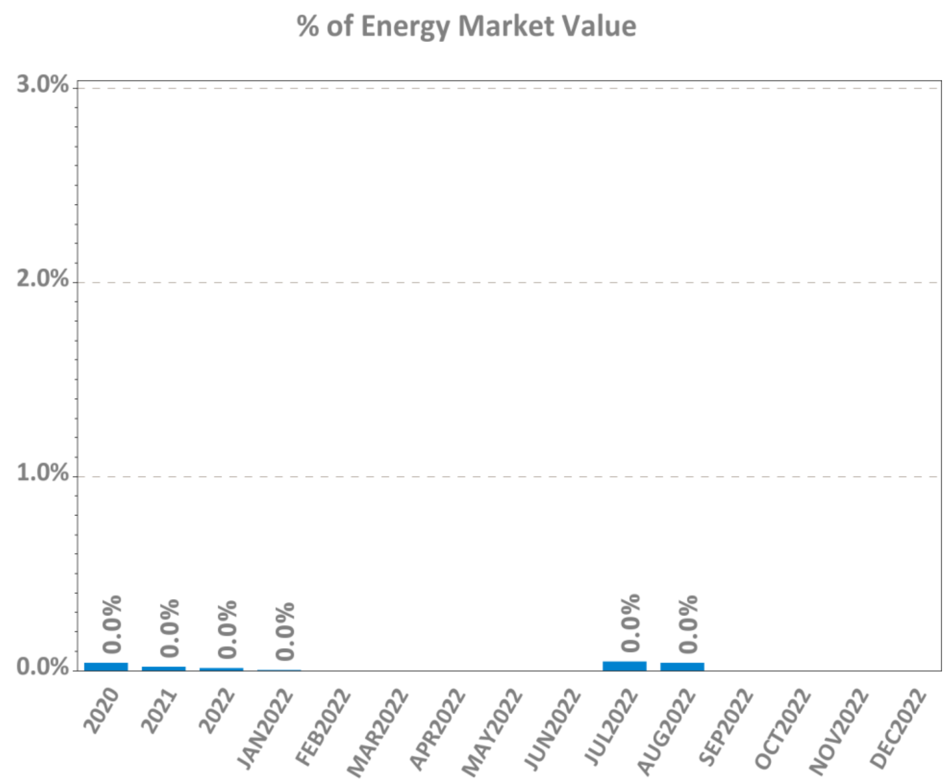




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution NCPC Charges





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

DA vs. RT Pricing

The following slides outline:

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

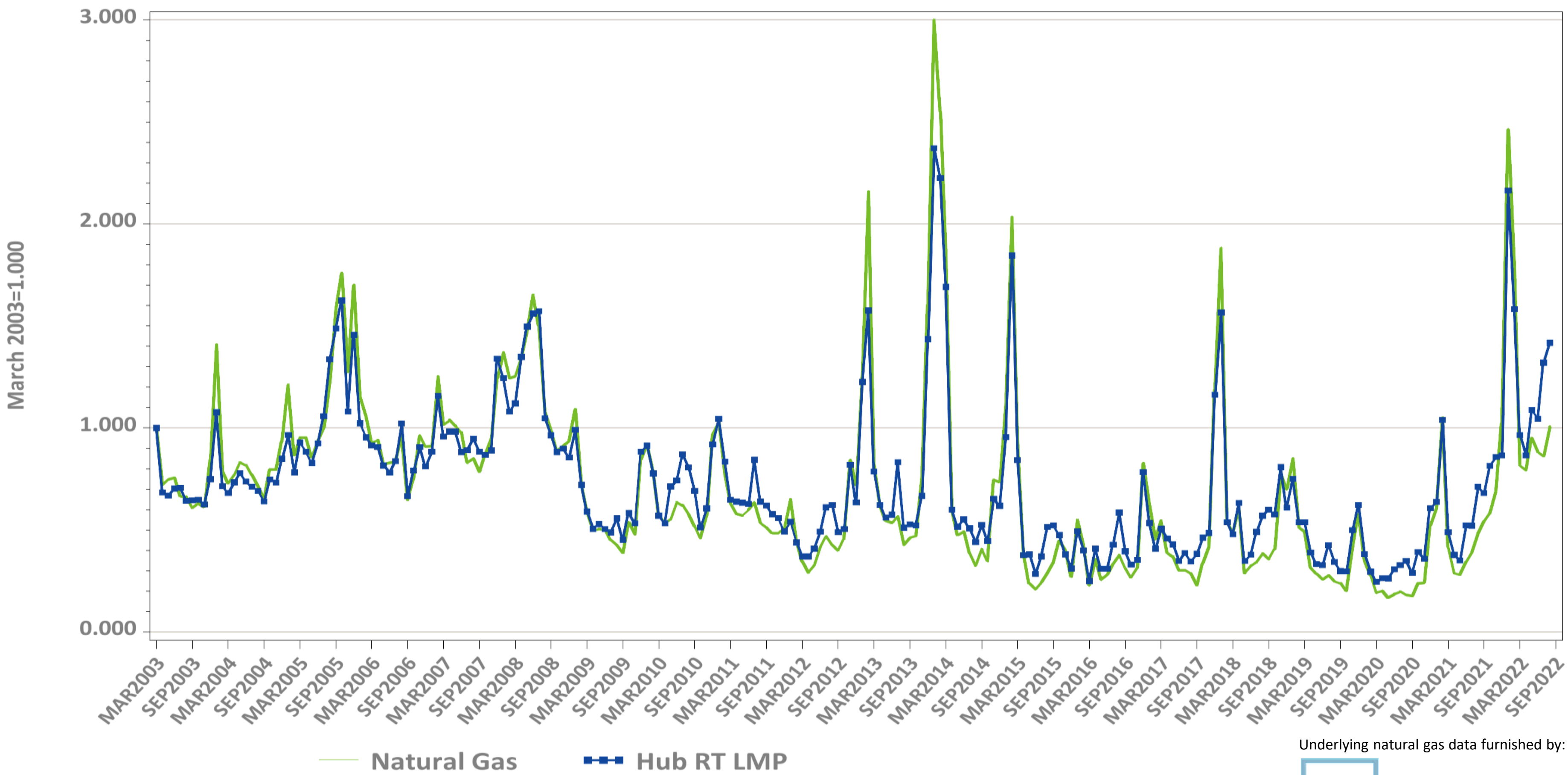
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2021	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$56.58	$53.52	$55.13	$56.17	$54.29	$55.36	$56.22	$55.40	$55.44
Real-Time	$54.58	$52.88	$53.26	$54.45	$53.22	$53.48	$54.30	$53.99	$53.99
RT Delta %	-3.5%	-1.2%	-3.4%	-3.1%	-2.0%	-3.4%	-3.4%	-2.5%	-2.6%
Year 2022	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$91.64	$89.42	$89.71	$91.16	$89.76	$90.84	$91.51	$91.11	$91.00
Real-Time	$90.01	$88.40	$87.68	$89.57	$88.07	$89.25	$89.91	$89.53	$89.43
RT Delta %	-1.8%	-1.1%	-2.3%	-1.7%	-1.9%	-1.8%	-1.7%	-1.7%	-1.7%

August-21	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$50.06	$48.44	$49.56	$50.11	$49.32	$49.19	$49.81	$49.52	$49.47
Real-Time	$49.61	$48.22	$49.12	$49.59	$48.67	$48.63	$49.29	$48.98	$48.92
RT Delta %	-0.9%	-0.5%	-0.9%	-1.0%	-1.3%	-1.1%	-1.0%	-1.1%	-1.1%
August-22	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$101.79	$99.31	$99.21	$101.64	$100.60	$100.66	$101.97	$101.16	$101.02
Real-Time	$98.20	$96.33	$96.00	$98.30	$97.23	$96.89	$98.06	$97.53	$97.33
RT Delta %	-3.5%	-3.0%	-3.2%	-3.3%	-3.4%	-3.7%	-3.8%	-3.6%	-3.7%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	103.4%	105.0%	100.2%	102.8%	104.0%	104.6%	104.7%	104.3%	104.2%
Yr over Yr RT	97.9%	99.8%	95.4%	98.2%	99.8%	99.2%	99.0%	99.1%	98.9%

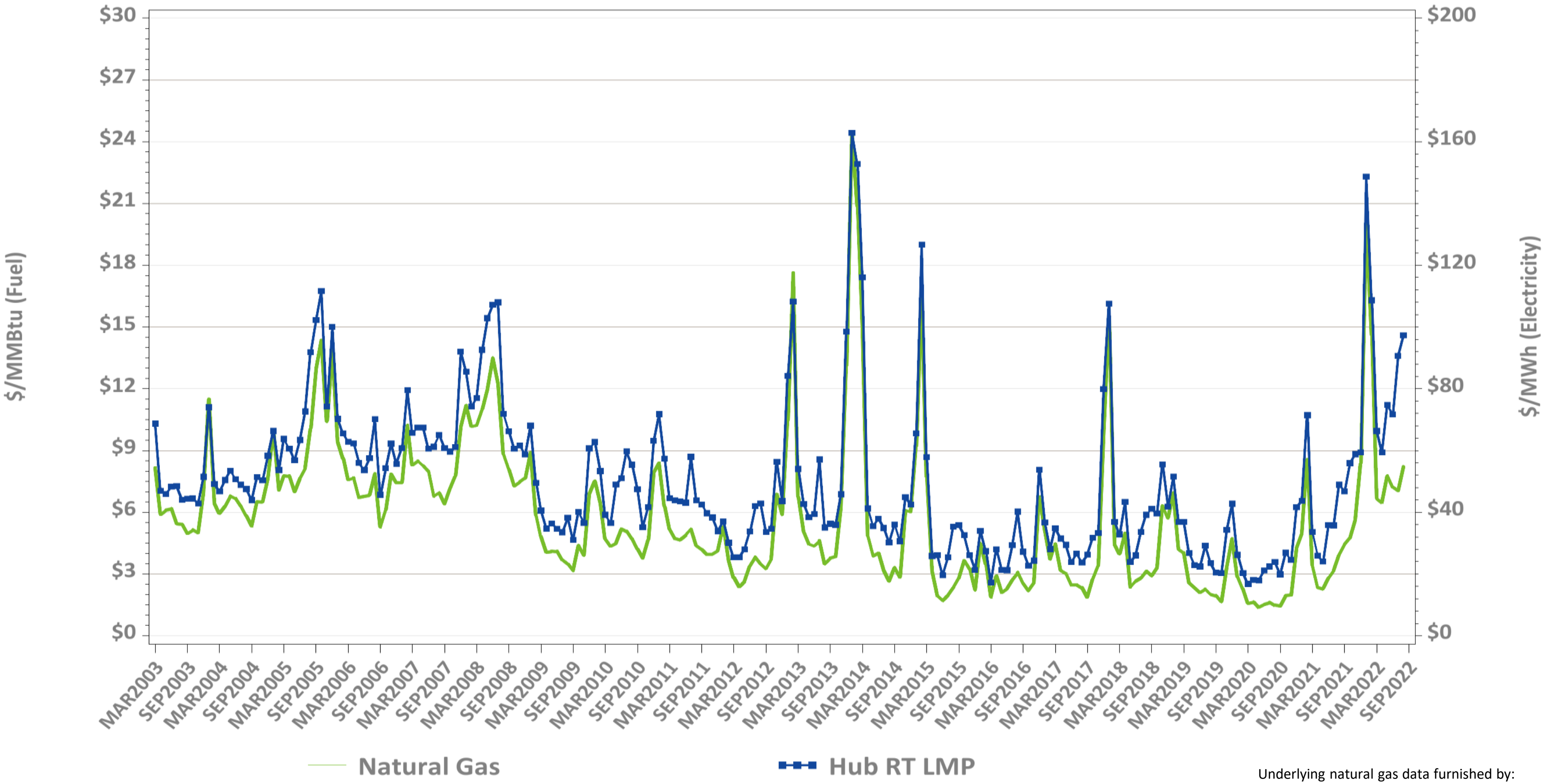
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

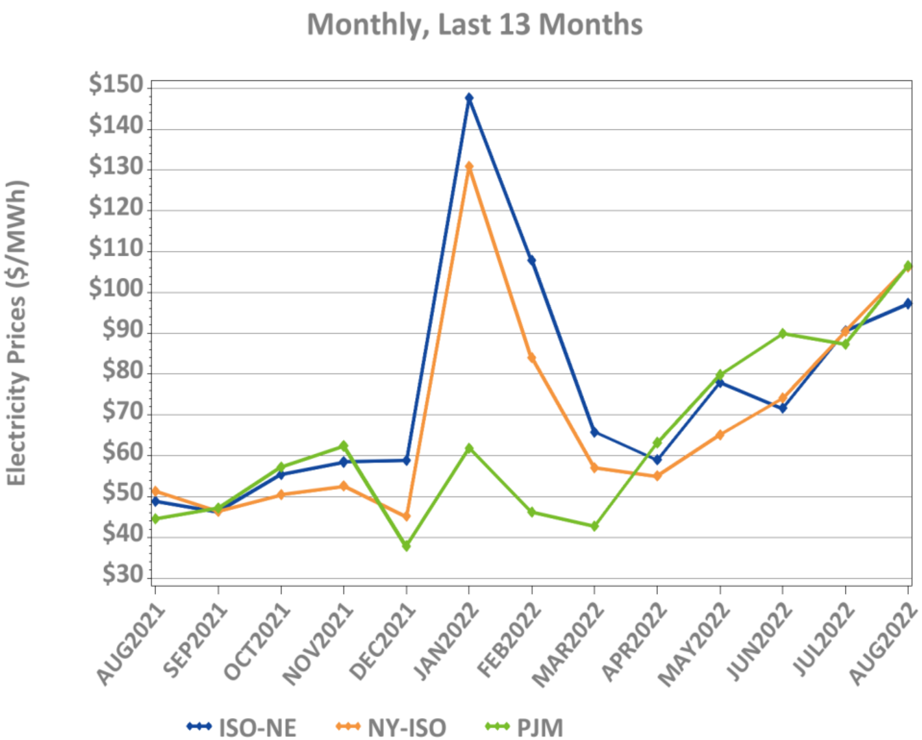
ICE Global markets in clear view

Monthly Average Fuel Price and RT Hub LMP

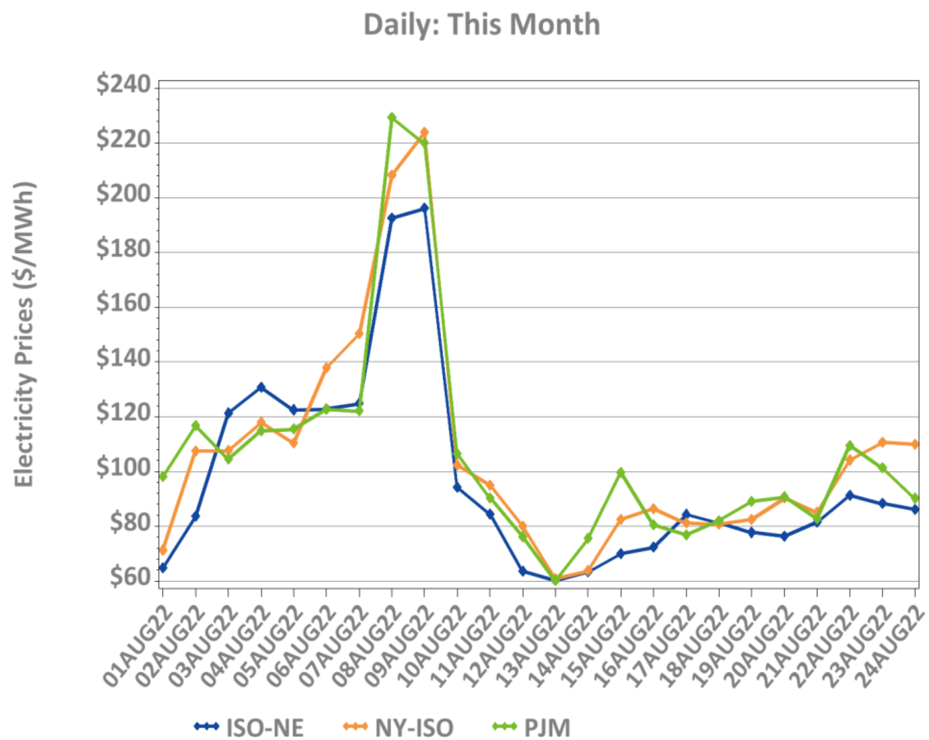


Underlying natural gas data furnished by: ICE Global markets in clear view

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

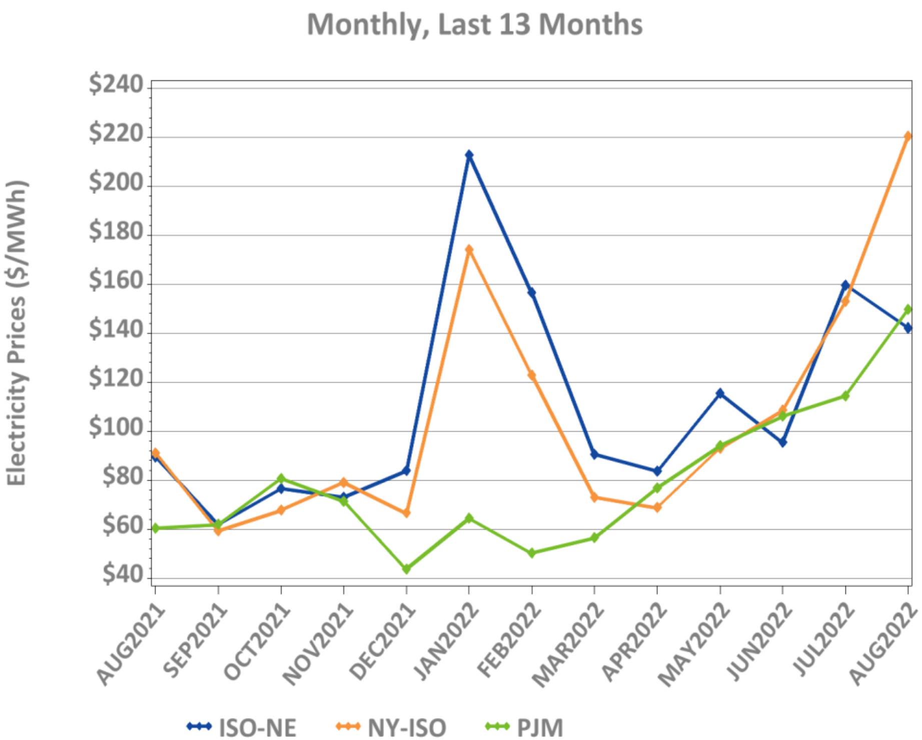


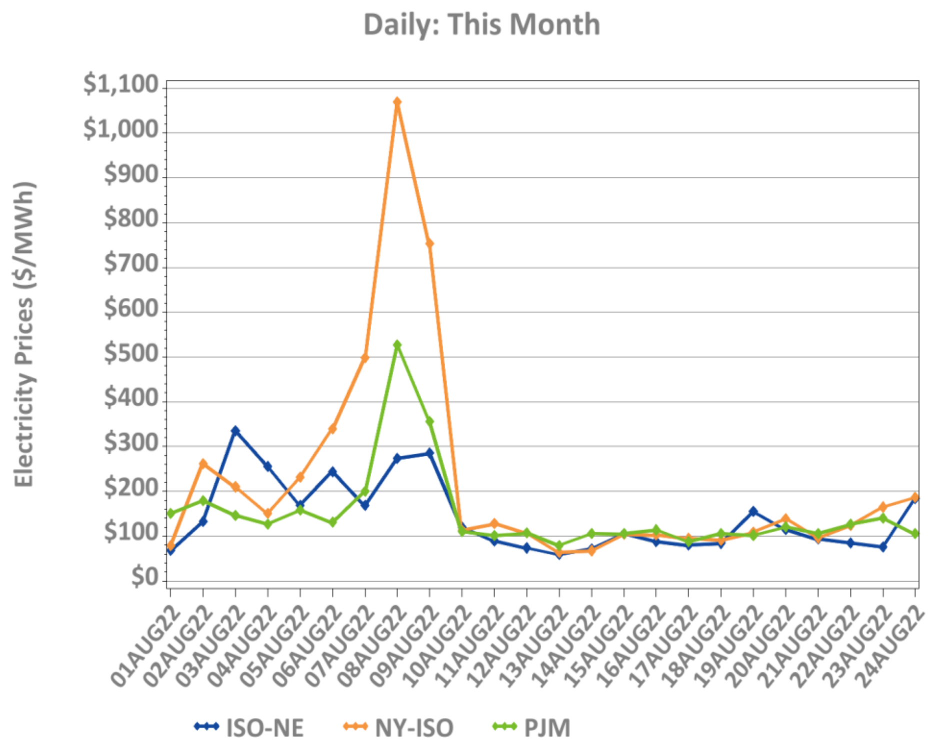
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





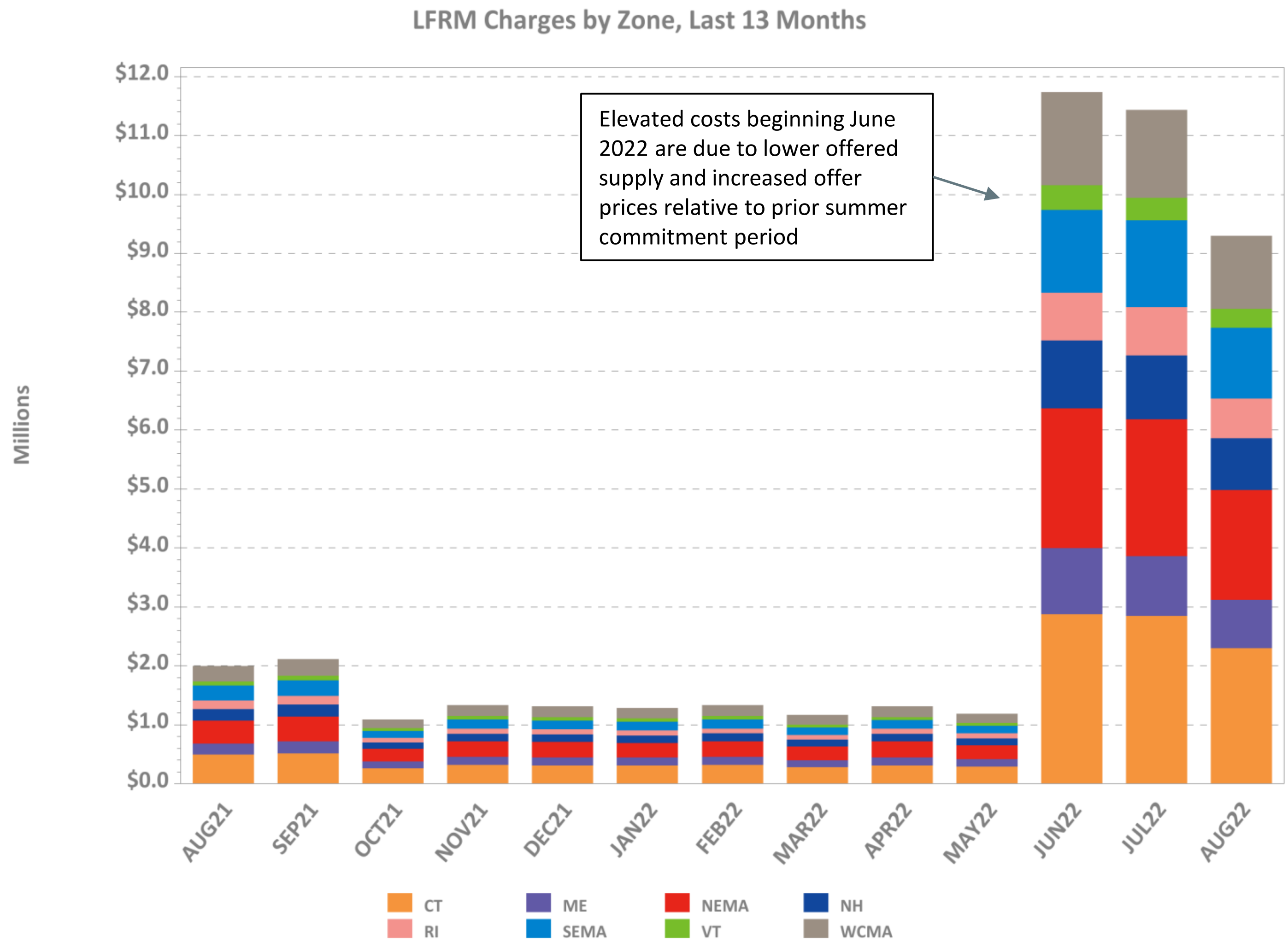
***Forecasted New England daily peak hours reflected**

Reserve Market Results – August 2022

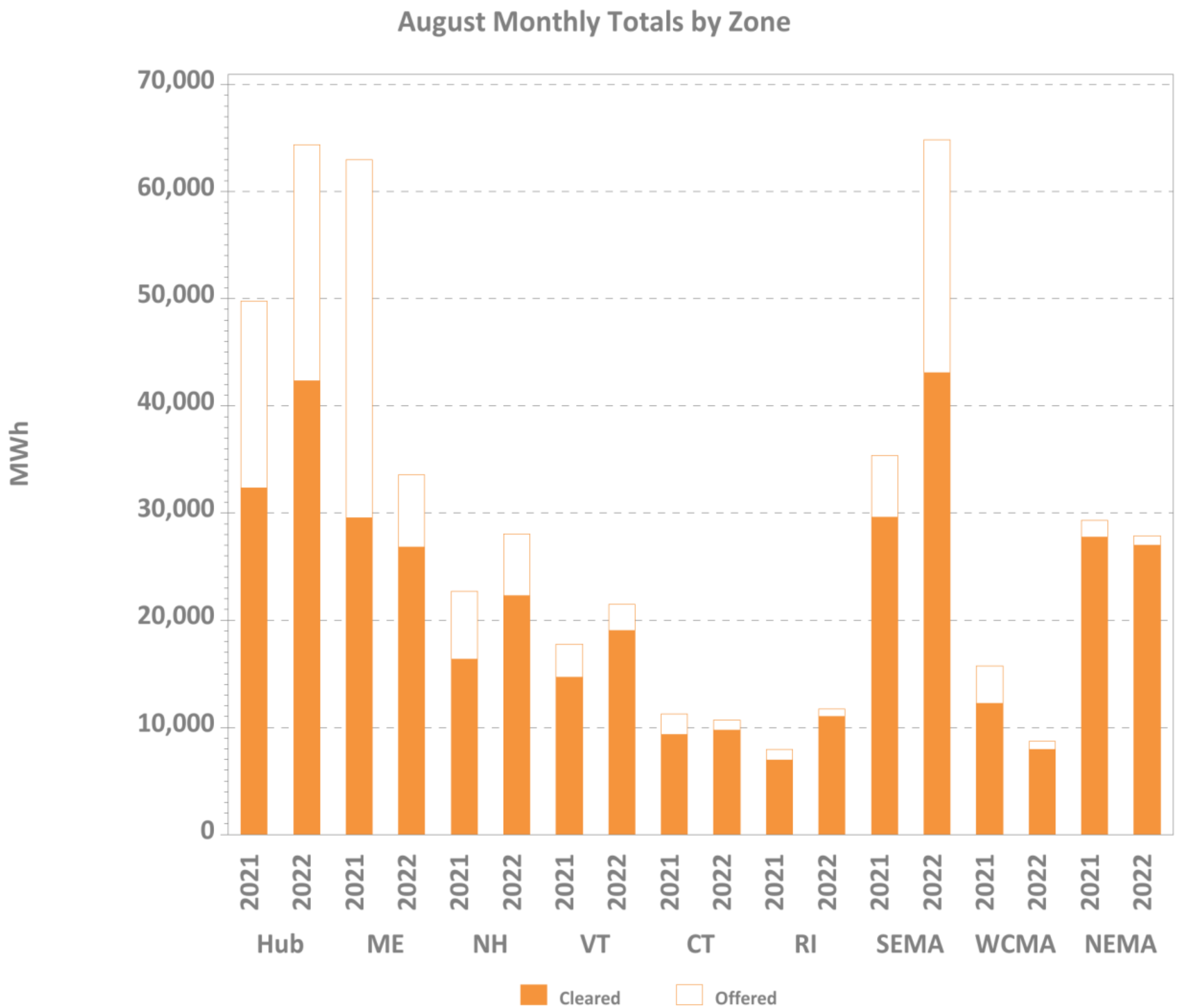
- Maximum potential Forward Reserve Market payments of $9.4M were reduced by credit reductions of $23K, failure-to-reserve penalties of $35K and failure-to-activate penalties of $3K, resulting in a net payout of $9.3M or 99% of maximum
  - Rest of System: $6.04M/6.08M (99%)
  - Southwest Connecticut: $0.03M/0.03M (93%)
  - Connecticut: $2.1M/2.12M (99%)
  - NEMA: $0.1M/0.1M (100%)
- $954K total Real-Time credits were reduced by $183K in Forward Reserve Energy Obligation Charges for a net of $771K in Real-Time Reserve payments
  - Rest of System: 168 hours, $472K
  - Southwest Connecticut: 168 hours, $116K
  - Connecticut: 168 hours, $119K
  - NEMA: 168 hours, $63K

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

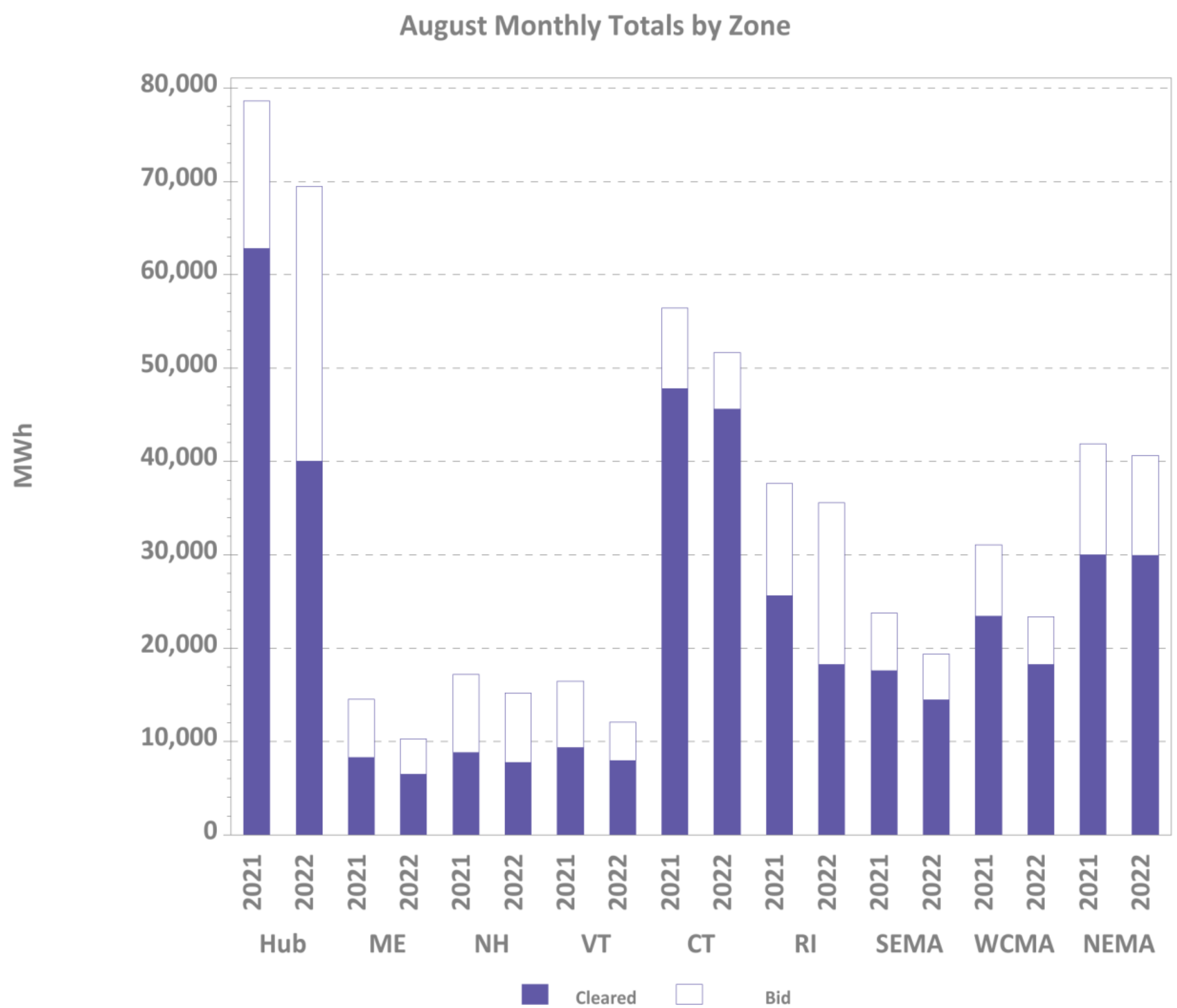
LFRM Charges to Load by Load Zone ($)



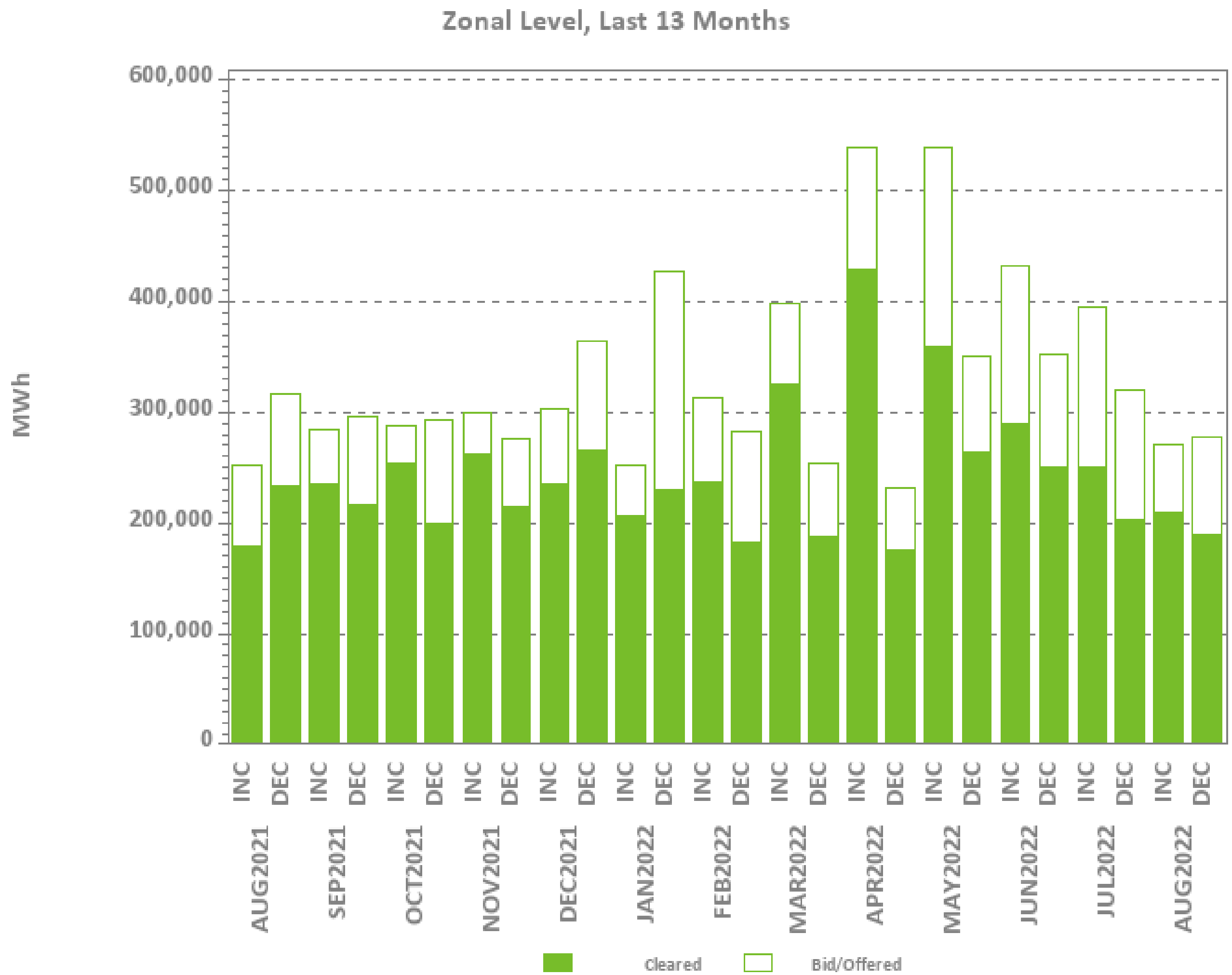
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

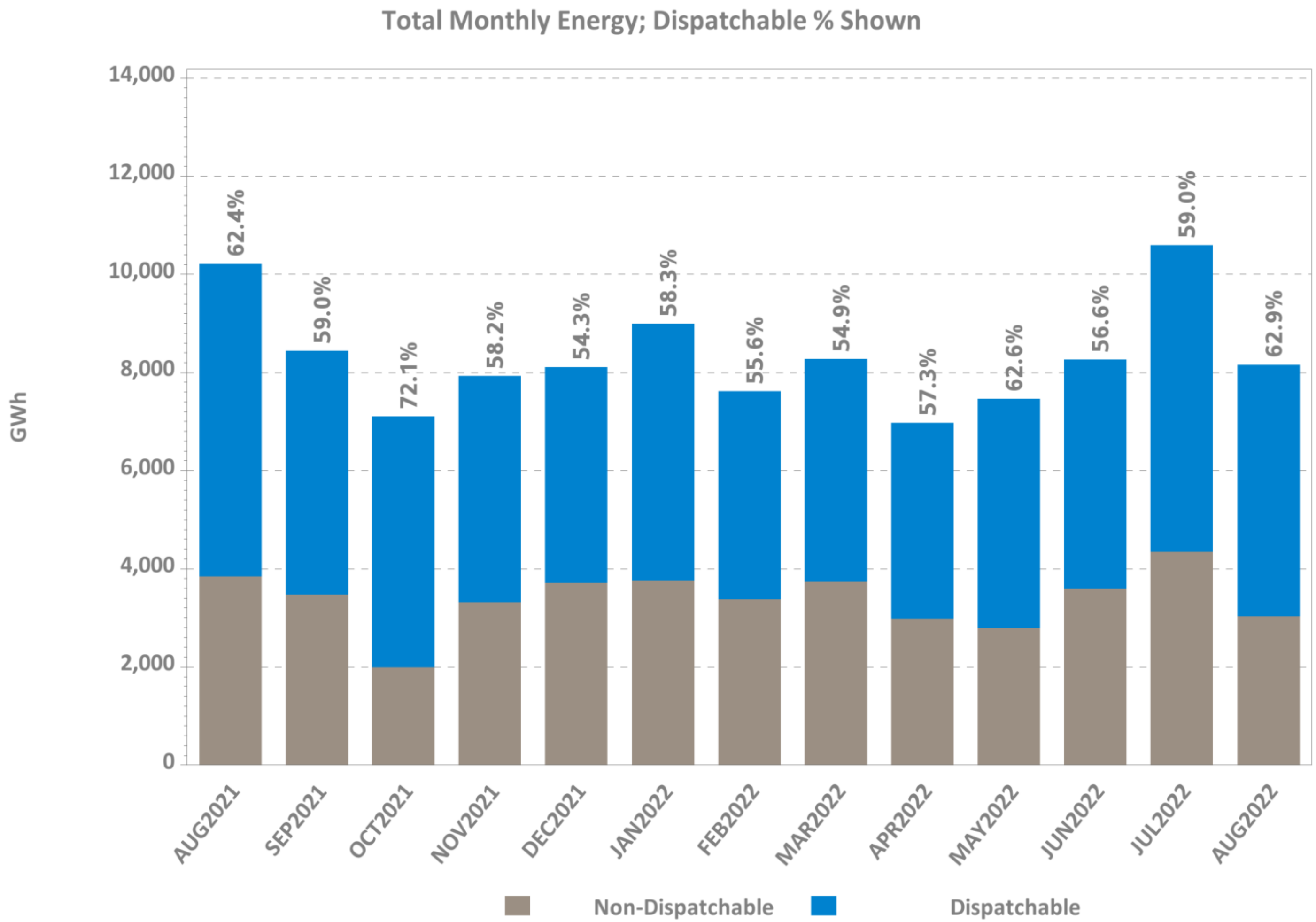


Total Increment Offers and Decrement Bids



Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



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

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- September 21 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - Greggs Substation Rebuild (Eversource)
    - Connecticut River Crossing and Structure Replacement/Separation of 348 & 1772 Lines (Eversource)
    - 115 kV Structure Replacements & Optical Ground Wire Installation (CT Line 1783 & NH Lines P106, Q171 (Eversource)
  - NPCC Bulk Power System Classification
  - Second Cape Cod Resource Integration Study Update

* 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, 6/15/22, and 8/24/22 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 was posted on July 29
  - Draft technical appendices expected to be posted late Q3/early Q4
- 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 new modeling features and initial benchmark scenario results were presented at the August PAC meeting

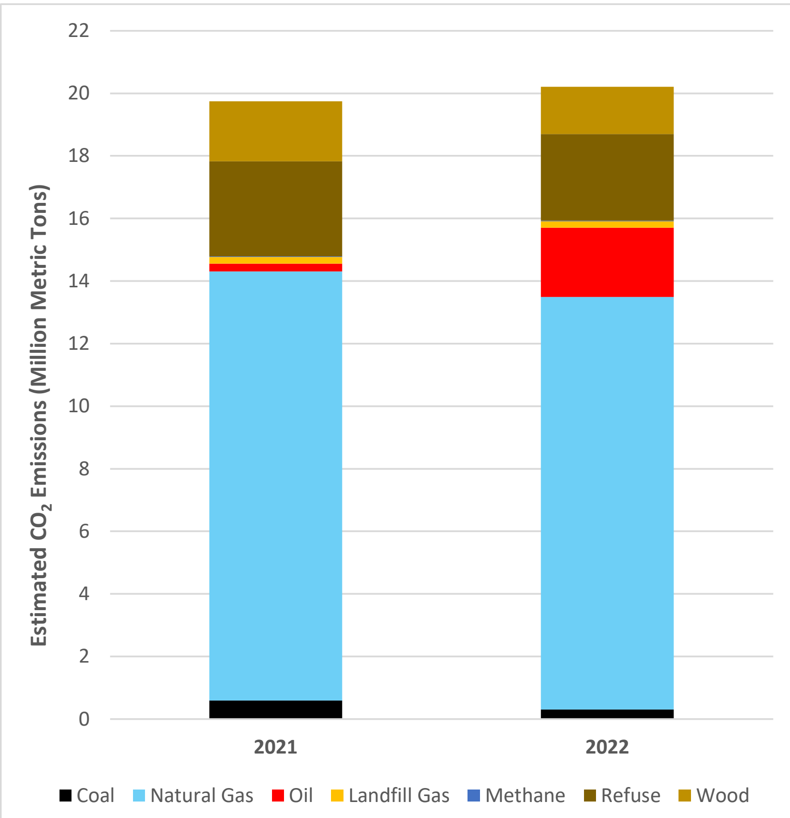
Future Grid Reliability Study (FGRS)

- 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 completed as the 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

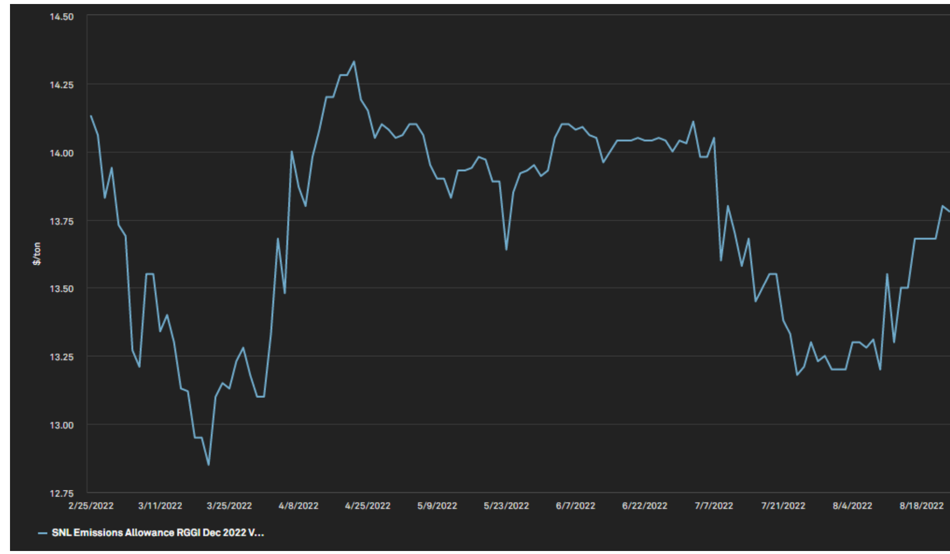
New England Power System Carbon Emissions

CO_2 emissions Up 2% 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



- 8/24/22: RGGI allowance spot price - $13.78 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 8/21/22

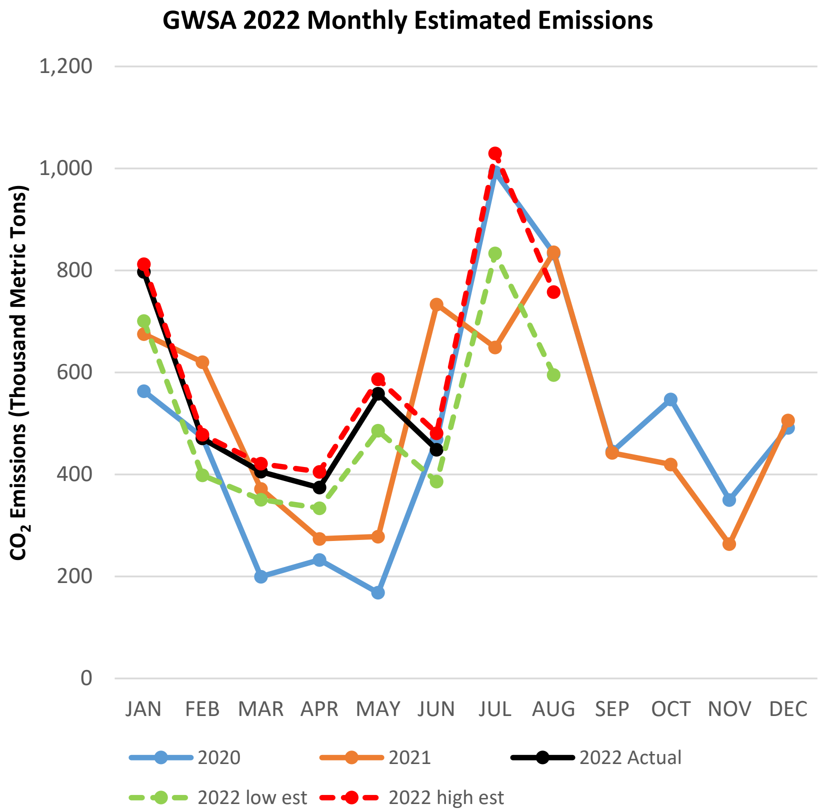
RGGI – Regional Greenhouse Gas Initiative

Massachusetts CO_2 Generator Emissions Cap

Uptick in 2022 Estimated Emissions Under CO_2 Cap

- 8/21/22: 2022 estimated GWSA CO_2 emissions range between 4.1 and 5.0 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 YTD estimated GWSA emissions were between 3% lower and 17% higher than YTD 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 8/23/2022

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 8/23/2022

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 8/23/2022

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 8/23/2022

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 8/23/2022

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 8/23/2022

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 8/23/2022

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 8/23/2022

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	3
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 8/23/2022

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 8/23/2022

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 8/23/2022

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	3
1851	Upgrade Card 115 kV to BPS standards	Mar-23	3
1852	Install one 115 kV circuit breaker in series with Card substation 4T	Mar-23	3
1853	Convert Gales Ferry substation from 69 kV to 115 kV	Dec-23	3
1854	Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Dec-22	3

Eastern CT Reliability Projects, cont.

Status as of 8/23/2022

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	3
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 8/23/2022

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 8/23/2022

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 8/23/2022

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	2

Upper Maine Solution Projects

Status as of 8/23/2022

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-24	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

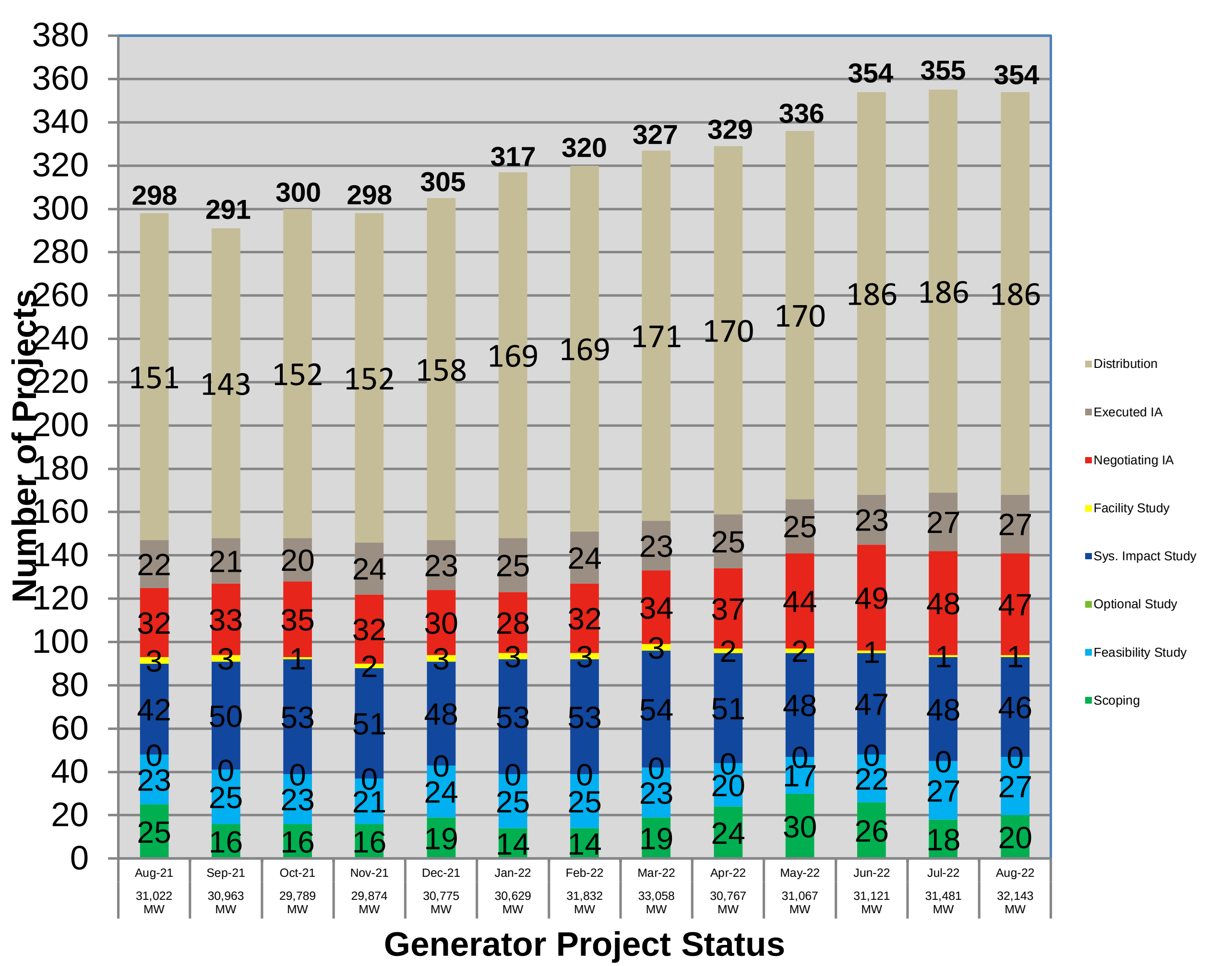
Upper Maine Solution Projects, cont.

Status as of 8/23/2022

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

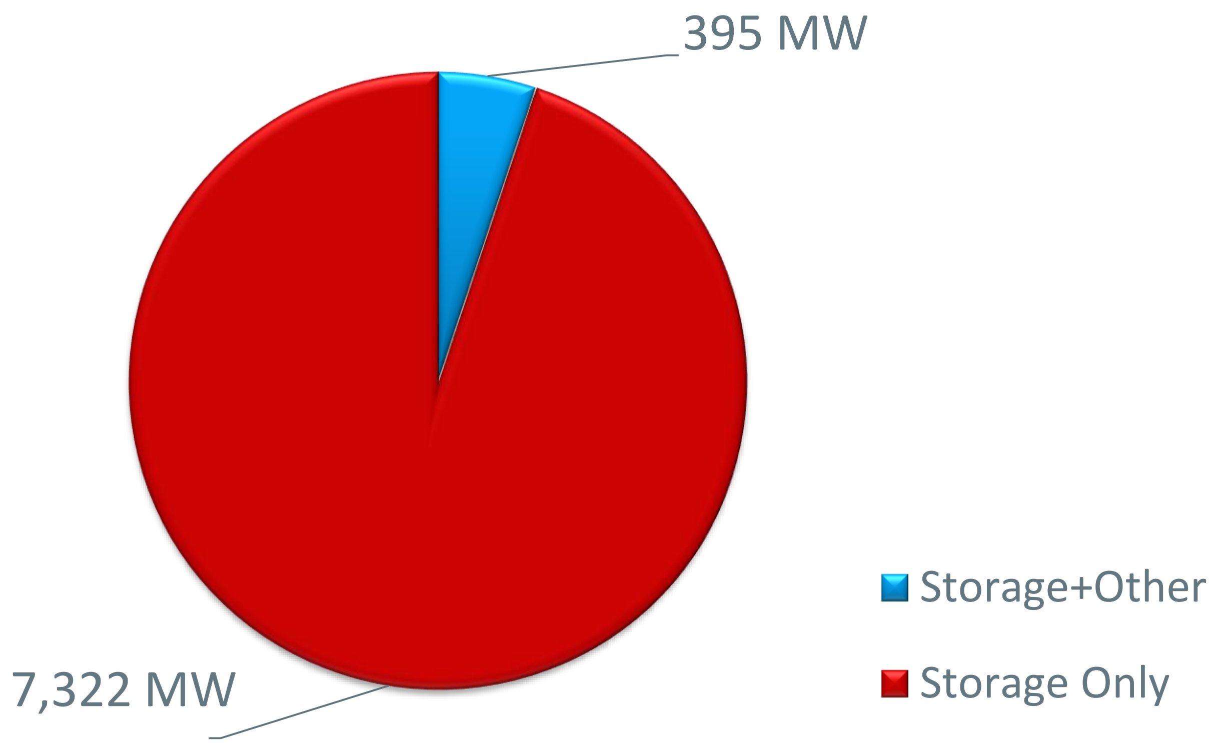
Status of Tariff Studies as of August 19, 2022



Note: August 2022 is based on partial data.
6 ETUs in Scoping, 2 in FS, 0 in SIS, 0 in OIS, 0 in FAC, 3 Negotiating IA, and 2 with Executed IA
Transmission Service Requests needing study: 1 in Scoping and 1 in SIS
https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of August 19, 2022)

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



OPERABLE CAPACITY ANALYSIS

Fall 2022 Analysis

Fall 2022 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Sep. - 2022[2] CSO (MW)	Sep. - 2022[2] SCC (MW)
Operable Capacity MW [1]	27,767	29,610
Active Demand Capacity Resource (+) [5]	510	453
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	660	660
Non Commercial Capacity (+)	32	32
Non Gas-fired Planned Outage MW (-)	2,311	2,702
Gas Generator Outages MW (-)	974	1,046
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)	23,584	24,907
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	660	1,983

[1]Operable Capacity is based on data as of **August 23, 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 **August 23, 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.

Fall 2022 Operable Capacity Analysis

90/10 Load Forecast	**Sep. - 2022[2] CSO (MW)**	**Sep. - 2022[2] SCC (MW)**
Operable Capacity MW [1]	27,767	29,610
Active Demand Capacity Resource (+) [5]	510	453
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	660	660
Non Commercial Capacity (+)	32	32
Non Gas-fired Planned Outage MW (-)	2,311	2,702
Gas Generator Outages MW (-)	974	1,046
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)	23,584	24,907
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	-816	507

[1] Operable Capacity is based on data as of **August 23, 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 **August 23, 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.

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

ISO-NE OPERABLE CAPACITY ANALYSIS

August 23, 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 September, October & November.

Report created: 8/23/2022

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
9/17/2022	27767	510	660	32	1499	272	2100	0	25098	20711	2305	23016	2082	N	Fall 2022
9/24/2022	**27767**	**510**	**660**	**32**	**2311**	**974**	**2100**	**0**	**23584**	**20619**	**2305**	**22924**	**660**	**Y**	**Fall 2022**
10/1/2022	28158	559	1070	70	3672	2822	2800	0	20563	15169	2305	17474	3089	N	Fall 2022
10/8/2022	28158	559	1070	70	3957	4157	2800	0	18943	15205	2305	17510	1433	N	Fall 2022
10/15/2022	28158	559	1070	70	3540	2319	2800	0	21198	16121	2305	18426	2772	N	Fall 2022
10/22/2022	28158	559	1070	70	1886	2499	2800	0	22672	16482	2305	18787	3885	N	Fall 2022
10/29/2022	28158	559	1070	70	2344	3250	3600	0	20663	16687	2305	18992	1671	N	Fall 2022
11/5/2022	28158	559	1070	70	2366	2249	3600	0	21642	16802	2305	19107	2535	N	Fall 2022
11/12/2022	28158	559	1070	70	1918	938	3600	0	23401	17143	2305	19448	3953	N	Fall 2022
11/19/2022	28158	559	1070	70	1156	305	3600	1065	23731	17875	2305	20180	3551	N	Fall 2022

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 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.

Fall 2022 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

August 23, 2022 - 90/10 FORECAST using CSO MW

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

Report created: 8/23/2022

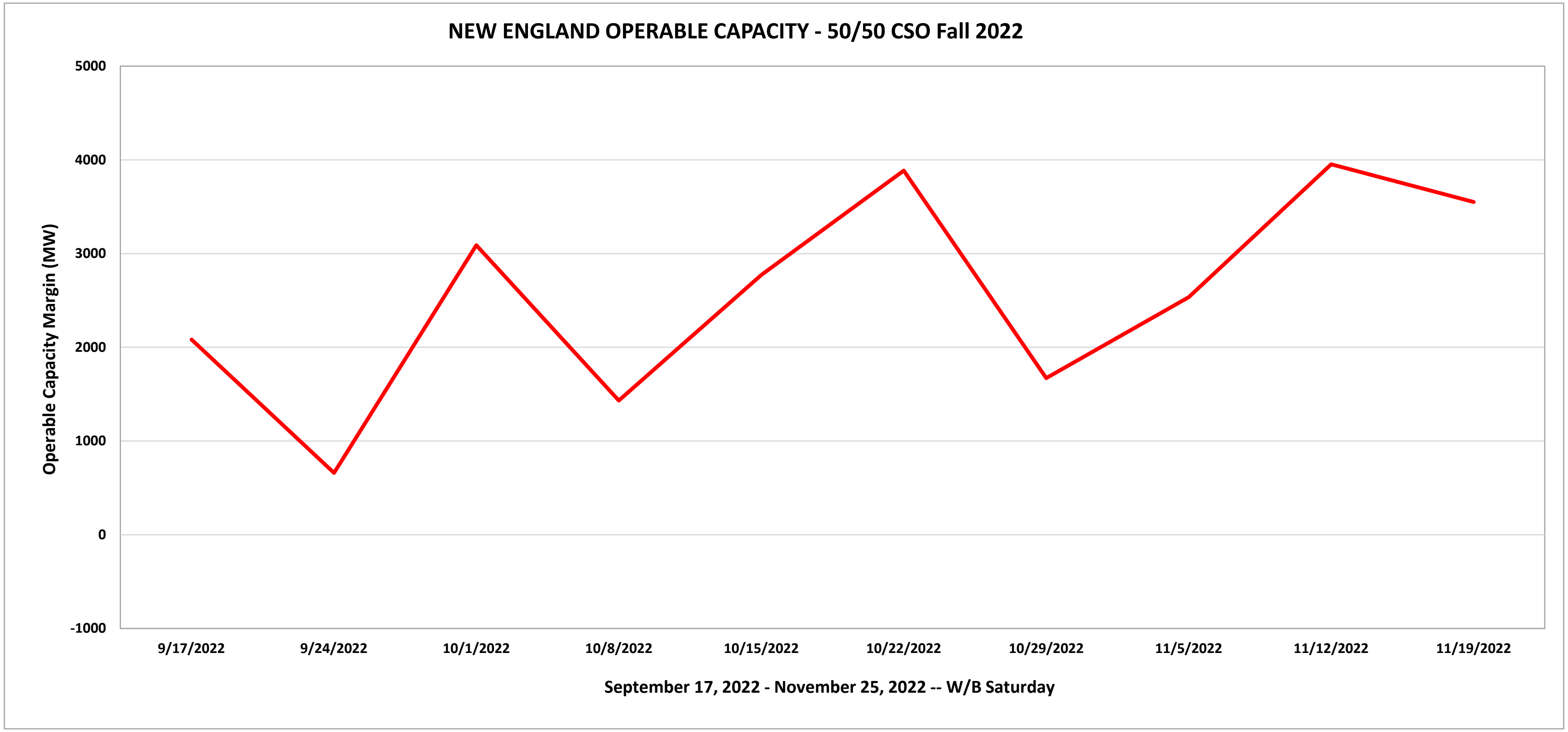
Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
9/17/2022	27767	510	660	32	1499	272	2100	0	25098	22192	2305	24497	601	N	Fall 2022
9/24/2022	**27767**	**510**	**660**	**32**	**2311**	**974**	**2100**	**0**	**23584**	**22095**	**2305**	**24400**	**-816**	**Y**	**Fall 2022**
10/1/2022	28158	559	1070	70	3672	2822	2800	0	20563	15709	2305	18014	2549	N	Fall 2022
10/8/2022	28158	559	1070	70	3957	4157	2800	0	18943	15745	2305	18050	893	N	Fall 2022
10/15/2022	28158	559	1070	70	3540	2319	2800	0	21198	16690	2305	18995	2203	N	Fall 2022
10/22/2022	28158	559	1070	70	1886	2499	2800	0	22672	17063	2305	19368	3304	N	Fall 2022
10/29/2022	28158	559	1070	70	2344	3250	3600	0	20663	17274	2305	19579	1084	N	Fall 2022
11/5/2022	28158	559	1070	70	2366	2249	3600	0	21642	17392	2305	19697	1945	N	Fall 2022
11/12/2022	28158	559	1070	70	1918	938	3600	597	22804	17744	2305	20049	2755	N	Fall 2022
11/19/2022	28158	559	1070	70	1156	305	3600	2000	22796	18498	2305	20803	1993	N	Fall 2022

Column Definitions

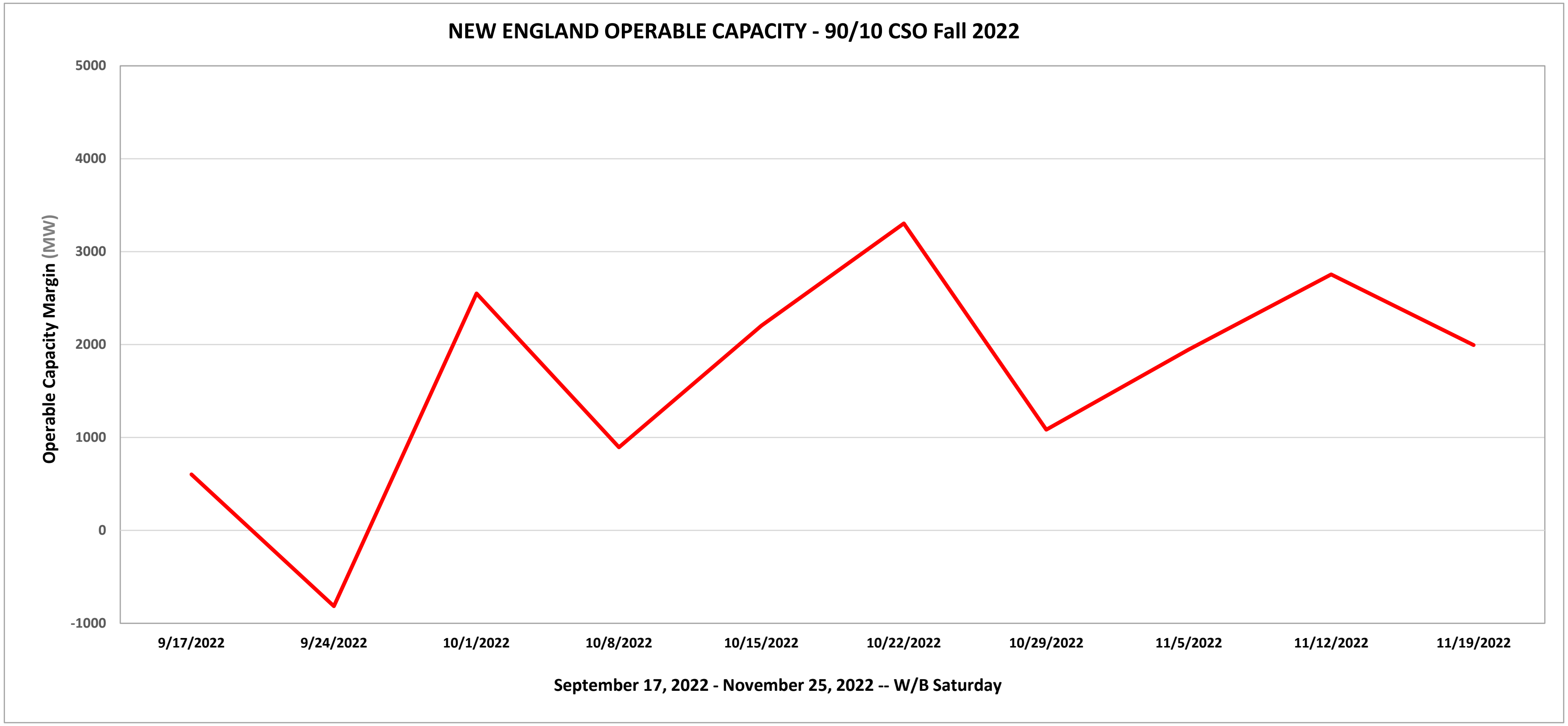
1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 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.

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

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



Fall 2022 Operable Capacity Analysis
90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Preliminary Winter 2022/23 Analysis

Preliminary Winter 2022/23 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan. - 2023[2] CSO (MW)	Jan. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,239	32,065
Active Demand Capacity Resource (+) [5]	560	413
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,070	1,070
Non Commercial Capacity (+)	70	70
Non Gas-fired Planned Outage MW (-)	75	139
Gas Generator Outages MW (-)	7	156
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	3,728	4,131
Net Capacity (NET OPCAP SUPPLY MW)	23,329	26,392
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,009	20,009
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,314	22,314
Operable Capacity Margin	1,015	4,078

[1]Operable Capacity is based on data as of **August 23, 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 **August 23, 2022.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 7, 2023.**

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

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

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

Preliminary Winter 2022/23 Operable Capacity Analysis

90/10 Load Forecast	Jan. - 2023[2] CSO (MW)	Jan. - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,239	32,065
Active Demand Capacity Resource (+) [5]	560	413
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,070	1,070
Non Commercial Capacity (+)	70	70
Non Gas-fired Planned Outage MW (-)	75	139
Gas Generator Outages MW (-)	7	156
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,539	5,061
Net Capacity (NET OPCAP SUPPLY MW)	22,518	25,462
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,695	20,695
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	23,000	23,000
Operable Capacity Margin	-482	2,462

[1]Operable Capacity is based on data as of **August 23, 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 **August 23, 2022.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 7, 2023.**

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

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

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

Preliminary Winter 2022/23 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

August 23, 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 from November through March.

Report created: 8/23/2022

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
11/26/2022	28158	559	1070	70	545	296	3600	1662	23754	18588	2305	20893	2861	N	Winter 2022/2023
12/3/2022	28239	560	1070	70	377	578	3200	1804	23980	18919	2305	21224	2756	N	Winter 2022/2023
12/10/2022	28239	560	1070	70	357	49	3200	2532	23801	19205	2305	21510	2291	N	Winter 2022/2023
12/17/2022	28239	560	1070	70	349	49	3200	2745	23596	19216	2305	21521	2075	N	Winter 2022/2023
12/24/2022	28239	560	1070	70	19	7	3200	3134	23579	19278	2305	21583	1996	N	Winter 2022/2023
12/31/2022	28239	560	1070	70	93	7	2800	3733	23306	19549	2305	21854	1452	N	Winter 2022/2023
1/7/2023	**28239**	**560**	**1070**	**70**	**75**	**7**	**2800**	**3728**	**23329**	**20009**	**2305**	**22314**	**1015**	**Y**	**Winter 2022/2023**
1/14/2023	28239	560	1070	70	75	7	2800	3583	23474	20009	2305	22314	1160	N	Winter 2022/2023
1/21/2023	28239	560	1070	70	75	7	2800	3134	23923	20009	2305	22314	1609	N	Winter 2022/2023
1/28/2023	28239	560	1070	70	47	7	3100	2835	23950	19789	2305	22094	1856	N	Winter 2022/2023
2/4/2023	28239	560	1070	70	47	7	3100	2536	24249	19524	2305	21829	2420	N	Winter 2022/2023
2/11/2023	28239	560	1070	70	47	7	3100	2237	24548	19496	2305	21801	2747	N	Winter 2022/2023
2/18/2023	28239	560	1070	70	20	7	3100	1788	25024	19236	2305	21541	3483	N	Winter 2022/2023
2/25/2023	28239	560	1070	70	123	7	3100	1489	25220	18258	2305	20563	4657	N	Winter 2022/2023
3/4/2023	28239	560	1070	70	90	783	2200	414	26452	17912	2305	20217	6235	N	Winter 2022/2023
3/11/2023	28239	560	1070	70	90	290	2200	308	27051	17718	2305	20023	7028	N	Winter 2022/2023
3/18/2023	28239	560	1070	70	780	447	2200	0	26512	17357	2305	19662	6850	N	Winter 2022/2023
3/25/2023	28239	560	1070	70	739	1670	2200	0	25330	16797	2305	19102	6228	N	Winter 2022/2023

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 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.

Preliminary Winter 2022/23 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

August 23, 2022 - 90/10 FORECAST using CSO MW

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

Report created: 8/23/2022

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 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
11/26/2022	28158	559	1070	70	545	296	3600	2576	22840	19234	2305	21539	1301	N	Winter 2022/2023
12/3/2022	28239	560	1070	70	377	578	3200	2792	22992	19571	2305	21876	1116	N	Winter 2022/2023
12/10/2022	28239	560	1070	70	357	49	3200	3519	22814	19866	2305	22171	643	N	Winter 2022/2023
12/17/2022	28239	560	1070	70	349	49	3200	3864	22477	19877	2305	22182	295	N	Winter 2022/2023
12/24/2022	28239	560	1070	70	19	7	3200	4280	22433	19941	2305	22246	187	N	Winter 2022/2023
12/31/2022	28239	560	1070	70	93	7	2800	4408	22631	20220	2305	22525	106	N	Winter 2022/2023
1/7/2023	**28239**	**560**	**1070**	**70**	**75**	**7**	**2800**	**4539**	**22518**	**20695**	**2305**	**23000**	**-482**	**Y**	**Winter 2022/2023**
1/14/2023	28239	560	1070	70	75	7	2800	4331	22726	20695	2305	23000	-274	N	Winter 2022/2023
1/21/2023	28239	560	1070	70	75	7	2800	4032	23025	20695	2305	23000	25	N	Winter 2022/2023
1/28/2023	28239	560	1070	70	47	7	3100	4032	22753	20468	2305	22773	-20	N	Winter 2022/2023
2/4/2023	28239	560	1070	70	47	7	3100	3583	23202	20195	2305	22500	702	N	Winter 2022/2023
2/11/2023	28239	560	1070	70	47	7	3100	3284	23501	20166	2305	22471	1030	N	Winter 2022/2023
2/18/2023	28239	560	1070	70	20	7	3100	2686	24126	19898	2305	22203	1923	N	Winter 2022/2023
2/25/2023	28239	560	1070	70	123	7	3100	2237	24472	18889	2305	21194	3278	N	Winter 2022/2023
3/4/2023	28239	560	1070	70	90	783	2200	1311	25555	18533	2305	20838	4717	N	Winter 2022/2023
3/11/2023	28239	560	1070	70	90	290	2200	1206	26153	18333	2305	20638	5515	N	Winter 2022/2023
3/18/2023	28239	560	1070	70	780	447	2200	600	25912	17960	2305	20265	5647	N	Winter 2022/2023
3/25/2023	28239	560	1070	70	739	1670	2200	0	25330	17383	2305	19688	5642	N	Winter 2022/2023

Column Definitions

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2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
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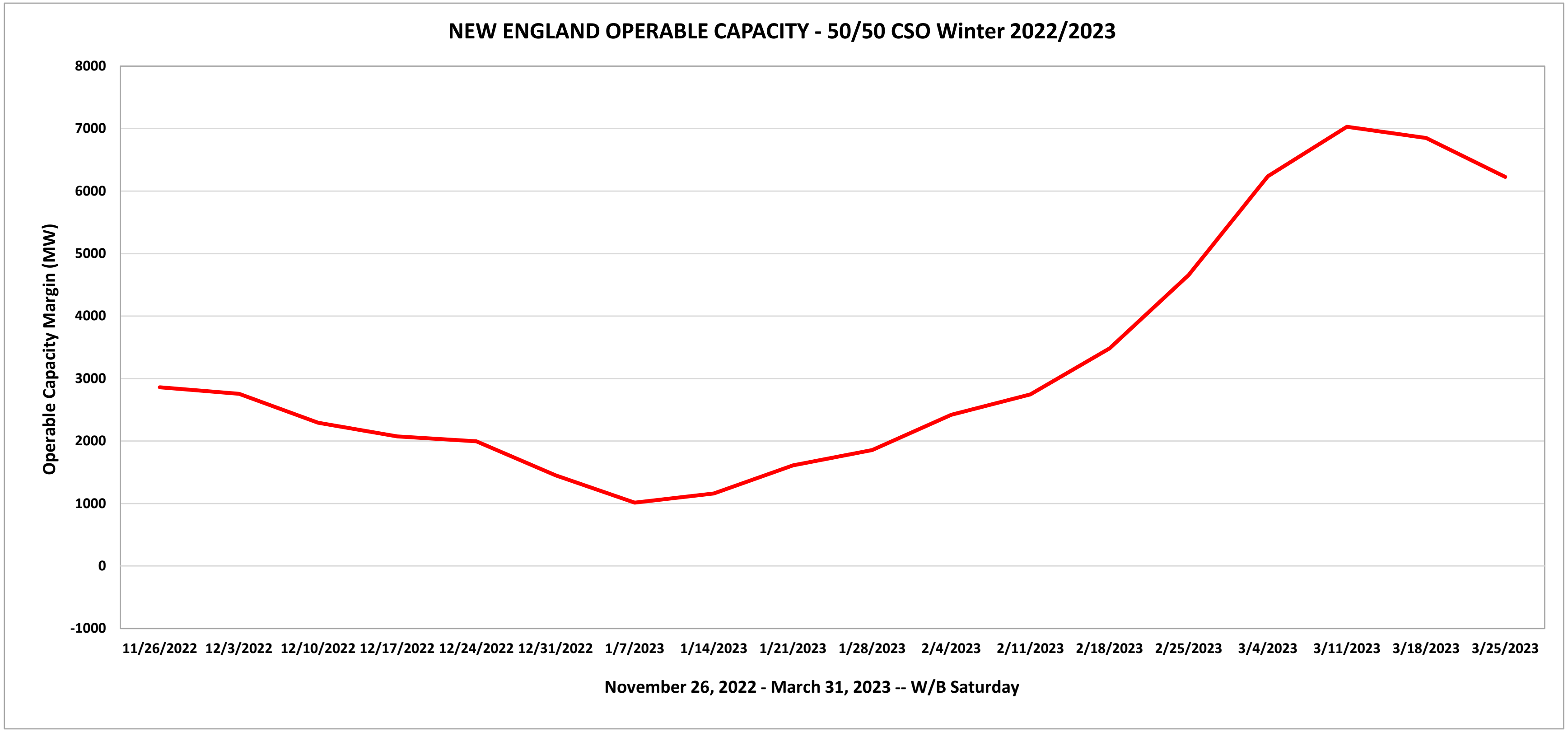
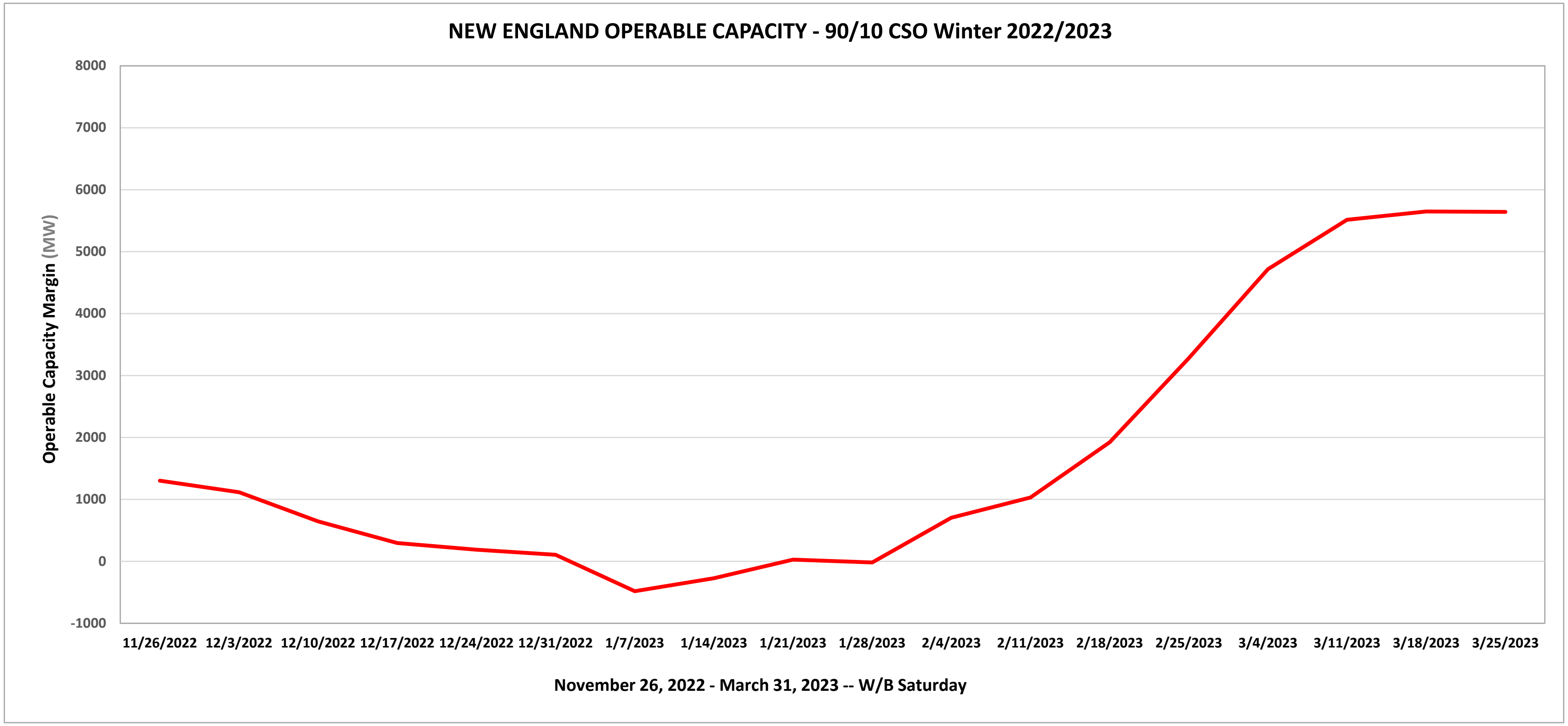
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Highlighted week is based on the week determined by the 90/50 Load Forecast Reference Week

Preliminary Winter 2022/23 Operable Capacity Analysis
50/50 Forecast (Reference)



Preliminary Winter 2022/23 Operable Capacity Analysis
90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4: Appendix A

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

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

Possible Relief Under OP4: Appendix A

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

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

M E M O R A N D U M

TO: Participants Committee (“NPC”) Members and Alternates

FROM: Pat Gerity, NEPOOL Counsel

DATE: August 25, 2022

RE: New England States’ Committee on Electricity (“NESCOE”) Budget Framework for 2023-2027

You will be asked at the September 1, 2022 teleconference meeting to approve NESCOE’s *fourth* five-year budget framework covering years 16 - 20 (2023-2027) of its operations (the “Fourth Budget Framework”). We have included with this memorandum a presentation provided to the Budget & Finance Subcommittee (the “Subcommittee”) that summarizes the Fourth Budget Framework.

NESCOE is required to present a 5-year framework for its annual budgets pursuant to the November 21, 2007 Memorandum of Understanding (“MOU”) among the ISO, NEPOOL and NESCOE (also included with this memorandum for those that may not have been involved at the time or that would like to refresh their recollection). In the absence of agreement with at least the NPC to the contrary, the framework must provide for annual budgets that do not increase more than 15% in any one year and do not increase more than 50% on a cumulative basis over the five-year period.

Ms. Heather Hunt, NESCOE’s Executive Director, presented the Fourth Budget Framework at a meeting of the Subcommittee on July 22, 2022, and offered to take questions on that presentation at the Subcommittee’s August 11, 2022 meeting. She explained that the Fourth Budget Framework was developed using the 2022 NPC- and FERC-approved NESCOE budget level as the baseline for year 16’s (2023’s) budget level. The Fourth Budget Framework then projects 3% annual increases for years 17 through 20, though actual annual budgets when presented to the Subcommittee and the NPC may reflect more than or less than the projected 3% inflationary increases based on needs or developments at the time. Notably, NESCOE committed not to seek a budget increase of more than 10% in any one year or more than 30% on a cumulative basis during years 16-20, which is consistent with, though more conservative than, the ceiling provided for in the MOU and noted above. Ms. Hunt confirmed that funds collected but unspent would continue to reduce future years’ collections. The Fourth Budget Framework contemplates professional and administrative staffing levels consistent with a return to NESCOE’s prior steady-state employee level of six, in light of a sustained increase in workload volume. Finally, as contemplated in the MOU, NESCOE will continue to present for Subcommittee and NPC review an annual budget each year,[1] which will continue also to be filed with the FERC for approval, as have each of NESCOE’s annual budgets to date.

There were no objections or concerns raised with respect to the Fourth Budget Framework, or to moving it to the NPC for consideration and approval. If approved by the NPC, the Framework will be filed with the FERC for information.

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[1] Consideration of the 2023 NESCOE Budget is underway. The 2023 Budget was presented at the Subcommittee’s August 11, 2022 meeting, is included with the materials for this meeting (Item 6.b), and will be voted at the October 6, 2022 NPC meeting.

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

> RESOLVED, that the Participants Committee supports NESCOE's fourth five-year budget framework, for years 16 through 20 of its operations (2023-2027), as presented by NESCOE's Executive Director at this meeting.

New England States
Committee on Electricity

2023 – 2027 5-Year Pro Forma Budget Framework

NEPOOL

Summer 2022

Background: 5-year pro forma

Term Sheet Provision

"NESCOE will continue to propose and obtain FERC approval of five-year budget frameworks following a consultative process…as long as its operations continue."

2023 - 2027 is the fourth such consultative process and 5-year pro forma framework

Background: Policy Priorities

Term Sheet Provision

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

Consistent with Term Sheet, annual *Reports to the New England Governors* (released simultaneously to NEPOOL and ISO-NE):

- ✓ Review work in prior year
- ✓ Project policy priorities
- ✓ Provide spending from prior year
- ✓ Project budget information for upcoming two years

5-year pro forma Framework Highlights

- ✓ Prior 5-year frameworks were supported by NEPOOL and accepted by FERC
- ✓ NESCOE has lived within the boundaries of all prior proposed 5-year pro forma frameworks
- ✓ The 2023 - 2027 5-year pro forma framework conforms to boundaries of the most recently reviewed 5-year pro forma supported by NEPOOL and accepted by FERC, including 3% overall annual inflationary adjustments and overall growth limitation commitments

5-year pro forma Framework Highlights, con't.

- ✓ As in all prior years, during the pro forma period, unspent funds in any year will be credited toward future year
- ✓ NESCOE commits again not to seek an increase over pro forma budget of more than 10% in any 1 year or more than 30% on a cumulative basis
  - This commits to a smaller potential growth rate than NESCOE had committed to at NESCOE's creation, which was as follows:

    "In the absence of agreement with at least the NEPOOL Participants Committee to the contrary, this framework will call for annual budgets that do not increase more than 15% in any one year and do not increase more than 50% on a cumulative basis over that five-year period"

5-year pro forma Framework Highlights, con't.

- ✓ As with prior 5-year pro forma frameworks, line items or categories of spending in the 5-year pro forma may be increased or decreased in any of the 5 budget years; any such changes will be subject to review and input by NEPOOL and FERC approval each year as has happened in the past
  - ✓ The line items in each annual budget proposal may vary from the 5-year pro forma, such as, for example, whether there are rent and utility costs (pro forma assumes none in 2023 and modest rent in later years) or the level of inflationary wage increases (pro forma assumes 5%, which number may vary over the 5-year period), etc.

NESCOE Notes

Employees

- ✓ Retain and attract diversity in academic training, skills, blend of private and public sector experience in the current competitive labor market
- ✓ First year of 5-year pro form, 2023, assumes return to NESCOE's prior steady state employee level of six in light of sustained increase in workload volume; legal staff solicitation issued 2022

Office Space

- ✓ Termination of office lease in Westborough MA, which was unused during COVID; assumes no rent or utility costs in 2023
- ✓ In out years, recognizes need for small office/meeting room may resurface

5-Year Pro Forma

NESCOE
PRO FORMA BUDGET 2023-2027*

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

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

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

2022 Approved Budget
for reference

	2022
Salaries and Wages	
Salaries	1,106,398
Payroll Taxes	110,640
Health and Other Benefits	92,855
Retirement §401(k)	44,256
Total, Salaries and Wages	**1,354,149**
Direct Expenses - Consulting	
Technical Analysis	362,070
Legal (FERC)	362,071
Total, Direct Expenses, Consulting	**724,141**
General and Administrative	
Rent	24,000
Utilities	5,971
Office and Administrative Expenses	47,530
Professional Services	40,000
Travel/Lodging/Meetings	55,000
Total General and Administrative	**172,501**
Capital Expend. & Contingencies	
Computer Equipment	8,442
Contingencies	225,923
Capital Expend. & Contingencies	**234,365**
TOTAL EXPENSES	**2,485,156**
BUDGET	***2,617,642***

Thank you

Questions?

EXECUTION COPY

MEMORANDUM OF UNDERSTANDING AMONG ISO NEW ENGLAND INC., THE NEW ENGLAND POWER POOL, AND NEW ENGLAND STATES COMMITTEE ON ELECTRICITY, LLC

This Memorandum of Understanding (this "MOU") is made and entered into as of November 21, 2007 by and among ISO New England Inc., a Delaware corporation ("ISO"), the New England Power Pool ("NEPOOL"), an unincorporated association created pursuant to the NEPOOL Agreement that has been amended numerous times and twice restated, and the New England States Committee on Electricity, LLC ("NESCOE"). Collectively, ISO, NEPOOL and NESCOE may be referred to herein as the "Parties" and, individually, each may be referred to as a "Party."

WHEREAS, ISO is the private, non-profit entity that serves as the Regional Transmission Organization for New England, and in such capacity operates the New England bulk power system and administers the New England wholesale energy markets pursuant to the ISO New England Transmission, Markets and Services Tariff (the "ISO Tariff") and the Transmission Operating Agreement with the New England transmission owners (the "TOA");

WHEREAS, NEPOOL is a voluntary association of more than 340 members that includes all of the electric utilities rendering or receiving service under the ISO Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, end users, demand response providers, developers, and a merchant transmission provider;

WHEREAS, NESCOE is a limited-liability company formed by its sole member, the New England Governors Conference, Inc., in order to serve as the Regional State Committee for New England and to represent the policy perspectives of the New England Governors and their collective interests in promoting a regional electric system that assures the lowest reasonable long-term cost for customers while maintaining reliable service and environmental quality;

WHEREAS, the Participants Process under the Participants Agreement between ISO and NEPOOL has been the means for consideration of proposals for changes to New England arrangements and for reaching common understanding and consensus if possible on such changes, and the Parties wish to use that Participants Process to consider, discuss, and seek consensus on NESCOE proposals as appropriate;

WHEREAS, NEPOOL, ISO and NESCOE have each previously approved the term sheet attached hereto as Exhibit A (the "Term Sheet") and desire to make the understandings contained therein binding;

WHEREAS, NEPOOL, ISO and NESCOE have filed Schedule 5 to Section IV.A of the ISO Tariff with the Federal Energy Regulatory Commission (the "FERC") in order to provide a mechanism for the collection and distribution to NESCOE of funds for

NESCOE's operation and wish to further outline the processes for the collection and distribution of those funds;

NOW, THEREFORE, ISO, NEPOOL and NESCOE, in consideration of the mutual agreements set forth herein, agree as follows:

SECTION 1. TERM AND TERMINATION.

1.1 Effectiveness. This MOU shall be effective as of the first calendar day of the month immediately following satisfaction of the last to occur of the following conditions:

(a) Schedule 5 to Section IV.A. of the ISO Tariff and the rate contained therein are accepted or approved by the FERC;

(b) Thirty (30) days have passed since NESCOE has submitted formal notice to the FERC indicating that it is operational and prepared to receive funding for the purposes specified in the Term Sheet;

(c) NESCOE has submitted to ISO, NEPOOL and the FERC (as part of the foregoing formal notice) its LLC Operating Agreement in the form accepted by the ISO and the Clerk of the Commonwealth of Massachusetts (the "Operating Agreement") and its Code of Conduct in a form approved by ISO and NEPOOL; and

(d) Thirty (30) days have passed since ISO, NEPOOL, and NESCOE have submitted this MOU to the FERC.

1.2 Termination. The term of this MOU shall continue until such time as a Party terminates the MOU, provided that the terminating Party shall provide the other Parties with ninety (90) days' prior written notice during which the other Parties shall have the opportunity to seek a FERC order delaying the termination. Notwithstanding the foregoing, unless all of the Parties agree otherwise in writing, this MOU shall terminate as provided in Section 4.5 or automatically upon the occurrence of any of the following events:

(a) the withdrawal from NESCOE by one of the six New England states;

(b) ISO ceases to be the RTO for New England;

(c) the TOA among ISO and transmission owners that are members of NEPOOL is terminated; or

(d) the Participants Agreement among ISO, NEPOOL and Individual Participants is terminated.

SECTION 2. BINDING NATURE OF TERM SHEET.

The Parties agree that the Term Sheet attached hereto is the binding obligation of the Parties. In particular, the Parties acknowledge that the agreement of ISO and NEPOOL to the terms and conditions of this MOU is conditioned on the following commitments of NESCOE and, accordingly, without limiting the breadth of the preceding sentence, NESCOE agrees to honor the following commitments (contained in more detail in the Term Sheet) to:

(a) maintain the decision-making process that requires policy determinations to be made only by a majority vote of the six New England states, both in number and weighted to reflect relative electric load of each state within the New England region's overall load;

(b) seek FERC approval before increasing its scope of activities beyond those activities identified in the Term Sheet;

(c) unless and until changed by agreement of the Parties, work within the process established by ISO and NEPOOL as outlined in Section 11.4 of the Participants Agreement, more specifically, (i) provide feedback on ISO's annual proposed Installed Capacity Requirement ("ICR") at the relevant NEPOOL Reliability Committee meeting, and (ii) have a representative at the NEPOOL Participants Committee meeting at which the ICR vote will be taken, in order to present NESCOE's position;

(d) work with the Planning Advisory Committee ("PAC"), which is the FERC-approved body for providing advisory input to ISO regarding the development of the Regional System Plan;

(e) make every effort to avoid duplication of efforts or conflicting policy positions with the New England Conference of Public Utility Commissioners Inc. and the New England Governors' Conference Power Planning Committee, including to the extent possible meeting with representatives of these organizations, ISO staff and other stakeholders on issues of common interests;

(f) consult regularly and substantially with ISO, the Participating Transmission Owners ("PTO") Administrative Committee ("PTO AC"), the PAC, NEPOOL participants and other interested stakeholders on matters within NESCOE's scope of activities, primarily by its participation in the Participant Process as set forth in Section 4.3 below, including, without limitation, the submission of its proposals to the NEPOOL Participants Committee for vote;

(g) if significant concerns arise, submit to audit and review by an independent and qualified management consulting firm of the NESCOE budget, activities and spending, with the firm chosen by, and the scope of audit and review and methods for such review, to be agreed upon among the Parties, and a draft report from any such review circulated to the Parties for comment before the report is finalized;

(h) produce and submit annual budgets for its first five years of operation within the limits and on the schedule outlined in the Term Sheet and propose frameworks for future budgets also as described therein;

(i) produce an annual public report to the New England Governors that includes any finalized report from an audit or review of the NESCOE budget activities and spending; and

(j) upon request by the PTO AC or an individual transmission owner that is a party to the TOA (a "PTO"), (i) file comments and documentation in a rate-making proceeding before any New England state public utility commission that support cost recovery of NESCOE-related costs in retail rates, and generally support the PTOs' collection of all NESCOE costs through filings, letters, and consultations with each state regulatory agency; (ii) request ISO to classify all NESCOE costs as "Regulatory Costs"; (iii) support a finding by the FERC that NESCOE costs are prudent, just and reasonable as "Regulatory Costs"; and (iv) support any ISO Tariff amendments needed to effectuate cost recovery.

SECTION 3. COLLECTION OF NESCOE FUNDS.

3.1 ISO's Obligations. ISO will collect costs associated with NESCOE's activities from all Regional Network Load through and in accordance with Schedule 5 to Section IV.A of the ISO Tariff, as accepted and approved by FERC. Except to the extent any such amounts collected are collected subject to refund pursuant to a FERC order, ISO shall remit such amounts to NESCOE monthly following their collection from Transmission Customers, by wiring such funds pursuant to instructions provided by NESCOE. Any amounts retained by ISO because they have been collected from Transmission Customers subject to refund shall either be remitted to NESCOE or refunded as appropriate promptly following a FERC order with respect to such collections that is no longer subject to or the subject of an appeal.

3.2 NESCOE's Obligations. NESCOE shall provide ISO with wiring instructions for the submission of its funds. Revenues received from ISO for NESCOE operations will be used exclusively for the purposes described in Section 4.1 below and will not be commingled with the funds of any other organization.

SECTION 4. NESCOE'S ORGANIZATION.

4.1 NESCOE Operating Agreement; Purpose. The Operating Agreement is attached hereto as Exhibit B. NESCOE shall not change the Operating Agreement without the prior written consent of ISO and NEPOOL. NESCOE further agrees that it shall operate exclusively for religious, charitable, scientific, literary, or educational purposes within the meaning of Section 501(c)(3) of the Internal Revenue Code of 1986, as amended, including the purposes described in the Term Sheet.

4.2 Code of Conduct. NESCOE will cause all of its employees to abide by a Code of Conduct in the form of Exhibit C hereto.

4.3 Consultation with ISO and NEPOOL; Involvement in Participant Processes. To implement the understandings in the Section of the Term Sheet entitled "Consultation and Dispute Resolution," NESCOE shall participate in NEPOOL activities as follows:

(a) NESCOE shall receive notice of and be entitled to attend all Principal Committee meetings, as well as meetings of any other committees, subcommittees, task forces, working groups or other bodies established by the Principal Committees or jointly by ISO and the Participants Committee, and shall have a reasonable opportunity to express views on any matter to be acted upon at such meeting, on the same basis as if it were a voting Participant, except for matters to be addressed in executive session;

(b) NESCOE shall identify a non-voting member and an alternate for each NEPOOL Principal Committee for the purposes of receiving notices of and background materials (other than confidential materials to be considered in executive session) for such meetings. The member and alternate shall each designate and maintain a current e-mail address to which such notices may be delivered. Such designation shall be in a written or electronic notice delivered to the Secretary of the Principal Committee which sets forth the name of the member or alternate and the current e-mail address;

(c) NESCOE shall present policy proposals it plans to initiate through changes to Market Rules, Operating Procedures, Manuals, Reliability Standards, General Tariff Provisions, or Non-TO OATT Provisions for Governance Participant consideration and NEPOOL Participant vote in accordance with the procedures set forth in Section 11 of the Participants Agreement and such NESCOE proposals shall be subject to the same Principal Committee consideration and action under Section 11 as ISO proposals; and

(d) NESCOE shall, whenever possible, collaborate with stakeholders to achieve negotiated resolutions that address its concerns.

4.4 No Participation in New England Markets. NESCOE shall not participate in the New England wholesale electricity markets and rights and attributes associated with such markets including, without limitation, Financial Transmission Rights and renewable and carbon attributes related to such electricity markets.

4.5 Required Renegotiation. In the event that a Court issues a final order materially altering the process for determining the ICR for New England (with such materiality to be reasonably determined by the initiating Party), any Party hereto may initiate a renegotiation of this MOU by submitting a written notice of renegotiation to the other Parties to this MOU. All Parties shall negotiate in good faith to modify the MOU to reflect the final order. In the event that the Parties are not able to reach agreement on renegotiated terms and conditions within ninety (90) days from the date of the aforementioned notice, this MOU shall automatically terminate.

SECTION 5. MISCELLANEOUS.

5.1 NEPOOL Representative; Amendments.

5.1.1 NEPOOL Representative. The Participants Committee, or its designee(s), shall have authority to act for NEPOOL in connection with the administration of this MOU and its amendment.

5.1.2 Amendments. This MOU may be amended only in writing and as agreed to by each Party. In order for a proposed amendment to this MOU to be approved by the Participants Committee, the Minimum Response Requirement must be satisfied with respect to the proposed amendment, and the affirmative ballot votes with respect to the proposed amendment must equal or exceed seventy percent (70%) of the aggregate Sector Voting Shares.

5.2 Dispute Resolution. The Parties agree that any dispute arising under this MOU or regarding the NESCOE budget shall be submitted to the FERC for resolution.

5.3 Governing Law. The terms of this MOU shall be construed and enforced in accordance with the laws of the State of Delaware.

5.4 No Assignment. The MOU shall not be assigned by any Party without the prior written consent of the other Parties. This MOU shall enure to the benefit of, and shall be binding upon, the permitted successors and assigns of the Parties.

5.5 Relationship of Parties. Nothing in this MOU is intended to create a partnership, joint venture or other joint legal entity making any Party jointly or severally liable for the acts or omissions of any other Party. Nothing in this MOU is intended to create a principal/agency relationship between or among any of the Parties and no Party shall have any authority, in any way, to bind any other Party. Each Party is acting in its individual capacity and has the full right to enforce its rights against the others under this MOU.

5.6 Waiver. Delay by any Party in enforcing its rights under this MOU shall not be deemed a waiver of such rights. Any waiver of rights by any Party with respect to any default or other matter arising under this MOU shall not be deemed a waiver with respect to any additional default or other matter arising under this MOU.

5.7 Notices. Any notice, demand, request or other communication required or authorized by this MOU to be given to a Party shall be in writing, and shall be (1) personally delivered to the Party's highest ranking officer; (2) mailed, postage prepaid, to the Party's highest ranking officer at its principal office; (3) sent by facsimile to the Party at the fax number of its highest ranking officer; or (4) delivered electronically to the Party's highest ranking officer at his or her electronic mail address. Any such notice, demand or request shall be deemed given when received by the Party to which it is sent.

5.8 No Third-Party Beneficiaries. This MOU is intended to be solely for the benefit of the Parties and their respective successors and permitted assigns and is not intended to and shall not confer any rights or benefits on any third party (other than successors and permitted assigns) not a signatory hereto.

5.9 Counterparts. This MOU may be executed in any number of counterparts, each of which shall be deemed to be an original and all of which shall constitute one and the same agreement.

5.10 Defined Terms; Documents. Terms used in this MOU that are not defined herein shall have the meanings ascribed to them in the NEPOOL Agreement, the Participants Agreement, or the ISO Tariff. All references to documents other than the Code of Conduct, Term Sheet and NESCOE's Operating Agreement are references to documents as the provisions thereof may be amended, modified or waived from time to time or successor documents thereof.

EXECUTION COPY

IN WITNESS WHEREOF, ISO, NEPOOL, and NESCOE have caused this MOU to be executed by their duly authorized representatives as of the date first written above.

ISO NEW ENGLAND INC.

By:____________________________
Name: Gordon van Welie
Title: President and Chief Executive Officer

NEW ENGLAND POWER POOL

By:____________________________
Name: Peter Fuller
Title: Chair, NEPOOL Participants Committee

NEW ENGLAND STATES COMMITTEE ON ELECTRICITY, LLC

By:____________________________
Name:
Title:

EXECUTION COPY

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ISO NEW ENGLAND INC.

By:____________________________
Name: Gordon van Welie
Title: President and Chief Executive Officer

NEW ENGLAND POWER POOL

By: Peter D. Fuller 11/21/07
Name: Peter Fuller
Title: Chair, NEPOOL Participants Committee

NEW ENGLAND STATES COMMITTEE ON ELECTRICITY, LLC

By:____________________________
Name:
Title:

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ISO NEW ENGLAND INC.

By:____________________________
Name: Gordon van Welie
Title: President and Chief Executive Officer

NEW ENGLAND POWER POOL

By:____________________________
Name: Peter Fuller
Title: Chair, NEPOOL Participants Committee

NEW ENGLAND STATES COMMITTEE ON ELECTRICITY, LLC

By: Charles C. Tretter
Name: Charles C. Tretter
Title: Executive Director, New England Governors' Conference, Inc.

EXHIBIT A

New England States Committee on Electricity (NESCOE)

Term Sheet

September 8, 2006

Introduction:

This term sheet presents the key points of the New England states' proposal to create a *Regional State Committee* or RSC as contemplated by the Federal Energy Regulatory Commission (FERC) in their SMD White Paper.[1] The contents are taken in part from the states' revised Petition filed with the Commission in January of 2005[2] and from the NESCOE Plan of Organization prepared by the states in April of 2005.[3] This term sheet has been created by the states to provide a readily accessible description of their plans for NESCOE and to facilitate dialogue with interested persons on the issues it raises. It reflects extensive consultations with many stakeholders in the New England region and includes many commitments designed to address their concerns. The states agree that they will seek FERC approval to create NESCOE consistent with the terms set forth herein and, if approved, will operate NESCOE in a manner consistent with these terms.

Organization:

The organization will be a not-for-profit corporation called the "New England States' Committee on Electricity" or NESCOE.

It will be directed by a committee representing the six New England States, with one or more representatives appointed by each Governor to represent their state.[4] It will have a staff sufficient to undertake the research and analysis, communication and consultation, and advocacy necessary to achieve its mission.

Decision-making:

Regardless of the number of individuals appointed by each Governor, each state will have one, undivided vote to cast in arriving at NESCOE determinations.

NESCOE will make policy determinations with a majority vote (i.e. …a numerical majority [of the states]) <u>and</u> a majority weighted to reflect relative electric load of each state within the region's overall load.[5]

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1 See SMD NOPR; "White Paper, Wholesale Power Market Platform,," FERC Docket No. RM01-12-000, April 28, 2003 ("White Paper")

2 Joint Amended Petition For Declaratory Order To Form A New England Regional State Committee, FERC Docket No. EL04-112-000, January 11, 2005. ("Revised Petition")

3 NESCOE: Plan of Organization, April 2005, ("Plan of Organization")

4 Revised Petition, p 16

5 Revised Petition, p 3

EXHIBIT A

Mission:

NESCOE's mission will be to represent the interests of the citizens of the New England region by advancing policies that will provide electricity at the lowest possible price over the long term, consistent with maintaining reliable service and environmental quality. Through collaboration with stakeholders and presentation of NESCOE's views to regulators, it will advance policies which seek to facilitate the efficient development of power generation, demand management and transmission resources needed to reliably serve the electricity requirements of consumers. It will seek to accomplish its objectives in the context of a wholesale electricity market that is primarily characterized by competitive market mechanisms, subject to the constraints and directions of law, regulation and public policy.

Scope of Activities

NESCOE will be active, and express its views, in two areas: resource adequacy and system planning and expansion. NESCOE's activities are in no way intended to diminish or affect any of the responsibilities and objectives of ISO-NE or NEPOOL relating to resource adequacy or system planning and expansion, as stated in all of their governing documents. NESCOE will strive to achieve a comprehensive and integrated approach to achieving resource adequacy and system planning and expansion without relying unduly on any single resource or type of infrastructure.

Resource Adequacy: NESCOE will recommend policies and comment on proposed market rule and tariff changes related to resource adequacy, demand response and energy efficiency. NESCOE will work within the process established by ISO-NE and NEPOOL as outlined in Section 11.4 of the Participants Agreement and, more specifically, (i) provide feedback on ISO-NE's annual proposed Installed Capacity Requirement ("ICR") at the relevant NEPOOL Reliability Committee meeting, and (ii) have a representative at the NEPOOL Participants Committee at which the ICR vote will be taken, in order to present NESCOE's position. [6]

In addition, NESCOE will work with State policy makers and legislatures to encourage the use of diverse fuels, including renewable fuels, for electricity generation, customer participation in demand response programs, implementation of cost-effective energy efficiency programs and retail pricing that aligns well with wholesale market pricing.

System Planning and Expansion: NESCOE will recommend policies designed to ensure that resources are available to provide for regional electric reliability and, where it is feasible and cost-effective, to eliminate persistent and costly congestion over

[6] The manner in which the ICR is determined is the subject of litigation brought by the State of Connecticut in the U.S. Court of Appeals for the District of Columbia, Docket No. 05-1411. The states recognize that the ICR determination process may be altered by the resolution of that litigation, which would take precedence over any commitments made here by the states on this issue.

EXHIBIT A

transmission lines[7] and to enable the inter-connection of generation resources. In addition, NESCOE will study and evaluate approaches to the siting of interstate transmission lines on a regional basis. [8] On these issues, NESCOE will work with the Planning Advisory Committee, which is the Commission-approved body for providing advisory input to ISO-NE regarding the development of the Regional System Plan.

The scope of activities set forth herein can only be expanded in the future beyond resource adequacy and system planning and expansion with the unanimous approval of the six states.[9] NESCOE would give due notice and opportunity for consultation to interested stakeholders of any proposed change in its scope of activities and will obtain approval by the Commission before acting on such a change.

NESCOE is not intended to replace or constrain the functioning of either the New England Conference of Public Utility Commissioners (NECPUC) or the Power Planning Committee (PPC) of the New England Governors Conference or the Commission-approved stakeholder processes for providing input to ISO-NE and the PTO Administrative Committee.[10] NECPUC and the PPC are expected to continue to carry out many of the functions they do now and in much the same way. Nevertheless, NESCOE will make every effort to avoid duplication of efforts or conflicting policy positions with these organizations. To the extent possible, this would include joining with them to meet jointly with ISO-NE staff and other stakeholders on issues of common interests.

NESCOE will communicate regularly with NECPUC and the PPC and will seek to hold a formal coordination meeting with both groups at least once a year to discuss up-coming regional electricity policy issues and allocate lead responsibility for developing recommendations to ISO-NE and NEPOOL. The purpose of these communication measures will be to avoid conflicting recommendations and to make efficient use of available staff and resources. The PPC and NECPUC will be asked to relay any particular concerns to NESCOE about its jurisdiction or position on issues. NESCOE will make every effort to address and reconcile such concerns before it makes a final recommendation to ISO-NE or NEPOOL on an issue. Whenever possible, through these regular and extensive communications, decisions on these matters will be made by consensus among the two or three organizations. When that is not possible, NESCOE will use its formal voting method to determine whether a matter is within its scope of activities, or to develop its recommendations on matters within its scope of activities.

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7 Revised Petition, p 13

8 Revised Petition, p 15

9 Revised Petition, p 11

10 For example, NECPUC and its member commissions have a jurisdiction that goes well-beyond electricity to natural gas, telecommunications, and other industries. It also has unique expertise in rate-making issues that render it far better equipped to address specific electricity rate-making issues in matters before the FERC, expertise that will not be duplicated by NESCOE. Likewise, the Power Planning Committee engages in activities that go well beyond electricity issues to all matters dealing with energy, including other fuels and uses (including for space heating and transportation).

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Consultation and Dispute Resolution:

NESCOE will consult regularly and substantially with ISO-NE, the Participating Transmission Owners ("PTO") Administrative Committee, the PAC, NEPOOL participants and other interested stakeholders on matters within its scope of activities. A primary means to accomplish this result will be NESCOE's functioning as an "Individual Participant" in NEPOOL advisory activities. Thereby NESCOE would engage in regular and active participation in the established NEPOOL and PAC stakeholder consultation process. NESCOE would submit any policy proposals it plans to initiate to these organizations' review processes and, where applicable, would bring those proposals to the NEPOOL Participants Committee for an advisory vote.[11] In so doing, NESCOE will make every effort to avoid duplication of consultative processes with these particular stakeholders. NESCOE also may, from time to time, undertake additional consultations or inquiries as it may find necessary and useful. To the extent this arrangement would benefit from being addressed explicitly in the Second Restated NEPOOL Agreement and/or the Participants Agreement, NESCOE would endeavor to reach agreement with NEPOOL and ISO-NE on implementation of those changes as soon as possible. In the event NEPOOL does not support a NESCOE policy proposal following this review and advisory vote, NESCOE reserves the right to pursue this policy proposal independently. More generally, in any instance when ISO-NE, the PTO Administrative Committee, NEPOOL participants and other interested stakeholders file proposed actions with the FERC concerning matters within the scope of NESCOE's activities, NESCOE reserves the right to intervene in such proceedings and file comments with the FERC stating NESCOE's views of the proposed action.

Following the consultations described above, including completion of the NEPOOL review and advisory voting process, NESCOE may seek a formal commitment from ISO-NE to pursue implementation of NESCOE's recommendation. Depending upon the nature of the NESCOE recommendation, NESCOE will request a written response from ISO-NE within a reasonable time frame as to whether ISO-NE intends to implement the recommendation or, if ISO-NE will not pursue implementation of the NESCOE recommendation, an explanation as to why not. If ISO-NE does not commit to pursue implementation of the NESCOE recommendation or proposes a schedule for implementation which is not acceptable to NESCOE, NESCOE will allow a reasonable period of time to attempt to resolve the matter with ISO-NE (and NEPOOL, if applicable) to the parties' mutual satisfaction. If the consultations described above and any further efforts to resolve the matter do not produce a resolution satisfactory to NESCOE, NESCOE may then forward as appropriate its recommendation directly to the FERC for action, including by means of one or more filings pursuant to Section 206 of the Federal

[11] In the event that NESCOE supports a market rule change different from a change proposed by ISO-NE, NESCOE would seek a vote of NEPOOL on the proposal. If NEPOOL supports NESCOE's proposal, the proposal will be subject to the "jump ball" filing provisions set forth in Section 11.1.5 of the Participants Agreement.

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Power Act. NESCOE will only take such action following a prevailing vote, determined in accordance with its formal voting process, and consultation with ISO-NE and NEPOOL in the manner outlined above.

NESCOE will not use litigation as a primary means to accomplish its mission, but rather, whenever possible, collaborate with stakeholders to achieve negotiated resolutions that address its concerns. Nevertheless, NESCOE reserves the right to use litigation to accomplish its mission if all attempts at negotiation and formal dispute resolution fail to do so.

Operating Expenses:

It is likely to take five years for NESCOE to reach its steady-state size and full capabilities. A first year staff of 3 persons would include the Executive Director and most of the senior staff. This staff is expected to grow to a total of 7 individuals in year five.

Salaries and benefits are anticipated to cost just over $430,000 in the first year and rise to $1.2 million in year five. Consulting services for economic, financial and engineering analyses along with legal service are anticipated to cost on average $350,000 per year over the five years. Operational expenses including rent and utilities, office equipment leases, fees for accounting and information technology assistance and travel are expected to average in total[12] about $200,000 per year. Allowing for a contingency at ten percent of expenses, the annual operating budget is expected to be approximately $930,000 in the first year and rise to slightly more than $2 million in the fifth year. At no time will NESCOE seek approval of a budget in excess of $1.4 million per year in its first two years of operation and no more than $2.2 million in its third through fifth year of operation.

Not later than the end of year four of its operations, NESCOE will present a framework for its annual budgets for years six through ten of its operations to the NEPOOL Participants Committee, the PTO Administrative Committee and ISO-NE for their review in the manner described in the next section ("Budget Timeline"). In the absence of agreement with at least the NEPOOL Participants Committee to the contrary, this framework will call for annual budgets that do not increase more than 15% in any one year and do not increase more than 50% on a cumulative basis over that five year period.

Unless altered or eliminated by agreement with at least the NEPOOL Participants Committee, NESCOE will continue to propose and obtain FERC approval of five-year budget frameworks following a consultative process similar to that described in this section as long as its operations continue. In light of the fact that five-year budget frameworks for NESCOE's operations will be established by agreement with these three organizations and/or by approval of the FERC, the annual review of its proposed budgets

12 Revised Petition, p 3

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by at least the NEPOOL Participants Committee will be limited to considerations of accounting and reconciliation, so long as spending remains within the boundaries established by those frameworks.

NESCOE will develop an operating budget recommendation for each year in consultation with NEPOOL, the PTO Administrative Committee and ISO-NE within the boundaries of the then-approved five year budget framework following a process and timeline as described in the next section.

Each year NESCOE will produce a "Report to the New England Governors" that will document its accomplishments from the preceding year and its projected policy priorities for the coming two years. This report will be public and shall be released to NEPOOL and ISO-NE simultaneously with its release to the New England Governors. This report will include a full accounting of spending by NESCOE during the preceding year and proposed budgets for each of the upcoming two years. Before NESCOE submits its proposed budget for the upcoming year to the FERC for approval, it will take a formal vote of the member states according to the voting methodology described above in the "Decision-Making" section to provide a public record of the states' positions on that budget.

Budget Timeline:

NESCOE would coordinate its budget process with the budget cycle that ISO-NE currently uses for its annual administrative expenses recovery filing with the Commission. The schedule below is a rough approximation of this timeline.

June	Draft budget prepared for the coming calendar year
August	Draft budget presented to NESCOE Board for review & analysis
September	Proposed budget presented to ISO-NE and NEPOOL Budget & Finance Subcommittee for review, input, and recommendations
October (begin)	Presentation of proposed budget to NEPOOL Participants Committee for review, input, and advisory vote.
October (mid)	Proposed budget to NESCOE Board for approval
No later than October 20	Filing to be prepared by NESCOE and submitted to ISO-NE; ISO-NE will use its best efforts to file any late submissions by November 1.
November 1	Adopted budget filed by ISO-NE in a stand-alone filing with the Commission.
January 1	Requested effective date

EXHIBIT A

Within this time frame, NESCOE will also seek input from interested stakeholders and provide ISO-NE and stakeholders an opportunity to provide comments. Ultimately, NESCOE has the responsibility to justify to FERC that its budget is just and reasonable.

If a significant concern arises during ISO-NE's and/or the NEPOOL review of the NESCOE budget, ISO-NE and/or the NEPOOL Participants Committee may request an audit/review of NESCOE's activities and spending by an independent and qualified management consulting firm. Such firm shall be chosen by agreement of NESCOE, ISO-NE and the Participants Committee and paid under a contract with NESCOE. The scope of the audit/review and methods used by the management consulting firm will be agreed upon by NESCOE, ISO-NE and the Participants Committee. This review will culminate in a report that will be made available to stakeholders in draft form, with an opportunity for them to comment before it is made final by the management consulting firm. The finalized report shall be formally transmitted to the Governors, ISO-NE and NEPOOL in the context of NESCOE's annual "Report to the Governors."

For its first year of operation, NESCOE's budget review process may not align exactly with the annual ISO-NE budget review cycle. In this event, NESCOE will endeavor to complete each of the steps in the review process outlined above in the most expeditious manner possible.

Cost Allocation and Revenue Collection:

ISO-NE in a filing to be joined by the six New England States will seek FERC approval for a tariff mechanism that will enable funding sufficient to cover NESCOE's costs to be collected from all Regional Network Load. Costs associated with NESCOE's activities would be collected by ISO-NE from all Regional Network Load through a new schedule included in Tariff Section IV.A[13] As defined by Section II.1.110 of the Tariff, Regional Network Load includes the load designated by all Network Customers. The filing will seek FERC approval for classification of all of NESCOE's costs as "Regulatory Costs" for purposes of cost recovery.

Under this arrangement, NESCOE's annual budget will not need the approval of ISO-NE nor will ISO-NE be required to defend the specifics of the tariff filing or the budget. More specifically, in its filings with the FERC related to NESCOE's costs, ISO-NE will support the collection of costs of NESCOE, in general, but will not take any position on the specific budget or costs of operation proposed by NESCOE. NESCOE will lead (and fund) any necessary defense of the specifics of its annual budget proposal and any other of its filings.

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[13] "Budget Process, Cost Allocation and Stakeholder Coordination...," Communication from Transmission Owners, July 26, 2005 "...Schedule 1 charges are billed directly by the ISO to Network Load (all regulated utility companies and municipal loads). The billing determinants for Schedule 1 are the monthly Network Load, and the Reserved Capacity of Point-to-Point Transmission Service. Schedule 1 revenues collected from Point-to-Point Transmission Service customers are credited to each Network Customer's monthly Network Load in that month."

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Updates to the NESCOE rates would be filed by ISO-NE, separately from ISO-NE's own budget updates. NESCOE will work with the PTO Administrative Committee and ISO-NE to arrive at exact language to facilitate the collection of funds from all Regional Network Load.

Revenue would be forwarded by ISO-NE to NESCOE on a schedule and in amounts consistent with NESCOE's FERC-approved budget. Over- or under-collections in a current year relative to amounts actually spent will be reconciled in the following year's budget.

Cost Recovery:

Participating Transmission Owners (as defined in the Transmission Operating Agreement) and their Distribution Affiliates that serve Network Load must have the ability to recover all costs they pay out for NESCOE activities, not just those costs that might be narrowly defined as "transmission related."

Upon request of the PTO Administrative Committee or an individual TO, NESCOE will file comments and documentation in a rate-making proceeding before any New England state public utility commission that support cost recovery of NESCOE-related costs in retail rates, and will generally support the TOs' collection of all NESCOE costs through filings, letters, and consultations with each state regulatory agency, will request ISO-NE to classify all NESCOE costs as "Regulatory Costs," will support a finding by FERC that NESCOE costs are prudent, just and reasonable as "Regulatory Costs," and will support any tariff amendments needed to effectuate cost recovery.

EXHIBIT B

OPERATING AGREEMENT

OF

New England States Committee on Electricity, LLC

EXHIBIT B

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EXHIBIT B

OPERATING AGREEMENT

OF

New England States Committee on Electricity, LLC

THIS OPERATING AGREEMENT (this "**Agreement**"), is made as of November 15, 2007 by New England States Committee on Electricity, LLC, a Massachusetts limited liability company ("**NESCOE**"), and New England Governors' Conference, Incorporated, a Massachusetts not for profit corporation, ("**NEGC**").

NEGC has caused NESCOE to be formed as a limited liability company under the Massachusetts Limited Liability Company Act and, as the sole Member of NESCOE, desires to adopt this Agreement as the operating agreement of NESCOE.

In consideration of the premises and the agreements contained herein, the undersigned declare and agree as follows:

ARTICLE I
DEFINITIONS

1.1. Terms Defined Herein. As used herein, the following terms have the following meanings:

"**Act**" means the Massachusetts Limited Liability Company Act, as amended from time to time.

"**Agreement**" means the Operating Agreement of NESCOE, as amended from time to time.

"**Certificate**" means the Certificate of Organization of NESCOE as filed with the Massachusetts Secretary of State, as amended from time to time.

"**Code**" means the Internal Revenue Code of 1986, as amended from time to time, or the corresponding provisions of future federal tax laws.

"**Credits**" means all tax credits allowed by the Code with respect to activities of the NESCOE or the Property.

"**Distributions**" means any distributions by NESCOE to Member of Liquidation Proceeds. Such distributions are strictly prohibited except for Liquidation Proceeds, but only if Section 4.2 permits them.

"**Fair Value**" of an asset means its fair market value.

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"**Income**" and "**Loss**" mean, respectively, for each fiscal year or other period, an amount equal to the NESCOE's taxable income or loss for such year or period, determined in accordance with the Code.

"**Interest**" refers to all of Member's rights and interests in NESCOE in Member's capacity as the sole Member of NESCOE, all as provided in the Certificate, this Agreement and the Act, including Member's interest in the capital, income, gain, deductions, losses, and credits of NESCOE.

"**Liquidation Proceeds**" means all Property at the time of liquidation of NESCOE and all proceeds thereof.

"Member" means NEGC.

"**NEGC**" means New England Governors' Conference, Incorporated, a Massachusetts not for profit corporation, the sole member of NESCOE, sometimes referred to herein as "Member" or any successor-in-interest to NEGC who becomes a Member in accordance with the Act and as provided in this Agreement.

"**NESCOE**" means New England States Committee on Electricity, LLC, a Massachusetts limited liability company..

"**Person**" means any individual, partnership, limited liability company, corporation, cooperative, trust or other entity.

"**Property**" means all properties and assets that NESCOE may own or otherwise have an interest in from time to time.

"**Reserves**" means amounts set aside from time to time by NESCOE pursuant to Section 4.4.

"**Substitute Member**" has the meaning set forth in Section 7.1.

"**Transfer**" means (i) when used as a verb, to give, sell, exchange, assign, transfer, pledge, hypothecate, bequeath, devise or otherwise dispose of or encumber, and (ii) when used as a noun, the nouns corresponding to such verbs, in either case voluntarily or involuntarily, by operation of law or otherwise.

"**Transferee**" has the meaning set forth in Section 7.1.

1.2. Other Definitional Provisions.

As used in this Agreement, accounting terms not defined in this Agreement, and accounting terms partly defined to the extent not defined, have the respective meanings given to them under generally accepted accounting principles.

The words "hereof," "herein" and "hereunder" and words of similar import when used in this Agreement refer to this Agreement as a whole and not to any particular provision of

EXHIBIT B

this Agreement, and section, subsection, schedule and exhibit references are to this Agreement unless otherwise specified.

Words of the masculine gender are deemed to include the feminine or neuter genders, and vice versa, where applicable. Words of the singular number are deemed to include the plural number, and vice versa, where applicable.

Additional terms may be found in the remaining Articles of this Agreement and are defined therein.

ARTICLE II
PURPOSES AND OFFICES

2.1. Purpose. The purpose of NESCOE will be to function as a regional state committee as contemplated by the Federal Energy Regulatory Commission (FERC) for the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. NESCOE is organized exclusively for such purpose and as a not for profit entity and no part of the net earnings of NESCOE shall inure to the benefit of any private shareholder or individual; no substantial part of the activities of NESCOE shall be carrying on propaganda, or otherwise attempting to influence legislation (except as otherwise provided in Code Section 503(h). NESCOE shall not participate in, or intervene in (including the publishing and distributing or statements) any political campaign on behalf of (or in opposition to) any candidate for public office. NESCOE is organized and will be operated exclusively for charitable and scientific purposes. NESCOE is formed only for such purposes and will not be deemed to create any declaration or agreement by NESCOE or by the Member with respect to any other activities whatsoever other than the activities within such purpose.

2.2. Powers. In addition to the powers and privileges conferred upon the Company by law and those incidental thereto, the Company has all the powers set forth in the Act and the same powers as a natural person to do all things necessary or convenient to carry out its purposes and affairs:

sue and be sued, complain and defend, and participate in administrative or other proceedings, in its name;

purchase, take, receive, lease as lessee, take by grant, gift, legacy, or otherwise acquire, own, hold, improve, use, and otherwise deal in and with any real or personal property, or any interest therein, wherever situated;

sell, convey, mortgage, pledge, lease as lessor, exchange, transfer, and otherwise dispose of all, any part of, or any interest in, its property and assets;

purchase, take, receive, subscribe for or otherwise acquire, own, hold, vote, use, employ, sell, mortgage, loan, pledge, or otherwise dispose of, and otherwise use and deal in and with, shares or other interests in, or obligations of, other domestic or foreign limited liability companies, corporations, associations, general or limited partnerships, or individuals, or direct or indirect obligations of the United States or of any other

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government, state, territory, governmental district or municipality or of any instrumentality thereof;

incur liabilities, borrow money for its proper purposes at any rate of interest that NESCOE may determine without regard to the restrictions of any usury law, issue notes, bonds, and other obligations, secure any of its obligations by mortgage or pledge or deed of trust of all or any part of its property, franchises, and income, and make contracts, including contracts of guaranty and suretyship;

invest its surplus funds from time to time, lend money for its proper purposes, and take and hold real and personal property as security for payment of funds so loaned or invested, except that no funds of NESCOE shall be commingled with funds of the Member, nor shall NESCOE loan funds to the Member nor make any distribution of funds to the Member, except upon the liquidation of NESCOE and then only if permitted by Section 4.2 hereof;

conduct its purposes and activities, carry on its operations, have offices within and without the Commonwealth of Massachusetts, and exercise in any other state, territory, district, or possession of the United States or in any foreign country the powers granted by the Act, the Certificate or this Agreement;

appoint agents and hire employees of NESCOE, define their duties, and fix their compensation and to indemnify them to the extent and in the manner permitted by law;

make and alter this Agreement, in any manner not inconsistent with the Certificate, the laws of the Commonwealth of Massachusetts and the regulations and orders of FERC, for the administration and regulation of the affairs of NESCOE;

transact any lawful activities in aid of the United States.

2.3. Principal Office. The principal office(s) of NESCOE will be located at such place(s) as the Member may determine from time to time, provided that the principal office(s) shall be located at all times within the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island or Vermont.

2.4. Registered Office and Registered Agent. The location of the registered office and the name of the registered agent of NESCOE in the Commonwealth of Massachusetts will be as stated in the Certificate. The registered office and registered agent of NESCOE may be changed, from time to time, in accordance with the Act.

2.5. Amendment of the Certificate. NESCOE may amend the Certificate at such time or times and in such manner as may be required by the Act and this Agreement.

2.6. Effective Date. This Agreement will be effective on the date of this Agreement. The Company will continue until dissolved pursuant to the Act, the Articles, or this Agreement.

2.7. No Liability of Member. The Member, solely by reason of being a Member, will not be liable, under a judgment, decree or order of a court, or in any other manner, for a debt,

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obligation or liability of NESCOE, whether arising in contract, tort or otherwise, or for the acts or omissions of NESCOE and any agent or employee of NESCOE. The failure of NESCOE to observe any formalities or requirements relating to the exercise of its powers or management of its activities or affairs under this Agreement or the Act will not be grounds for imposing liability on the Member for liabilities of NESCOE.

ARTICLE III
CAPITAL CONTRIBUTIONS AND LOANS

3.1. Capital Contributions. The Member is not obligated to make any contributions to the capital of NESCOE and, accordingly, the Member will not be liable for damage to NESCOE as a result of the failure of the Member to make any contributions. The Member may make capital contributions to NESCOE at such times and in such amounts as shall be determined and approved by the Member.

3.2. Capital Withdrawal Rights, Interest. Except as expressly provided in this Agreement or as otherwise determined by the Member, (a) the Member is not entitled to withdraw or receive any Distributions from NESCOE, and (b) the Member is not entitled to receive or be credited with any interest on any contributions made to NESCOE at any time.

3.3. Loans. The Member may make loans to NESCOE in such amounts, at such times, and on such terms and conditions as may be determined by the Member. Loans by the Member to NESCOE will not be considered as contributions to the capital of NESCOE.

ARTICLE IV
ALLOCATIONS AND DISTRIBUTIONS

4.1. Non-Liquidation Cash Distributions. No cash distributions shall be made from NESCOE to the Member, other than distribution of Liquidation Proceeds and no commingling or other combination of funds belonging to NESCOE shall be made with funds belonging to the Member.

4.2. Liquidation Distributions. Liquidation Proceeds will be distributed in the following order of priority:

To the payment of debts and liabilities of NESCOE (including those due to NEGC, to the extent otherwise permitted by law and applicable contractual restrictions) and the expenses of liquidation.

Next, to the setting up of such reserves as the Person required or authorized by law to wind up NESCOE's affairs may reasonably deem necessary or appropriate for any disputed, contingent or unforeseen liabilities or obligations of NESCOE, provided that any such reserves must be paid over by such Person to an independent escrow agent, to be held by such agent or its successor for such period as such Person deems advisable for the purpose of applying such reserves to the payment of such liabilities or obligations and, at the expiration of such period, the balance of such reserves, if any, will be distributed as hereinafter provided.

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Next, to the return to ISO New England, Inc. of any remaining monies remitted to NESCOE by ISO New England, Inc. under Schedule 5 of the ISO New England tariff.

The remainder shall be distributed for purposes described in Code Section 501(c)(3) and may be distributed to the Member for such purposes, but only if the Member is then described in Code Section 501(c)(3). If the Member is not then described in Code Section 501(c)(3) then the remainder shall be distributed for purposes described in Code Section 501(c)(3).

4.3. Income, Losses and Credits. NESCOE's Income or Loss, as the case may be, and applicable Credits, for each fiscal year of NESCOE, as determined in accordance with such method of accounting as may be adopted for NESCOE, will be allocated to the Member for both financial accounting and income tax purposes, except as otherwise provided for herein or unless the Member determines otherwise.

4.4. Reserves. NESCOE has the right to establish, maintain and expend Reserves to provide for working capital, for future maintenance, repair or replacement of the Property, for debt service, for future investments and for such other purposes as NESCOE may deem necessary or advisable.

ARTICLE V
MANAGEMENT

5.1. Management. The business and affairs of the Company shall be managed by one or more Persons designated by the then sitting Governors of the member states of the NEGC, who shall be referred to as "Managers" and who, acting as a board, shall constitute the "Management Committee." Each Manager shall hold office until removed by the then sitting Governor of the member state of the NEGC who appointed the Manager or until such Manager's earlier death, resignation or removal, with or without cause, by the then sitting Governor of the member state of the NEGC who appointed the Manager. Except as expressly limited by law, the Certificate or this Agreement, the Property and the business of the Company shall be controlled and managed by the Management Committee. The Management Committee shall have and is vested with all powers and authorities, except as expressly limited by law, the Certificate or this Agreement, to do or cause to be done any and all lawful things for and in behalf of the Company, to exercise or cause to be exercised any or all of its powers, privileges and franchises, and to seek the effectuation of its objects and purposes. The Management Committee may from time to time, as reasonably necessary to carry on the day-to-day business and affairs of the Company and carry out the decisions of the Management Committee, delegate its powers and authorities to employees of the Company, or to any other representatives of the Company, as officers or in such other capacities as the Management Committee, with the approval of the Member, may determine.

5.2. Designation of Managers. Each then sitting Governor of the member states of the NEGC may at any time and from time to time designate one (1) or more Managers to serve on the Management Committee, which Managers shall serve until their successors have been duly designated by the then sitting Governor of the member state of the NEGC who appointed the Manager or until their earlier death, resignation or removal, with or without cause, by the then

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sitting Governor of the member state of the NEGC who appointed the Manager. Designation of Managers shall not be required at any regular frequency, but, instead, shall occur at such times as the then sitting Governors of the member states of the NEGC shall individually determine.

5.3. Manner of Acting by Management Committee. Regardless of the number of individuals appointed by a Governor of a member state of the NEGC to serve as a Manager, each member state will have one, undivided vote to cast in arriving at NESCOE determinations. NESCOE will make policy determinations with a majority vote (i.e., a numerical majority of the member states of the NEGC **and** a majority weighted to reflect the relative electric load of each state within the overall load of the region encompassed by the NEGC. The relative electric load shall be based each calendar year on the relative peak electric loads of each member state reported in the Fourth Quarter Markets Report submitted to FERC by ISO New England, Inc. during the prior calendar year. The initial relative peak electric loads of each member state of NEGC for calendar year 2008 shall be based on figures contained in ISO New England's July 16, 2007 Fourth Quarter Markets Report for the fourth quarter of 2006.

5.4 Meetings of the Management Committee; Place of Meetings. Meetings of the Management Committee shall not be required to be held at any regular frequency, but, instead, shall be held upon the call of the Managers representing at least three (3) of the member states of the NEGC. All meetings of the Management Committee shall be held at any location within the member states of the NEGC as shall be designated by the Managers calling the meeting and stated in the notice of the meeting or in a duly executed waiver of notice thereof. Managers may participate in a meeting of the Management Committee by means of conference telephone equipment or similar communications equipment whereby all Managers participating in the meeting can hear each other and participation in a meeting in this manner shall constitute presence in person at the meeting.

5.5 Quorum; Voting Requirement. At all meetings of the Management Committee, the presence of Managers representing a majority of the member states of the NEGC shall constitute a quorum for the transaction of business. Subject to any and all other express restrictions or requirements under this Agreement, the act of a majority of the member states of the NEGC present at any meeting of the Management Committee at which a quorum is present shall be the act of the Management Committee.

5.6 Notice of Meeting. Notice of each meeting of the Management Committee, stating the place, day and hour of the meeting shall be given to each Manager at least two days before the day on which the meeting is to be held. The notice may be given by any Manager having authority to call the meeting. "Notice" and "call" with respect to such meetings shall be deemed to be synonymous.

5.7 Waiver of Notice. Whenever any notice is required to be given to any Manager under the provisions of this Agreement, a waiver thereof in writing signed by such Manager, whether before or after the time stated therein, shall be deemed equivalent to the giving of such notice. Attendance of a Manager at any meeting shall constitute a waiver of notice of such meeting except where a Manager attends a meeting for the express purposes of objecting to the transaction of any business because the meeting is not lawfully called or convened.

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5.8 Compensation of Managers. Managers shall not receive any compensation for their services as such, unless approved by the member states of NEGC appointing the Manager. Nothing herein contained shall be construed to preclude any Manager from serving the Company in any other capacity and receiving compensation therefor. In addition, subject to such reasonable policies and documentation requirements as the Management Committee may adopt from time to time, each Manager shall be entitled to payment by or reimbursement from the Company of all reasonable out-of-pocket expenses incurred by such Manager in the course of furnishing services as a Manager of the Company under this Agreement (other than for any salaries, wages, fringe benefits, or other compensation of such Manager or any agents or employees, or for any general overhead expenses incurred by such Manager, all of such expenses being the responsibility of the member state appointing the Manager).

5.9 Authority of the Member. The Member may at any time and from time to time impose such other or additional restrictions on the authority of the Management Committee as the Member may deem appropriate.

5.10 Execution of Documents Filed with State Secretary of Massachusetts. The Member, the Management Committee or the designee of the Management Committee shall be authorized to execute and file with the State Secretary of the Commonwealth of Massachusetts any document permitted or required by the Act. The Member hereby waives any requirement under the Act of receiving a copy of any document filed with the State Secretary of the Commonwealth of Massachusetts. The Member hereby ratifies and affirms the Certificate as heretofore filed on behalf of the Company.

5.11 Limitation of Liability; Indemnification.

(a) Limitation. To the fullest extent permitted by applicable law, no Person shall be liable to the Company or its Member for any loss, damage, liability or expense suffered by the Company or its Member on account of any action taken or omitted to be taken by such Person as a Member or Manager of the Company, or by such Person while serving at the request of the Company as an officer, agent, employee or in any other capacity for the Company, if such Person discharges such Person's duties in good faith, and in a manner such Person reasonably believes to be in or not opposed to the best interests of the Company and, with respect to any criminal action or proceeding, had no reasonable cause to believe that such Person's conduct was unlawful. The Member's or Manager's liability hereunder shall be limited only for those actions taken or omitted to be taken by such Member or Manager in connection with the management of the business and affairs of the Company.

(b) Right to Indemnification. To the fullest extent permitted by applicable law, the Company shall indemnify each Person who has been or is a party or is threatened to be made a party to any threatened, pending or completed action, suit or proceeding, whether civil, criminal, administrative, investigative or appellate (regardless of whether such action, suit or proceeding is by or in the right of the Company or by third parties) by reason of the fact that such Person is or was a Member or Manager of the Company, or is or was serving at the request of the

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Company as a director, officer or in any other comparable position of the Company against all liabilities and expenses, including, without limitation, judgments, amounts paid in settlement, attorneys' fees, excise taxes or penalties, fines and other expenses, actually and reasonably incurred by such Person in connection with such action, suit or proceeding (including, without limitation, the investigation, defense, settlement or appeal of such action, suit or proceeding), if such Person discharged such Person's duties in good faith and in a manner such Person reasonably believed to be in or not opposed to the best interests of the Company and, with respect to any criminal action or proceeding, if such Person had no reasonable cause to believe that such Person's conduct was unlawful; provided, however, that the Company shall not be required to indemnify or advance expenses to any Person from or on account of such Person's conduct that was finally adjudged to have been knowingly fraudulent, deliberately dishonest or willful misconduct; provided, further, that the Company shall not be required to indemnify or advance expenses to any Person in connection with an action, suit or proceeding initiated by such Person unless the initiation of such action, suit or proceeding was authorized in advance by the Company; provided, further, that a Member or Manager shall be indemnified hereunder only for those actions taken or omitted to be taken by such Member or Manager in connection with the management of the business and affairs of the Company and that the provisions of this Section 5.11 are not intended to extend indemnification to the Member or any Manager for any actions taken or omitted to be taken by the Member or Manager in any other connection, including, but not limited to, any other express obligation of the Member or Manager undertaken in this Agreement. The termination of any action, suit or proceeding by judgment, order, settlement, conviction or under a plea of ***nolo contendere*** or its equivalent, shall not, of itself, create a presumption that such Person seeking indemnification did not discharge such Person's duties in good faith and in a manner such Person reasonably believed to be in or not opposed to the best interests of the Company, that such Person had reasonable cause to believe that such Person's conduct was unlawful with respect to any criminal action or proceeding, or that such Person's conduct was knowingly fraudulent, deliberately dishonest or willful misconduct.

(c) Enforcement of Indemnification. In the event the Company refuses to indemnify any Person who may be entitled to be indemnified or to have expenses advanced under this Section 5.11, such Person shall have the right to maintain an action in any court of competent jurisdiction against the Company to determine whether or not such Person is entitled to such indemnification or advancement of expenses hereunder. If such court action is successful and the Person is determined to be entitled to such indemnification or advancement of expenses, such Person shall be reimbursed by the Company for all fees and expenses (including attorneys' fees) actually and reasonably incurred in connection with any such action (including, without limitation, the investigation, defense, settlement or appeal of such action).

(d) Advancement of Expenses. Expenses (including attorneys' fees) reasonably incurred in defending an action, suit or proceeding, whether civil,

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criminal, administrative, investigative or appellate, shall be paid by the Company in advance of the final disposition of such action, suit or proceeding upon receipt of an undertaking by or on behalf of such Person to repay such amount if it shall ultimately be determined that such Person is not entitled to indemnification by the Company. In no event shall any advance be made in instances where the Member or independent legal counsel reasonably determines that such Person would not be entitled to indemnification hereunder.

(e) Non-Exclusivity. The indemnification and the advancement of expenses provided by this Section 5.11 shall not be exclusive of any other rights to which those seeking indemnification or advancement of expenses may be entitled under any statute, or any agreement, policy of insurance or otherwise, both as to action in their official capacity and as to action in another capacity while holding their respective offices, and shall not limit in any way any right that the Company may have to make additional indemnifications with respect to the same or different Persons or classes of Persons. The indemnification and advancement of expenses provided by, or granted pursuant to, this Section 5.11 shall continue as to a Person who has ceased to be a Member or Manager of the Company, and as to a Person who has ceased serving at the request of the Company as a director, officer or in any other comparable position of the Company and shall inure to the benefit of the heirs, executors and administrators of such Person.

(f) Insurance. Upon the approval of the Management Committee, the Company may purchase and maintain insurance on behalf of any Person who is or was a Member, Manager, agent or employee of the Company, or is or was serving at the request of the Company as a director, officer or in any other comparable position of the Company, against any liability asserted against such Person and incurred by such Person in any such capacity, or arising out of such Person's status as such, whether or not the Company would have the power, or the obligation, to indemnify such Person against such liability under the provisions of this Section 5.11.

(g) Amendment and Vesting of Rights. Notwithstanding any other provision of this Agreement, the terms and provisions of this Section 5.11 shall not be amended or repealed and the rights to indemnification and advancement of expenses created hereunder shall not be changed, altered or terminated except by the Member. The rights granted or created hereby shall be vested in each Person entitled to indemnification hereunder as a bargained-for, contractual condition of such Person's serving or having served as a Member or Manager of the Company or serving at the request of the Company as a director, officer or in any other comparable position of any Other Enterprise and, while this Section 5.11 may be amended or repealed, no such amendment or repeal shall release, terminate or adversely affect the rights of such Person under this Section 5.11 with respect to any act taken or the failure to take any act by such Person prior to such amendment or repeal or with respect to any action, suit or proceeding with respect to such act or failure to act filed after such amendment or repeal.

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(h) Definitions. For purposes of this Section 5.11, references to:

"Company" shall include, in addition to the resulting or surviving limited liability company (or other entity), any constituent limited liability company (or other entity) (including any constituent of a constituent) absorbed in a consolidation or merger so that any Person who is or was a member or manager of such constituent limited liability company (or other entity), or is or was serving at the request of such constituent limited liability company (or other entity) as a director, officer or in any other comparable position shall stand in the same position under the provisions of this Section 5.11 with respect to the resulting or surviving limited liability company as such Person would if such Person had served the resulting or surviving limited liability company (or other entity) in the same capacity;

"defense" shall include investigations of any threatened, pending or completed action, suit or proceeding as well as appeals thereof and shall also include any defensive assertion of a cross-claim or counterclaim.

(i) Severability. If any provision of this Section 5.11 or the application of any such provision to any Person or circumstance is held invalid, illegal or unenforceable for any reason whatsoever, the remaining provisions of this Section 5.11 and the application of such provision to other Persons or circumstances shall not be affected thereby and, to the fullest extent possible, the court finding such provision invalid, illegal or unenforceable shall modify and construe the provision so as to render it valid and enforceable as against all Persons and to give the maximum possible protection to Persons subject to indemnification hereby within the bounds of validity, legality and enforceability. Without limiting the generality of the foregoing, if the Member or any Manager of the Company or any Person who is or was serving at the request of the Company as a director, officer or in any other comparable position of the Company, is entitled under any provision of this Section 5.11 to indemnification by the Company for some or a portion of the judgments, amounts paid in settlement, attorneys' fees, ERISA excise taxes or penalties, fines or other expenses actually and reasonably incurred by any such Person in connection with any threatened, pending or completed action, suit or proceeding (including, without limitation, the investigation, defense, settlement or appeal of such action, suit or proceeding), whether civil, criminal, administrative, investigative or appellate, but not, however, for all of the total amount thereof, the Company shall nevertheless indemnify such Person for the portion thereof to which such Person is entitled.

5.12 Contracts with the Member, any Manager, or Affiliates. No contract or transaction between the Company and the Member or any Manager or between the Company and any Person in which the Member or any Manager is a director or officer, or has a financial interest, shall be void or voidable solely for this reason, and the Member or applicable Manager shall not be obligated to account to the Company for any profit or benefit derived by the Member or applicable Manager if the Member consents to such contract or transaction.

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5.13 Other Business Ventures. The Member or any Manager may engage in, or possess an interest in, other activities or ventures of every nature and description, independently or with others, whether or not similar to or in competition with the business of the Company, and neither the Company nor the Member shall have any right by virtue of this Agreement in or to such other activities or ventures or to the income or profits derived therefrom. Neither the Member nor any Manager shall be required to devote all of their time or efforts to the affairs of the Company, but shall devote so much of their time and attention to the Company as is reasonably necessary and advisable to manage the affairs of the Company.

ARTICLE VI
ACCOUNTING AND BANK ACCOUNTS

6.1 Fiscal Year. The fiscal year and taxable year of NESCOE will end on June 30 of each year, the same fiscal year as NEGC, unless otherwise established by the Code.

6.2 Books and Records. At all times during the existence of NESCOE, NESCOE will cause to be maintained full and accurate books of account, which must reflect all transactions of NESCOE and be appropriate and adequate for the activities of NESCOE. The books and records of NESCOE will be maintained at its principal office. The Member and all Managers shall have the right during ordinary business hours and upon reasonable notice to inspect and copy (at NEGC's expense) all books and records of NESCOE.

6.3 Bank Accounts. All funds of NESCOE must be deposited in a separate bank, money market or similar account or accounts approved by NEGC and in NESCOE's name. Withdrawals therefrom shall be made only by individuals authorized to do so by NESCOE.

ARTICLE VII
TRANSFERS OF INTERESTS

7.1 General Provisions. The Member may Transfer all or any part of its Interest. Upon any Transfer to any transferee (a "Transferee") of all or any part of the Member's Interest, such Transferee will become a Member of the Company (a "Substitute Member") only to the extent that the Member has expressly stated such intention in writing. Except to the extent that a Transferee becomes a Substitute Member, such Transferee shall not be entitled to exercise any rights as a Member in NESCOE, including the right to vote, grant approvals, or give consents with respect to the applicable Interest, the right to require any information or accounting of NESCOE's business or the right to inspect NESCOE's books and records, but such Transferee shall only be entitled to receive, to the extent of the Interest transferred to such Transferee, the Distributions attributable thereto.

7.2 Redemption of Interests. Any Interest may be redeemed by NESCOE, by purchase or otherwise, as determined by NESCOE with the approval of NEGC.

ARTICLE VIII
DISSOLUTION AND TERMINATION

8.1 Events Causing Dissolution. The Company will be dissolved only upon the first to occur of the following dates or events:

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(a) The written determination of the Member to dissolve.

(b) Upon the entry of a decree of dissolution with respect to NESCOE by a court of competent jurisdiction.

(c) When the Company is not the surviving entity in a merger or consolidation under the Act.

8.2 Effect of Dissolution. Except with respect to the occurrence of an event referred to in Section 8.1(c) and except as otherwise provided in this Agreement, upon the dissolution of NESCOE, the Member shall take such actions as may be required pursuant to the Act and shall proceed to wind up, liquidate and terminate the activities and affairs of NESCOE. In connection with such winding up, the Member will have the authority to liquidate and reduce to cash (to the extent necessary or appropriate) the assets of NESCOE as promptly as is consistent with obtaining Fair Value therefor, to apply and distribute the proceeds of such liquidation and any remaining assets in accordance with the provisions of Section 8.3, and to do any and all acts and things authorized by, and in accordance with, the Act and other applicable laws for the purpose of winding up and liquidation.

8.3 Application of Proceeds. Upon dissolution and liquidation of NESCOE, the assets of NESCOE shall be applied and distributed in the order of priority set forth in Section 4.2.

ARTICLE IX
MISCELLANEOUS

9.1 Title to the Property. Title to the Property will be held in the name of NESCOE. Neither the Member or the Managers shall have any ownership interest or rights in the Property.

9.2 Notices and Determinations. Any notice or determination required or permitted to be given or made by this Agreement or the Act will be sufficient if given or made in writing.

9.3 No Third Party Rights. None of the provisions contained in this Agreement are for the benefit of or enforceable by any third parties, including creditors of NESCOE; provided, however, NESCOE or the Member may enforce any rights granted to them under the Act, the Certificate or this Agreement.

9.4 Amendments to this Agreement. This Agreement may not be modified or amended in any manner other than by the Member.

9.5 Severability. If any provision of this Agreement is held to be illegal, invalid or unenforceable to any extent, the legality, validity and enforceability of the remainder of this Agreement will not be affected thereby and will remain in full force and effect and shall be enforced to the greatest extent permitted by law.

9.6 Binding Agreement. The provisions of this Agreement are binding upon, and will inure to the benefit of, the parties hereto and their respective successors and permitted assigns.

9.7 Headings. The headings of the Articles and the sections of this Agreement are for convenience only and may not be considered in construing or interpreting any of the terms or provisions thereof and hereof.

9.8 Governing Law. This Agreement is governed by, and is to be construed in accordance with, the laws of the Commonwealth of Massachusetts.

The Company, acting through the Member, and the Member have executed this Agreement as of the date first written above.

New England States Committee on Electricity, LLC (the "Company")

By: New England Governors' Conference, Incorporated ("the Member)

By: Charles C. Tretter

Name: Charles C. Tretter
Title: Executive Director, New England Governors' Conference, Inc.

EXHIBIT C

NEW ENGLAND STATES COMMITTEE ON ELECTRICITY, LLC
CODE OF CONDUCT

The mission of the New England States Committee on Electricity, LLC, (NESCOE) the regional state committee for New England, is to represent the interests of the citizens of the New England region by advancing policies that will provide electricity at the lowest possible price over the long term while maintaining reliable service and environmental quality. NESCOE will fulfill its mission by carrying out the responsibilities within its scope, which is contractually limited to matters of resource adequacy and system planning and expansion. In carrying out NESCOE's mission, its Managers, officers and employees will act in a non-discriminatory fashion toward all participants in the electricity markets in New England. Accordingly, its Managers, officers and employees will strictly adhere to the rules and spirit of this *Code of Conduct.*

Capitalized terms not otherwise defined herein shall have the meanings given to them in the ISO New England Inc. ("ISO-NE") Transmission, Markets and Services Tariff.

1. CONFLICTS OF INTEREST

Certain contacts with Market Participants may constitute or appear to constitute a conflict of interest. For purposes of the *Code of Conduct*, the term "Market Participants" refers to the following persons (natural or legal) and their Affiliates: any person that is a party to the Participants Agreement, a Market Participant Service Agreement or a Transmission Service Agreement, other than (i) any Transmission Customer solely taking Through Service under the Tariff, and (ii) FTR Holders Only. The term "Affiliate," with respect to an entity, means any individual, corporation, partnership, firm, joint venture, association, joint-stock company, trust or unincorporated organization, or other form of entity, directly or indirectly Controlling, Controlled by, or under common Control with, such entity. The term "Control" means the possession, directly or indirectly, of the power to direct the management or policies of an entity. A voting interest of ten percent or more creates a rebuttable presumption of control.

Potential conflicts of interest are discussed below.

1.1 Prohibited Financial Interests

In order for NESCOE to be truly independent and free of any control and appearance of control of decision-making by any individual Market Participant or any one class of Market Participants, NESCOE Managers, officers and employees may not have a "Prohibited Financial Interest." A NESCOE Manager, officer or employee will be deemed to have a "Prohibited Financial Interest" if he or she, or his or her spouse or minor child owns, controls or holds with the power to vote Securities (defined below) of a Market Participant, whether directly or through participation in mutual funds concentrating in investments in Market Participants.

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Prohibited Financial Interests do not include interests in a publicly traded or publicly available mutual fund or other collective investment fund or in a widely held pension or similar fund, provided that the fund's prospectus does not indicate the objective or practice of concentrating its investment in Market Participants or similar entities and there is no ability to exercise control over the financial interests held in the fund.

"Securities" means stocks, stock options, bonds and any other instruments of debt or equity, and includes all interests in debt or equity instruments, including, without limitation, secured and unsecured bonds, debentures, notes, securitized assets, commercial paper, preferred and common stock, any beneficial or legal interest derived from a trust, and any right to acquire any long or short position in such securities, including, without limitation, interests convertible into the aforementioned securities, options, rights, warrants, puts, calls and straddles with respect to such securities.

1.1.1 Prohibited Securities List

Please refer to the list of Market Participants at www.iso-ne.com.

1.1.2 Divestiture of Prohibited Securities

If a NESCOE Manager, officer or employee, or his or her spouse or minor children, has a Prohibited Financial Interest described above, divestiture must occur as follows:

- Within six months of the commencement of your relationship with NESCOE as a manager, director, officer or employee;
- If a Prohibited Financial Interest results from an entity becoming a Market Participant, within six months of receipt of the notice from NEPOOL regarding such new Market Participant; and
- If a Prohibited Financial Interest results from a gift, inheritance, distribution of marital property or other involuntary acquisition, within six months of the acquisition.

1.2 No Association with ISO-NE or Market Participants

A NESCOE Manager, officer or employee may not be "Associated" with ISO-NE or any Market Participant. For the purposes of this paragraph, a NESCOE Manager, officer or employee will be deemed "Associated" if he or she:

- is an officer, director, partner, or employee of ISO-NE or a Market Participant;

EXHIBIT C

- served as a former executive officer or director of ISO-NE or a Market Participant within the last two years or is receiving continuing benefits under an existing employee benefit plan (other than a defined benefit pension plan or other plan pursuant to which the benefits are independent of the financial condition of ISO-NE or the Market Participant and pension payments are distributed by a trustee, not as compensation but in accordance with the rules of the pension plan), arrangement or policy of ISO-NE or the Market Participant;

- has a material ongoing business or professional relationship with ISO-NE or a Market Participant (including employees of ISO-NE and Market Participants); or

- has a spouse that is a director, partner, or employee of ISO-NE or a Market Participant.

1.3 Non-Participation in Market Transactions

To ensure that NESCOE maintains independence from ISO-NE and any Market Participant, NESCOE and its Managers, officers and employee are prohibited from engaging in any energy market transactions. This provision shall not, however, prevent NESCOE or any NESCOE Manager, officer or employee from purchasing electricity, power and energy as retail customers from a Market Participant.

1.4 Other Conflicts of Interest

Conflicts of interest can occur when positions or responsibilities in NESCOE present or appear to present an opportunity for personal gain, or when personal interests or the interests of family or cohabitants are, or appear to be, inconsistent with Company interests. This includes not only a conflict of interest but also any action that could reasonably be expected to create an appearance of a conflict of interest. Under all circumstances Managers, officers or employees are expected to adhere to and maintain the highest ethical standards when conducting Company business. In meeting this requirement, Managers, officers or employees must be careful to avoid any situations or relationships that can cause actual, potential or perceived conflicts of interest. A position in NESCOE may never be used to improperly benefit oneself, family members or cohabitants.

It will be considered a conflict of interest if a NESCOE Manager, officer or employee requests or accepts anything with a value of more than $50 ("Nominal Value"), including but not limited to money, a loan or discount, vacations, property, contributions, goods or services from ISO-NE or a Market Participant or any other person or entity doing business with NESCOE. Such gifts should be returned or offers declined, with an appropriate explanation. Acceptance of an occasional business-related meal or entertainment is permissible when the value involved is not significant and clearly will not create any obligation to the donor.

EXHIBIT C

If a NESCOE Manager, officer or employee is seeking other employment, or has an arrangement concerning prospective employment, with ISO-NE or a Market Participant, he or she must notify his or her supervisor and disqualify himself or herself from participating in any matter that will have an effect on the interests of ISO-NE or such Market Participant.

It will be considered a conflict of interest for a NESCOE Manager, officer or employee, spouse or minor children, or, with knowledge, any other family member or relative, to have an interest in any contractor, company, business, or enterprise which has, or is seeking to establish, business relations with NESCOE.

1.5 Consultants and Contractors

NESCOE shall develop and apply reasonable and objective conflict of interest guidelines for consultants and contractors. These criteria shall, whenever possible, prevent NESCOE's use of consultants and contractors who are simultaneously employed by ISO-NE, NEPOOL or a Market Participant.

2. TREATMENT OF CONFIDENTIAL INFORMATION

As a Manager, officer or employee of NESCOE, information may be received that is considered to be confidential and that NESCOE has committed to maintain in confidence. All such confidential information shall be treated in accordance with NESCOE's commitments to maintain the confidentiality of such information. A failure to do so will be considered a violation of this *Code of Conduct*.

3. COMPANY RECORDS

NESCOE requires that honest and accurate business records be maintained. NESCOE's books, records, accounts and financial information must be maintained in reasonable detail, must appropriately reflect all of its transactions and all other events that are the subject of a specific regulatory record-keeping requirement and must conform both to applicable legal requirements and to NESCOE's system of internal controls.

4. VIOLATIONS OF THE CODE OF CONDUCT; WAIVERS

If a NESCOE Manager, officer and employee violates the *Code of Conduct* or fails to report a known violation he or she may be subject to disciplinary action, including suspension from duties and termination from NESCOE. In addition, willful and knowing violation of the *Code of Conduct*, may require restitution to NESCOE for financial injury suffered by NESCOE as a result of the violation.

The highest-ranking officer of NESCOE is charged with overseeing the administration of this *Code of Conduct* and ensuring that prompt action is taken to investigate any potential violations of or noncompliance with NESCOE's policies. The highest-ranking officer of NESCOE shall report any violations of this *Code of Conduct* to

EXHIBIT C

the Chief Executive Officer and General Counsel ISO-NE and to the Chairperson and Secretary of the NEPOOL Participants Committee.

The highest-ranking officer of NESCOE, following consultation with ISO-NE. and the NEPOOL Participants Committee, may grant a waiver of compliance from a specific provision of the *Code of Conduct* to avoid unjust or unreasonable results.

ISO new england

memo

To: NEPOOL Participants Committee Members and Alternates

From: Robert C. Ludlow, VP & CF/CO

Date: September 1, 2022

Subject: ISO New England Inc. 2023 Operating and Capital Budgets

Budget Process

This memo provides an update to the NEPOOL Participants Committee on the 2023 budget process. At its August 11, 2022 meeting, the NEPOOL Budget & Finance Subcommittee ("B&F") reviewed the ISO's proposed 2023 operating and capital budgets (collectively, the "Budgets"). Included with this memorandum is a presentation of the Budgets. The more detailed presentation provided to B&F can be found on the ISO's website at 7_isone_2023_proposed_op_cap_budget.pdf (iso-ne.com). The ISO has also presented the Budgets to the New England state agencies; following that presentation the state agencies submitted questions. The ISO will be responding to state agencies' questions by August 26. The questions and the ISO's response will be posted on August 26 under the budget section on the ISO's website at Budget (iso-ne.com).

For both meetings, the discussions covered the ISO's vision, strategic goals, and initiatives; key drivers of the proposed cost increase; the allocated resources in the 2023 budget to achieve the related objectives; and the 2023 budget risks. Additionally, we outlined factors contributing to the increase in the capital budget over the next several years and the estimated impact to our debt structure and borrowing needs. Questions that were asked during the B&F call included whether enough resources were included in the budget in the areas of Corporate Communications, System Planning (including for the interconnection queue process), and for Market & Credit Risk. The ISO believes the proposed increased resources are sufficient to address the ISO's workload.

In our discussion with the state agencies, questions included the depth and breadth of the next Generation Energy Management (nGEM) platform, how metrics drive performance and future initiatives, and the ISO's responsiveness to NEPOOL requests. In response we noted that Vamsi Chadalavada will be providing an nGEM program update at today's meeting (which will also be shared with the NECPUC chair); we highlighted the information provided in the budget materials on trends and metrics driving the 2023 objectives and for measuring performance (these are included as Appendices 1 and 2 of today's budget presentation); and, as noted above, we explained that we believe the proposed budgeted resources allow us to complete the work ahead and address NEPOOL requests through the stakeholder process.

The Participants Committee will be asked to vote on the proposed budgets at the October 6, 2022 meeting.

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Proposed 2023 Budgets

The budget assumptions and key drivers remain consistent with the preliminary budgets presented to NEPOOL in June; however, the operating budget is $1.1 million higher than amounts in the preliminary budget due to the inclusion of $0.75 million for a second phase of Pathways Study work (funds will only be used for this purpose), and the inclusion of a $0.46 million increase in the previously estimated NPCC and NERC dues. Other changes from the preliminary budgets, that largely offset, were a result of the detailed bottom-up approach (as opposed to the preliminary top-down approach). The 2023 operating budget year-over-year increase before depreciation is $20.2 million or 10.7%; the increase, including depreciation is $25.1 million or 11.7%. The 2023 Revenue Requirement, taking into account the 2021 true-up, is an increase of $9.5 million or 4.4% over 2022.

The proposed budget reflects resourcing to move forward with the goals and priorities of the region, regulators, and market participants while allowing the ISO to evolve operations, protect the ISO's assets and information, and maintain a highly skilled workforce to carry out the ISO's mission and strategic goals. This work includes continuing efforts towards the implementation of market mechanisms to reflect the region's effort to transition to high levels of renewable and distributed resources while maintaining a robust fleet of balancing resources, and continuing to manage and adapt to the proliferation of new and an increased number of generating resources each of which result in increased complexity for system operations and planning. Funding also addresses managing an increasing number of external ad-hoc stakeholder requests and building stakeholder consensus on the prioritization of work, to support hiring and retention in the tight and competitive labor market, and for information technology initiatives (for cyber security, to accommodate shifting technologies, the use of cloud infrastructure, and to improve modeling capabilities).

Assessing resourcing needs, the ISO anticipates the need for approximately 52 full-time equivalent ("FTE") additions between 2023 and 2024. The 2023 budget includes the recruitment of 32 additional positions, with funding for 23 FTEs with onboarding expected to occur throughout the year. In 2024 the funding for a full year of all 32 of the 2023 positions plus the addition of 20 positions for 2024 is expected, bringing the two year total to 52. The additional 2023 positions are in Market Development, Information & Cyber Security Services, System Planning, Participant Relations & Services, Advanced Technology Solutions, System Operations & Market Administration, External Affairs & Corporate Communications, and Human Resources.

The capital budget is $33.5 million. As signaled during the 2022 budget process, the capital budget is expected to increase by up to $7M over the next several years over the 2021 budget level of $28M. The increased capital budget need is being driven by four primary drivers: the nGEM platform; major market and reliability related efforts; cyber security work; and information technology asset and infrastructure replacement.

I will be available during the meeting for any questions regarding the 2023 Budgets. Please also feel free to reach out to me after today with any additional comments or questions regarding the 2023 Budgets.

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SEPTEMBER 1, 2022

ISO New England Proposed 2023 Operating and Capital Budgets

NEPOOL Participants Committee Meeting

Robert Ludlow

VP, CHIEF FINANCIAL & COMPLIANCE OFFICER

Contents of Presentation

- The presentation includes:
  - 2023 Budget Introduction and Overview (Slides 3-7)
  - Strategic Planning Process Overview (Slides 8-10)
  - Coordinating ISO Strategy and Budget (Slides 11-22)
  - 2023 Budget Overview (Slides 23-28)
  - Summary 2023 Budget Information (Slides 29-31)
  - 2023 Operating Budget Risks (Slides 32-33)
  - Capital Budget Summary (Slides 34-37)
- The following appendices are also included for reference:
  - Appendix 1: Trends & Metrics Driving 2023 Objectives
  - Appendix 2: Metrics for Measuring ISO-NE Performance and Progress
  - Appendix 3: Cyber Security and CIP Compliance History and Costs
  - Appendix 4: ISO/RTO Financial Comparison
  - Appendix 5: New England Wholesale Electricity Costs and Retail Electricity Rates

2023 BUDGET INTRODUCTION AND OVERVIEW

2023 Budget Review Process

- At both the June 6, 2022 meeting with the New England Conference of Public Utilities Commissioners (NECPUC), and the June 21, 2022 NEPOOL Participants Committee meeting, management presented and reviewed the preliminary operating and capital budgets for 2023
- The proposed 2023 budget presented today is the bottom-up detailed budget (prepared with input from each ISO business unit and refinements to preliminary estimates), compared to the top-down budget presented in June (that included preliminary estimates). The detailed bottom-up budget resulted in a $1.06 million increase compared to the preliminary top-down version. Key changes consist of:
  – An estimated $0.75 million added for a second phase of Pathways Study work
    - Funding will only be used for this work and not reallocated for other purposes
  – A $0.46 million increase in the amounts budgeted for Northeast Power Coordinating Council (NPCC) and North American Electric Reliability Corporation (NERC) dues assessed to the ISO
    - The preliminary top-down budget was based on the estimated 2023 increases in each entity's 2022 Business Plan and Budgets; each entity has recently published its 2023 Business Plan and Budgets and the bottom-up budget reflects this updated information
  – Several other changes, that largely offset, also occurred including Professional Fees and Computer Services increases and decreases due an increase is in the employee vacancy rate and lower availability of staff augmentation consulting

2023 Budget Review Process *(cont.)*

The 2023 Operating Budget reflects:

- Working towards the implementation of market mechanisms to reflect the region's effort to transition to high levels of renewable and distributed resources while maintaining a robust fleet of balancing resources
- Continuing to manage and adapt to the proliferation of new and an increased number of generating resources each of which result in increased complexity for system operations and planning
- Managing an increasing number of external ad-hoc stakeholder requests and building stakeholder consensus on the prioritization of work
- Increased funding to support hiring and retention in the tight and competitive labor market, reflecting the difficulty in acquiring and retaining highly skilled employees while remaining competitive within the limitations of the ISO's not-for-profit status

2023 Budget Review Process *(cont.)*

- Information Technology initiatives, including addressing increasingly complex and frequent cyber security threats; shifting technology to utilize increased levels of cloud infrastructure and virtualization technology in a coordinated manner to improve performance while maintaining IT system reliability; and improving power system modeling capabilities, for both reliability and planning purposes, reflecting the increasing levels of Distributed Energy Resources
- Managing the significant impacts of supply chain and inflationary pressures, including challenges in procuring IT assets and competing for IT staff augmentation consulting support
- Resourcing to move forward with the goals and priorities of the region, regulators, and market participants while allowing the ISO to evolve operations, protect the ISO's assets and information, and maintain a highly skilled workforce to carry out the ISO's mission and strategic goals

2023 Budget Review Process *(cont.)*

- The ISO reviewed the 2023 proposed Operating and Capital Budgets:
  - With the NEPOOL Budget & Finance Subcommittee on August 11; for further detail on ISO-NE's 2023 budget, please see the presentation provided to the NEPOOL Budget & Finance Subcommittee at the August 11, 2022 meeting; the presentation can be found at:

    7_isone_2023_proposed_op_cap_budget.pdf (iso-ne.com)
  - With the State Agencies' on August 12
    - State Agencies submitted questions on ISO-NE's proposed budget on August 19
    - ISO New England will be responding to State Agencies' questions by August 26; once complete the State Agencies questions and ISO-NE's response can be found under the budget section on ISO-NE's website at:
      - Budget (iso-ne.com)
    - State Agencies may submit comments regarding the proposed budget by September 6
    - The ISO Board of Directors will review the budgets, stakeholder feedback, and State Agencies comments on September 15
    - ISO-NE responses to State Agencies' comments are due on or about September 22
- The ISO will conduct additional meetings as requested
- The NEPOOL Participants Committee (NPC) will vote on the ISO-NE 2023 Budgets on October 6
- The ISO Board of Directors will vote on the 2023 Budgets after the NPC meeting
- The ISO will file the 2023 Budgets with FERC on or about October 14

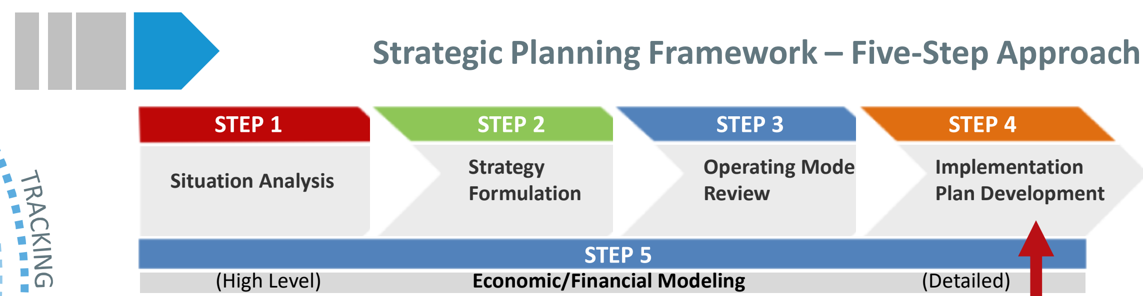
STRATEGIC PLANNING PROCESS OVERVIEW

The Annual Process – Strategic Planning

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

The Strategic Planning Framework

The strategic planning annual cycle and the key steps in the process framework



ISO-NE has integrated its budget and work plans with strategy to identify how the company is allocating resources in furtherance of its Strategic Goals

The strategic framework represents an ongoing process cycle to review and update strategy as necessary for implementation

COORDINATING ISO STRATEGY & BUDGET

Our Guidepost: The ISO New England Vision Statement

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

Vision Statement:

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

Our Responsibility to the Region: ISO's Mission

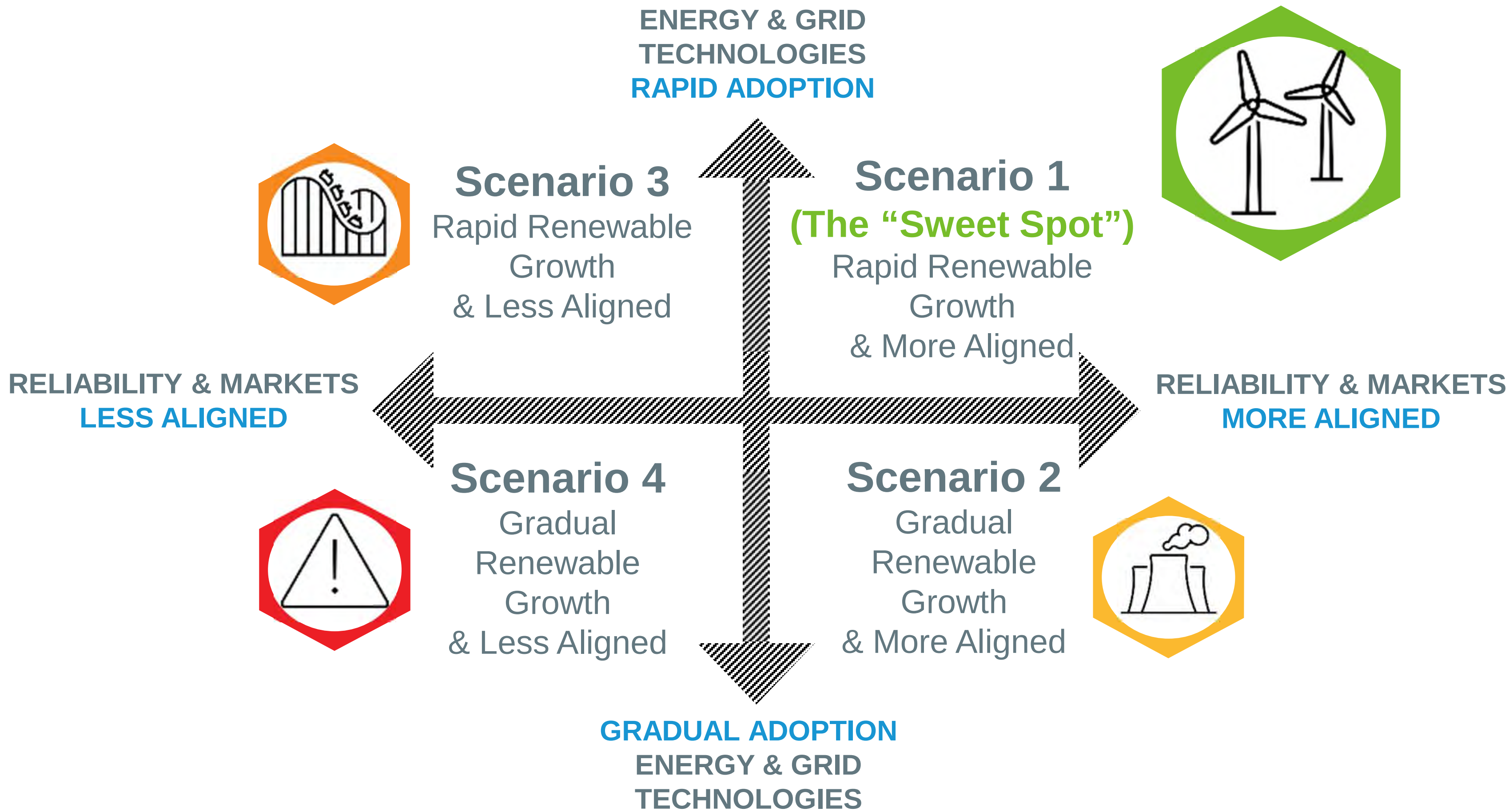
The ISO-NE Mission Statement outlines the core role and responsibilities of the ISO's daily operations

Mission Statement:

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

Scenario Framework

Scenario planning is a strategic method used for long-range planning, that charts Critical Uncertainties affecting the power industry in New England.



A scenario where all "Four Pillars of the Clean Energy Transition", are robust and solidly support the region's transition to clean energy represents the ideal scenario outcome for the region

Four Pillars Critical to Developing and Maintaining the Clean, Decarbonized Grid of the Future

To be sure we're ready for the future, we've called upon our quarter century of experience planning the region's power system, as well as expertise from the industry at large, and identified four pillars that are critical to developing and maintaining a clean, decarbonized grid

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

2 **Balancing resources** that keep electricity supply and demand in equilibrium

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

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

ISO-NE's Strategic Goals

The strategic goals of the organization are the broad primary outcomes of what the ISO seeks to achieve to fulfill the Mission and Vision, and support the "Four Pillars"; the ISO's work effort is in furtherance of these Strategic Goals

ISO-NE Strategic Goals

- **Responsive Market Designs:** Improve the current market structure and continue to evolve and reposition the market design to reflect the states' objectives and the transition to high levels of renewables and distributed resources. Maintain a robust fleet of balancing resources and preserve the ability of the market to attract new entry.
- **Progress and Innovation:** Evolve capabilities to support the grid as the region transitions to clean energy, including improved power system and market modeling. Support investments in transmission infrastructure to enable renewable energy. Facilitate the integration of distributed energy resources. Provide data and information-based services.
- **Operational Excellence:** Continuously improve operations and processes, with a focus on efficiency and effectiveness, business results, and continuity of reliable operations.
- **Stakeholder Engagement:** Collaboratively understand and anticipate needs, demonstrate thought leadership through high quality analysis and communication, and nurture productive relationships with FERC, the states and market participants.
- **Attract, Develop, and Retain Talent:** Develop a sense of community around our Core Values, Mission, Vision, and Goals; prepare the workforce; recognize and reward employee's success and innovation; and honor diversity and promote inclusion.

Overview of Key 2023 Objectives & Initiatives

- The ISO's implementation of its strategic plan encompasses the slate of work across departments and considers projects that have multi-year timeframes
- The annual objectives for the organization summarize the work being done to support progress towards the five Strategic Goals
- Highlights for 2023 include:
  - Responsive Market Designs:
    - Follow-up work related to The Pathways Report, Resource Capacity Accreditation, and Day-Ahead Ancillary Services Improvements
  - Progress and Innovation:
    - The next Generation Energy Management (nGEM) platform that supports a system with a growing number/types of grid assets
  - Operational Excellence:
    - Cybersecurity and Cloud Computing Initiatives
  - Stakeholder Engagement:
    - Transmission planning for the clean energy transition and yet-to-be-defined/scope project on Energy Adequacy

See Appendix 2 for Trends & Metrics Driving 2023 Objectives

Responsive Market Designs

- Objective: Promote New and Enhanced Market Designs for Non-Emitting Resources
  - Initiatives that focus on the ISO's work supporting market constructs for and participation of non-emitting resources
    - Follow-up to Pathways Report and develop a Preferred Path for Clean Energy Pricing
    - Storage Market Modeling Enhancements Assessment
    - Storage as a Transmission-Only Asset Implementation
- Objective: Support Reliability Through Competitive Market Mechanisms
  - Initiatives that help the ISO ensure system reliability via enhanced market incentives
    - Energy Shortage Pricing Assessment
    - Solar Do Not Exceed Dispatch Implementation
    - Resource Capacity Accreditation Design
    - Day-Ahead Ancillary Services Improvements Design

See Appendix 2 for Trends & Metrics Driving 2023 Objectives

Progress & Innovation

- Objective: Implement New Technologies to Address Increased Power System Complexity
  - Initiatives that increase the ISO's ability to model and forecast for a grid with a growing number of assets and more complex market features
    - nGEM Phases 1, 2, and 3
    - Models and Simulators to Support Future Grid
- Objective: Improve Weather Forecasting Capabilities
  - Improving weather forecasting as a means of better forecasting for the increasing number of weather-dependent resources on the grid and modeling extreme weather impacts
    - Model Operational Impacts of Extreme Weather
    - Expanded Weather Analytics for 21-Day to Intra-Day Load-Forecasting

See Appendix 2 for Trends & Metrics Driving 2023 Objectives

Operational Excellence

- Objective: Maintain IT Reliability
  - Cyber Security Initiatives
  - IT Management and Energy Market Applications Maintenance and Support
- Objective: Support Increased Workload and Complexity
  - Cloud Computing
  - Hybrid Workforce Support
  - Support Qualification and Participation of Increased Volume of Distributed Resources
- Objective: Assess FERC Orders and Stakeholder Requests
  - Address FERC Orders requiring changes to administration of markets, system operations, and system planning practices
  - Forward Capacity Market Enhancements

See Appendix 2 for Trends & Metrics Driving 2023 Objectives

Stakeholder Engagement

- Objective: Facilitate Input into Annual Work Plan
  - Initiatives that promote active stakeholder engagement and prioritize requests to ISO for assessment of issues and resolution of concerns
    - Administer NEPOOL work requests
    - Active Stakeholder Outreach
- Objective: Inform on Power System and Wholesale Markets Performance and Needs
  - Informing stakeholders about challenges to the grid and ensuring they are apprised of concerns to daily operations and system planning challenges
    - Energy Adequacy work; Annual Economic Studies; and Implement any lessons learned from Outage Tabletop Exercise
    - Future Grid Reliability Study Phase 2 and Completion
- Objective: Administer Transmission Planning to Enable the Clean Energy Transition
  - The clean energy transition will be dependent on a substantial investment in transmission and the ISO is engaged in initiatives to address this pillar
    - Extended-Term Transmission Planning
    - 2050 Transmission Study
    - Addressing FERC NOPR and Orders

See Appendix 2 for Trends & Metrics Driving 2023 Objectives

Attract, Develop, & Retain Talent

- Objective: Maintain Competitiveness in Labor Market
  - Initiatives for recruiting, providing competitive salaries, and administering benefits across the organization
    - Recruitment
    - Compensation Structure
    - Benefit Programs
    - Support Post-pandemic Posture
    - HR Policy and Program Administration
- Objective: Support the Professional Development of the ISO Workforce
  - Supporting employee trainings, ISO policies, and diversity, among a hybrid workforce as well as championing the ISO's strategy to address the clean energy transition
    - Council for Diversity and Inclusion
    - Championing Organizational Strategy and Vision
    - Administer Employee Training

See Appendix 2 for Trends & Metrics Driving 2023 Objectives

2023 BUDGET OVERVIEW

2023 Budget Overview

Resourcing needs in budget

- To support the objectives of Four Pillars of the Clean Energy Transition and to continue to maintain its ongoing responsibilities, the ISO anticipates the need for approximately 52 FTE additions between 2023 and 2024.
- The increased FTEs will better position the ISO to adeptly move forward with the major challenges facing the region.
- The FTE additions are primarily focused in key departments to support the markets and the planning of the transmission system. A small amount of additions are also included in a few back office departments.
- Summary of planned 2023 and estimated 2024 FTE additions by year:

Planned FTE Additions		
2023*	2024	Total
32	20	52
*For 2023, the proposed budget includes the recruitment of 32 positions with funding for 23 that are expected to onboard throughout the year		

2023 Budget Overview *(cont.)*

Resourcing needs in budget (cont.)

- The ISO evaluates each position that becomes vacant to determine the continued need in that area and for possible repurposing for use in other areas of the organization
  - Since 2018 this has resulted in 28 positions being repurposed for other work where a more urgent need existed
  - Positions repurposed since 2018 include: 6 for Information Technology for Software Development, Cyber Security, Power System Modeling, and Application Support; 5 for System Operations & Market Administration for Energy Security, Asset Registration & Auditing, Control Room Operations, and Operations Training; 4 for Market Development analysis and market design work; 3 for Human Resources for recruiting support and to replace contract positions; 2 for Advanced Technology Solutions; 2 for Market Monitoring; 1 for Load Forecasting to replace a contract position; 1 for Resource Studies & Assessments; 1 for Participant Support; 1 for Market & Credit Risk; 1 for Corporate Strategy; and 1 for Internal Auditing (IT audit work)

2023 Budget Overview *(cont.)*

The 2023 budget includes the following:

- The addition of 32 FTEs as noted on slide 24, with funding for approximately 23 positions due to onboarding throughout 2023
- Other Salary and Benefit related changes including:
  - 5.75% increase for annual merit and promotional increases, including targeted promotional amounts for specific positions or areas (larger increase than prior years to ensure competitive compensation to attract and retain necessary talent to support the ISO's mission and support the transition to clean energy)
  - increases for employee health and dental benefit costs
  - increases for defined contribution plan and post-retirement benefit contributions
  - funding for recruiting, retention, and succession planning
  - a reduction for an increase in the budgeted vacancy rate from 4% to 5%
- Professional Fees increases for studies and specialty work; a net increase of three consultant FTEs to augment staff in the areas of Information Technology, Forward Capacity Market Administration, and Finance; and various other increases including inflationary and rate increases across our consulting structure including staff augmentation consulting

2023 Budget Overview *(cont.)*

The 2023 budget includes the following *(cont.)*:

- Computer Service increases for cyber security product fees and maintenance related to the significant investment made in our cyber infrastructure; for expanded use of virtualization technology; for energy management and market system support; and for inflationary increases across multiple enterprise computer products. Computer Service increases partially offset with savings realized from the replacement of higher cost technology with lower cost products already in use.
- Inflationary increases for other line items, including Insurance Expense, NPCC and NERC Dues, and Interest Expense
- Depreciation Expense increases due primarily to the mid-year go-live of the nGEM Market Clearing Engine Implementation project [(1)]

(1) Upon completion of the nGEM Market Clearing Engine Implementation, scheduled for June 2023, the following associated Work-In-Progress projects will begin depreciating: CIMNET Simultaneous Feasibility Test with Data Transfer Enhancements, nGEM Value Added Development, nGEM Market Clearing Engine Implementation, nGEM Software Development Parts I and II, and nGEM Hardware Phases I and II.

2023 Budget Overview *(cont.)*

- In summary, the 2023 operating budget year-over-year increase before depreciation is $20,172,500 or 10.7%; the increase, including depreciation is $25,134,500 or 11.7%
  – The 2023 Revenue Requirement, taking into account the 2021 true-up (a $14.6 million reduction for 2023 vs. a $1.1 million increase in 2022), is an increase of $9,475,500 or 4.4% over 2022
- The 2023 Capital Budget is $33.5 million
  – Beginning in 2022 and through at least 2028, the capital budget is expected to increase by up to $7M over the $28M budget that had been in place for several years through 2021
    - The increased capital budget need is being driven by four primary drivers – nGEM platform (replacing current market system); major market and reliability related efforts; cyber security; IT asset and infrastructure replacement
    - The increased capital spending will result in higher interest expense costs and depreciation expense in future years as capital projects go into production and are included in budgets and rates
  – The 2023 Capital Budget is an increase of $1.5 million from the 2022 Capital Budget
  – A list of projects, by strategic goal, that are currently chartered and on-going or in planning/conceptual design is included (See Slides 35-37)

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

SUMMARY 2023 BUDGET INFORMATION

Summary Budget Information

(Budget Amounts are in Millions)	2023	% Change	2022	% Change	2021	% Change	2020	% Change	2019	% Change	2018
Operating Budget Before Depreciation	$209.2	10.7%	$189.1	5.8%	$178.6	1.8%	$175.4	3.9%	$168.9	2.9%	$164.2
Capital Budget	33.5	4.7%	32.0	14.3%	28.0	0.0%	28.0	0.0%	28.0	0.0%	28.0
Total Cash Budget	**$242.7**	**9.8%**	**$221.1**	**7.0%**	**$206.6**	**1.6%**	**$203.4**	**3.3%**	**$196.9**	**2.5%**	**$192.2**
Operating Budget Before Depreciation	$209.2	10.7%	$189.1	5.8%	$178.6	1.8%	$175.4	3.9%	$168.9	2.9%	$164.2
Depreciation	31.0	19.1%	26.0	(1.2)%	26.3	0.2%	26.3	(9.6)%	29.1	(6.3)%	31.0
Revenue Requirement Before True-up	240.2	11.7%	215.1	4.9%	205.0	1.6%	201.7	1.9%	198.0	1.5%	195.2
True up	(14.6)		1.1		0.2		(2.9)		(9.3)		0.4
Revenue Requirement	**$225.6**	**4.4%**	**$216.1**	**5.4%**	**$205.1**	**3.2%**	**$198.8**	**5.4%**	**$188.7**	**(3.5)%**	**$195.5**
Forecast – TWhs (1)	**143.0**	**(1.0)%**	**144.4**	**(2.0)%**	**147.4**	**1.0%**	**145.9**	**0.2%**	**145.6**	**2.5%**	**142.1**
$/KWh Rate	**$0.00158**	**5.4%**	**$0.00150**	**7.5%**	**$0.00139**	**2.1%**	**$0.00136**	**5.1%**	**$0.00130**	**(5.8%)**	**$0.00138**
Average Monthly Consumer Cost (2)	**$1.18**		**$1.12**		**$1.04**		**$1.02**		**$0.97**		**$1.03**

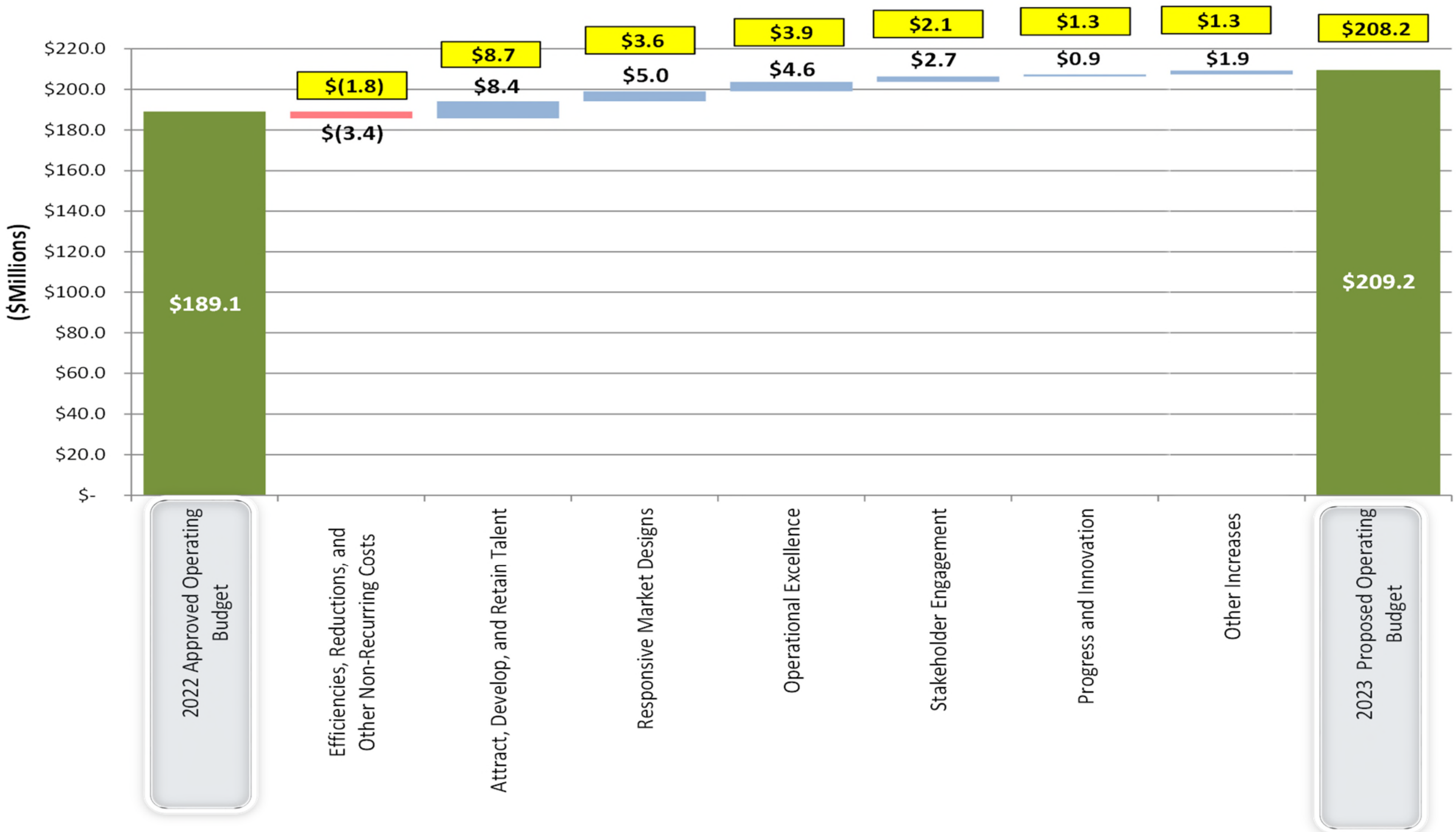
(1) 2023 Forecast based on May 2022 CELT Report (Schedule 1.5.2 - Net Annual Energy - Gross (without reductions)). All other years based on CELT Report for the applicable year, which can be found on www.iso-ne.com.

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

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

2023 Budget Changes by Strategic Goal Proposed vs. Projected

(net increase of 10.7% (vs. 10.1%) over 2022)



Note: Items in yellow above represent the estimate that was included in the 2023 preliminary budget presented in June 2022.

2023 OPERATING BUDGET RISKS

2023 Operating Budget Risks

- Additional funding may be required to construct new models to study extreme weather and contingencies; and to conduct new studies related to the integration of variable resources and emerging technologies, including long-range transmission planning studies
- Information Technology software licensing and maintenance costs, and cloud migration costs may each require additional funding
- Insurance policy renewals may be higher than increases estimated in the budgets
- Mystic Cost of Service audit support may require additional funding
- Interest Rates may impact the ISO floating rates on tax-exempt debt, pension and post-retirement benefit plans liability costs, and interest income on settlement float balance
- Legal costs from material litigation that may arise during the course of the year would pose a risk to the ISO's ability to operate within the approved budget
- Federal and state policy directives/changing policies could result in additional cost associated with new requirements
- Workforce sourcing and related pay rates and supply chain disruption may each have budgetary impacts
- Increases across multiple expense lines due to inflationary pressures in the current economic environment

CAPITAL BUDGET SUMMARY

Capital Budget
2023 Expenditures

Goal: Responsive Market Designs Project	2023 Budget	Total Project Cost	Estimated Completion Date	Project Stage
Day-Ahead Ancillary Services Improvements	$3.5M	$11.7M	10/24	Planning/Conceptual Design
FERC Order 2222	$0.4M	$7.4M	12/26	Planning/Conceptual Design
Elimination of Minimum Offer Price Rule	$0.6M	$1.5M	12/24	Planning/Conceptual Design
Solar Do Not Exceed Dispatch Phase II	$1.0M	$1.0M	12/23	Planning/Conceptual Design
PI Historian for Short-Term PMU Data Repository	$0.5M	$0.9M	09/23	In Development
Forward Capacity Market Order 2222	$0.4M	$0.5M	03/23	Planning/Conceptual Design
Total:	**$6.4M**			

Goal: Progress and Innovation Project	2023 Budget	Total Project Cost	Estimated Completion Date	Project Stage
nGEM Market Clearing Engine Implementation (see Note 1)	$1.3M	$13.8M	06/23	In Development
nGEM Real-Time Market Clearing Engine Implem. (see Note 1)	$3.0M	$8.0M	06/25	Planning/Conceptual Design
nGEM Software Development Part II (see Note 1)	$0.7M	$4.8M	06/23	In Development
Forecast Enhancements	$0.6M	$1.9M	07/23	In Development
nGEM Software Development Part III (see Note 1)	$1.5M	$1.5M	12/23	Planning/Conceptual Design
Control Room Voice Recorder Upgrade	$0.1M	$0.2M	03/23	Planning/Conceptual Design
MIS Reporting by Sub Accounts	$0.2M	$0.2M	03/23	Planning/Conceptual Design
Total:	**$7.4M**			

Note 1: nGEM related projects will advance multiple goals including Responsive Market Designs, Progress and Innovation, and Operational Excellence. For purposes of this presentation, nGEM projects have been grouped under the Progress and Innovation strategic goal.

Capital Budget

2023 Expenditures *(cont.)*

Goal: Operational Excellence

Project	2023 Budget	Total Project Cost	Estimated Completion Date	Project Stage
Forward Capacity Tracking System Infrastructure Conversion Part III	$0.7M	$3.2M	04/23	In Development
Enterprise Resource Planning System Replacement	$0.1M	$3.1M	09/26	Planning/Conceptual Design
CIP Electronic Security Perimeter Redesign Phase II	$2.0M	$2.3M	01/24	Planning/Conceptual Design
Web to Cloud Migration Phase II	$1.2M	$1.6M	12/24	Planning/Conceptual Design
Microsoft 365 Service Adoption	$0.5M	$1.5M	06/24	Planning/Conceptual Design
Privileged Account Management Security Enhancements 2023	$1.3M	$1.3M	09/23	Planning/Conceptual Design
Physical Security Improvement Project	$0.5M	$1.2M	12/23	In Development
Inventoried Energy Program	$1.0M	$1.0M	09/23	Planning/Conceptual Design
Web to Cloud Migration Phase I	$0.8M	$0.8M	11/23	Planning/Conceptual Design
Windows Server 2019R2 Deployment	$0.5M	$0.8M	10/23	Planning/Conceptual Design
2023 Issue Resolution Project	$0.7M	$0.7M	12/23	Planning/Conceptual Design
E-mail List Server Technology Refresh	$0.1M	$0.7M	01/23	In Development
IT Asset Workflow Integration and Updates	$0.5M	$0.6M	01/24	Planning/Conceptual Design
Identity and Access Management Phase III	$0.5M	$0.6M	12/23	Planning/Conceptual Design
Replace Messaging Software	$0.1M	$0.6M	03/23	In Development
Non-Project Capital Expenditures	$4.8M			Planning/Conceptual Design
Total:	**$15.3M**			

Capital Budget

2023 Expenditures Summary

- 2023 Capital Budget Expenditure Summary

Allocation Category	2023 Budget
Goal: Responsive Market Designs	$ 6.4M
Goal: Progress and Innovation	$ 7.4M
Goal: Operational Excellence	$15.3M
Other Emerging Work	$ 3.8M
Capital Interest	$ 0.6M
Total:	**$33.5M**

APPENDIX 1: TRENDS & METRICS DRIVING 2023 OBJECTIVES

Trends & Metrics Driving 2023 Objectives

- Successful implementation of ISO New England's Strategy means making progress towards the Organizational Strategic Goals and Vision
- The upcoming work for 2023 has been prioritized because of trends & metrics that help outline a need and/or indicate progress towards the shared goals of the ISO and region
- The primary driver of work in 2023 is the need to support the clean-energy transition and changing resource mix, and the success of this work can be summarized by a set of metrics outlined in the coming slides

Trends & Metrics Driving 2023 Objectives *(cont.)*

Responsive Market Designs

- Across a range of metrics, the ISO-NE wholesale electricity markets are generally considered to be performing well and exhibiting competitive outcome. Quarterly and Annual Reports available at: Internal Market Monitor (iso-ne.com)
- As the New England states move to reduce carbon emissions from the electric, heating, and transportation sectors, setting aggressive targets to increase renewable energy resources and reduce greenhouse gas emissions to nearly zero by 2050, there has been increased participation of wind, solar, battery and other non-emitting resources
- The ISO has set forth two objectives to establish market mechanisms and harness the power of competition in support of states' decarbonization efforts and to accommodate the changing resource mix:
  - "Promoting New Market Designs for Non-Emitting Resources" and
  - "Supporting Reliability Through Competitive Market Mechanisms"

Trends & Metrics Driving 2023 Objectives *(cont.)*

Progress and Innovation

- New England power system has been planned and operated in a highly reliable manner, with a high rate of compliance with NERC Reliability Standards. *See also* monthly COO NEPOOL reports and annual transmission outage coordination metrics, Transmission Outage Scheduling (iso-ne.com)
- Many of the non-emitting resources coming on-line, and scheduled to come on-line through the interconnection queue are weather-dependent and intermittent requiring ISO to develop improved capabilities and situational awareness.
  - Have an increased capability of weather forecasting
  - Sophisticated modeling and forecasting capabilities for a grid with a growing number of assets and more complex market features
    - Ramping analyses for behind-the-meter and intermittent resources, behavior of demand response resources, better load-forecasting, understanding the impacts of extreme weather, and preparing for difficult winter operations increase in priority with increased instances of extreme weather (*e.g.,* polar vortex) all help reach these objectives
- To address increasing complexity in forecasting and modeling, the ISO has set forth two objectives to address these factors:
  - "Implementing New Technologies to Address Increased Power System Complexity"
  - "Improving Weather Forecasting"

Trends & Metrics Driving 2023 Objectives *(cont.)*

Operational Excellence

- “Maintaining IT Reliability”, “Supporting Increased Workload and Complexity”, and “Implementing FERC Orders and Stakeholder Requests” are company objectives to respond to the internal operational challenges that have arisen as a result the changing resource mix
- The ISO has prioritized cybersecurity initiatives and IT management of energy and market applications that are growing in complexity and number as the resource mix evolves
  - The increased volume of grid assets and complexity of forecasting and qualifying these new assets necessitates more robust internal processes
  - Cyber security needs to keep pace with the increasing threat capability of individuals, hacktivist groups, and nation-states; there has been an escalated threat due to the ongoing war in Ukraine
- Increasing penetration of DER has necessitated a broadening and deepening of capabilities to support the distributed nature of resources on the grid
- Evolving workforce expectations and increasing need for advanced technologies is driving initiatives for supporting a hybrid workforce (HR, Finance, Etc.), and Cloud Computing
- The clean energy transition requires a high level of responsiveness to state and stakeholder requests and FERC orders, which has increased the overall workload for the organization

Trends & Metrics Driving 2023 Objectives *(cont.)*

Stakeholder Engagement

- Supporting the clean energy transition necessitates more system planning work and coordination with states and stakeholders as the grid gains complexity; this drives the objectives of "Facilitating Input into Market Development and System Planning Work "Plan" & "Informing on Power System and Wholesale Markets Performance & Needs"
  - Compelling an increased level of work in the form of critical planning studies and stakeholder outreach
- Upgrading the region's transmission system is necessary for the successful transition to clean energy resources and, in response to stakeholder requests, the ISO identified the explicit objective of "Administering Transmission Planning to Enable the clean energy transition"

Trends & Metrics Driving 2023 Objectives *(cont.)*

Attract, Develop, and Retain Talent

- In order to perform the company's Mission and advance the Vision, the ISO must respond to the challenging labor market, economic conditions, and social trends that impact the ISO workforce
- ISO seeks to "Maintain Competitiveness in Labor Market" and "Support the Professional Development of the ISO Workforce" through
  - salary benchmarking; taking into account broad economic trends like inflation; and tracking internal metrics on turnover, vacancies, and time-to-fill positions
- Retaining and developing employees also relies on supporting training, diversity, and hybrid work environment as well as championing the ISO's strategy to address the clean energy transition

APPENDIX 2: METRICS FOR MEASURING ISO-NE PERFORMANCE AND PROGRESS

Metrics for Measuring ISO-NE Progress and Performance

- System Reliability
  - Compliance requirements set in the North American Electric Reliability Corporation ("NERC") Reliability Standards to measure system reliability performance and progress,
    - Inter-area Operating Standard that is based on a count of Interconnection Reliability Operating Limit ("IROL") exceedances and time to clear above defined time thresholds
    - System regulating metrics, such as NERC balancing standards
    - Balancing Authority Area Control Error Limit
    - Ability to activate operating reserves to restore its ACE following large resource losses – Disturbance Control Standard
  - Transmission equipment outage coordination metrics –Transmission Outage Scheduling (iso-ne.com). The Transmission Outage Coordination Working Group ("TOCWG") annually reviews the trends, performance and challenges of the outage-coordination process, and proposes new goals for transmission outage-coordination metrics for the upcoming year to improve outage coordination and performance Imports & exports
  - Accuracy of ISO-NE's estimation of congestion cost impacts
    - Long-term impacts on ISO-NE's rescheduling of transmission-outage requests
    - The provision of information to the Participating Transmission Owners ("PTOs") to facilitate their identification of opportunities to improve outage coordination, reduce congestion costs, or increase operational flexibility
    - A long-term planning metric to measure the successful submittal of outages into the long-term outage process that could have an impact on economic dispatch and system reliability
    - 90-day metric to measure the submittal of requests for outages that could have an impact more than 90 days before the planned outage date
    - A planned outage goal to improve coordination of all planned transmission outages
    - An outage cancellation goal to improve timely notifications to ISO-NE for cancelling a transmission equipment outage by a specified time
    - Metrics that tracked outage coordination performance over the past three years
  - Metrics on system reliability performance are reflected in the monthly reports of ISO-NE's Executive Vice President and Chief Operating Officer to the NEPOOL Participants Committee
    - Accuracy in load forecasting for all hours in the day and the peak hour of the day
    - Load curve trends

Metrics for Measuring ISO-NE Progress and Performance *(cont.)*

- The wholesale markets (capacity, energy, and ancillary)
  - ISO-NE's Internal Market Monitor ("IMM") publishes quarterly and annual markets reports that assess the state of competition in the wholesale electricity markets operated by ISO-NE
    - The IMM has regularly found the ISO-NE capacity, energy, and ancillary services markets performed well and exhibited competitive outcomes
  - ISO-NE's External Market Monitor ("EMM"), Potomac Economics, publishes an Annual Assessment of the Electricity Markets in New England
    - The EMM has regularly found that ISO-NE's wholesale electricity markets performed competitively; that market power concerns have diminished in Boston and New England; and the markets performed with little evidence of significant market power abuses or manipulation
- Operational efficiency and effectiveness
  - Measuring compliance with NERC standards
  - Cyber security audits and reporting
  - Forecasting and study preparation
  - Forward Capacity Market milestones
  - Outage Requests and Other Market Initiatives
  - Measures of budget accuracy
  - Information technology systems
  - Employee training requirements
  - The NEPOOL technical committee process
  - *The performance against these metrics is measured and reported to senior management on a monthly basis and is regularly published internally*

Metrics for Measuring ISO-NE Progress and Performance *(cont.)*

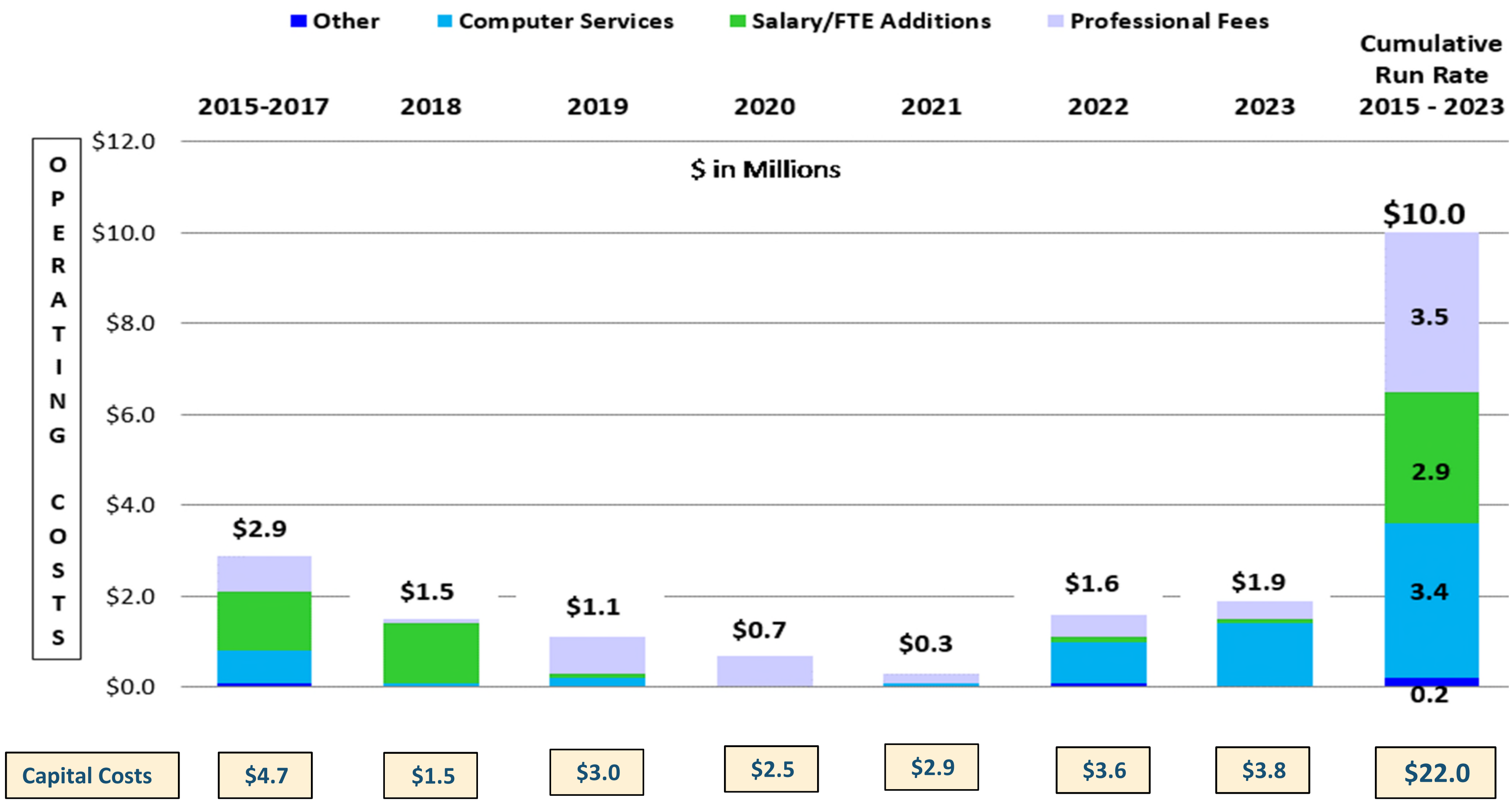
- Cybersecurity
  - On a monthly basis, ISO-NE senior management reviews ISO-NE's cyber security performance against the NIST "Framework Core"
    - *Management's monthly review has indicated that ISO-NE's cyber security controls are functioning adequately and Appropriately*
  - The functioning of the cybersecurity program is regularly reviewed and audited
    - ISO-NE's Internal Audit Department actively reviews ISO-NE's processes and systems and maintains a particular focus on cyber security risks, including internal cyber security risks and third party risks
    - Audits regarding cyber security risks have indicated ISO-NE has an adequate cyber security posture and in some instances, maintains above-average cyber security controls
    - ISO-NE has procured various external cyber security reviews and audits that have confirmed ISO-NE has a solid cyber security foundation

Metrics for Measuring ISO-NE Progress and Performance *(cont.)*

- Incorporating State Policy Goals
  - ISO-NE reflects state-specified metrics into its annual regional system planning process
  - State energy efficiency goals and program spending and photovoltaic resource development
  - Forecasting the electrification of transportation and heating
  - State policy goals as inputs to regional wind and solar forecasting, tracking, and dispatch procedures
  - Plans to incorporate new ancillary services that support greater amounts of variable and distributed resources, and other flexible products
- Transmission system interconnections and upgrades
  - Quarterly performance metrics for Interconnection Requests in compliance with FERC's Order No. 845
  - Processing time for each Interconnection Study
  - Statistics on Interconnection Requests withdrawn from the interconnection queue at different phases of the interconnection process
  - Metrics track the number of completed Interconnection Studies and the number of those studies for which ISO-NE exceeded the deadlines specified in the tariff for completion of the studies (without accounting for allowable Reasonable Efforts)
  - *Since ISO-NE began calculating and reporting on the Interconnection Study timeline metrics, it has observed continuous improvements for the Feasibility Study timeline*

APPENDIX 3: CYBER SECURITY AND CIP COMPLIANCE HISTORY AND COSTS

Cyber Security and CIP Compliance Annual Capital and Incremental Operating Costs 2015-2023



Above amounts represent cumulative annual costs for cyber security that have been added in the 2015 through 2023 budgets and are on-going and included in the 2023 proposed budget. An additional $1.2 million of incremental non-recurring cyber security costs were incurred from 2015 through 2022 that are not included above.

APPENDIX 4: ISO/RTO FINANCIAL COMPARISON

Financial Results Summary

ISO/RTO Financial Summary - 2021 Actual Results

Operating Expense and Capital Expenditures for Calendar Year 2021, and Outstanding Debt as of December 31, 2021 (1)

(Amounts in Millions)

	ISO-NE (2)	NYISO	CAISO	IESO (3)	PJM	MISO	SPP	ERCOT
Operating Expense - 2021	$ 201.7	$ 192.1	$ 223.1	$ 230.0	$ 380.9	$ 395.0	$ 201.3	$ 233.3
Less: Amortization & Depreciation	(26.2)	(25.3)	(30.6)	(23.9)	(35.6)	(32.5)	(17.5)	(27.9)
Regulatory Fees	(6.1)	(15.5)	-	-	(72.1)	(64.1)	(27.0)	-
Grant Expenses	-	-	-	-	-	-	-	-
Net Operating Expense - 2021	$ 169.4	$ 151.3	$ 192.5	$ 206.1	$ 273.2	$ 298.5	$ 156.8	$ 205.4
Other Financial Data								
Capital Expenditures for 2021	$ 27.5	$ 15.8	$ 25.9	$ 50.3	$ 35.3	$ 38.9	$ 14.0	$ 33.3
Outstanding Debt as of 12/31/21	$ 92.9	$ 78.7	$ 174.4	$ 120.0	$ 10.8	$ 274.3	$ 192.8	$ 843.0
Actual full-time equivalent headcount as of 12/31/21	573.5	544.0	635.0	770.0	754.0	964.0	625.0	767.0

(1) Applicable amounts were taken from each entity's 2021 audited financial statements.

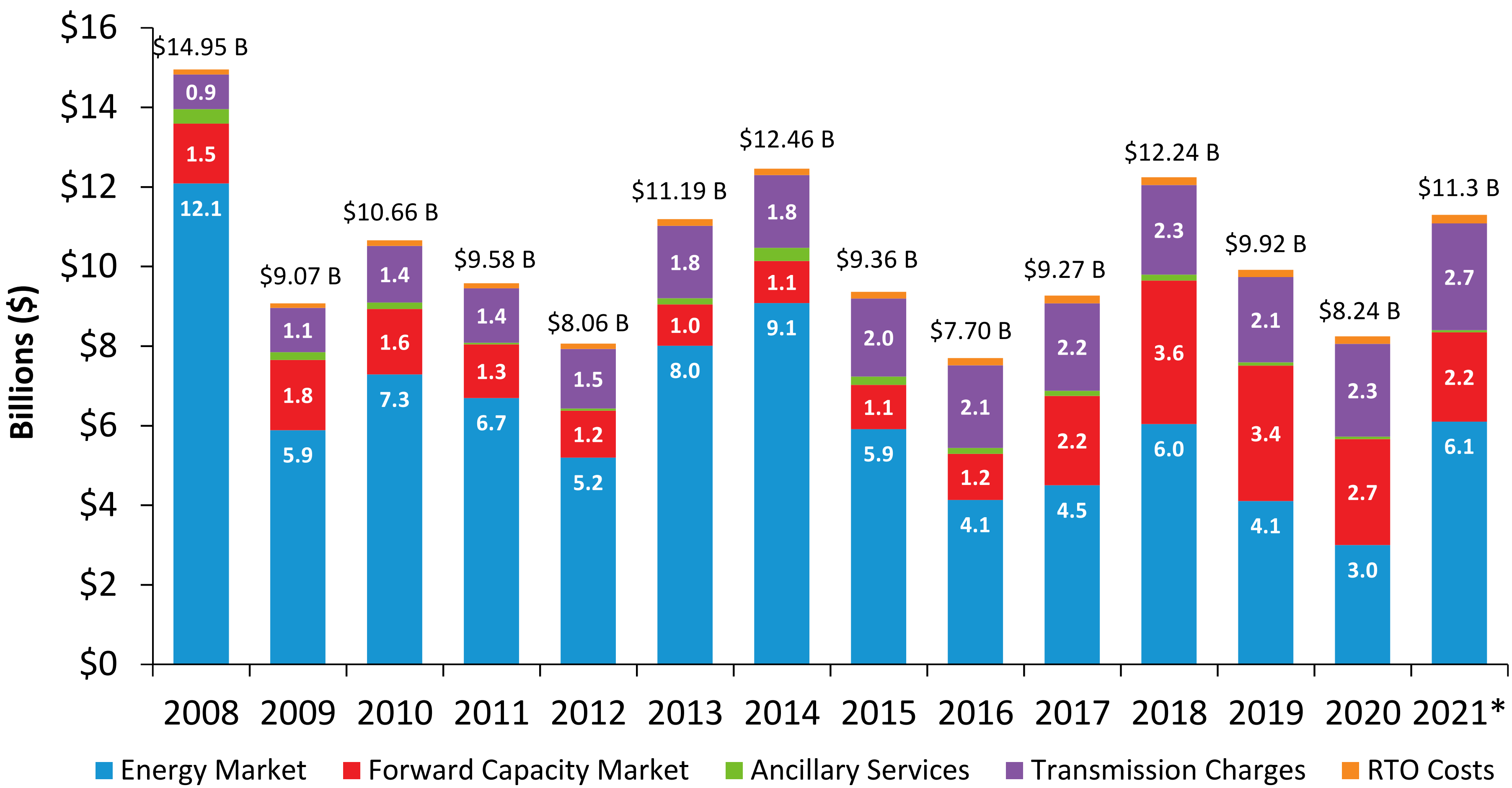
(2) ISO-NE Amortization & Depreciation and Capital Expenditures are presented on a cash-flow basis

(3) Amounts are in Canadian dollars

APPENDIX 5: NEW ENGLAND WHOLESALE ELECTRICITY COSTS AND RETAIL ELECTRICITY RATES

New England Wholesale Electricity Costs

Annual wholesale electricity costs have ranged from $7.7 billion to $15 billion



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

Source: *2021 Report of the Consumer Liaison Group*; *2021 data is preliminary and subject to resettlement

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

New England Wholesale Electricity Costs[(a)]

	2017		2018		2019		2020		2021*	
	$ Mil.	¢/kWh	$ Mil.	¢/kWh	$ Mil.	¢/kWh	$ Mil.	¢/kWh	$ Mil.	¢/kWh
Wholesale Market Costs										
Energy (LMPs)[(b)]	$4,498	3.5	$6,041	4.7	$4,105	3.3	$2,996	2.4	$6,101	4.8
Ancillaries[(c)]	$132	0.1	$147	0.1	$83	0.1	$62	0.1	$52	0.0
Capacity[(d)]	$2,245	1.8	$3,606	2.8	$3,401	2.7	$2,662	2.2	$2,243	1.8
Subtotal	*$6,875*	*5.4*	*$9,794*	*7.6*	*$7,589*	*6.0*	$5,720	4.7	$8,396	6.6
Transmission charges[(e)]	$2,199	1.7	$2,250	1.7	$2,146	1.7	$2,331	1.9	$2,687	2.1
RTO costs[(f)]	$193	0.2	$196	0.2	$184	0.1	$191	0.2	$216	0.2
Total	**$9,267**	**7.3**	**$12,240**	**9.4**	**$9,918**	**7.9**	**$8,242**	**6.7**	**$11,299**	**8.9**

(a) Average annual costs are based on the 12 months beginning January 1 and ending December 31. Costs in millions = the dollar value of the costs to New England wholesale market load servers for ISO-administered services. Cents/kWh = the value derived by dividing the dollar value (indicated above) by the real-time load obligation. These values are presented for illustrative purposes only and do not reflect actual charge methodologies. ***The wholesale values for 2021 are preliminary and subject to resettlement.**

(b) Energy values are derived from wholesale market pricing and represent the results of the Day-Ahead Energy Market plus deviations from the Day-Ahead Energy Market reflected in the Real-Time Energy Market.

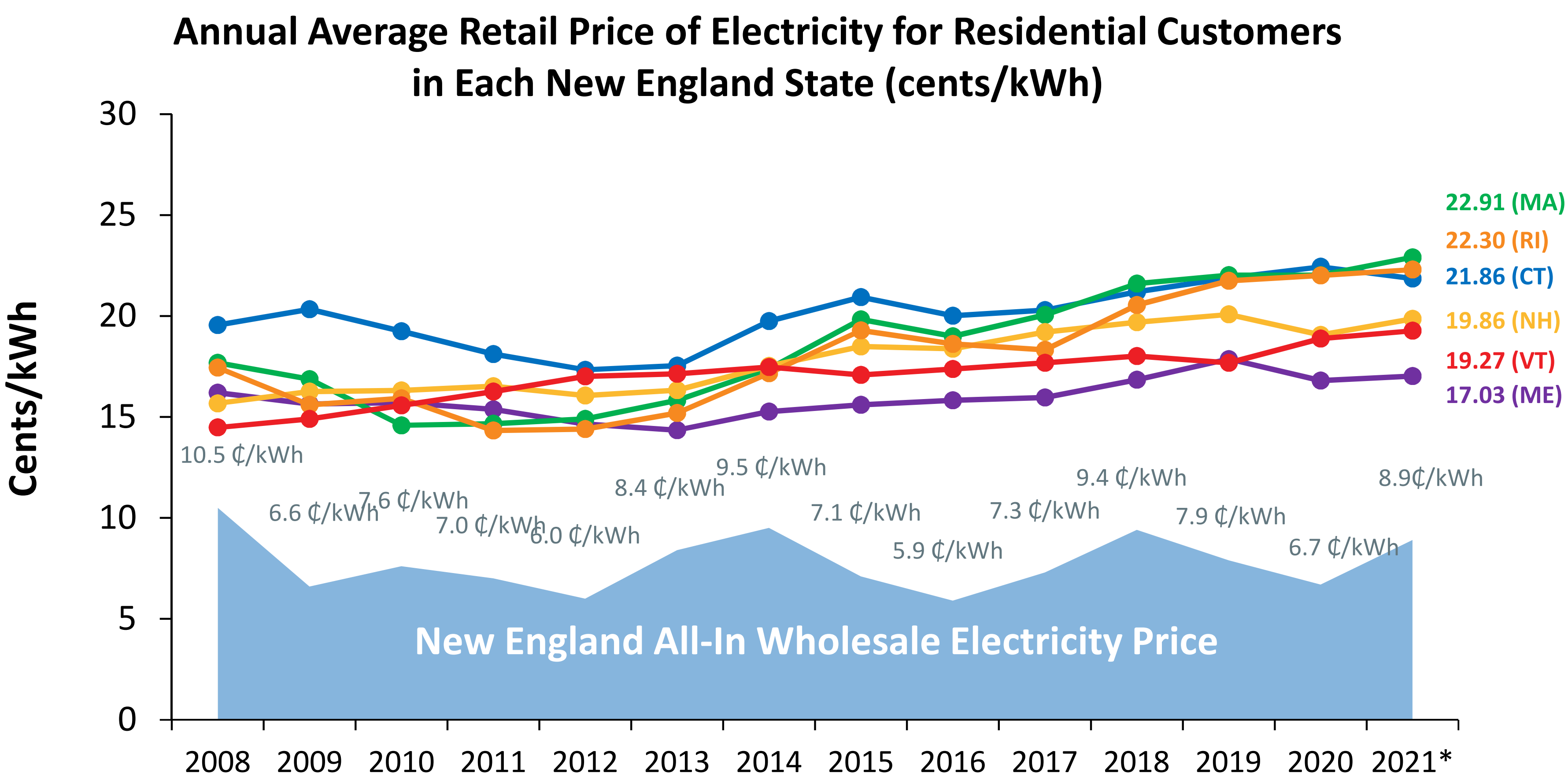
(c) Ancillaries include first- and second-contingency Net Commitment-Period Compensation (NCPC), forward reserves, real-time reserves, regulation service, and a reduction for the Marginal Loss Revenue Fund.

(d) Capacity charges are those associated with the Forward Capacity Market (FCM).

(e) Transmission charges reflect the collection of transmission owners' revenue requirements and tariff-based reliability services, including black-start capability, voltage support, and FCM reliability.

(f) RTO costs are the costs to run and operate ISO New England and are based on actual collections, as determined under Section IV of the *ISO New England Inc. Transmission, Markets, and Services Tariff*.

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



Source: U.S. Energy Information Administration, *Electric Power Monthly*, Table 5.6.B Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State (Through Dec. 2021); *2021 Report of the Consumer Liaison Group*, the New England all-in wholesale electricity price is derived by dividing total wholesale electricity costs by real-time load obligation (presented for illustrative purposes; does not reflect actual charge methodologies)

NECPUC State Agencies' Questions to ISO-NE regarding 2023 Budget

1) Please provide a link to the latest copy of ISO-NE's FERC Form 1.

   Electronic pdf version is attached.

2) Please provide a link to the most recent copy of ISO-NE's Form 990.

   Electronic pdf version is attached.

3) Metrics. Refer to the metrics identified in the 2021 FERC Common Metrics Staff Report in Docket No. AD19-16-000. For each of the metrics identified in that report, explain how ISO-NE uses the metric to measure its progress, the goals, if any, it is looking to achieve regarding the metric, and the expected net benefit of achieving the goals. In particular, address each of the following sets of metrics:

   a) Group 1 Administrative and Descriptive Metrics (7 metrics);
   b) Group 2 Energy Market Metrics (12 metrics); and
   c) Group 3 Capacity Market Metrics (10 metrics).

   The FERC Common Metrics Staff Report (Docket No. AD19-16-000) is a tool that FERC uses to examine the performance and benefits of ISOs/RTOs, specifically in response to a Government Accountability Office report recommending that FERC develop measures to track performance of RTO/ISO operations and markets. Those metrics were designed to assist FERC in carrying out its mission and were not specifically designed to measure ISO-NE; accordingly, ISO-NE does not use the metrics as a primary means of measuring its own performance. Instead, as explained in response to Question 5 below, ISO-NE believes the most effective metrics to evaluate our performance are more specifically tailored to our mission and the New England markets. Therefore, ISO-NE uses the metrics reflected in Appendix 4 of the *ISO-NE England Proposed 2023 Operating and Capital Budgets* presentation (the "Budget Presentation") presented to the states on August 12, 2022 (the "ISO-NE Metrics") to evaluate our performance.[1]

   Specifically, the topics covered by Group 1 metrics in the FERC Common Metrics Staff Report are covered by similar, but not identical, system reliability metrics identified in Appendix 4 of the Budget Presentation. These metrics assess the system's reliability and can help identify areas for improved operational tools and procedures. Many of the topics in Groups 2 and 3 are addressed by the annual market reports by the Internal Market Monitor and External Market Monitor. These metrics assess the performance of the wholesale markets and can help identify areas for enhancements to the market rules.

[1] The ISO-NE Metrics reflected in Appendix 4 of the Budget Presentation are similar (with some additional details provided) to those reflected in ISO-NE's response to the State Agencies' 2022 Budget questions (available at https://www.iso-ne.com/static-assets/documents/2021/08/6_states_2022_budget_questions_08_2021.pdf).

4) Metrics. What metrics does ISO-NE use to determine/track the relative cost effectiveness of its transmission fixes? For each of these metrics, describe the expected impact of:

   a) Identifying transmission needs sooner;
   b) Requiring a competitive process for transmission fixes when and where possible; and
   c) Allowing non-transmission fixes to compete with transmission fixes.

   Explain the process ISO-NE uses to ensure that these impacts on metrics are consider when determining how best to improve the cost effectiveness of transmission fixes.

In most cases, ISO-NE selects transmission projects based on the lowest estimated installed cost, so the metric used is project costs. Under the solution process, alternative approaches to addressing transmission needs are developed. The preferred solution is selected among the alternatives, with cost generally being the most important factor. Other considerations, such as operability and flexibility, are also important, but for a given performance standard, cost is the primary criteria. Moving forward, stakeholders have indicated that they would like to consider expected future transmission needs (e.g., those identified in the 2050 Transmission Study) when identifying and selecting solutions. ISO-NE supports this approach.

While identifying system concerns earlier would be beneficial from a number of perspectives, it is not clear that this would have a material impact on the cost effectiveness of solutions that are implemented. Earlier identification would be expected to allow solutions to be placed in service sooner, increasing reliability and, in some cases, providing an immediate increase in transfer capability, which works to reduce congestion and reliance on local resources. However, most transmission reliability needs in the recent past have been driven by sudden changes in assumptions typically prompted by resource retirements. Under the current process, ISO-NE cannot prepare the system for an upcoming resource retirement until a delist bid is submitted in the Forward Capacity Market. Therefore, there is not a means of "getting ahead" of these significant needs triggers. ISO-NE has recognized the desire of many stakeholders for more forward-looking planning and has been responding. As a result of the Transmission Planning for the Clean Energy Transition effort, ISO-NE has developed a method of looking forward to address "minimum load" system concerns based on forecasted energy efficiency and photovoltaic resources. Additionally, at the August 2022 Planning Advisory Committee meeting, ISO-NE will be proposing to consider the retirement of resources greater than 50 years old, one at a time, in Needs Assessments.

While ISO-NE has run only one competitive transmission solicitation to date (the two most important selection criteria were cost and in-service date), the selected solution was developed by the incumbent transmission owners. There is no way of knowing what would have happened if the competitive transmission development process had not been used, but there is nothing that would have prevented this same solution from being developed through ISO-NE working with the same incumbent transmission owners. There also is no way to know what the costs would have been under the Solutions Study process. ISO-NE follows its FERC-accepted tariff when determining whether to use the competitive transmission development process. In cases where the timing of solution development is not critical, such as the longer-term transmission planning process, ISO-NE has previously indicated to the

New England States Committee on Electricity ("NESCOE") that it will support the use of the competitive transmission process.

Non-transmission fixes are already considered in ISO-NE's planning process, and, in fact, are given preference over the development of transmission solutions. Under Attachment K of the ISO-NE Open Access Transmission Tariff, ISO-NE accounts for all existing resources and all future resources that have an obligation either through the Forward Capacity Market or a contract. In addition, up until the point where a solution has been placed in service, ISO-NE can terminate transmission solution development based on updated assumptions resulting from non-transmission alternatives. There have already been examples where ISO-NE has cancelled reliability-based upgrades which were part of the Regional System Plan. Finally, the Storage as a Transmission-Only Asset (SATOA) project will enable the building of storage projects to address certain transmission needs.

Going forward, the majority of transmission investment is expected to be needed to meet state-defined public policy goals. As described in our recent FERC filing, we (and NESCOE) are advocating for the states to have decisional roles in determining the public policy need, the most cost effective transmission paths, the cost allocation method for the various investments, and the means for procuring the transmission (competitive or not). We see ISO-NE's role as being a technical specialist supporting state decision making. We look forward to working with the states to develop the decision making process and associated criteria.

5) Metrics/Best Practices. What specific steps does ISO-NE take to identify/determine the metrics it should use and the best practices it should pursue across the range of its responsibilities to ensure that it is prudently fulfilling those responsibilities?

There are several different frameworks that ISO-NE uses when determining what metrics to use to measure our effectiveness in fulfilling our responsibilities. First, ISO-NE believes that for the ISO-NE Metrics to be a useful evaluation tool, they must either: (1) measure performance against achieving our strategic goals; (2) measure risk tolerance for identified risks in light of available resources; or (3) measure compliance with various regulatory requirements.

ISO-NE uses a "balanced scorecard framework" to translate its strategic goals into performance metrics. Generally, the "balanced scorecard framework" uses four different perspectives to measure performance: (1) financial; (2) customer satisfaction; (3) internal business processes; and (4) learning and growth.[2] These four perspectives are reflected in various ISO-NE metrics. For example, financial indicators are covered by budget accuracy metrics (addressing elements of the Operational Excellence strategic goal). Customer satisfaction (i.e., stakeholder satisfaction) is reflected in several metrics such as the New England Power Pool ("NEPOOL") stakeholder process, including the annual work plan and annual regional system planning processes (addressing elements of the Stakeholder

[2] *See*, *e.g.*, Balanced Scorecard Basics Overview, available at https://balancedscorecard.org/bsc-basics-overview/; Robert S. Kaplan and David P. Norton, *Putting the Balanced Scorecard to Work*, Harvard Business Review (September – October 1993).

Engagement strategic goal). Internal business processes is covered by metrics such as cyber security audits and reporting, North American Electric Reliability Corporation ("NERC") compliance measurements, wholesale electricity markets reports, and forecasting accuracy results (addressing elements of the Responsive Market Designs, Progress and Innovation, and Operational Excellence strategic goals). Finally, learning and growth is covered by metrics measuring employee training requirements (addressing elements of the Attract, Develop, and Retain Talent strategic goal).

As noted in response to the State Agencies' 2022 Budget questions, ISO-NE annually develops a work plan (published in the fall and updated in the spring), which outlines major priorities and activities for the year that are designed to improve upon existing ISO-NE systems, practices, and services to New England. The work plan is a result of ISO-NE planning and engagement with stakeholders; ISO-NE seeks stakeholder input on its work plan by sharing and discussing it with the NEPOOL Participants Committee and representatives of the New England states through the New England Conference of Public Utilities Commissioners ("NECPUC") and NESCOE. Although the work plan specifies priorities and activities, ISO-NE necessarily maintains some flexibility to take on additional assignments or reprioritize previously identified initiatives.

Because the work plan involves the prioritization of resources and ISO-NE's commitment to spending integrity, ISO-NE is purposeful when determining goals and objectives, and which "best-practices" to pursue. As noted above, we use the "balanced scorecard" methodology to measure performance. To ensure we maintain an appropriate risk tolerance, ISO-NE maintains a risk register that includes measures of risk and mitigation that management and ISO-NE's Board of Directors use for situational analysis and when reviewing the ISO-NE strategic plan. Finally, ISO-NE maintains a compliance management system that tracks over 5000 compliance obligations and related measures.

NESCOE Pro Forma Budget
Proposed 2023

	2023
Salaries and Wages	
Salaries	1,311,718
Payroll Taxes	131,172
Health and Other Benefits	110,098
Retirement §401(k)	52,469
Total, Salaries and Wages	**1,605,457**
Direct Expenses - Consulting	
Technical Analysis	342,932
Legal (FERC)	342,933
Total, Direct Expenses, Consulting	**685,865**
General and Administrative	
Rent	-
Utilities	-
Office and Administrative Expenses	48,956
Professional Services	41,200
Travel/Lodging/Meetings	56,650
Total General and Administrative	**146,806**
Capital Expend. & Contingencies	
Computer Equipment	8,695
Contingencies	244,682
Capital Expend. & Contingencies	**253,377**
TOTAL EXPENSES	**2,691,505**
BUDGET	***2,696,171***

New England States Committee on Electricity

2023 Budget Presentation

NEPOOL Budget & Finance Subcommittee

August 11, 2022

Background: Budget Review

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

✓ Proposed 2023 budget conforms to:

- Boundaries of 5-year pro forma (2023 - 2027) reviewed by Budget & Finance
- NESCOE commitment not to seek an increase over pro forma budget of more than 10% in any 1 year: 2023 proposed budget is less than 2023 5-year pro forma budget

✓ Following calendar year 2021, independent auditor concluded NESCOE books conform to generally accepted accounting principles

Background: Policy Priorities

Term Sheet Provision Governing Identification of Policy Priorities:

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

Consistent with Term Sheet, 2021 *Report to the New England Governors*:

- ✓ Reviewed work in 2021
- ✓ Projected policy priorities
- ✓ Provided spending from prior year
- ✓ Projected budget information for upcoming two years

Projected Policy Priorities

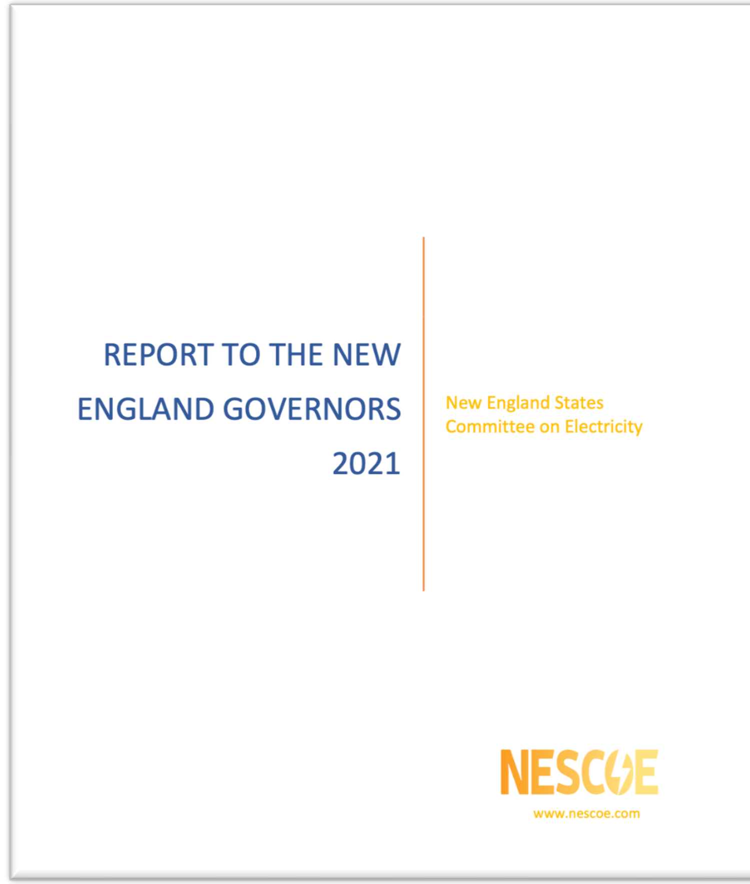
- ✓ NESCOE provided to the Governors the ***2021 Annual Report to New England Governors***

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

- ✓ NESCOE identified forward looking policy priorities at Section V, pages 15

Report in "Resource Center"

www.nescoe.com


REPORT TO THE NEW ENGLAND GOVERNORS 2021

New England States Committee on Electricity

NESCOE

www.nescoe.com

Projected Policy Priorities

- ✓ **Future Grid**. With ISO-NE and stakeholders, consider the contemplated Phase 2 Future Grid analysis to assess revenue sufficiency and system security in a gap analysis; advance the Pathways process, including governance approaches that provide an appropriate role for states.
- ✓ **Transmission**. Work with ISO-NE and stakeholders on tariff changes to enable states to consider options to address issues identified in the longer-term public policy-related transmission analysis; engage in FERC's reform of transmission planning, generator interconnection, and cost allocation processes, highlighting the critical need for states' appropriate, meaningful role in public-policy transmission planning and cost allocation.
- ✓ **Winter**. Continue to seek and assess timely analysis and recommendations from ISO-NE on near-term winter risks; assess means to value the contribution of resources needed for regional energy security/winter reliability; participate in ISO-NE's effort to assess potential operational implications of low probability/high impact extreme weather events and to identify a cost-effective approach to any mitigation; ensure consumer interests are chief among the metrics by which winter proposals are evaluated.

NESCOE Organization & Misc.

Employees

- ✓ Retain and attract diversity in academic training, skills; blend of private & public sector experience
- ✓ Assumes return to NESCOE's prior steady state employee level of six in light of sustained increase in workload volume; legal staff solicitation issued 2022

Office Space

- ✓ Terminated office space in Westborough, MA

Other Organization Matters

Technical Consultants

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

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

- ✓ Wilson Energy Economics
- ✓ PeterGFlynn, LLC
- ✓ NewGen
- ✓ Supplement with other expertise, as needed

Legal Counsel

Litigation is not the primary means by which NESCOE seeks to accomplish its objectives & thus, greater resource and focus has historically, and thus far in 2022, been on technical consulting. Further, while NESCOE produces most legal pleadings and analysis internally, the frequency and type of litigation brought by others influences the extent to which NESCOE engages outside counsel.

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

5-Year Pro Forma

Proposed 2023 budget conforms to 2023 budget in 5-year Pro Forma Framework

✓ 2023 Projected Budget in 5-Year Pro Forma:	$2,696,171
✓ 2023 Proposed Budget:	$2,691,505
✓ 2022 Budget, for reference:	$2,485,156

In relation to 2022 Budget, 2023 Proposed Budget reflects:

- ✓ Return to prior steady state of six employees
- ✓ Inflationary pressures
- ✓ No office rent

5-Year Pro Forma, for reference

NESCOE
PRO FORMA BUDGET 2023-2027*

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

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

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

2023 Proposed Budget

	2023
Salaries and Wages	
Salaries	1,311,718
Payroll Taxes	131,172
Health and Other Benefits	110,098
Retirement §401(k)	52,469
Total, Salaries and Wages	**1,605,457**
Direct Expenses - Consulting	
Technical Analysis	342,932
Legal (FERC)	342,933
Total, Direct Expenses, Consulting	**685,865**
General and Administrative	
Rent	-
Utilities	-
Office and Administrative Expenses	48,956
Professional Services	41,200
Travel/Lodging/Meetings	56,650
Total General and Administrative	**146,806**
Capital Expend. & Contingencies	
Computer Equipment	8,695
Contingencies	244,682
Capital Expend. & Contingencies	**253,377**
TOTAL EXPENSES	**2,691,505**
BUDGET	***2,696,171***

2021 & 2022 Spending & Implications for 2023

Unspent funds in any year credited toward future year

2021 Total Spending:	$1,379,375*
2022 Spending to end of June:	$740,914
2022 Projected Year End:	$1,942,044 *

* Cumulative prior years' true up, including 2020, was reflected in the 2022 revenue requirement and rates. The 2021 true up will be reflected in the 2023 revenue requirement and rates (see next slide). Any 2022 true up will be reflected in the 2024 revenue requirements and rates.

2023 Projected Billing Rate

With thanks to ISO-NE for calculations -

2023 Budget:	$2,691,505
Less 2021 True Up:	($1,108,802)
Total Revenue Recovery:	$1,582,703
Divided by Total Network Load:	231,453,876

(total network load from 2022 ISO-NE tariff; no escalation or reduction used in calculation)

2023 Schedule 5 Estimated **Rate $0.00684 per kW-month**

Thank you.

Questions?

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of August 31, 2022

The following activity, as more fully described in the attached litigation report, has occurred since the report dated August 2, 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)	Aug 3-18	NEPOOL, Calpine, MPUC, EPSA, PJM, SPP, Public Citizen intervene ISO-NE response due ***Oct 26, 2022*** A special B&F meeting has been scheduled for ***Sep 22, 2022*** to review and provide input on ISO-NE's proposed response
	3	NMISA Complaint Against PTO AC (Reciprocal TOUT Discount) (EL22-31)	Aug 24	NMISA requests rehearing of the FERC's Jul 28 order denying the NMISA Complaint seeking a reciprocal TOUT Discount; FERC action required on or before ***Sep 23, 2022***

II. Rate, ICR, FCA, Cost Recovery Filings

*	8	FCA17 De-List Bids Filing (ER22-2651)	Aug 10	ISO-NE submits filing describing Permanent and Retirement De-List Bids submitted on or prior to the FCA17 Existing Capacity Retirement Deadline
			Aug 19-31	NEPOOL, National Grid intervene
	9	Essential Power Newington CIP-IROL (Schedule 17) Section 205 Cost Recovery Filing (ER22-2469)	Aug 8-12	NEPOOL, CSC, Eversource intervene
	9	GenConn Middletown CIP IROL (Schedule 17) Cost Recovery Schedule Filing (ER22-2367)	Aug 19	FERC accepts GenConn Middletown's CIP-IROL Costs rate schedule, eff. Sep 12, 2022
	10	Mystic 8/9 COS Agreement First CapEx Info Filing (ER18-1639)	Aug 9	(-015) First CapEx Info. Filing Settlement Judge Procedures. 2nd settlement conf scheduled for ***Nov 17, 2022***

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

12	CSF Revisions (ER22-2546)	Aug 11-19	Calpine, Eversource, National Grid intervene
12	Information Policy Cyber Security Incident Information Sharing Changes (ER22-2366)	Aug 31	FERC accepts Changes, eff. Sep 11, 2022
12	New England's *Order 2222* Compliance Filing (ER22-983)	Aug 9	AEE, AEMA, PowerOptions, and SEIA answer ISO-NE Jul 25 answer

IV. OATT Amendments / TOAs / Coordination Agreements

13	*Phase I/II HVDC-TF Order 881 Compliance Filing (ER22-2468 and (ER22-2467)*	Aug 3	IRH Management Committee intervenes
14	Process Modifications - DER Interconnection/Interconnection Study Coordination (ER22-2226)	Aug 4 Aug 26	ISO-NE answers SEIA's comments FERC accepts process modifications, eff. Aug 28, 2022

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

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

*	15	Schedule 21-NEP: Narragansett/ Pawtucket Power Decomm. CRA (ER22-2732)	Aug 26	Narragansett files Decommissioning Cost Reimbursement Agreement with Pawtucket Power Associates LP covering work to support decommissioning of certain interconnection facilities and related equipment for Pawtucket's now-retired 69 MW generating facility
	16	Schedule 20A (Phase I/II HVDC-TF Service Agreement) Reassignm't Agreements: CMP & UI/ BRTM/ HQUS (ER22-2433/32/31)	Aug 15	FERC accepts 3 Phase I/II HVDC-TF service agreements (1 with CMP; 2 with UI) that transfer Brookfield transmission service rights and obligations to HQUS, eff. Sep 1, 2022
	16	Schedule 20A (Phase I/II HVDC-TF Service Agreement) Reassignm't Agreement: NEP/BRTM/HQUS (ER22-2398)	Aug 15	FERC accepts NEP Phase I/II HVDC-TF service agreement that transfers Brookfield transmission service rights and obligations to HQUS; eff. Sep 1, 2022
*	16	Schedule 21-NEP: NEP/NSTAR Civil Work & Construction Agreement (ER22-2175)	Aug 9	FERC accepts Agreement, eff. Apr 19, 2022

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

	17	Capital Projects Report - 2022 Q2 (ER22-2667)	Aug 11 Aug 24 Aug 31	ISO-NE files 2022 Q2 Report; comment date ***Sep 1, 2022*** NEPOOL intervenes and files comment supporting the Report National Grid intervenes
*	18	Interconnection Study Metrics Processing Time Exceedance Report Q2 2022 (ER19-1951)	Aug 21	ISO-NE files required quarterly report
*	19	IMM Quarterly Markets Reports - 2022 Spring (ZZ21-4)	Aug 19	IMM files Spring 2022 Report, to be reviewed at the Sep 13-14 Markets Committee meeting
*	19	ISO-NE FERC Form 3Q (2022/Q2) (not docketed)	Aug 25	ISO-NE submits its 2022 Q2 FERC Form 3Q

IX. Membership Filings

	19	July 2022 Membership Filing (ER22-2260)	Aug 19	FERC accepts (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

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

*	20	2023 NERC/NPCC Business Plans and Budgets (RR22-4)	Aug 23	NERC submits proposed 2023 Business Plan and Budget for itself and its Regional Entities, including NPCC; comment deadline ***Sep 13, 2022***
	20	NPCC Bylaws Changes (RR22-2)	Aug 10	FERC grants NERC/NPCC request for 30-day extension of time, to ***Oct 6, 2022***, to submit compliance filing in response to the requirements of the Jul 8 order accepting the changes

	21	Rules of Procedure Changes (Reliability Standards Development Revisions) (RR21-8)	Aug 25	FERC approves Revisions, eff. Aug 25, 2022

XI. Misc. - of Regional Interest

	22	203 Application: Waterside Power / KKR (EC22-79)	Aug 19	FERC authorizes sale of 100% of Applicants' equity interests to KKR
	22	203 Application: Stonepeak/JERA Americas (EC22-71)	Aug 8	Applicants submit informational filing
	22	Versant MPD OATT *Order 881* Compliance Filing (ER22-2358)	Aug 2	MPUC protests filing
	23	VTransco Shared Structure Participation Agreements (ER22-2189)	Aug 22	FERC accepts two Shared Structure Participation Agreements between VTransco and Green Mountain Power, eff. Jan 1, 2022
	23	IAs: NEP / Narragansett (ER22-2039/2038)	Aug 3, 4	FERC accepts IA-NECO-56 (ER22-2039) and IA-NEP-55 (ER22-2038) (the wire-to-wires IA that governs the interconnection of NEP's and Narragansett's transmission systems), each eff. May 25, 2022
	23	*Orders 864/864-A* (Public Util. Trans. ADIT Rate Changes): New England Compliance Filings (various)	Aug 12	*ER20-2133 (Versant –BHD Formula Rate). Versant* supplements its Apr 12, 2022 compliance filing with further amendments to Attachment P-VP to Schedule 21-VP

XII. Misc. - Administrative & Rulemaking Proceedings

*	24	Interregional HVDC Merchant Transmission (AD22-13)	Aug 26	Comments filed by 12 parties, including CSC, Invenergy, Phase I/II Asset Owners and IRH, Joint Consumer Advocates, ACORE, ACPA, SEIA, Neptune and Hudson
*	24	Reliability Technical Conference (AD22-10)	Aug 23	FERC issues notice of annual tech conf to be held ***Nov 10, 2022*** at FERC HQ
	24	New England Gas-Electric Winter Forum (AD22-9)	Aug 22	FERC posts supplemental notice of Forum, including an agenda, description of proposed panels and panelist identities
	25	Joint Federal-State Task Force on Electric Transmission (AD21-15)	Aug 3 Aug 11	Post-Jul 20 JFSTF meeting comments may be filed by ***Sep 2, 2022*** Fourth JFSTF meeting transcript posted in eLibrary
	27	NOPR: Duty of Candor (RM22-20)	Aug 12	NOPR published in Fed. Reg., comments due ***Oct 11, 2022***
	27	NOPR: Extreme Weather Vulnerability Assessments (RM22-16; AD21-13)	Aug 30	Comments filed by over 13 parties, including, among others, Eversource, NRDC, NERC, MISO, PJM, EPSA
	30	NOPR: ISO/RTO Credit Information Sharing (RM22-13)	Aug 8	NOPR published in Fed. Reg.; comments and reply comments due ***Oct 7, 2022*** and ***Nov 7, 2022***, respectively
	30	NOPR: Transmission System Planning Performance Requirements for Extreme Weather (RM22-10)	Aug 11-29	Comments filed by over 37 parties, including, among others, ISO-NE, Eversource, NESCOE, NRDC, UCS, NERC, ERCOT, MISO, NYISO, PJM, ACPA, EPRI, EPSA, NARUC, Trade Associations

	32	*Transmission NOPR* (RM21-17)	Aug 4-18	Nearly 200 sets of comments were filed, including by NEPOOL, ISO-NE, Acadia/CLF, Anbaric, AEE, Avangrid, BP, Dominion, Enel, Engie, Eversource, Invenergy, LSP Power, MOPA, MMWEC/CMEEC/ NHEC/VPPSA, National Grid, NECOES, NESCOE, NextEra, NRG, Onward Energy, Orsted, PPL, Shell, Transource, VELCO, Vistra, ISO/RTO Council, NERC, US DOJ/FTC, MA AG, State Agencies, VT PUC/DPS, Potomac Economics, ACPA, ACRE, APPA, EEI, EPSA, Industrial Customer Organizations, LPPC, NASUCA, NRECA, Public Interest Organizations, SEIA, TAPS, WIRES, Harvard Electricity Law Initiative, New England for Offshore Wind, and the R Street Institute; reply comments due ***Sep 19, 2022***

XIII. FERC Enforcement Proceedings

*	36	CPower (IN22-7)	Aug 25	FERC approves Stipulation and Consent Agreement that resolved OE's investigation into CPower's compliance with the ISO-NE Tariff's Energy Market Offer Requirements (§III.13.6.1.5.1) between Jun 2018 and Feb 2019; CPower must ***disgorge $2,460,628*** and pay a ***$2,539,372 civil penalty***
	39	Total Gas & Power North America, Inc. et al. (IN12-17)	Aug 30	Chief Judge Satten extends the hearing commencement date and the initial decision deadline to Jan 23, 2023 and July 10, 2023, respectively

XIV. Natural Gas Proceedings

	41	Northern Access Project (CP15-115)	Aug 30	The request for rehearing of the *Northern Access Project Add'l Extension Order* denied by operation of law

XV. State Proceedings & Federal Legislative Proceedings

*	43	Maine - NECEC Transmission LLC et al. v. Bureau of Parks and Lands et al. (BCD-21-416)	Aug 30	The Maine Supreme Judicial Court concludes that the legislation enacted as a result of the passage of Maine's Nov 2, 2021 ballot question, and that effectively halted construction of the NECEC Project, was unconstitutional to the extent it required the legislation to be applied retroactively to the Project's CPCN if NECEC had acquired vested rights to proceed with Project construction

XVI. Federal Courts

*	44	Mystic III (*True-Up Orders*) (22-1215)	Aug 25	Court issues order consolidating this case with 21-1198 et al. and requiring docketing statements and statement of issues by ***Sep 26, 2022***; dispositive motions, if any, by ***Oct 11, 2022***
	44	*2nd Revised Narragansett LSA Orders* (22-1108, 22-1161) (consol.)	Aug 15	Green Development files Statement of Issues and Docketing Statement
			Aug 29	Court grants New England Power's Aug 10, 2022 motion for leave to intervene
			Aug 30	Court establishes a revised briefing schedule
	45	Mystic II (ROE & True-Up) (21-1198 et al.) (consol.)	Aug 9	Court, having decided MISO TOs, orders the parties to file motions to govern future proceedings in this case by ***Sep 8, 2022***
			Aug 25	Court consolidates Case 22-1215 with these cases

45	Mystic I (Original Cost Test, Capital Structure, Everett Cost Recovery, Clawback, True-Up Mechanism) (20-1343 et al.) (consol.)	Aug 12	Mystic informs Court of settlement in principle that could resolve the issues of Mystic's proper capital structure and cost of debt
		Aug 23	Court issues decision holding that Mystic's petition for review be dismissed in part and denied in part; State Petitioners' petitions for review be granted; the clawback portions and the challenged delay provision of the orders under review be vacated; and the cases be remanded for the FERC to address NESCOE's request for clarification about revenue credits and for clarification of the apparent contradictions in the FERC's Dec 2020 Rehearing Order
46	*Opinion 531-A* Compliance Filing Undo (20-1329)	Aug 11	FERC files status report indicating that the proceedings before the Commission remain ongoing and that this appeal should continue to remain in abeyance
47	ISO-NE's Inventoried Energy Program Proposal (19-1224 et al.) (consol.)	Aug 9	Court issues mandate to FERC; ball's in FERC's court
48	*Opinion 569/569-A*: FERC's Base ROE Methodology (16-1325 et al.) (consol.)	Aug 9	Court issues its decision granting customers' petitions for review, dismissing transmission owners' petitions for review, vacating the underlying FERC orders, and remanding the cases to the FERC to re-open its proceedings
49	Algonquin Atlantic Bridge Project Cases (21-1115 et al. (consol.); and 22-1146 et al. (consol.))	Aug 16	Court deconsolidates 22-1146 and 22-1147 from 21-1115 et al., consolidates Cases 22-1146 and 22-1147 together, and issues a briefing schedule for the separately consolidated cases

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: August 31, 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 31, 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] A special Budget & Finance Subcommittee meeting has been scheduled for September 22, 2022 to review and provide input on ISO-NE's proposed response.

The *FTR Collateral Show Cause 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

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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).

practices for credit risk management in organized wholesale electric markets.[7] In the *FTR Collateral Show Cause Order*, the FERC stated that, although the record developed through the technical conference highlighted numerous different approaches to managing credit risk, "we believe that two specific practices may be particularly critical to effectively managing credit risk for FTRs: the use of a mark-to-auction mechanism and a volumetric minimum collateral requirement for FTRs."[8] ISO-NE currently employs a mark-to-auction mechanism but not volumetric FTR collateral requirements.

The FERC issued on July 28, 2022, a notice of this proceeding and of the refund effective date, which will be August 3, 2022.[9] Those interested in participating in this proceeding were required to intervene on or before August 18, 2022. Doc-less interventions were been filed by NEPOOL, Calpine, DC Energy, NRG, the Maine Public Utilities Commission ("MPUC"), Electric Power Supply Association ("EPSA"), PJM, SPP, and Public Citizen. 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,[10] Vistra/LSP Power, State Parties,[11] 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,[12]

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

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

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

[11] "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").

[12] "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").

CT PURA, MA DPU, MPUC, Repsol, APPA, EPSA, the Institute for Policy Integrity at New York University School of Law, and Public Citizen. On July 20, 2022, ISO-NE submitted a letter requested expeditious action on the Complaint (a request NEPOOL supported). RENEW/ACPA 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 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 August 24, 2022, the Northern Maine Independent System Administrator ("NMISA") requested rehearing of the FERC's order denying NMISA's complaint against ISO-NE and 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").[13] As previously reported, 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".[14] 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 FPA Section 206 statutory burden. In requesting rehearing, NMISA asserted that the FERC erred by (i) failing to provide a reasoned explanation for its determination that NMISA and NYISO are not similarly situated; and (ii) failed to justify its decision not to enforce the requirement that ISO-NE engage in extensive efforts to reduce seams with neighboring control areas. The NMISA request for rehearing is pending, with FERC action required on or before ***September 23, 2022***, or the request will be deemed denied by operation of law. 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)**

Still pending before the FERC is the FERC-instituted FPA Section 206 proceeding under which the FERC is considering whether Schedule 25 and Tariff § I.3.10 may be unjust and unreasonable.[15] As previously reported, 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.[16]

The FERC directed ISO-NE to: (1) show cause as to why Schedule 25 and Tariff § I.3.10 remain just and reasonable or (2) explain what changes to Schedule 25 and/or Tariff § 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

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[13] *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).

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

[15] *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*").

[16] *Id.* at P 20.

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 is 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[17] and included 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.

ISO-NE Answer. On November 8, 2021, ISO-NE submitted its answer explaining why Schedule 25 and Tariff § 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.

As noted, 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).

- **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[18] 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.

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

[18] 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.

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).[19] Initial briefs[20] were due on 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

[19] *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).

[20] 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, 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.

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,[21] set the TOs' Base ROE at 10.57% (reduced from 11.14%), capped the TOs' total ROE (Base ROE _plus_ transmission incentive adders) at 11.74%, and required implementation effective as of October 16, 2014 (the date of *Opinion 531-A*).[22] However, the FERC's orders were challenged, and in *Emera Maine,*[23] 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)[24] and third (EL14-86)[25] 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.[26] 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[27] also went to hearing before an Administrative Law Judge ("ALJ"), Judge Glazer, who issued his initial decision on March

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[21] 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*")).

[22] *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*").

[23] *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).

[24] 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 Complainan ts"), challenged the TOs' 11.14% ROE, and seeks a reduction of the Base ROE to 8.7%.

[25] 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 r educe 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.

[26] *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*").

[27] 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 t han 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 Sept ember 20, 2016. Settlement procedures did not lead to a settlement, were terminated, and hearings were held subsequently held December 11-15,

27, 2017.[28] The *Base ROE IV Initial Decision* concluded that the currently-filed base ROE of 10.57%, which may reach a maximum ROE of 11.74% with incentive adders, was ***not*** unjust and unreasonable for the Complaint IV period, and hence was not unlawful under Section 206 of the FPA.[29] 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.[30] 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*[31] (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.[32]

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

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

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

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

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

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

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

[31] *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*.

[32] *Id.* at P 19.

unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[33] The new ROE would be effective as of the date of *Opinion 531-A*, or October 16, 2014. Accordingly, the issue to be addressed in the Base ROE Complaint II proceeding is whether the ROE established on remand in the first complaint proceeding remained just and reasonable based on financial data for the six-month period September 2013 through February 2014 addressed by the evidence presented by the participants in the second proceeding. Similarly, briefing in the third and fourth complaints will have to address whether whatever ROE is in effect as a result of the immediately preceding complaint proceeding continues to be just and reasonable.

The FERC directed participants in the four proceedings to submit briefs regarding the proposed approaches to the FPA section 206 inquiry and how to apply them to the complaints (separate briefs for each proceeding). Additional financial data or evidence concerning economic conditions in any proceeding must relate to periods before the conclusion of the hearings in the relevant complaint proceeding. Following a FERC notice granting a request by the TOs and Customers[34] 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*[35] 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

- **FCA17 De-List Bids Filing (ER22-2651)**

Pursuant to Market Rule 1 § 13.8.1(a), ISO-NE submitted on August 10, 2022 a filing describing the Permanent De-List Bids and Retirement De-List Bids that were submitted on or prior to the May 6, 2022 FCA17 Existing Capacity Retirement Deadline. ISO-NE reported that it received 3 Permanent De-List Bids and 2 Retirement De-List Bids. The bids were for resources located in the VT, South Eastern Massachusetts, and Western Central MA Load Zones, with 20.362 MWs of aggregate capacity. All of the Bids were for resources under 20 MW or that did not meet the affiliation requirements that would have required Internal Market Monitor ("IMM") review. The IMM's determination regarding those bids is described in the version of the filing that was filed confidentially as required under §13.8.1(a) of Market Rule 1. Comments on this filing were due on or before August 31; none were filed. Doc-less interventions were filed by NEPOOL and National Grid. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

[33] *Id.* at P 59.

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

[35] *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).

- **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,[36] 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 were due on or before August 12, 2022; none were filed. Doc-less interventions only were filed by NEPOOL, Cross-Sound Cable ("CSC"), Eversource, and NESCOE. 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).

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

On August 19, 2022, the FERC accepted GenConn Middletown's rate schedule that will allow it to begin the recovery period for certain CIP-IROL Costs under ISO-NE Tariff Schedule 17.[37] As GenConn explained, the rate schedule provides 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 contemplated by Schedule 17 and a subsequent Section 205 filing identifying the specific costs to be recovered. GenConn's rate schedule was accepted effective as of September 12, 2022, as requested. Unless the August 19, 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).

- **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

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[36] *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).

[37] *GenConn Middletown LLC*, Docket No. ER22-2367-000 (Aug. 19, 2022) (unpublished letter order).

[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.

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 Satten substituted ALJ Patricia M. French for Judge Glazer (who has now retired). Judge French will conduct the ongoing settlement judge procedures going forward.

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

[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*").

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 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. A second settlement conference is scheduled for ***November 17, 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] Mystic appealed the *Mystic First CapEx Info. Filing Order* and the June 27, 2022 notice (together the "*True-Up Orders*") to the DC Circuit, which has since consolidated the *True-Up Orders* appeal with the ROE appeals (*see* Section XVI, Case No. 21-1198 below).

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 formula 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,

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

[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").

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.

The July 29 filing was reviewed with the Transmission Committee at its August 16, 2022 summer meeting and at an August 22, 2022 technical session for Interested Parties. The July 29 filing triggered the commencement of the Information Exchange Period and a Review Period under the Interim Protocols. Interested Parties 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 were due on or before August 19, 2022; none were filed. Doc-less interventions only were filed by Calpine, Eversource and National Grid. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

On August 31, 2022, the FERC accepted changes jointly filed by ISO-NE and NEPOOL 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").[51] The Changes were acpeted effective as of September 11, 2022, as requested. Unless the August 31, 2022 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **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

[51] *ISO New England Inc. and New England Power Pool*, Docket No. ER22-2366-000 (Aug. 31, 2022) (unpublished letter order).

Organizations;[52] MA AG; Voltus; AEMA and 4 New England US Senators.[53] Doc-less interventions were filed by: 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. On August 9, 2022, AEE, AEMA, PowerOptions, and SEIA answered ISO-NE's July 25 answer.

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

- ***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 service (together, the "Phase I/II HVDC-TF *Order 881* Compliance Filing"). Comments on the Phase I/II HVDC-TF *Order 881* Compliance Filing were due on or before August 12, 2022; none were filed. The IRH Management Committee submitted a doc-less intervention. 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).

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

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

[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.

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

As previously reported, ISO-NE, NEPOOL, the PTO AC, and CSC (the "Filing Parties") filed, on July 12, 2022, proposed revisions to the OATT in response to the requirements of *Order 881*[56] ("*Order 881* Compliance Changes"). Specifically, the Filing Parties proposed the addition of a new Attachment Q to the OATT, and to revise OATT Schedules 18 (MTF; MTF Service) and 21 (Local Service - Common). The *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; none were filed. 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).

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

On August 28, 2022, the FERC accepted[57] changes to the Tariff to modify the process for interconnection of new distributed energy resources ("DERs") and to improve the coordination of interconnection studies ("DER Interconnection Revisions")[58] jointly filed by ISO-NE, NEPOOL and the PTO AC. The DER Interconnection Revisions were accepted effective August 28, 2022, as requested. In accepting the DER Interconnection Revisions, the FERC found that ISO-NE's proposal to exclude DERs from its interconnection procedures was (i) was "just and reasonable because it would promote certainty in ISO-NE's interconnection process and reduce a significant burden on ISO-NE"[59]; and (ii) accomplishes the purposes of *Orders 2003* and *2006*.[60] The FERC also clarified that "the [FERC]'s jurisdiction over wholesale sales from DERs and their participation in the wholesale markets, and any potential use of "a [FERC]-jurisdictional wholesale distribution charge for the DERs' use of the distribution system for wholesale transactions" [was] not impacted by the Tariff revisions" and noted that "disputes related to state interconnection procedures that do not implicate these wholesale market issues will be more appropriately resolved through a state process."[61] Unless the *DER Interconnection Revisions 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).

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[56] *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*").

[57] *ISO New England Inc., New England Power Pool Participants Comm. and Participating Transmission Owners Admin. Comm.*, 180 FERC ¶ 61,129 (Aug. 26, 2022) ("*DER Interconnection Revisions Order*").

[58] 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.

[59] *Id.* at P 19.

[60] *Id.* at P 20. "Here, as in Order No. 2222, an increase in distribution-level interconnections could create uncertainty as to whether certain interconnections are subject to Commission jurisdiction or state/local jurisdiction, and whether they would require the use of the Commission's standard interconnection procedures and agreement. Additionally, the increase in interconnection requests from DERs could burden ISO-NE with an overwhelming volume of interconnection requests. We also find that permitting DERs in ISO-NE to interconnect through the state interconnection process advances the objectives of Order Nos. 2003 and 2006 by increasing energy supply and lowering wholesale prices for customers by increasing the number and variety of new generation that will compete in the wholesale electricity market, while ensuring processes are in place to preserve reliability."

[61] *Id.* at P 21.

- ***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*,[62] ISO-NE and 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").[63] 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).

- ***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").[63] An effective date as of the date the FERC may determine was requested. Comments on this filing were 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").[63] 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 21-NEP: Narragansett/Pawtucket Power Decommissioning CRA (ER22-2732)**

On August 26, 2022, Narragansett filed a Decommissioning Cost Reimbursement Agreement ("CRA") with Pawtucket Power Associates LP (Pawtucket") to facilitate the performance of certain work that Pawtucket has

[62] *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.

[63] 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.

requested Narragansett undertake to support the decommissioning of certain interconnection facilities and related equipment for Pawtucket's 69 MW Rhode Island generating facility that was completely retired on June 1, 2022. Comments on this filing are due on or before ***September 16, 2022***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On August 15, 2022, the FERC accepted three Phase I/II HVDC-TF service agreements ("Schedule 20A TSAs") that transfer the transmission service rights and obligations that Brookfield Renewable Trading and Marketing LP ("BRTM" or the "Reseller") held under existing Schedule 20A TSAs (one with CMP; two with UI) to H.Q. Energy Services (U.S.) Inc. ("HQUS" or the "Assignee").[64] The Agreements were accepted September 1, 2022. Unless any of the orders are challenged, these proceedings will be concluded. 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)**

Also on August 15, 2022, the FERC accepted a New England Power ("NEP") Phase I/II HVDC-TF service agreements ("NEP Schedule 20A TSA") that transfers the transmission service rights and obligations that BRTM held under an existing Schedule 20A TSA (TSA-NEP-96) to HQUS.[65] The NEP Schedule 20A TSA was similarly accepted effective as of September 1, 2022. Unless the NEP Schedule 20A TSA order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Schedule 21-NEP: NEP/NSTAR Civil Work & Construction Agreement (ER22-2175)**

On August 9, 2022, the FERC accepted an Agreement for Limited Civil Work and Construction ("Agreement") between New England Power ("NEP") and NSTAR Electric Company ("NSTAR") (designated as E&P-NEP-02 under Schedule 21-NEP).[66] The Agreement relates to a project proposed by NSTAR to replace certain structures along its 1113 and 1134 Lines. That project requires the replacement of flying taps, conductor loops, and hardware, relocation of the NEP static line at the Five Corners Substation, removal of certain NEP static lines, and the installation by NSTAR of install certain temporary facilities on NEP property near the Five Corners Substation. The Agreement was accepted, effective April 19, 2022, as requested. Unless the August 9 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).

- **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

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[64] *Central Maine Power Co.*, Docket No. ER22-2433-000 (Aug. 15, 2022) (unpublished letter order) (CMP-BRTM 85 MW TSA); *The United Illuminating Co.*, Docket No. ER22-2432-000 (Aug. 15, 2022) (unpublished letter order) (UI-BRTM 32 MW TSA); and *The United Illuminating Co.*, Docket No. ER22-2431-000 (Aug. 15, 2022) (unpublished letter order) (UI-BRTM 1 MW TSA).

[65] *New England Power Co.*, Docket No. ER22-2398-000 (Aug. 15, 2022) (unpublished letter order).

[66] *New England Power Co.*, Docket No. ER22-2175-00 (Aug. 9, 2022) (unpublished letter order).

matter remains 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 10, 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*[67] *and 531-B*[68] also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***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 Q2 (ER22-2667)**

On August 11, 2022, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the second quarter ("Q2") of calendar year 2022 (the "Report"). 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) New Cyber Security Operations Center ($934,800); (ii) 2022 Issue Resolution Project ($820,000); and (iii) Privileged Account Management Security Enhancements ($706,300). Significant changes for Chartered Projects (2022 budget impact

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

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

in parentheses) were: (i) Physical Security Improvement Project ($369,000 decrease); (ii) FCTS Infrastructure Conversion Part III ($285,000 decrease); (iii) nGEM Software Development Part II ($637,000 decrease); (iv) nGEM Hardware Phase II ($192,000 decrease); and (v) PI Historian for Short-Term Phasor Measurement Units Data Repository ($130,000 increase). Comments on the Q2 Report are due on or before September 1, 2022. On August 24, 2022, NEPOOL intervened and filed comments supporting the Report. New England Power submitted a doc-less intervention on August 31, 2022. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **Interconnection Study Metrics Processing Time Exceedance Report Q2 2022 (ER19-1951)**

On August 12, 2022, ISO-NE filed, as required,[69] public and confidential[70] versions of its Interconnection Study Metrics Processing Time Exceedance Report (the "Exceedance Report") for the Second Quarter of 2022 ("2022 Q2"). ISO-NE reported that all three of the 2022 Q2 ***Interconnection Feasibility Study ("IFS") reports*** delivered to Interconnection Customers were delivered later than the best efforts completion timeline.[71] In addition, five IFS Reports that are not yet completed have exceeded the 90-day completion expectation. The average mean time from ISO-NE's receipt of the executed IFS Agreement to delivery of the completed IFS report to the Interconnection Customer was 158.7 days (20 days sooner than Q1 2022). Five of the seven ***System Impact Study ("SIS") reports*** delivered to Interconnection Customers were delivered later than the best efforts completion timeline of 270 days. 12 SIS reports that are not yet completed have also exceeded the 270-day completion expectation. The average mean time from ISO-NE's receipt of the executed SIS Agreement to delivery of the completed SIS report to the Interconnection Customer was 525.6 days (up 65 days from 2022 Q1). One Facility Study was delivered to an Interconnection Customer, and was delivered later than the best efforts completion timeline of 180 days. Facility Studies in progress have not exceeded the 90-day/180-day completion expectation. Section 4 of the Report identified steps ISO-NE has identified to remedy issues and prevent future delays, including mitigating the impact of backlogs and initiating clustering, moving to earlier in the process certain Interconnection Customer data reviews, and enhanced information sharing and coordination efforts with Interconnecting TOs. This report was 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.

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

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

[71] 90 days from the Interconnection Customer's execution of the study agreement.

- **IMM Quarterly Markets Reports – Spring 2021 (ZZ22-4)**

On August 19, 2022, the IMM filed with the FERC its Spring 2021 report of "market data regularly collected by [the IMM] in the course of carrying out its functions under … Appendix A and analysis of such market data," as required pursuant to Section 12.2.2 of Appendix A to Market Rule 1. These filings are not noticed for public comment by the FERC. The Spring 2022 Report will be discussed at the September 13-14, 2022 Markets Committee meeting.

- **ISO-NE FERC Form 3Q (2022/Q2) (not docketed)**

On August 25, 2022, ISO-NE submitted its 2022/Q2 FERC Form 3Q (quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is a quarterly regulatory requirement which supplements the annual FERC Form 1 financial reporting requirement. These filings are not noticed for comment.

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 were due on or before August 22, 2022; none were filed. This filing is pending before the FERC.

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

On August 19, 2022, the FERC accepted (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.[72] Unless the August 19 order is challenged, this proceeding will be concluded.

- **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.

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.[73]

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[72] *New England Power Pool Participants Comm.*, Docket No. ER22-2260-000 (Aug. 19, 2022) (unpublished letter order).

[73] 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.

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.

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

On August 23, 2022, NERC submitted its proposed Business Plan and Budget, as well as the Business Plans and Budgets for the Regional Entities, including NPCC, for 2023. FERC regulations[74] require NERC to file its proposed annual budget for statutory and non-statutory activities 130 days before the beginning of its fiscal year (January 1), as well as the annual budget of each Regional Entity for their statutory and non-statutory activities, including complete business plans, organization charts, and explanations of the proposed collection of all dues, fees and charges and the proposed expenditure of funds collected. NERC reports that its proposed 2023 funding requirement represents an overall increase of approximately 13.7% over NERC's 2022 funding requirement. The NPCC U.S. allocation of NERC's net funding requirement is $10.97 million. NPCC has requested $18.14 million in statutory funding (a U.S. assessment per kWh (2021 NEL) of $0.0000600) and $1.07 million for non-statutory functions. Comments on this filing are due on or before ***September 13, 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).[75] 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 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[76] 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. On August 10, 2022, the FERC granted NERC/NPCC's request, with the deadline for the required compliance filing extended to and including ***October 6, 2022***.

- **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.[77] Specifically, the FERC approved the proposed revisions to the NERC ROP for the Personnel Certification and Credential Maintenance

[74] 18 CFR § 39.4(b) (2014).

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

[76] 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.

[77] *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").

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 were due on or before August 8, 2022; none were filed. NERC's compliance filing is pending before the FERC.

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

On August 25, 2022, the FERC approved NERC's 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").[78] The Reliability Standards Development ROP Revisions were approved and became effective as of August 25, 2022. In approving the Revisions, the FERC found Public Citizen's protests related to NERC's governance[79] outside the scope of this proceeding because NERC did not propose revisions to those governance arrangements.[80] Unless the August 25 order is challenged, this proceeding will be concluded.

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").[81] Upon consummation, Centrica and CPower will become Related Persons and members of the AR Sector's RG Sub-Sector.[82] Comments on the 203 application were due on or before August 3, 2022; none were filed. Doc-less interventions were filed by PJM's IMM and Public Citizen. This matter is pending before the FERC. 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 remains pending before the FERC. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

[78] *N. Am. Elec. Rel. Corp.*, 180 FERC ¶ 61,122 (Aug. 25, 2022).

[79] As previously reported, Public Citizen argued that NERC's Compliance and Certification Committee voting structure is lacking a consumer advocate representative and there is a lack of diversity in the NERC Board of Trustees, both of which it argued contribute to a failure to ensure balanced viewpoints.

[80]

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

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

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

  On August 19, 2022 the FERC authorized the sale of 100% of the equity interests in Applicants, including Generation Group Seat Member Waterside Power, among others,[83] 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")).[84] Pursuant to the *August 19 Order*, notice must be filed within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

  On June 1, 2022, Stonepeak[85] 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").[86] 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. On August 8, 2022, Applicants submitted an informational filing informing the FERC that the Applicants and parties to the Transaction have received all other required regulatory approvals and the FERC's authorization in this proceeding is the only remaining regulatory approval for the Transaction and requested a FERC order authorizing the transaction by August 15, 2022. Notwithstanding Applicants' request, this matter remains pending before the FERC. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

  On July 12, 2022, in response to the requirements of *Order 881*, Versant Power filed a proposed new Attachment T to the Versant Power Open Access Transmission Tariff for the Maine Public District ("MPD OATT"). Attachment T, Versant reported, incorporates all the contents of the *pro forma* OATT's new Attachment M. An effective date of July 12, 2025 was requested in an errata filing submitted on August 1, 2022. On August 2, 2022, MPUC submitted comments asserting that Versant's Compliance Filing, without further detail, is insufficient to meet the requirements of *Order 881* and should either (i) be rejected outright, ordering Versant to re-file with sufficient detail, or (ii) subject to a deficiency letter requiring further information with respect to the Compliance Filing. 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).

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[83] 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.

[84] *Lea Power Partners, LLC*, 180 FERC ¶ 62,086 (Aug. 19, 2022) ("*August 19 Order*").

[85] "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").

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

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

On August 22, 2022, the FERC accepted two Shared Structure Participation Agreements ("ShPA") between VTransco and GMP[87] - the first ShPA relating to the Duxbury 115 kV transmission line (the "Duxbury ShPA"); the second, to the Bennington 115 kV transmission line ("Bennington ShPA"). As previously reported, the ShPAs calculate and allocate costs not recovered though the Tariff. The Duxbury ShPA provides for Shared Use Rent;[88] the Bennington ShPA does not. The ShPAs were accepted effective as of January 1, 2022, as requested. Unless the August 22 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).

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

On August 3 and 4, 2022, the FERC accepted the filings made by Narragansett (ER22-2039) and New England Power (ER22-2038), respectively, that made a part of their respective filed rates the wires-to-wires interconnection agreement ("IA") governing the interconnection of the two companies' transmission systems.[89] The filings were accepted effective as of May 25, 2022, as requested. Unless either of the orders are challenged, this proceeding will be concluded. If you have any questions concerning these filings, 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").[63] 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).

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

In accordance with *Order 864*[90] and *Order 864-A,*[91] 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

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[87] *Vermont Transco LLC*, Docket No. ER22-2189-000 (Aug. 22, 2022) (unpublished letter order).

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

[89] *The Narragansett Elec. Co.*, Docket No. ER22-2039 (Aug. 3, 2022) (unpublished letter order); *New England Power Co.*, Docket No. ER22-2038 (Aug. 4, 2022) (unpublished letter order).

[90] *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.

[91] *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*").

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	Versant Power (BHD Formula Rate)	Aug 12, 2022	Pending

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

♦ ***ER20-2133-003 (Versant Power)***. On August 12, 2022, Versant supplemented its April 12, 2022 *Order 864* compliance filing with further amendments to Attachment P-VP of Schedule 21-VP (the "BHD Formula Rate").

XII. Misc. - Administrative & Rulemaking Proceedings

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

On July 19, 2022, Invenergy Transmission filed a petition requesting that the FERC hold a technical conference to explore ways to potentially make available and compensate certain grid reliability and resilience benefits associated with interregional high voltage direct current ("HVDC") merchant transmission. Any comments to be considered by the FERC in its determination of any action to be taken were due on or before August 26, 2022. Comments were filed by 12 parties and included, among others, CSC, Invenergy, Phase I/II Asset Owners and IRH, Joint Consumer Advocates, ACORE, ACPA, SEIA, and Neptune and Hudson. This matter is pending before the FERC.

- **Reliability Technical Conference (Nov 10) (AD22-10)**

On November 10, 2022, the FERC will convene its annual Commissioner-led technical conference to discuss policy issues related to the reliability of the Bulk-Power System ("BPS"). The conference will be open for the public to attend, and there is no fee for attendance. Supplemental notices will be issued prior to the conference with further details regarding the agenda, how to register, how to participate, and the conference format.

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

The FERC will hold a forum on September 8, 2022 at the DoubleTree by Hilton 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. Since the last Report, the FERC issued On July 21, the FERC issued a supplemental notice of the forum that included an agenda, description of proposed panels and panelist identities.

Planned ISO-NE comments will be discussed at the September 1 meeting and is materials filed in this proceeding by September 2. 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")[92] 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[93] and were filed by: AEP, Clean Energy Entities,[94] 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.[95] 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").[96] The Transmission Task Force is comprised of all FERC Commissioners as well as representatives from 10 state commissions (two from each NARUC region). State commission representatives will serve one-year terms from the date of appointment by FERC and in no event will serve on the Task Force for more than three consecutive terms. The Transmission Task Force will convene multiple formal meetings annually, with FERC issuing orders fixing the time and place and agenda for each meeting, and the meetings will be open to the public for listening and observing and on the record. The Transmission Task Force will focus on "topics related to efficiently and fairly planning and paying for transmission, including transmission to facilitate generator

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

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

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

[95] *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.

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

interconnection, that provides benefits from a federal and state perspective."[97] 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.[98]

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*. A transcript of the meeting was posted in eLibrary on August 11, 2022. The FERC invited post-meeting comments addressing issues raised during and in the agenda for the July 20 meeting. Those comments are due on or before September 2, 2022.

♦ ***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[99] 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; 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

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[97] 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.

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

[99] *Modernizing Wholesale Electricity Market Design*, 179 FERC ¶ 61,029 (Apr. 21, 2022) ("*Order Directing 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[100] and energy and ancillary services markets.[101]

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

On July 28, 2022, the FERC issued a NOPR[102] 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 ***October 11, 2022***.[103]

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

On June 16, 2022, as corrected on July 12, 2022, the FERC issued a notice[104] 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[105] (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

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[100] 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.

[101] 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.

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

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

[104] *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*").

[105] "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".

weather risks). Initial comments were due August 30, 2022[106] and were filed by over 13 parties, including among others, Eversource, NRDC, NERC, MISO, PJM, and EPSA.

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

On June 16, 2022, the FERC issued a notice of proposed rulemaking ("NOPR"),[107] 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.[108]

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;
- 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;[109]
- Implement a commercial readiness framework whereby interconnection customers must show demonstrable milestones towards commercial readiness in order to enter the cluster, such as an

[106] 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.

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

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

[109] 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 interc onnection customer would submit a deposit of $10,000 per MW, subject to a floor of $500,000 and a ceiling of $2 million.

executed term sheet, reasonable evidence the project was selected in a resource plan, or a provisional LGIA;[110] and
- Impose withdrawal penalties when the interconnection customer withdraws from the interconnection queue.[111]

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); and
- 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;
- 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

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[110] *Id.* at P 128.

[111] 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.

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[112] proposing to revise its regulations to permit ISO/RTOs to share among themselves[113] credit-related information regarding market participants.[114] 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 ***October 7, 2022***; reply comments ***November 7, 2022***.[115]

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

On June 16, 2022, the FERC issued a notice[116] 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 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 were due August 26, 2022[117] and were filed by over 37 parties, including, among others, ISO-NE, Eversource, NESCOE, NRDC, UCS, NERC, ERCOT, MISO, NYISO, PJM, ACPA, EPRI, EPSA, NARUC, and Trade Associations. This matter is pending before the FERC.

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

113 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).

114 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.

115 The *ISO/RTO Credit-Related Info Sharing NOPR* was published in the *Fed. Reg.* on Aug. 8, 2022 (Vol. 87, No. 151) pp. 48,118-48,125.

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

117 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.

- **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[118] 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,[119] 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[120] proposing to direct NERC to develop and submit for FERC approval new or modified Reliability Standards that require internal network security monitoring ("INSM")[121] 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."[122]

Comments on the *Internal Network Security Monitoring NOPR* were due on or before March 28, 2022.[123] 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, 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[124] seeking comments on reactive power capability compensation and market design. Specifically, the FERC seeks comments on whether (i) the AEP

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[118] *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*").

[119] "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").

[120] *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*").

[121] 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 trust worthy but could still introduce a cybersecurity risk to a high or medium impact BES Cyber System.

[122] *Id.* at P 2.

[123] 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.

[124] *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*").

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,[125] MISO TOs, PJM IMM, PSEG, Vistra, and N. Bhushan. This matter is pending before the FERC.

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

Following its ANOPR process,[126] the FERC issued on April 21, 2022 a NOPR[127] 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

(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

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[125] "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").

[126] *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.

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

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*.

Comments. Following a number of requests for extensions of time, comments on the *Transmission NOPR* were due August 17, 2022.[128] Nearly 200 sets of comments were filed, including by NEPOOL , ISO-NE, Acadia/CLF, Anbaric, AEE, Avangrid, BP, Dominion, Enel, Engie, Eversource, Invenergy, LSP Power, MOPA, MMWEC/CMEEC/NHEC/VPPSA, National Grid, NECOES, NESCOE, NextEra, NRG, Onward Energy, Orsted, PPL, Shell, Transource, VELCO, Vistra, ISO/RTO Council, NERC, US DOJ/FTC, MA AG, State Agencies, VT PUC/DPS, Potomac Economics, ACPA, ACRE, APPA, EEI, EPSA, Industrial Customer Organizations, LPPC, NASUCA, NRECA, Public Interest Organizations, SEIA, TAPS, WIRES, Harvard Electricity Law Initiative, New England for Offshore Wind, and the R Street Institute.

Reply Comments. Reply comments are due ***September 19, 2022***.

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[129] 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. In July, Voltus again submitted comments in support of eliminating the DR Opt-Out, with responses to those comments filed by the Mississippi PSC and R. 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.

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

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

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

On July 28, 2022, the FERC issued a NOPR[130] 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]***.[131]

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

On December 17, 2020, the FERC issued a NOPR[132] 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.,[133] 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[134] 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.

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

Supplemental NOPR. In light of comments already received in this proceeding,[135] the FERC issued on April 15, 2021 a *Supplemental NOPR*[136] 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*.[137]

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

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

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

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

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

[135] 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.

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

[137] 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.

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.[138] Reply comments were also posted from New England State Parties,[139] 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[140] 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,[141] EDF Renewables, EEI, the Industrial Energy Consumers of America ("IECA"), National Grid, PJM IMM, TAPS.

- ***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 and 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.

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

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

[140] 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).

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

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

- **CPower (IN22-7)**

  On August 25, 2022, the FERC approved a Stipulation and Consent Agreement with Enerwise Global Technologies, LLC d/b/a CPower ("CPower")[142] that resolved OE's investigation into whether CPower complied with its offer obligations in the Energy Market during the June 1, 2018 through February 28, 2019 period (the "Period"). Specifically, OE concluded that CPower violated Market Rule 1 § III.13.6.1.5.1 (Energy Market Offer Requirements) during the Period by failing to submit Demand Reduction Offers for certain Demand Response Resources at a value equal to or greater than its Active Demand Capacity Resources' CSOs.[143] Under the Settlement, in which CPower neither admits nor denies the alleged violations, CPower agreed to ***disgorge $2,460,628***, to ***pay a civil penalty of $2,539,372*** to the United States Treasury, and to submit one annual compliance monitoring report, with the requirement of a second annual report at OE's option. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

On June 27, 2022, the FERC approved a Stipulation and Consent Agreement with Salem Harbor Power Development LP ("Salem Harbor")[144] 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.[145] 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 Bankruptcy Court in Salem Harbor's ongoing Chapter 11 Cases, Salem Harbor must ***disgorge $26.7 million***,[146] and ***pay a $17.1 million civil penalty*** to the United States Treasury.[147] If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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[142] *Enerwise Global Technologies, LLC d/b/a CPower*, 180 FERC ¶ 61,126 (Aug. 25, 2022).

[143] OE determined that CPower's Demand Reduction Offers were deficient because it failed to enroll sufficient capacity by the start of the delivery month to meet its offer obligation. Because CPower maintained CSOs in excess of its Demand Reduction Offers, rather than entering into transactions to bring its CSOs in line with its Demand Reduction Offers, CPower earned excess monthly capa city revenues.

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

[145] 18 CFR § 35.41(b) (2022).

[146] 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.

[147] 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

- **PacifiCorp (IN21-6)**

On April 15, 2021, in the FERC's first-ever Show Cause Order addressing alleged violations of NERC Reliability Standards,[148] 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).

Natural Gas-Related Enforcement Actions

- **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.[149]

As previously reported, on March 18, 2021, the FERC issued a show cause order[150] 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).[151] The FERC directed Respondents to show cause why they should not be assessed civil penalties in

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.

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

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

[150] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 174 FERC ¶ 61,208 (Mar. 18, 2021) ("*Rover/ETP CPCN Show Cause Order*").

[151] 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,

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, 2021.

Procedural Schedule Suspended. As previously reported, ALJ Joel DeJesus will be the presiding judge for hearings in this matter. On May 24, 2022, the Honorable Judge Karen Gren Scholer of the U.S. District Court for the Northern District of Texas issued an order staying this proceeding. Consistent with that order and out of an abundance of caution, Judge DeJesus suspended the procedural schedule until such time as the Court's stay is lifted and the parties provide jointly a proposed amended procedural schedule.

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

On December 16, 2021, the FERC issued a show cause order[152] 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,[153] 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;[154] (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.[155] This matter is pending before the FERC.

- **BP (IN13-15)**

On December 17, 2020, the FERC issued *Opinion 549-A*,[156] a 159-page decision addressing arguments raised on rehearing requested of *Opinion 549.*[157] *Opinion 549-A* modifies the discussion in *Opinion 549*, but

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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.

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

153 *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").

154 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.

155 *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.

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

157 *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*")).

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.[158] 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.[159]

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 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[160] 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.[161]

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.[162] On July 27, Chief Judge Cintron designated Judge Suzanne Krolikowski as the Presiding ALJ and established an extended Track III Schedule[163] for the proceeding.

[158] *BP Penalties Allegheny Order* at P 1.

[159] *Id*. at P 319.

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

[161] 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 uneconom ic 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.

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

[163] 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.

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 interlocutory appeal, Judge Krolikowski denied Respondents' Reconsideration Motion. Respondents May 2, 2022 interlocutory appeal was denied on May 9, 2022.[164]

Since the last Report, highlights from the procedural activity in this proceeding have included continuing discovery and an extension of the hearing commencement date and the initial decision deadline, which have been extended to ***January 23, 2023*** and ***July 10, 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.[165] 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.

[164] Notice of Determination by the Chairman, *Total Gas & Power North America, Inc. et al.*, Docket No. IN12-17 (May 9, 2022).

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

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, 2019, the FERC denied the NY DEC and Sierra Club requests for rehearing.[166] 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*.[167] 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,[168] 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.[169] 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.[170] 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.

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[166] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 167 FERC ¶ 61,007 (Apr. 2, 2019).

[167] *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).

[168] 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).

[169] *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*").

[170] *Nat'l Fuel Gas Supply Corp. v. NYSDEC et al*. (2d Cir., Case No. 17-1164).

- On August 8, 2019, the NY DEC again denied Applicants request for a Water Quality Certification, and as directed by the Second Circuit,[171] 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, even if the NY DEC and Sierra Club prevail in their currently pending court petitions challenging the basis for the Commission's Waiver Order.[172]
- 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, [173] 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.[174]
- 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.[175]
- A request for rehearing of the *Northern Access Project Add'l Extension Order* was denied by operation of law.[176]

XV. State Proceedings & Federal Legislative Proceedings

[171] 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).

[172] *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).

[173] *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 173 FERC ¶ 61,197 (Dec. 1, 2020).

[174] *Id.* at P 10.

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

[176] *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 180 FERC ¶ 62,099 (Aug. 30, 2022).

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

On August 30, 2022, the Maine Supreme Judicial Court concluded that the legislation enacted as a result of the passage of Maine's November 2, 2021 ballot question,[177] and that effectively halted construction of the NECEC Project,[178] was unconstitutional to the extent it required the legislation to be applied retroactively to the certificate of public convenience and necessity ("CPCN") issued for the Project if NECEC had acquired vested rights to proceed with Project construction (by undertaking substantial construction consistent with and in good-faith reliance on the CPCN before the Initiative was enacted). The Court remanded to the Business and Consumer Docket the factual question of whether NECEC performed substantial construction in good faith according to a schedule that was not created or expedited for the purpose of generating a vested rights claim (which it suggested appeared to be the case from the limited record developed in connection with the request for preliminary injunctive relief in this matter).

- **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/).

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.

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

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

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).

- **Mystic III (*True-Up Orders*) (22-1215)**
  Underlying FERC Proceeding: EL18-1639-000,[179] -017[180]
  Petitioner: Mystic
  Status: Consolidated with Mystic ROE (21-1198 et al.)

On August 22, 2022, Mystic petitioned the DC Circuit Court of Appeals for review of the FERC's orders addressing its filing providing 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").[181] On August 25, 2022, the Court issued an order consolidating this proceeding with the Mystic ROE cases in Case Nos. 21-1198 et al. Mystic was further directed to file a docketing statement and statement of issues to be raised on or before ***September 26, 2022***. Reporting on this matter will continue under the Mystic ROE appeal summary (Case Nos. 21-1198 et al. (see below)).

- ***2nd Revised Narragansett LSA Orders* (22-1161, 22-1108) (consolidated)**
  Underlying FERC *Proceeding*: ER22-707[182]
  Petitioner: Green Development
  Status: Initial Submissions Submitted; Revised Briefing Scheduled Established

On June 15, 2022, Green Development petitioned the DC Circuit for review of the FERC's *2nd Revised Narragansett LSA Orders*.[183] 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 filed, on August 15, 2022, a Statement of Issues and Docketing Statement. On August 30, 2022, the Court established a revised briefing schedule that calls for the following: Petitioner's Brief (October 11, 2022); Respondent's Brief (December 12, 2022); Intervenor for Respondent's Brief (December 19, 2022); Petitioner's Reply Brief (January 9, 2023); Deferred Appendix (January 17, 2023); and Final

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

180 *Constellation Mystic Power, LLC*, 179 FERC ¶ 62,179 (June 27, 2022) ("*June 27 Notice*") (Notice of Denial By Operation of Law of Rehearings of *Mystic First CapEx Info. Filing Order*).

181 The FERC appealed from granted in part, and denied in part, ENECOS' and NESCOE's formal challenges to Mystic's First CapEx Projects Info. Filing, subject to refund, and established hearing and settlement judge procedures.

182 *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*".

183 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.

Briefs (January 31, 2023). New England Power Company's August 10, 2022 motion for leave to intervene was granted on August 29, 2022.

- **Mystic II (ROE & True-Up)**
  (21-1198; 21-1222, 21-1223, 21-1224, 22-1001, 22-1008, 22-1026, 22-1215) (consolidated)
  Underlying FERC Proceeding: EL18-1639-010, -011,[184] -013[185] -017[186]
  Petitioners: Mystic, CT Parties,[187] MA AG, ENECOS
  Status: Abeyance Ended; Motions to Govern Future Proceedings Due Sep 8, 2022

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.

As previously reported, on July 8, 2022, Connecticut Parties and ENECOS jointly moved to hold these proceedings in abeyance until 30 days after the DC Circuit 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*). Although Constellation opposed the abeyance request, the Court granted the abeyance request on July 27, 2022, directing the Parties to file motions to govern future proceedings within 30 days of the court's disposition of *MISO TOs*.

Since the last Report, on August 9, 2022, the Court decided *MISO TOs*, and ordered the parties to file motions to govern future proceedings in this case by September 8, 2022. In addition, On August 25, 2022, the Court consolidated Mystic III (Case No. 22-1215) with these cases, Case No. 21-1198 continuing as the lead case.

- **Mystic I (Original Cost Test, Capital Structure, Everett Cost Recovery, Clawback, True-Up Mechanism)**
  (20-1343; 20-1361, 20-1362; 20-1365, 20-1368; 21-1067; 21-1070)(consolidated)
  Underlying FERC Proceeding: EL18-1639[188]
  Petitioners: Mystic (20-1343), NESCOE (20-1361, 21-1067), MA AG (20-1362), CT Parties (20-1365, 20-1368, 21-1070)
  Status: Court Issues Decision

As previously reported, Mystic, NESCOE, MA AG, and CT Parties separately petitioned the DC Circuit Court of Appeals for review of the FERC's orders addressing the COS Agreement among Mystic, Constellation and ISO-

[184] *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).

[185] *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).

[186] *Constellation Mystic Power, LLC*, 179 FERC ¶ 61,011 (Apr. 28, 2022) ("*Mystic First CapEx Info. Filing Order*"); *Constellation Mystic Power, LLC*, 179 FERC ¶ 62,179 (June 27, 2022) ("*June 27 Notice*") (Notice of Denial By Operation of Law of Rehearings of *Mystic First CapEx Info. Filing Order*).

[187] 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").

[188] *July 2018 Order*; *July 2018 Rehearing Order*; *Dec 2018 Order*; *Dec 2018 Rehearing Order; Jul 17 Compliance Order*.

NE.[189] The cases were consolidated into Case No. 20-1343. Following briefing, oral argument was held on May 5, 2022 before Judges Srinivasan, Henderson and Rao.

On August 23, 2022, the Court issued its decision holding that:

- Mystic's petition for review be dismissed in part and denied in part;
- State Petitioners' petitions for review on the cost allocation issue be granted;
- the clawback portions excluding Everett costs and the challenged delay provision of the orders under review be vacated; and
- the cases be remanded for the FERC to address NESCOE's request for clarification about revenue credits and for clarification of the apparent contradictions in the FERC's December 2020 Rehearing Order.

The Court ordered that issuance of the mandate be withheld until seven days after disposition of any timely petition for rehearing or petition for rehearing en banc.

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  Underlying FERC Proceeding: ER18-619[190]
  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[191]
  Petitioners: TOs' (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[192] 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*[193] 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

[189] 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.

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

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

[192] 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.

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

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

On May 4, 2021, the Court ordered that this case remain in abeyance pending further order of the Court, directing the FERC to file a status report by September 1, 2021 and at 120-day intervals thereafter. The parties were directed to file motions to govern future proceedings in this case within 30 days of the completion of agency proceedings. The FERC's last status report, indicating that the proceedings before the Commission remain ongoing and that this appeal should continue to remain in abeyance, was filed on August 11, 2022. The next status report is due on or before ***December 9, 2022***.

- **ISO-NE's Inventoried Energy Program ("IEP") Proposal (19-1224***; 19-1247; 19-1252; 19-1253)(consolidated); Underlying FERC Proceeding: ER19-1428**[194]
  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[195] leaving intact the FERC's June 2020 *IEP Remand Order*[196] ***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. Since the last Report, On August 9, 2022, the Court issued the mandate to the FERC, putting the matter back in the FERC's hands consistent with the June 17, 2022 decision. Reporting on this matter will return to Section III in future Reports.

[194] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

[195] *Belmont Mun. Light Dept., et al., v. FERC*, 2022 WL 2182810 (June 17, 2022).

[196] *ISO New England Inc.*, 171 FERC ¶ 61,235 (June 18, 2020) ("*IEP Remand Order*").

Other Federal Court Activity of Interest

- ***Order 872*** **(20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[197]
  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*.[198] Briefing is complete and oral argument was held March 8, 2022 before Judges Nguyen, Miller and Bumatay. This matter is pending before the Court.

- **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[199]
  Petitioners: MISO TOs, Transource Energy, Dec 23 Petitioners et al.
  Status: Decision Issued on August 9, 2022

The MISO TOs, Transource and "Dec 23 Petitioners",[200] among others, appealed *Opinion 569/569-A*. The MISO TOs' case was 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.

On August 9, 2022, the Court issued its decision granting customers' petitions for review, dismissing transmission owners' petitions for review, vacating the underlying FERC orders, and remanding the cases to the FERC to reopen proceedings. In reaching its decision, the Court found that the "FERC failed to offer a reasoned explanation for its decision to reintroduce the risk-premium model [ ] after initially, and forcefully, rejecting it. Because FERC adopted that significant portion of its model in an arbitrary and capricious fashion, the new [ROE] produced by that model cannot stand. We therefore vacate FERC's orders." Because the Court ordered the FERC to vacate its prior rate orders, it dismissed the remaining surviving challenges (e.g. refund and authority issues), which can be resolved in and following the FERC proceedings that will ensue following this remand. Of course, this decision and those proceedings to follow are expected to impact multiple proceedings in which the FERC this now-vacated ROE methodology, including the Mystic ROE proceeding pending before the DC Circuit and the New England ROE cases that are pending before the FERC and from which the ROE issue originated.

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197 *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).

198 *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.

199 *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).

200 "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; Cooperati ve 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.

- **Algonquin Atlantic Bridge Project Orders (21-1115*, 21-1138, 21-1153, 21-1155 consol.) and (22-1146, 22-1147 consol.)**
  Underlying FERC Proceeding: CP16-9-012[201]
  Petitioners: LS Power, Algonquin, INGA
  Status: Cases 22-1146/47 Deconsolidated and Briefing Schedule Set; Remaining Cases (21-1115 et al.) Being Held 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).

On August 16, 2022, the Court deconsolidated 22-1146 and 22-1147 from 21-1115 et al., which is to remain in abeyance pending a further order of the Court. The Court consolidated Cases 22-1146 and 22-1147 together and issued a briefing schedule that calls for Joint Brief of Petitioners by October 28, 2022; Respondent Brief by January 12, 2023, Joint Brief of Intervenors by January 26, 2023, Joint Reply Brief of Petitioners by February 16, 2023, Deferred Joint Appendix by March 2, 2023, and Final Briefs by March 9, 2023. The date of oral argument and the composition of the merits panel will be provided at a later date.

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

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