NEPOOL
NEW ENGLAND POWER POOL

David T. Doot
Secretary

October 27, 2021

VIA ELECTRONIC MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of November 3, 2021 NEPOOL Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the November meeting of the Participants Committee will be held **in person on *Wednesday*, November 3, 2021, at the Hilton Boston Logan Airport Hotel, One Hotel Drive, Boston, MA in the International Ballroom following individual, modified Sector meetings with the ISO Board that begin for two Sectors at 9:00 a.m. and are scheduled to continue through 1:45 p.m.** (A schedule of those planned Sector meetings is included with this notice.). We expect that the Participants Committee meeting will begin at **2:00 p.m.** following those Sector meetings for the purposes set forth on the attached agenda and that has also been posted with the meeting materials at nepool.com/meetings/.

For your information, the November 3 Participants Committee 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 in attendance or participating, either in person or by phone, are required to identify themselves and their affiliation at the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.

We have included with this notice the safety protocols that will be in effect for in-person attendance at the November 3 Participants Committee meeting. In summary, only those who are fully vaccinated, and have provided in advance of the meeting verification of full vaccination, will be permitted to attend in person. Pursuant to the City of Boston's mask mandate, all attendees must wear masks or face coverings at all times during an indoor meeting except when actively eating or drinking. Additional safety measures are outlined in the protocols. An e-mail with instructions for meeting registration will be sent under separate cover.

As with any in-person meeting, there will be COVID-related risks associated with in-person attendance at the November 3 Participants Committee meeting, but there are also substantial benefits from being together in-person. Efforts have been made to reduce the risks and to ensure that no unvaccinated people attend the meeting, but each of you will need to perform your own risk/benefit calculus in deciding whether to participate remotely or in-person. We look forward to seeing those who decide to attend in person as your elected officers work to maximize the value and benefit of the stakeholder process in the region.

For those who otherwise attend NEPOOL meetings but plan to participate in the November 3 meeting virtually, please use the following dial-in information: **866-803-2146; Passcode: 7169224.** To join using WebEx, click this link and enter the event password **nepool**. Please note that the Sector meetings with the Board will be in person. We are working to provide an opportunity for those who cannot join the Board panel and their fellow constituents in person to at least listen, if not participate in the discussion, by phone. Please note, though, that such telephonic participation may be challenged by technology (the equipment that has been used for virtual meetings in the past is unavailable since it will be set up for the full Participants Committee meeting later that day). We will circulate additional Sector-specific information as it becomes available.

There are a limited number of rooms available at the Hilton Logan Airport Hotel for the evening before the November 3 meeting. If you wish to take advantage of the arrangements that have been made, please contact Kathryn Dube (kdube@daypitney.com) to confirm availability and secure a room.

Looking forward, please make sure that your calendars reflect the upcoming NEPOOL Annual Meeting, which will be on Thursday, December 2, 2021 at the Colonnade Hotel in Boston. A holiday breakfast is planned to begin at 9:00 a.m.

Stay safe - stay well.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the draft minutes of the October 7, 2021 Participants Committee meeting. The draft preliminary minutes of that meeting are included with this supplemental notice and posted with the meeting materials. Please provide us with any comments on the draft minutes no later than **noon, Monday, November 1, 2021**.

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

3. To receive an ISO Chief Executive Officer report. The November CEO report will be circulated and posted in advance of the meeting.

4. To receive a report from the ISO Chief Operating Officer on the following:
   a. Operations Report Highlights.
   b. Operational Impact of Extreme Weather Events

   The November COO Report (4.a) will be circulated and posted in advance of the meeting. A presentation on the operational impact of extreme weather events deferred from the October 7 meeting (4.b) is included with this supplemental notice and posted with the meeting materials.

4A. To consider and take action, as appropriate, on a Participant-sponsored proposal to revise Schedule 11 of Section II of the ISO-NE Tariff so that annual costs associated with Distribution Upgrades, Stand Alone Network Upgrades and Network Upgrades would no longer be allocated to Interconnection Customers, but instead would be recovered from Transmission Customers. Background materials and a draft resolution are included with this supplemental notice and posted with the meeting materials.

5. 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.

6. To receive reports from Committees, Subcommittees and other working groups:
   - Markets Committee
   - Reliability Committee
   - Transmission Committee
   - Budget & Finance Subcommittee
   - Others

7. Administrative matters.

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

NEPOOL PARTICIPANTS COMMITTEE
NOVEMBER 2021 SECTOR/GROUP MEETING SCHEDULE**
v. 2021.10.27

No tie zone: We understand that the ISO Board has adopted a "jackets/no ties" policy for its meetings this November and pass along this information as requested should it happen to influence or inform any attire decision(s) for the meetings.

SECTOR/GROUP	ISO Board Panel 1	ISO Board Panel 2	State Officials
Generation / Long		**Wed, Nov 3** 12:30 – 1:45 p.m. ***(New England Ballroom)***	**TBD**
Transmission	**Wed, Nov 3** 9:00 – 10:15 a.m. ***(Hampshire Room)***		**TBD**
Supplier / Short (LSE)	**Wed, Nov 3** 10:35 – 11:50 a.m. ***(Hampshire Room)***		**TBD**
Publicly Owned Entity	**Wed, Nov 3** 12:30 – 1:45 p.m. ***(Hampshire Room)***		**TBD**
AR		**Wed, Nov 3** 9:00 – 10:15 a.m. ***(New England Ballroom)***	**TBD**
End User		**Wed, Nov 3** 10:35 – 11:50 a.m. ***(New England Ballroom)***	**TBD**

ISO Board Panel 1: Brook Colangelo, Mike Curran, Catherine Flax, Cheryl LaFleur, and Gordon van Welie.

ISO Board Panel 2: Steve Corneli, Roberto Denis, Barney Rush, Mark Vannoy, and Vickie VanZandt.

State Officials: [TBD per session].

**** Subject to change**

eff. September 22, 2021

NEPOOL
NEW ENGLAND POWER POOL

Protocols for In-Person Attendance at NEPOOL Meetings
During the Covid-19 Pandemic

These protocols for return to in-person NEPOOL meetings are effective as of the date above and may be modified from time to time as guidelines from the U.S. Centers for Disease Control ("CDC"), applicable state or local requirements, or circumstances change.

Background

The Protocols provided herein outline recommended and preventative measures to reduce the COVID-related risks associated with attendance in person at NEPOOL meetings.[1] Measures include safety precautions individuals must take while at in-person meetings. In-person attendance will follow and adhere to the latest CDC guidelines (as well as any additional, applicable state or local requirements that may be in place). As with any in-person meeting, there will be COVID-related risks associated with in-person attendance. **Each in-person attendee should perform their own risk/benefit calculus in deciding whether to participate in-person or remotely.**

Safety Precautions

Proof of Full Vaccination Required. To attend a NEPOOL meeting in person, each attendee must be fully vaccinated.[2] Proof of vaccination (e.g., a copy of a completed COVID-19 Vaccination Record/Card) must be provided to NEPOOL counsel (pmgerity@daypitney.com) in advance of the meeting.[3] An attendee who is unable to provide a copy of a completed COVID-19 Vaccination Record may sign and provide a COVID-19 Vaccination Status Attestation as an alternate form of proof. All such records will be maintained by NEPOOL Counsel in a confidential file. Those who are not vaccinated, or who have not timely provided proof of vaccination, will not be permitted in the meeting room and will be encouraged to participate by teleconference/WebEx. An individual's ability to attend a meeting in person will be restored following proof of vaccination.

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[1] 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 in attendance or participating, either in person or by phone, are required to identify themselves and their affiliation at the meeting.

[2] A person is considered fully vaccinated: (i) 2 weeks after their second dose in a 2-dose series, such as the Pfizer or Moderna vaccines, or (ii) 2 weeks after a single-dose vaccine, such as Johnson & Johnson's Janssen vaccine. If you don't meet either of these criteria, regardless of age, you are NOT fully vaccinated.

[3] Proof of vaccination of ISO employees or representatives, as a condition of their in-person attendance, will be confidentially (i) collected and maintained by the ISO and (ii) verified by an ISO committee officer with NEPOOL counsel in advance of attendance at a meeting.

eff. September 22, 2021

Registration Required; Contact Tracing. Registration for in-person attendance will be required and the Committee Secretary will keep a separate record of all individuals in attendance in person for the purpose of later contact tracing. Specific contact tracing information is confidential and NEPOOL will not use this information for any other reason. Contact tracing information will be kept for 28 days and destroyed thereafter.

Attendance In-Person Not Permitted if Experiencing Covid-19 Indicative Symptoms. Individuals should not attend an in-person meeting if they are experiencing new or worsening symptoms of any of the following in the last 14 days:

- Fever of 100.4 ^{0}F (38.0 ^{0}C) or higher
- Chills
- Cough
- Shortness of breath or difficulty breathing
- Fatigue
- Muscle or body aches
- Headache
- New Loss of Taste or Smell
- Sore Throat
- Congestion or runny nose
- Nausea or vomiting
- Diarrhea

Attendance In-Person Not Permitted if Recent Exposure to Covid-19-Positive Individual. Individuals should not attend in-person meetings if they have had a likely exposure to a COVID-19 positive individual in the last 14 days.

Physical Distancing. The opportunity for physical distancing at meeting tables will be provided where and as possible, but will not be enforced. Attendees are encouraged, whenever otherwise possible, to separate themselves by 6 feet of distance. Seating at round tables should be limited to six or fewer.

Masks. If and as required by CDC guidelines or by the requirements of the state or locale in which the meeting is taking place, face coverings ("masks") shall be worn. Where physical distancing cannot be maintained, it is recommended that attendees wear masks whenever they are not seated, including while in transit to or from their seat and while standing in lines or in the room.

Sanitizing. Hand sanitizer and wipes will be made available at each meeting. Additional arrangements will be implemented to facilitate sanitation measures. (e.g. All microphones will be positioned and sanitized prior to arrival. Microphones will also be sanitized at lunch and at the end of the day. Alcohol sanitizing wipes will be available for attendees to utilize during the meeting to sanitize the microphones between users.)

eff. September 22, 2021

Reporting and Communicating a Positive COVID-19 Result

In the event of a COVID-19-positive test result, an individual that attended an in-person meeting within 14 days of that result should immediately contact NEPOOL Counsel (pmgerity@daypitney.com) to report their COVID-19 status. NEPOOL Counsel will maintain the individual's privacy while notifying those that attended the meeting in person of the positive test result. Please be advised that all health information is private and strictly confidential and will only be shared on a need-to-know basis to confirm and trace any contact with the positive tester at a NEPOOL in-person meeting and contact those who may have been exposed. Any notice of a COVID-19-positive test result will be kept for 28 days and destroyed thereafter.

Remote Participation

For those individuals who are otherwise authorized to attend a NEPOOL meeting, but choose not to, or because of safety measures are unable to, attend meetings in person, remote participation (i.e. by teleconference and/or by WebEx) will continue to be made available.

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held via teleconference beginning at 10:00 a.m. on Thursday, October 7, 2021. 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 teleconference meeting.

Mr. David Cavanaugh, Chair, presided, and Mr. David Doot, Secretary, recorded. Mr. Cavanaugh welcomed members to the first in-person NEPOOL committee meeting in more than a year and a half. He thanked members for their resiliency and patience during that period and looked forward to reclaiming the many important benefits of being around the table and interacting together in person. He committed that the full return to in-person NEPOOL meetings would be accomplished in a way that, to the maximum extent possible, prioritizes members' safety and takes into account evolving circumstances, noting the protocols for in-person meeting attendance that had been developed for that purpose and were in effect. He acknowledged that there would surely be additional challenges to face, but hoped to build upon the experiences of this meeting as NEPOOL works towards a full return to in-person meetings.

APPROVAL OF SEPTEMBER 2, 2021 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the September 2, 2021 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of that meeting were unanimously approved as circulated, with an abstention by Mr. Michael Kuser's alternate noted.

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 approved as circulated, with oppositions noted by Calpine, CSC and LIPA, and abstentions noted by Brookfield, Dynegy, FirstLight, Great River Hydro, Nautilus, PSEG, Wheelabrator, and Mr. Kuser's alternate. Calpine explained that it opposed the Consent Agenda Item concerning the FCA16 HQICC and ICR and Related Values because, in its view, a Control Area, such as New England, should not be counting on non-firm external energy from neighboring Control Areas. CSC and LIPA both explained their opposition to those Values in light of the continuing treatment of the Cross Sound Cable as having zero reliability benefits in the ISO's calculation of tie benefits. With the exception of Brookfield and Mr. Kuser's alternate, abstentions on the Consent Agenda were attributed to the FCA16 HQICC and ICR and Related Values, most for reasons similar to those expressed by Calpine's representative. The Brookfield representative explained that Participant's abstention, which related specifically to a concern that the changes to OP-21 (Generator Winter Readiness Survey Question Revisions) should be accompanied by mechanisms or requirements to make the process more efficient for Participants with multiple, particularly smaller, resources.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the presentation regarding the ISO's response to the New England States' Vision Statement and Advancing the Vision Report and provided a brief summary. He then highlighted the work the ISO had done in response to NESCOE's report as outlined in the presentation. Members who commented noted with appreciation how the Board responded to the request for increased transparency. They explained that open Board meetings of other RTOs were not particularly informative, with most business being conducted in executive sessions. In contrast, the ISO-NE Board met at least twice annually with the States and all Sectors, and those meetings were highly informative and productive. In response to a request that Mr. van Welie clarify the Board's intent at its planned annual open Board meeting, he explained that the ISO intended to alternate the focus each year between markets and planning. He further noted that questions/feedback from Participants would be incorporated into the annual meeting process.

ISO COO REPORT

Operations Highlights

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by referring the Committee to his October report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through September 29, 2021, unless otherwise noted. The report highlighted: (i) Energy Market value for September 2021 was \$497 million, down \$188 million from the updated August 2021 value of \$685 million and up \$290 million from September 2020; (ii) September 2021 average natural gas prices were 12% higher than August average prices; (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for September (\$46.48/MWh) were 5% lower than August averages; (iv) average September 2021 natural gas prices and Real-Time Hub LMPs over the period were up 206% and 134%, respectively, from September 2020 average prices; (v) average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 99.9% during September (down from 100.5% in August), with the minimum value for the month (92.7%) on September 1; and (vi) Daily Net Commitment Period Compensation (NCPC) payments for September totaled \$1.3 million, which was down \$2.0 million from August 2021 and down \$1.1 million from

September 2020. September NCPC payments, which were 0.3% of total Energy Market value, were comprised of: (a) $1.3 million in first contingency payments (down $0.5 million from August, (b) $5,000 in second contingency, and (c) $3,000 in voltage and distribution payments.

Dr. Chadalavada noted that FCA16 intends to model the same zones as FCA15. He additionally noted that summaries of the substitution auction demand bids and permanent and retirement de-list bids were revised and reposted to reflect de-list withdrawals made after the IMM reissued its determinations based on the FERC-accepted CONE, Net CONE and Capacity Performance Payment Rate values for FCA16.

Turning to the evaluation of the upcoming Winter, Dr. Chadalavada provided an overview on the seasonal planning and data gathering the ISO was currently undertaking. He began by providing the following key points: (i) liquefied natural gas (LNG) prices globally were at $40 in Europe and Asia compared to $23 at Algonquin; (ii) energy consumption during weather extremes had increased because of the shift in societal behaviors as a result of COVID; (iii) domestic gas storage levels were 10% below the prior year at the same time and coal supplies were at the lowest levels in last decade, suggesting a potential increase in the reliance on and price of oil; (iv) as of the week before, usable fuel oil in New England was at 51% of total tank storage capacity, which was a 7% decrease from the same time the prior year; and (v) the weekly supply of light oil to New England was down and at its lowest level in the last five years. He noted the ISO's plan to continuously evaluate this information and adjust its predictions and study data for New England, with refined data to be provided at the November meeting.

In response to a comment about how information updates would be disseminated to stakeholders, Dr. Chadalavada confirmed that the information would be updated and shared monthly. Additionally, the ISO would provide *ad hoc* updates as needed. Further, when asked about the frequency of the updates received by the ISO, Dr. Chadalavada confirmed that weekly data profiles were received from asset owners and oil farms and tanks. He noted New England's reliance on LNG as a swing fuel on cold days, as well as the light subscription to pipeline gas and the increased demand that can only be served by LNG. Absent global price convergence, discretionary LNG deliveries to New England were unlikely. The ISO planned to continue to monitor this information closely and noted that, given the uncertain range of conditions both through demand and constraints, they would continue to study the trend line. For planning purposes, assumptions would be based on worst case conditions and they would share the range of conditions they intend to study. He went on to note two very important improvements. The first, OP-21, was an improved tool which would reflect the latest daily conditions and would provide a 21-day rolling advance notice assessment. The second was the incorporation of opportunity cost as a factor in energy offers. When asked whether the reduction of truck and barge deliveries may impact supply, Dr. Chadalavada acknowledged the concern, noting limited available data and the need to head into winter in the best position possible. In response to a question about ongoing reporting, Dr. Chadalavada confirmed that the ISO would utilize OP-21 for operational scenarios and they would highlight impacts with same the structural reporting as in the past.

Draft 2022 Work Plan

Turning to the annual work plan, Dr. Chadalavada highlighted the anchor projects, encompassing operations and planning improvements for the Future Grid and transmission planning, as outlined in the presentation that was circulated and posted in advance of the meeting. He noted that, as in years past, unanticipated projects would impact the timely completion of work outlined in the plan. Dr. Chadalavada then provided forewarning of the

ISO's intent to decouple certain aspects of the Day-Ahead Ancillary Services from future Forward Capacity Auctions (FCAs). When asked to clarify the intended decoupling and the associated timeline of Ancillary Service changes from future FCAs, Dr. Chadalavada explained that a mid-2023 filing of Ancillary Service changes would include a request for late 2024 implementation, rather than waiting until the Capacity Commitment Period coupled with the FCA held in 2024. In response to a question about resource capacity accreditation, he indicated that the ISO planned a phased approach, with phase-in achieved by technology class. The first change would be targeted for inclusion in FCA18. Part one would be supply side focused; part two, demand side focused. He further noted that market efficiency and reliability impacts would drive resource category identification and the review of different technology types. When asked why a single implementation with uniform treatment was not being instituted, he noted the tradeoffs and pressures within the market and the broader understanding of certain technology types. Some participants encouraged the ISO to relook at how they planned to proceed, especially with the use of outside expert consultants to assist in expediting these improvements.

Dr. Chadalavada indicated in response to a question that the ISO was working to plan future discussions on potential changes to Pay for Performance (PFP) and will provide further comment on this topic in the future. Participants provided additional feedback noting the importance of inclusion of PFP in the work plan. Dr. Chadalavada explained that the work plan was being continuously evaluated to consider and address the uncertainties that may impact it in the future, all of which will be shared in the midyear update. Dr. Chadalavada then confirmed the intent to do another impact analysis in regard to the day-ahead ancillary services improvements and asked for feedback and assistance from stakeholders.

2022 ISO AND NESCOE BUDGETS

Mr. Tom Kaslow, Budget & Finance Subcommittee (B&F) Chair, referred the Committee to the materials circulated and posted in advance of the meeting related to the proposed 2022 ISO Operating and Capital Budgets (ISO Budgets) and the 2022 NESCOE Budget. Mr. Kaslow provided an overview of the process by which the budgets had been disseminated and reviewed, noting that usual stakeholder review had been completed.

The Committee considered and unanimously approved in a single vote the following two motions, with abstentions recorded on the ISO Budgets by the representative of Littleton (NH) Water & Light and the Vermont Electric Cooperative and on both motions by Mr. Kuser's alternate:

> RESOLVED, that the Participants Committee supports the Year 2022 ISO operating budget and capital budget proposed by the ISO, as presented at this meeting.
>
> RESOLVED, that the Participants Committee supports the 2022 NESCOE budget, as proposed by NESCOE at this meeting, as the Year 2022 operating budget for NESCOE.

REMOVAL OF THE NOTARIZATION REQUIREMENTS FROM SECTIONS II.A.2 AND II.A.3 OF THE FINANCIAL ASSURANCE POLICY

Mr. Kaslow then referred the Committee to the materials circulated and posted in advance of the meeting related to the removal of the notarization requirement for certain documents provided under the ISO New England Financial Assurance Policy (FAP) as included and summarized in the meeting materials. The ISO planned to propose that the changes become effective January 1, 2022, the same day that the FERC's COVID-related blanket waiver of ISO/RTO notarization requirements was due to expire.

The Committee considered and unanimously approved the following motion, with an abstention by Mr. Kuser's alternate recorded:

> RESOLVED, that the Participants Committee supports the elimination of the notarization requirements under the ISO New England Financial Assurance Policy, as proposed by the ISO and as circulated to this Committee with the September 30, 2021 supplemental notice, together with such non-substantive changes as may be approved by the Chair of the Budget and Finance Subcommittee.

OATT ATTACHMENT K RESOURCE ASSUMPTIONS REVISIONS

Ms. Emily Laine, the Chair of the Transmission Committee, referred the Committee to the materials circulated and posted in advance of the meeting related to a proposal to allow the ISO to expand the resources that can be relied on to address system concerns, and to provide clarification on the current language. She reported that the Transmission Committee had unanimously recommended support for the revisions and, but for timing of its action, the revisions would have been on the Consent Agenda

The Committee considered and unanimously approved the following motion, with abstentions by CLF, LIPA and Mr. Kuser's alternate recorded:

> RESOLVED, that the Participants Committee supports the Resource Assumption Revisions as recommended by the Transmission Committee and as distributed to the Participants Committee for its October 7, 2021 meeting, together with [any non-substantive changes agreed to be by the Chair and Vice-Chair of the Transmission Committee after the meeting.

NEPOOL COMMENTS ON FERC'S TRANSMISSION PLANNING AND ALLOCATION AND GENERATION INTERCONNECTION ANOPR

Mr. Doot referred the Committee to the materials circulated and posted in advance of the meeting related to proposed initial comments of NEPOOL in response to the FERC's Advance Notice of Proposed Rulemaking (ANOPR) regarding "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection." He explained that the comments, which had been reviewed with the Officers and the Transmission Committee, and summarized prior and current action of the various NEPOOL committees, did not require a vote unless that was the will of the Committee or any Participant. He explained further that, absent different direction from the Committee, the initial comments would be finalized and submitted. The Chair confirmed that the Participants Committee was satisfied with the draft comments and no Participant sought a vote on the comments.

ASSOCIATE NON-VOTING PARTICIPANT (ANVP) MEMBERSHIP PROPOSAL

Ms. Sarah Bresolin, Membership Subcommittee Chair, referred the Committee to the materials circulated and posted in advance of the meeting related to the proposal to replace the definition of, and reference to, Fuels Industry Participant in the Second Restated NEPOOL Agreement with "Associate Non-Voting Participant" (the Amendments), as well as certain related actions to reflect and implement those Amendments.

The Committee considered and unanimously approved in a single vote the following motions, with an abstention by Mr. Kuser's alternate recorded:

> RESOLVED, that the Participants Committee authorizes and directs the Balloting Agent (as defined in the Second Restated NEPOOL Agreement) to circulate ballots for the approval of changes to the Second Restated NEPOOL Agreement (that replace the definition of, and reference to, Fuels Industry Participant with "Associate Non-Voting Participant") (the Amendments), but with such non-material changes therein as the Chair of the Membership Subcommittee may approve, to each Participant for execution by its voting member or alternate on this Committee or such Participant's duly authorized officer.
>
> RESOLVED, that, subject to Participants Committee approval in balloting and FERC acceptance of the Amendments, each of the following are determined as permitted by those amendments to be a "Associate Non-Voting Participant": Algonquin Gas Transmission, Excelerate Energy, Repsol Energy North America, Advanced Energy Economy, American Petroleum Institute, and The New England Power Generators Association.

RESOLVED, that the Participants Committee, pursuant to Sections 8.1.3(f) and (g) of the Participants Agreement, hereby delegates to the Membership Subcommittee the authority to approve an applicant to be an Associate Non-Voting Participant, subject to acceptance of the Standard Conditions, Waivers and Reminders, if the Subcommittee determines that the applicant is either:

(i) a ***gas industry participant*** (i.e. an Entity that meets all four of the following criteria: (a) the Participant is engaged in the production, gathering, processing, marketing, or transmission of natural gas for sale at wholesale or retail in one or more of the New England states; and (b) the Participant does not participate directly in the New England Markets; and (c) the Participant is not eligible to join or designate a voting member of a Sector (other than the End User Sector); and (d) the Participant elects to be a treated as an Associate Non-Voting Participant before its membership application is approved by NEPOOL); or

(ii) an ***energy sector trade association*** (i.e. an organization of Entities engaging in the storage, production, supply, transportation, or distribution of energy, organized to promote and improve business conditions in the energy sector and not to engage in a regular business of a kind ordinarily carried on for profit, and no part of the net earnings of which inures to the benefit of any of its members).

LITIGATION REPORT

Mr. Doot referred the Committee to the October 5 Litigation Report that had been circulated and posted the day before the meeting. He highlighted the following:

(i) With respect to the FERC's administrative proceeding on ISO/RTO Energy and Ancillary Service Markets, the materials filed in advance of the first technical conference, which he encouraged those interested to review, and a recording of that technical conference, which was also accessible on the FERC website;

(ii) The complaint proceeding initiated by FERC to re-consider the justness and reasonableness of the processes for considering changes to the bulk power system under Section

I.3.10 and Schedule 25 to Section II of the ISO Tariff. He expected NEPOOL to defend those NEPOOL-approved processes, subject to discussions with the appropriate committees; and

(iii) The materials submitted by the ISO at the FERC's request in the litigation on the required treatment of the Seabrook facility in light of the effect on those facilities of the NECEC transmission project.

COMMITTEE REPORTS

Markets Committee (MC). Mr. William Fowler, the MC Vice-Chair, reported that the next MC meeting would be held October 13-14, both in person and virtual, and would include a discussion on monitoring the Generation Information System (GIS) for errors. Those interested in participating in person at that meeting were required to register by the end of following day. An additional MC meeting would take place virtually on October 21 to discuss stakeholder amendments related to the removal of the Minimum Offer Price Rule.

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that the regularly-scheduled RC meeting would be held October 19 and would include a discussion on proposed amendments to the ISO's response to FERC Order 2222. Registration was required by October 15 for in-person attendance at that meeting.

Transmission Committee (TC). Mr. José Rotger, the TC Vice-Chair, reported that the scheduled October 26 TC meeting was planned to be in person and would include a vote on Schedule 11 of the Tariff operating and maintenance (O&M) charges for network upgrades associated with new generation interconnections. Additionally, the ISO planned to introduce proposed tariff changes to the regional system planning process to allow the ISO to perform routine, extended-term planning studies and analysis.

Budget & Finance Subcommittee. Mr. Kaslow reported that the next B&F meeting was scheduled for October 12 and would include a discussion on conforming changes to the billing and financial assurance polices to support accelerated FCM billing and settlement, as well as proposed changes to the financial assurance requirements for non-commercial resources.

Membership Subcommittee. Ms. Bresolin noted that the next Membership Subcommittee meeting was scheduled for October 12 at 1:30 p.m.

ADMINISTRATIVE MATTERS

Mr. Cavanaugh noted that the next Pathways Study meeting was scheduled for October 25 and would be held in person.

Mr. Doot indicated that the November 3 Participants Committee meeting would be held on Wednesday, November 3, at the Hilton Boston Logan Airport and would be preceded by Sector meetings with ISO board members. Materials for the Sector meetings were due by October 15. Looking ahead, he indicated that the Annual Meeting would be held on December 2 at the Colonnade Hotel. This meeting would include officer elections, and might include a FERC Commissioner as a guest. Lastly, he reminded Participants of the mask mandate in Boston, and noted that Westborough, the location of most Technical Committee meetings, did not at that point have a mask mandate in place. He further shared that NEPOOL masks would be made available for anyone who might need or like to have one.

There being no other business, the meeting adjourned at 1:25 p.m.

Respectfully submitted,

____
David Doot, Secretary

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN OCT 7, 2021 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Melissa Birchard (tel)		
American Petroleum Institute	Fuels Industry Participant	Paul Powers (tel)		
AR Large Renewable Generation (RG) Group Member	AR-RG	Alex Worsley		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell (tel)		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
Associated Industries of Massachusetts (AIM)	End User			Mary Smith (tel)
AVANGRID: CMP/UI	Transmission	Alan Trotta (tel)	Jason Rauch (tel)	
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh (tel)	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh (tel)		
Borrego Solar Systems Inc.	AR-DG	Liz Delaney		
Boylston Municipal Light Department	Publicly Owned Entity		Brian Thomson	
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity			Dave Cavanaugh (tel)
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Calpine Energy Services, LP	Supplier	Brett Kruse		Bill Fowler (tel)
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh (tel)	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield (tel)		
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh (tel)	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw (tel)		
Connecticut Office of Consumer Counsel (CT OCC)	End User		Dave Thompson (tel)	Victor Owusu-Nantwi (tel)
Conservation Law Foundation (CLF)	End User	Phelps Turner (tel)		
Consolidated Edison Energy, Inc.	Supplier	Norman Mah (tel)		
CPV Towantic, LLC (CPV)	Generation	Joel Gordon (tel)		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh (tel)	
Dick Brooks	End User	Dick Brooks (tel)		
Dominion Energy Generation Marketing	Generation	Mike Purdie (tel)	Weezie Nuara (tel)	
DTE Energy Trading, Inc.	Supplier			José Rotger
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein (tel)		Bill Fowler (tel)
Emera Energy Services	Supplier			Bill Fowler (tel)
Enel X North America, Inc.	AR-LR	Michael Macrae		
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Environmental Defense Fund	End User	Jolette Westbrook (tel)		
Eversource Energy	Transmission		Dave Burnham (tel)	
Exelon Generation Company	Supplier	Steve Kirk (tel)	Bill Fowler (tel)	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger		
Generation Group Member	Generation	Dennis Duffy	Abby Krich	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh (tel)	
Great River Hydro	AR-RG			Bill Fowler (tel)
Groton Electric Light Department	Publicly Owned Entity		Brian Thomson	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh (tel)	
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	Louis Guilbault (tel)	Bob Stein	
High Liner Foods (USA) Incorporated	End User		William P. Short III (tel)	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh (tel)	
Holden Municipal Light Department	Publicly Owned Entity		Brian Thomson	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN OCT 7, 2021 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Holyoke Gas & Electric Department	Publicly Owned Entity		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Ipswich Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Jericho Power LLC (Jericho)	AR-RG	Mark Spencer (tel)	Nancy Chafetz (tel)	
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh (tel)	
Littleton (NH) Water & Light Department	Publicly Owned Entity		Craig Kieny (tel)	
Long Island Power Authority (LIPA)	Supplier			José Rotger
Maine Power LLC	Supplier	Jeff Jones (tel)		
Maine Public Advocate's Office	End User	Drew Landry (tel)		Erin Camp (tel)
Mansfield Municipal Electric Department	Publicly Owned Entity		Brian Thomson	
Maple Energy LLC	AR-LR			Doug Hurley (tel)
Marble River, LLC	Supplier		John Brodbeck (tel)	
Marblehead Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Mass. Attorney General's Office (MA AG)	End User	Tina Belew (tel)	Ben Griffiths (tel)	
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh (tel)	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Brian Thomson		
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh (tel)	
Michael Kuser	End User		Jason York	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh (tel)	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh (tel)	
National Grid	Transmission	Tim Brennan (tel)	Tim Martin (tel)	
Nautilus Power, LLC	Generation	Dan Pierpont (tel)	Bill Fowler (tel)	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski (tel)		Brian Forshaw (tel); Dave Cavanaugh (tel); Brian Thomson
New Hampshire Office of Consumer Advocate	End User		Erin Camp (tel)	
New England Power Generators Association (NEPGA)	Fuels Industry Participant	Bruce Anderson (tel)	Dan Dolan	
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh (tel)	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh (tel)	
NRG Power Marketing LLC	Generation	Neal Fitch (tel)		
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh (tel)	
Paxton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Peabody Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Princeton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PSEG Energy Resources & Trade LLC (PSEG)	Supplier		Eric Stallings (tel)	
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh (tel)	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh (tel)	
Russell Municipal Light Dept.	Publicly Owned Entity		Brian Thomson	
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Brian Thomson	
Small RG Group Member	AR-RG	Erik Abend (tel)		
South Hadley Electric Light Department	Publicly Owned Entity		Brian Thomson	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Brian Thomson	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh (tel)	
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh (tel)	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
The Energy Consortium	End User	Bob Espindola (tel)	Mary Smith (tel)	
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny (tel)		
Vermont Electric Power Company (VELCO)	Transmission			Dave Burnham (tel)

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN OCT 7, 2021 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley (tel)	
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw (tel)
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity		Dave Cavanaugh (tel)	
Vitol Inc.	Supplier	Joe Wadsworth (tel)		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Brian Thomson	
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh (tel)	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh (tel)	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh (tel)	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler (tel)	

CONSENT AGENDA

Reliability Committee (RC)

From the previously-circulated notice of actions of the RC's October 19, 2021 meeting, dated October 19, 2021.[1]

1. <u>HQICC Values for the 2022-23 3rd ARA, 2023-24 2nd ARA, and 2024-25 1st ARA</u>
Support the following Hydro-Québec Interconnection Capability Credit (HQICC) values for the Third Annual Reconfiguration Auction (ARA) for the 2022-23 Capacity Commitment Period (CCP), Second ARA for the 2023-24 CCP and First ARA for the 2024-25 CCP, as recommended by the RC at its October 19, 2021 meeting, with such further non-material changes as the Chair and Vice-Chair of the RC may approve:

Month	2022-2023 HQICC Values (MW)	2023-2024 HQICC Values (MW)	2024-2025 HQICC Values (MW)
June	919	941	883
July	919	941	883
August	919	941	883
September	919	941	883
October	919	941	883
November	919	941	883
December	919	941	883
January	919	941	883
February	919	941	883
March	919	941	883
April	919	941	883
May	919	941	883

The motion to recommend Participants Committee support was approved, with two oppositions in the Supplier Sector and 10 abstentions (2 - Generation Sector; 6 - Supplier Sector; and 2 - AR Sector) noted.

[continued on next page]

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

2. ICR and Related Values for the 2022-23 3rd ARA, 2022-24 2nd ARA and 2023-25 1st ARA

3rd ARA for the 2022-23 CCP

Support, for the 3rd ARA for the 2022-23 CCP, the following New England Installed Capacity Requirement (ICR), Net ICR, Southeast New England (SENE) LSR, and Northern New England (NNE) Maximum Capacity Limit (MCL) values:

	2022-2023 ARA 3 ICR values (MW)
Installed Capacity Requirement	32,509
Net Installed Capacity Requirement	31,590
Southeast New England Local Sourcing Requirement	8,914
Northern New England Maximum Capacity Limit	8,645

and the following Marginal Reliability Impact (MRI) Capacity Demand Curves -- System-Wide, SENE Import-Constrained Capacity Zone, and the NNE Export-Constrained Capacity Zone:

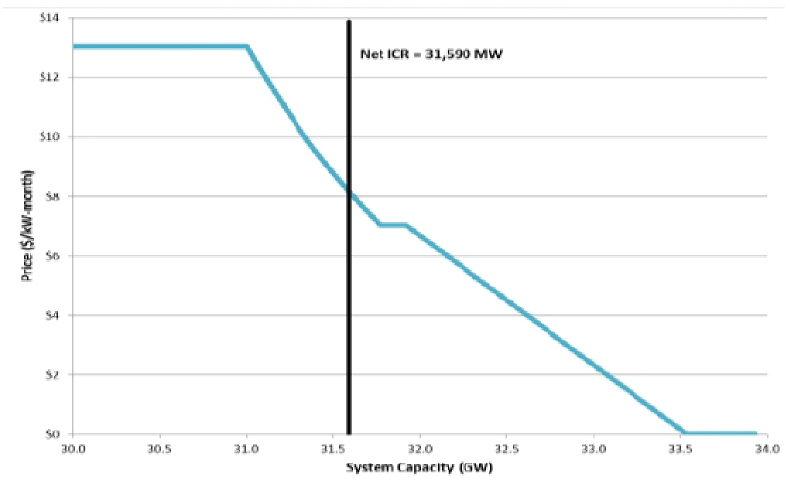


Figure 1 2022-23 CCP ARA3 System-Wide MRI Capacity Demand Curve

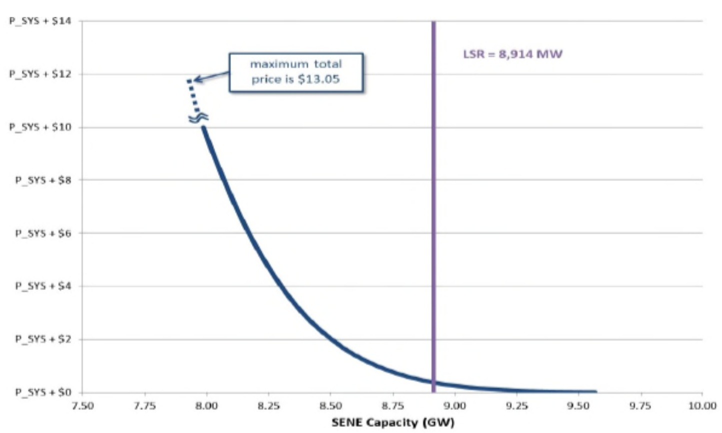


Figure 2 2022-23 CCP ARA3 SENE Import-Constrained MRI Capacity Demand Curve

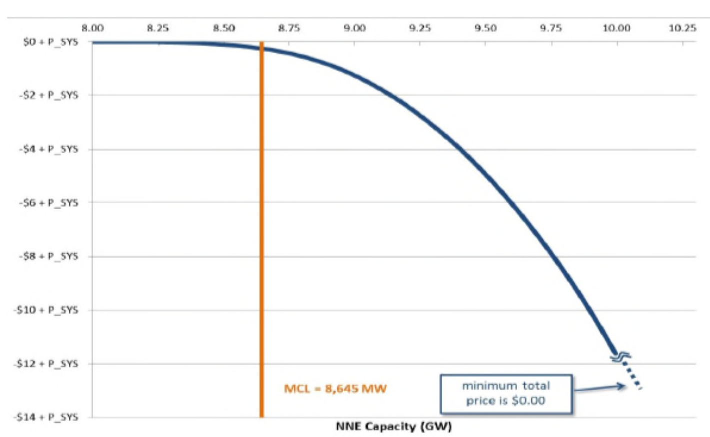


Figure 3 2022-23 CCP ARA3 NNE Export-Constrained MRI Capacity Demand Curve

2nd ARA for the 2023-24 CCP

Support, for the 2nd ARA for the 2023-24 CCP, the following New England ICR, Net ICR, SENE LSR, Maine MCL, and NNE MCL values:

	2023-2024 ARA 2 ICR values (MW)
Installed Capacity Requirement	32,421
Net Installed Capacity Requirement	31,480
Southeast New England Local Sourcing Requirement	9,009
Maine Maximum Capacity Limit	4,225
Northern New England Maximum Capacity Limit	8,640

and the following MRI Capacity Demand Curves -- System-Wide, SENE Import-Constrained Capacity Zone, Maine Export-Constrained, and the NNE Export-Constrained Capacity Zone:

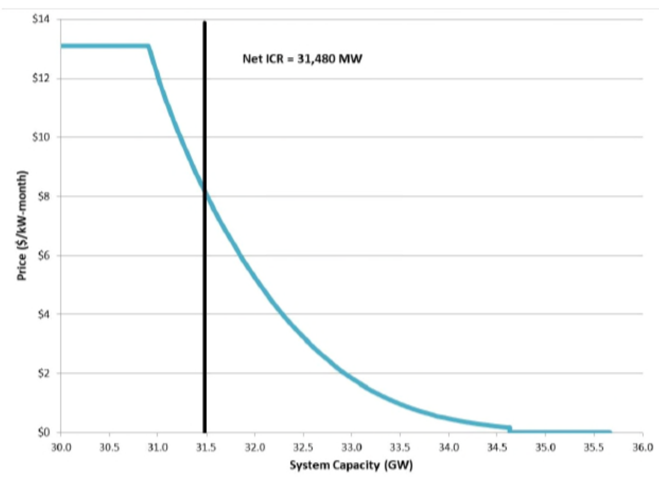


Figure 4 2023-24 CCP ARA2 System-Wide MRI Capacity Demand Curve

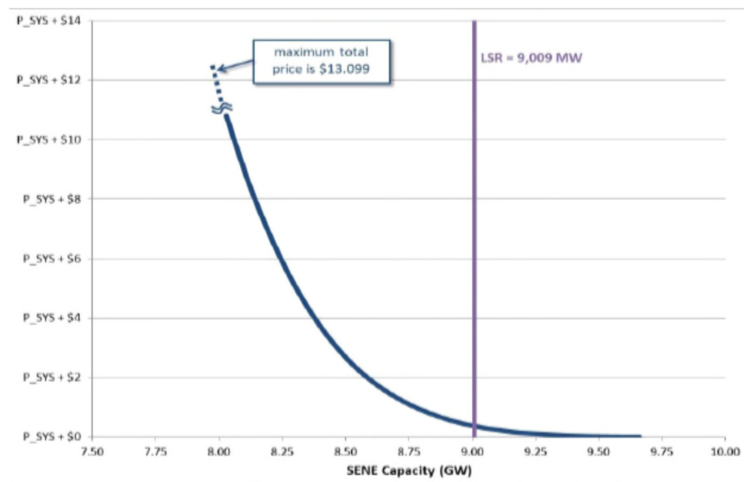


Figure 5 2023-24 CCP ARA2 SENE Import-Constrained MRI Capacity Demand Curve

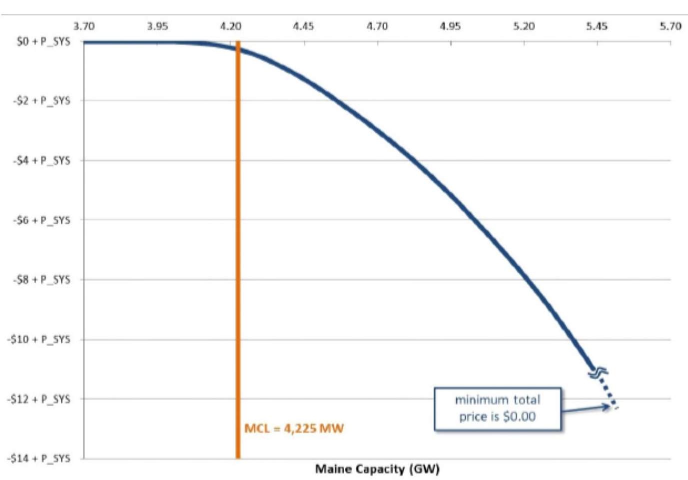


Figure 6 2023-24 CCP ARA2 Maine Export-Constrained MRI Capacity Demand Curve

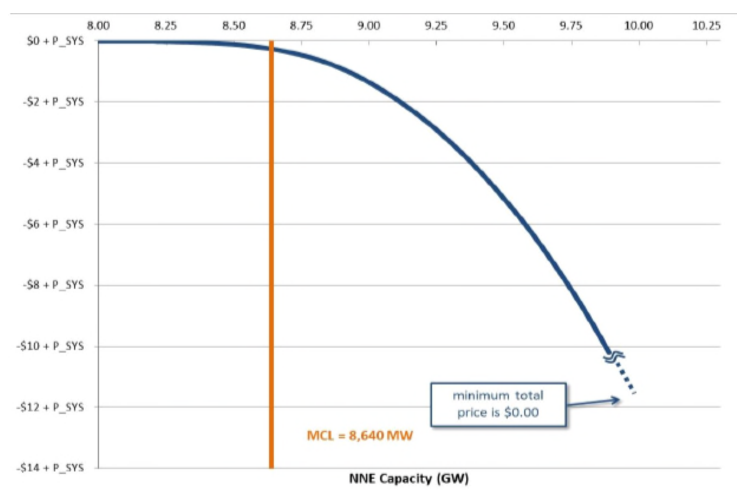


Figure 7 2023-24 CCP ARA2 NNE Export-Constrained MRI Capacity Demand Curve

1st ARA for the 2024-25 CCP

Support, for the 1st ARA for the 2024-25 CCP, the following New England ICR, Net ICR, SENE LSR, Maine MCL, and NNE MCL values:

	2024-2025 ARA 1 ICR values (MW)
Installed Capacity Requirement	32,658
Net Installed Capacity Requirement	31,775
Southeast New England Local Sourcing Requirement	9,400
Maine Maximum Capacity Limit	4,245
Northern New England Maximum Capacity Limit	8,685

and the following MRI Capacity Demand Curves -- System-Wide, SENE Import-Constrained Capacity Zone, Maine Export-Constrained Capacity Zone, and the NNE Export-Constrained Capacity Zone:

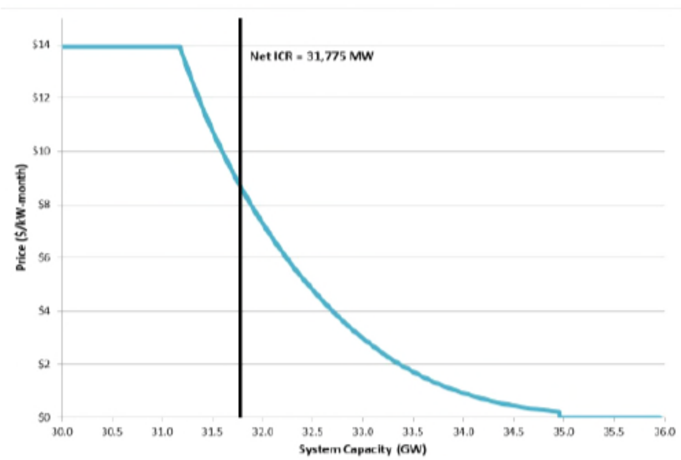


Figure 8 2024-25 CCP ARA3 System-Wide MRI Capacity Demand Curve

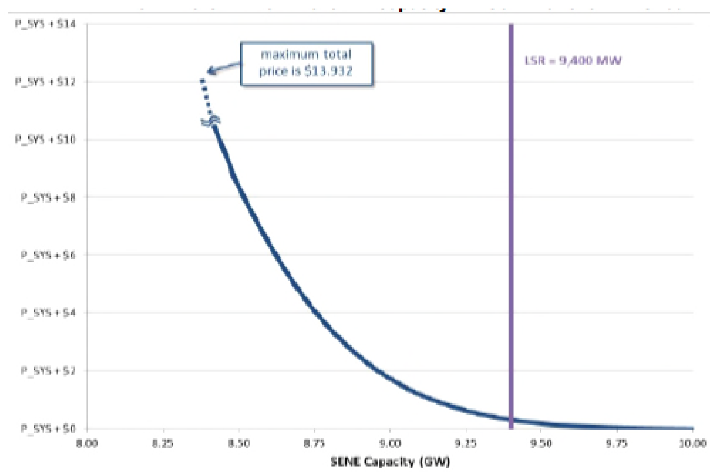


Figure 9 2024-25 CCP ARA3 SENE Import-Constrained MRI Capacity Demand Curve

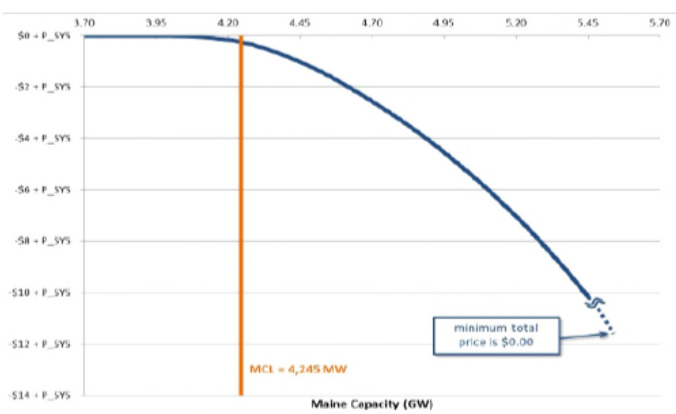


Figure 10 2024-25 CCP ARA3 Maine Export-Constrained MRI Capacity Demand Curve

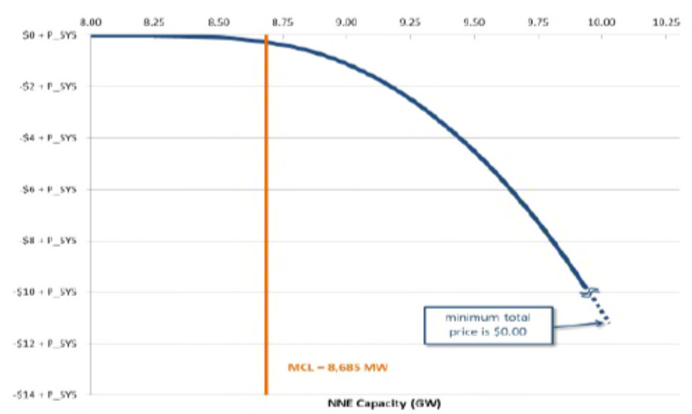


Figure 11 2024-25 CCP ARA3 NNE Export-Constrained MRI Capacity Demand Curve

each as recommended by the RC at its October 21, 2021 meeting, with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was approved, with two oppositions in the Supplier Sector and 10 abstentions (2 - Generation Sector; 6 - Supplier Sector; and 2 - AR Sector) noted.

3. **Tariff Changes Associated with Order 1000 Lessons Learned**
   Support the revisions to Section III.12.6.4 of the Tariff related to FERC Order 1000, as recommended by the RC at its October 19, 2021 meeting, with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

   The motion to recommend Participants Committee support was approved unanimously.

Transmission Committee (TC)

From the previously-circulated notice of actions of the TC's September 28, 2021 meeting, dated September 28, 2021.[2]

4. **Tariff Changes Associated with Order 1000 Lessons Learned**
   Support the revisions to Attachments K and P of Section II of the Tariff related to FERC Order 1000, as recommended by the TC at its September 28, 2021 meeting, with such further non-material changes as the Chair and Vice-Chair of the TC may approve.

   The motion to recommend Participants Committee support was approved unanimously, with two abstentions recorded (one in the End User Sector and one by a Provisional Member).

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

NEPOOL Participants Committee Report

November 2021

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: September 2021 Energy Market value totaled $511M
  - October Energy market value was $469M, down $42M from September 2021 and up $231M from October 2020
    - October 2021 natural gas prices over the period were 5.5% higher than September 2021 average values
    - Average RT Hub Locational Marginal Prices ($55.08/MWh) over the period were 18% higher than September averages
      - DA Hub: $57.46/MWh
    - Average October 2021 natural gas prices and RT Hub LMPs over the period were up 139% and up 105%, respectively, from the same month last year
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 99.9% during October, down from 99.8% during September*

All data through October 26th

    - The minimum value for the month was 95.9% on Tuesday, October 26th

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

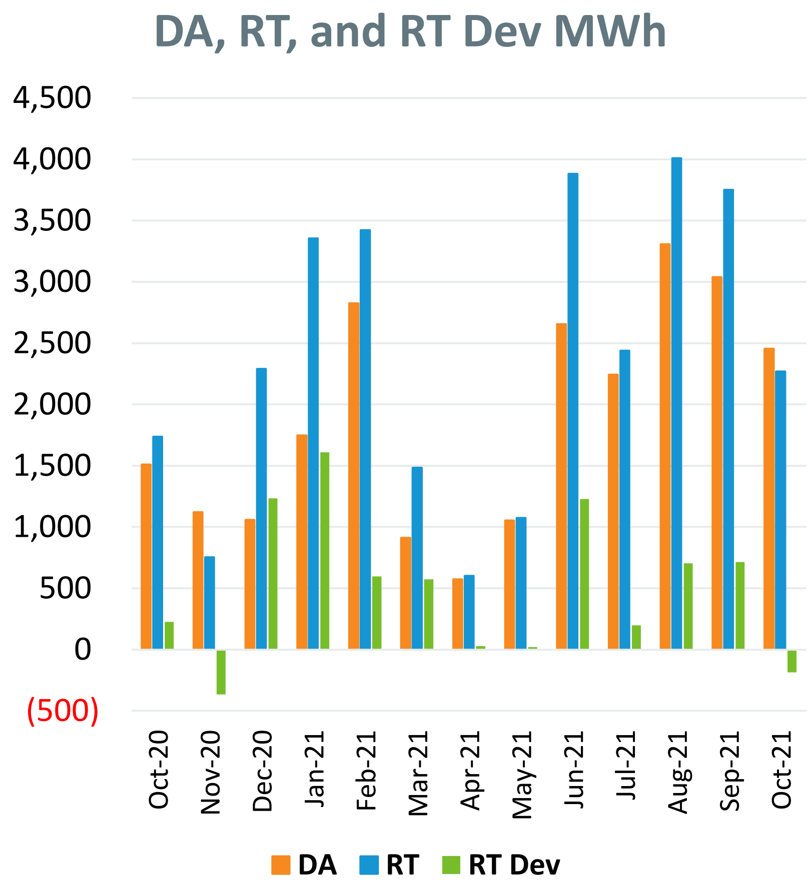
*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

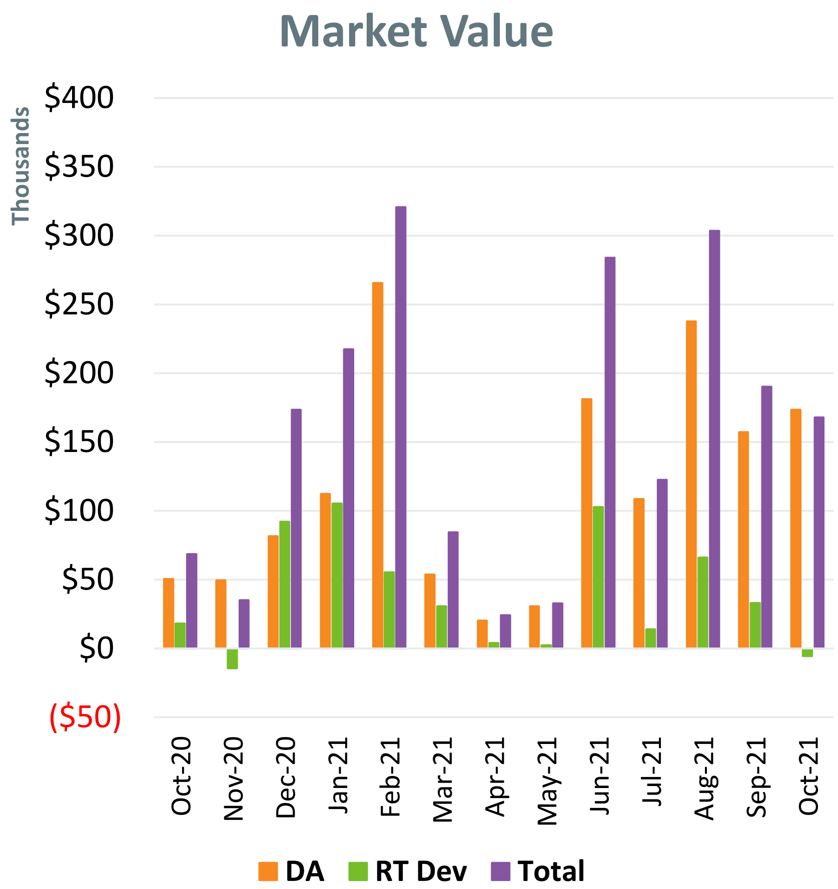
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - October 2021 NCPC payments totaled $3.1M over the period, up $1.7M from September 2021 and up $0.3M from October 2020
    - First Contingency payments totaled $2.4M, up $1M from September 2021
      - $2M paid to internal resources, up $0.7M from September
        - » $723K charged to DALO, $724K to RT Deviations, $599K to RTLO*
      - $385K paid to resources at external locations, up $339K from September
        - » $212K charged to DALO at external locations, $173K to RT Deviations
    - Second Contingency payments totaled $0.7M
    - Voltage and Distribution payments both zero
  - NCPC payments over the period as percent of Energy Market value were 0.7%

* NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $261K; Rapid Response Pricing (RRP) Opportunity Cost - $273K; Posturing - $0K; Generator Performance Auditing (GPA) - $66K

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

- High-level transmission and ancillary services results for the 2021 Economic Study (Future Grid Reliability Study) were discussed at the October 20 PAC meeting
  - The ISO presented a revised scope of analysis to the joint MC/RC on October 19 and after some minor revisions from stakeholders, the revisions were accepted by consensus
- FCA 16 ICR and Related Values FERC filing to be made by November 9
- ICR and Related Values for 2022 ARAs are on track to be filed with FERC by November 30
- ISO-NE Board is reviewing the RSP21 report for final approval
- Four Attachment K revisions are in various stages of development
- Transmission Planning for the Clean Energy Transition full written report on the pilot study is expected to be released in late 2021

Forward Capacity Market (FCM) Highlights

- CCP 12 (2021-2022)
  - Third and final annual reconfiguration auction (ARA3) was held on March 1-3, and results were posted on March 29
- CCP 13 (2022-2023)
  - Second annual reconfiguration auction (ARA2) was held on August 2-4, and results were posted on August 31
  - ICR and Related Values to be filed with FERC by November 30
- CCP 14 (2023-2024)
  - First annual reconfiguration auction (ARA1) was held on June 1-3, and results were posted June 30
  - ICR and Related Values to be filed with FERC by November 30
- CCP 15 (2024-2025)
  - Auction results were filed with FERC on February 26 and FERC approved on June 24
  - ICR and Related Values to be filed with FERC by November 30

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 16 (2025-2026)
  - FCA 16 will model the same zones as FCA 15
    - Export-constrained zones: Northern New England, and Maine nested inside Northern New England
    - Import-constrained zones: Southeast New England
  - Existing capacity values were posted on March 5
  - A summary of permanent and retirement de-list bids was posted on March 17, and a summary of substitution auction demand bids was posted on April 30
    - These summaries were reposted on June 11 to reflect de-list bid withdrawals made after the Internal Market Monitor reissued its determinations based on the FERC-accepted CONE, Net CONE and Capacity Performance Payment Rate for FCA 16
  - Qualification determination notifications were issued on October 1
  - ICR and Related Values to be filed no later than November 9, 2021

CONE – Cost of New Entry

FCM Highlights, cont.

- CCP 17 (2026-2027)
  - The qualification process has started, and training materials are under development
  - Topology certifications were sent to the TOs on October 2
    - TOs to identify in-service dates for new transmission projects and revisions to previously certified projects
    - Approved projects to be shared with the RC at their January 2022 meeting
  - Capacity zone development discussions will begin at the November 17 PAC meeting
    - All subsequent reconfiguration auctions model the same zones as the FCA

Load Forecast

- Efforts continue to enhance load forecast models and tools to improve day-ahead and long-term load forecast performance
- Continuing to evaluate the impacts of COVID-19 to the load forecast
- Efforts to expand/improve the transportation electrification forecast for CELT 2022 have commenced
- Upcoming Meetings
  - Load Forecast Committee Meeting will be held on November 12
  - Both the Energy-Efficiency Forecast Working Group (EEFWG) and Distributed Generation Forecast Working Group (DGFWG) will meet on December 6

FERC Order 1000

- Qualified Transmission Project Sponsor (QTPS)
  - 25 companies have achieved QTPS status
- Competitive Solution Process: Order 1000/Boston 2028 Request for Proposal Lessons Learned
  - The ISO held discussions on the associated Tariff changes at the 7/14/21, 8/24/21, and 9/28/21 TC meetings
  - The Tariff changes were also discussed at the RC on 9/21/21 and 10/19/21
  - PC discussion and vote are scheduled for 11/3/21, with an anticipated FERC filing in late November/early December

Highlights

- The lowest 50/50 and 90/10 Fall Operable Capacity Margins are projected for week beginning November 20, 2021.

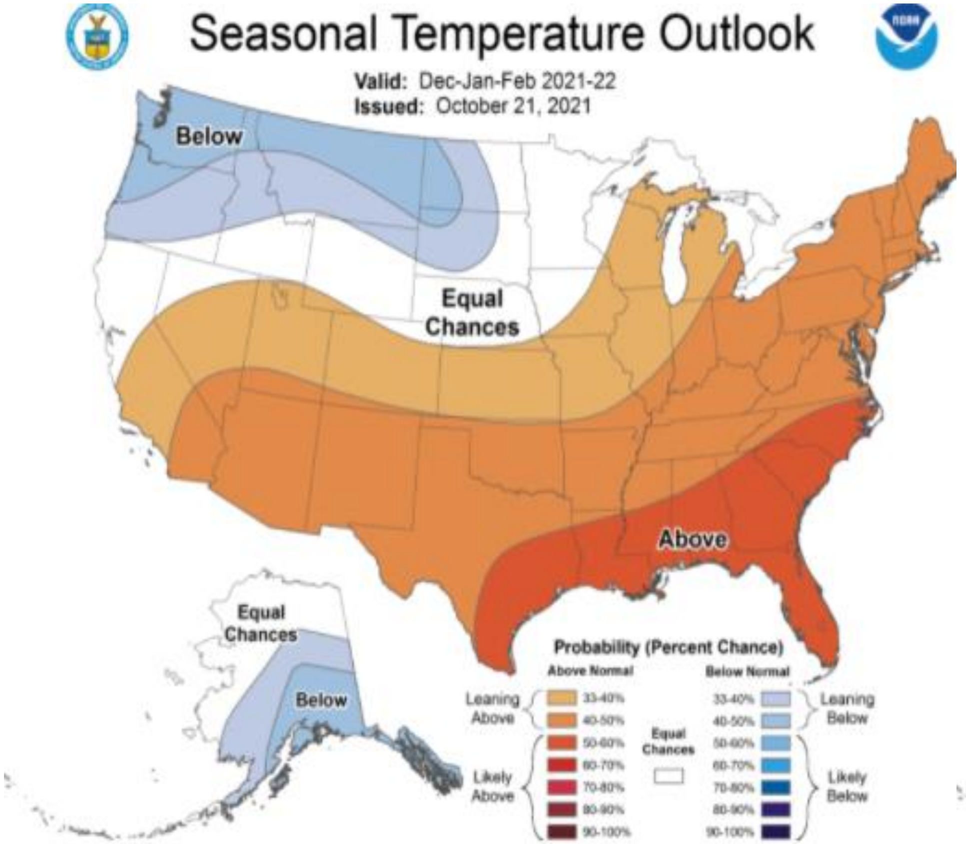
- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning January 8, 2022.

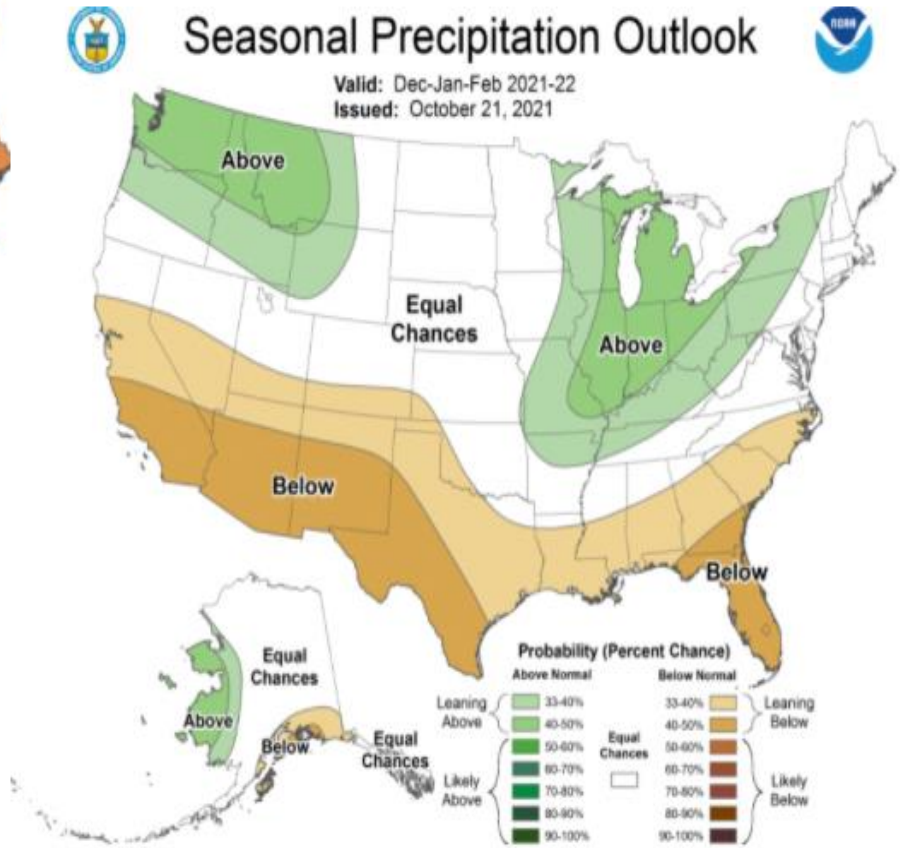
New England Winter Outlook 2021/2022

Highlights

- Winter Outlook
  - The seasonal temperature outlook for the winter months of December-January-February indicates a 40-50% probability of above normal temperatures for all of New England
  - An equal chance for above average or below average precipitation is forecasted across the majority of New England
  - Capacity analysis for the 50/50 and the 90/10 load forecast indicates a surplus even after accounting for generation at risk due to gas supply
    - Capacity analysis is generally limited in that it assumes all resources that are not de-rated can supply energy when called

Winter Temperature & Precipitation Probability





Winter Expectations 2021-2022

- Winter Demand Forecast
  - 50/50 winter peak demand forecast of 19,710 MW, which is 456 MW (2.3%) lower than the 2020-21 forecast
  - 90/10 winter peak demand forecast of 20,349 MW, which is 457 MW (2.2%) lower than the 2020-21 forecast
- Scheduled Generation and Transmission Outages
  - All generation and transmission outages continue to be coordinated to minimize adverse transmission or capacity conditions
  - No significant generation or transmission outages are currently scheduled
- Transfer Capability
  - Transfer capability on the New York Northern AC ties will be increased from 1,400 to 1,600 MW for the winter period

Winter Expectations 2021-2022, cont.

- Natural Gas Deliverability
  - Continue to monitor natural gas deliverability throughout the winter
  - Approximately 3,700 MW may be at risk due to pipeline constraints
- Fuel and Emissions Availability
  - Continue to closely monitor fuel inventories and potential emissions restrictions of resources via weekly (or) daily surveys
  - Entering Winter 20/21 fuel oil tanks were approximately 58% full; Entering Winter 21/22 fuel oil tanks are approximately 51% full
- Winter Capacity Outlook
  - Projecting the lowest 50/50 operable capacity margin of 2,654 MW and 90/10 capacity margin of 1,204 MW for the week beginning January 8, 2022[1]
  - Extended periods of cold weather may rapidly deplete fuel inventories and capacity outlook will be adjusted accordingly

1-Based on resource Capacity Supply Obligations and 50/50 load forecast

Winter Preparations 2021-2022

- Winter Readiness Seminar
  - Hosted a WebEx Generator Winter Readiness Seminar with Market Participants on October 1, 2021
- Winter Generator Readiness Survey
  - Will distribute a Winter Generator Readiness Survey to all generating resources in the region by November 1, 2021 with responses due by December 1, 2021
  - Survey will be of weekly or daily frequency during the season
- Continue to perform a weekly 21-day energy assessment
- Completed the annual Natural Gas Critical Infrastructure Survey process to ensure critical infrastructure is not part of automatic or manual load shed schemes

21-Day Energy Assessment & Alert Thresholds

- In order to identify and communicate potential reliability issues, the ISO performs a weekly 21-day energy assessment and posts the results on the ISO public website
  - The energy assessment is based on latest responses to generator surveys, as well as planned outages, load & weather forecasts, and anticipated LNG injections
- ISO's OP-21 describes the thresholds for declaration of an Energy Alert or Energy Emergency
  - ISO will declare an **Energy Alert** if the energy assessment indicates either the use of OP-4 Actions 6-11 (voltage reduction and conservation appeals) or OP-7 Action in at least **1 hour on 1 or more consecutive days in days 6 through 21**
  - ISO will declare an **Energy Emergency** if the energy assessment indicates the use of OP-4 Actions 6-11 (voltage reduction and conservation appeals) or OP-7 Action in at least **1 hour on 1 or more consecutive days in days 1 through 5**

Key Takeaways

- Energy security risks in New England are well-documented, with heightened concerns this winter due to sharp increases in global demand and prices
- Weather, which is more unpredictable and extreme, will be a key factor affecting regional energy availability and related reliability concerns this winter
- LNG imports are critical to meeting New England's energy needs during cold weather
- While a majority of New England's oil-fired generating capability is from resources that utilize distillate fuel oil, they account for a smaller percentage of regional oil storage capability and their inventories diminish quickly without replenishment
- Logistics will drive the ability of market participants to replenish fuel within the season

Key Takeaways, cont.

- Given the fuel constraints on the natural gas system, situational awareness of the available LNG and fuel-oil inventories and replenishment plans for those inventories is essential to understanding regional energy availability
- ISO's winter preparations and Energy Emergency procedures will aid in proactive and effective communication with stakeholders; however, ISO and resource owners may need assistance from state and federal governments, including well-coordinated public appeals, to help manage the impacts in case of emergencies

Regional LNG Supply: Sources and Logistics

- LNG deliveries to Canaport in St. John, New Brunswick, Distrigas in Everett, MA, and Excelerate offshore of Salem, MA are sourced primarily from Trinidad and Tobago
- Logistics:
  - Tankers carry approximately 3 Bcf (3,000,000 MMBtu) per delivery
  - Transit time to Canaport and Distrigas import terminals: approx. **five days**
  - Loading and unloading time: approx. **one day** for each evolution
  - Additional time is required to arrange logistics, especially if not done ahead of time

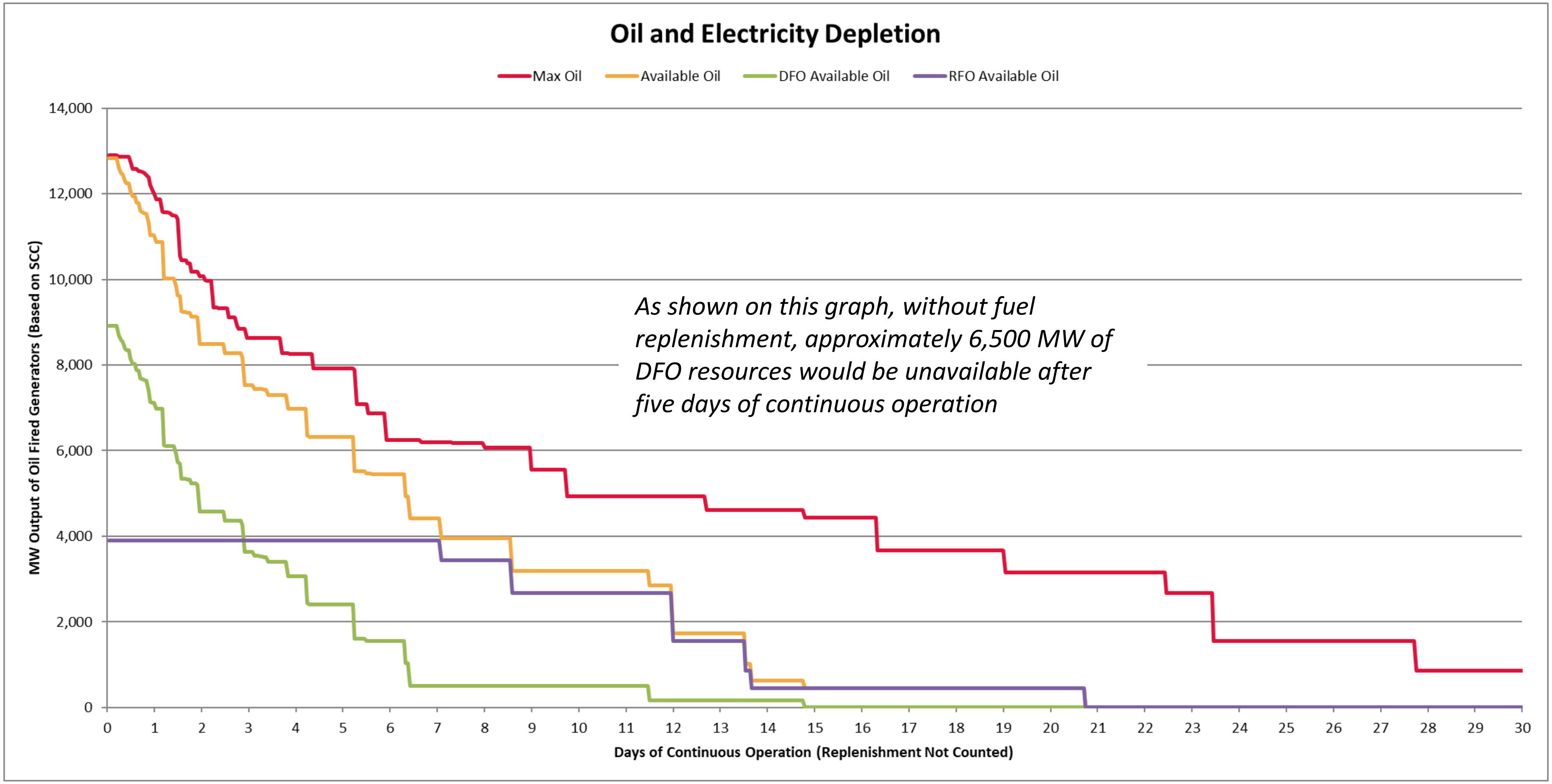
LNG Pricing & Replenishment

- Winter 2020-2021
  - Forward natural gas prices for Algonquin were approximately $7.20/MMBtu
  - European and Asian prices were below $6.00/MMBtu, making New England more attractive, price-wise, for LNG cargoes
  - Overall scheduled LNG to New England pipelines was approximately 30 Bcf
- Winter 2021-2022
  - European natural gas prices are higher than in New England, currently making New England a less attractive destination for LNG
  - In early October, European prices for January delivery were as high as $40/MMBtu
    - $40/MMBtu prices are equivalent to approximately $300/MWh electric prices

Oil-Fired Generating Capability

- New England has seventy-three generating stations, with approximately 12,800 MW of combined capability, that utilize oil as a primary or alternate fuel
  - Of the 12,800 MW, approximately 8,900 MW of resources utilize distillate fuel oil (DFO)
  - Resources that utilize DFO account for 70% of the generating capacity, but only 31% of the oil storage capability; these resources have smaller fuel oil tanks that diminish quickly if operated without replenishment
  - Current generator fuel-oil inventories are trending toward their lowest pre-winter levels since 2014 and are concentrated in a limited number of generating sites
  - As was observed during the 2017-2018 cold snap, emissions restrictions can limit the ability to fully utilize oil-fired generating capability
  - For some dual-fuel resources, air permit restrictions limit the use of fuel oil to periods when natural gas is unavailable and/or operating under ISO-declared emergency conditions

Fuel Oil Inventories – Depletion Rate



[1] Fuel oil storage capability, inventory, generator capabilities, and replenishment data is based on 10/12/21 Generator Survey Data

High Level Winter Assessment

- If the 2021/22 winter profile is similar to that of winter 2020/21, the ISO anticipates that the system can be operated reliably without the need for emergency procedures
  - Assumes no significant generation or transmission outages and limited fuel replenishment
- Winter 2020/21 was mild with the following characteristics:
  - Milder than normal with a few short periods of below normal temperatures
  - Average temperature departure from normal was +1.8°F degrees
  - Winter peak load of 18,756 MW
  - Natural gas was available as needed, fuel oil usage was minimal and fuel supplies remained steady
  - The total energy served during this period was 32,188 GWh

High Level Winter Assessment, cont'd.

- If the 2021/22 winter profile is similar to that of winter 2017/18, the ISO anticipates that the system can be operated reliably, but may require the implementation of capacity deficiency procedures
  - Assumes no significant generation or transmission outages and limited fuel replenishment
- If the region has adequate fuel replenishment, the ISO anticipates that the system can be operated reliably without the need for emergency procedures
- Winter 2017/18 was milder than normal, except for a long cold spell, and with the following characteristics:
  - Milder than normal except for a two-week span of significantly below normal temperatures
  - Average temperature departure from normal was +0.5°F degrees
  - The region was impacted by an extended stretch of cold weather from December 25 through January 8; All major cities in New England experienced temperatures below normal for at least 13 consecutive days, of which 10 days averaged more than 10°F below normal
  - Winter peak load of 20,631 MW
  - The cold snap was marked by significant reductions in natural gas availability and price inversion contributed to high oil usage; several oil-fired resources were postured to maintain fuel reserves.
  - The total energy served during this period was 33,186 GWh

High Level Winter Assessment, cont'd

- If the 2021/22 winter profile is similar to that of winter 2013/14 with persistent below normal temperatures and several cold stretches, the ISO anticipates that it may require the implementation of all available emergency procedures
  - Assumes no significant generation or transmission outages and limited fuel replenishment
- If the region has adequate fuel replenishment, the ISO anticipates that the system can be operated reliably without the need for emergency procedures
- Winter 2013/14 characteristics:
  - Colder than normal and highlighted by a polar vortex event with significant stretches of cold weather in New England and surrounding regions
  - Average temperature departure from normal was -2.3°F degrees
  - The region experienced several cold weather stretches of four or more consecutive days, including a stretch of ten consecutive days at or below freezing
  - Winter peak load of 21,514 MW
  - High demand on both the electric and natural gas systems
  - The total energy served during this period was 35,509 GWh

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (5.6°F) Max: 78°F, Min: 52°F Precipitation: 3.67" – Above Normal Normal: 3.52"	Hartford	Temperature: Above Normal (4.7°F) Max: 79°F, Min: 52°F Precipitation: 3.76" - Below Normal Normal: 4.03"

Peak Load:	15,131 MW	October 14, 2021	19:00 (ending)

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

Procedure	Declared	Cancelled	Note
M/LCC 2	10/26/2021 13:00	10/28/2021 16:00	Severe Weather

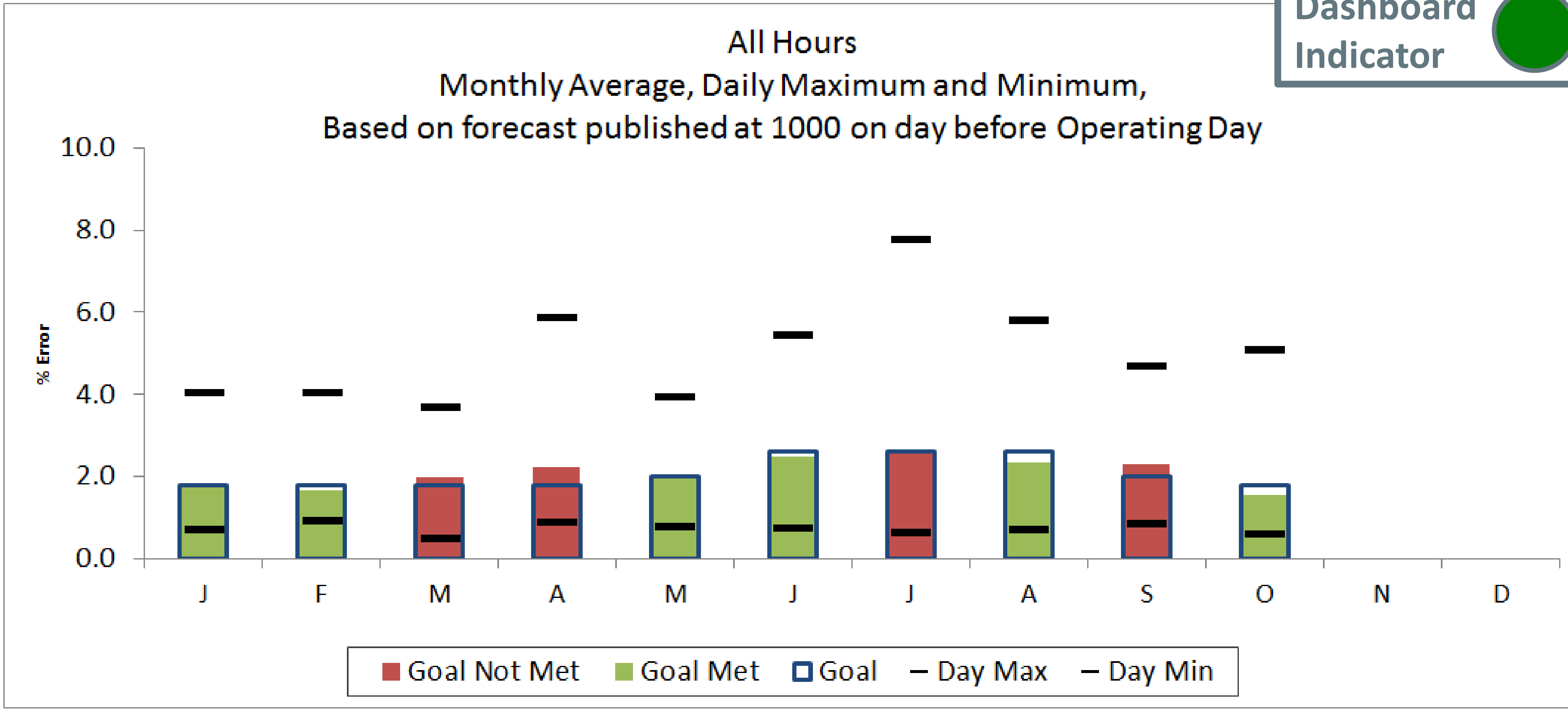
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
10/10/2021	NYISO	530
10/12/2021	NYISO	530
10/13/2021	NYISO	540
10/16/2021	ISONE	600
10/17/2021	NYISO	618
10/18/2021	NYISO	1200

2021 System Operations - Load Forecast Accuracy

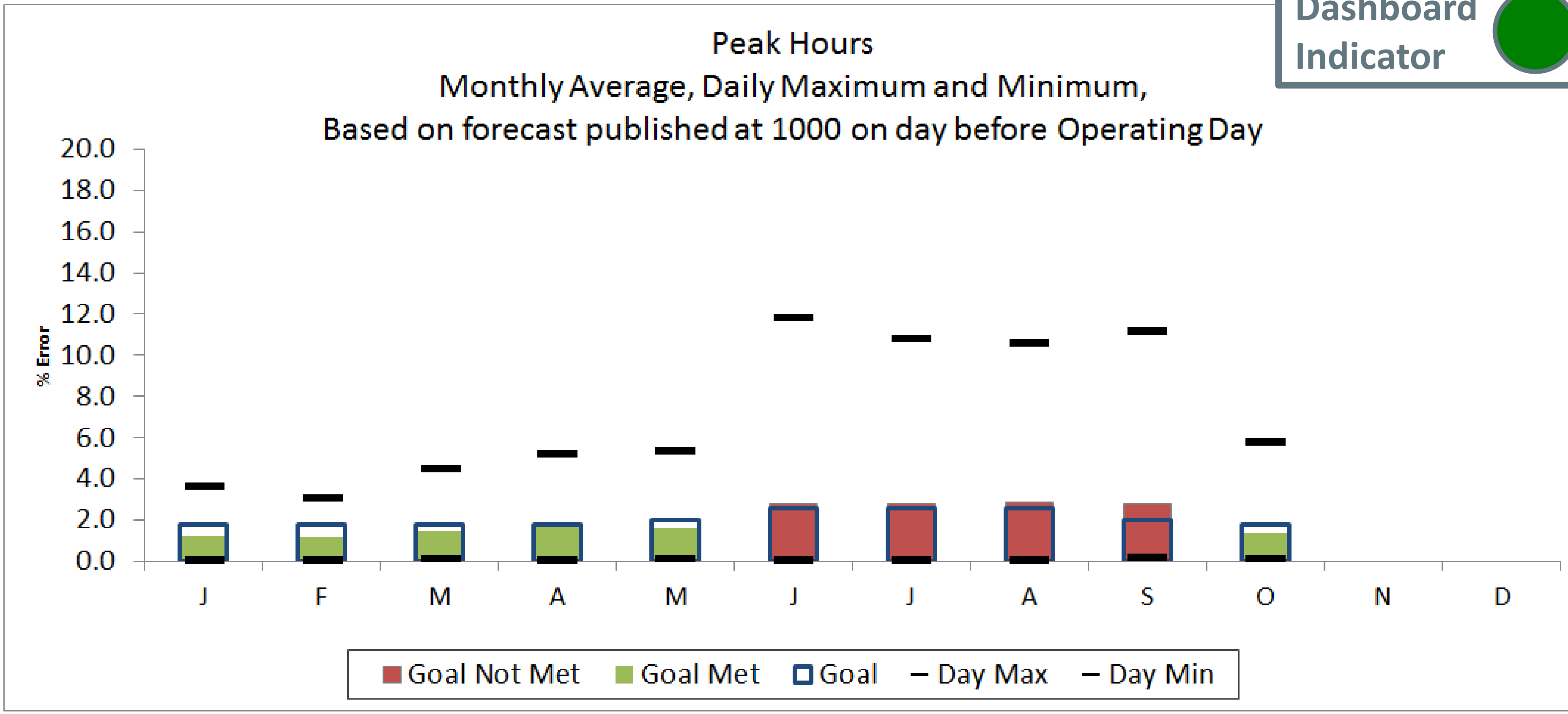
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.04	4.03	3.67	5.85	3.92	5.41	7.75	5.77	4.68	5.08			7.75
Day Min	0.70	0.92	0.49	0.88	0.77	0.73	0.63	0.71	0.86	0.60			0.49
MAPE	1.72	1.66	1.97	2.24	1.95	2.50	2.61	2.33	2.30	1.56			2.09
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80			

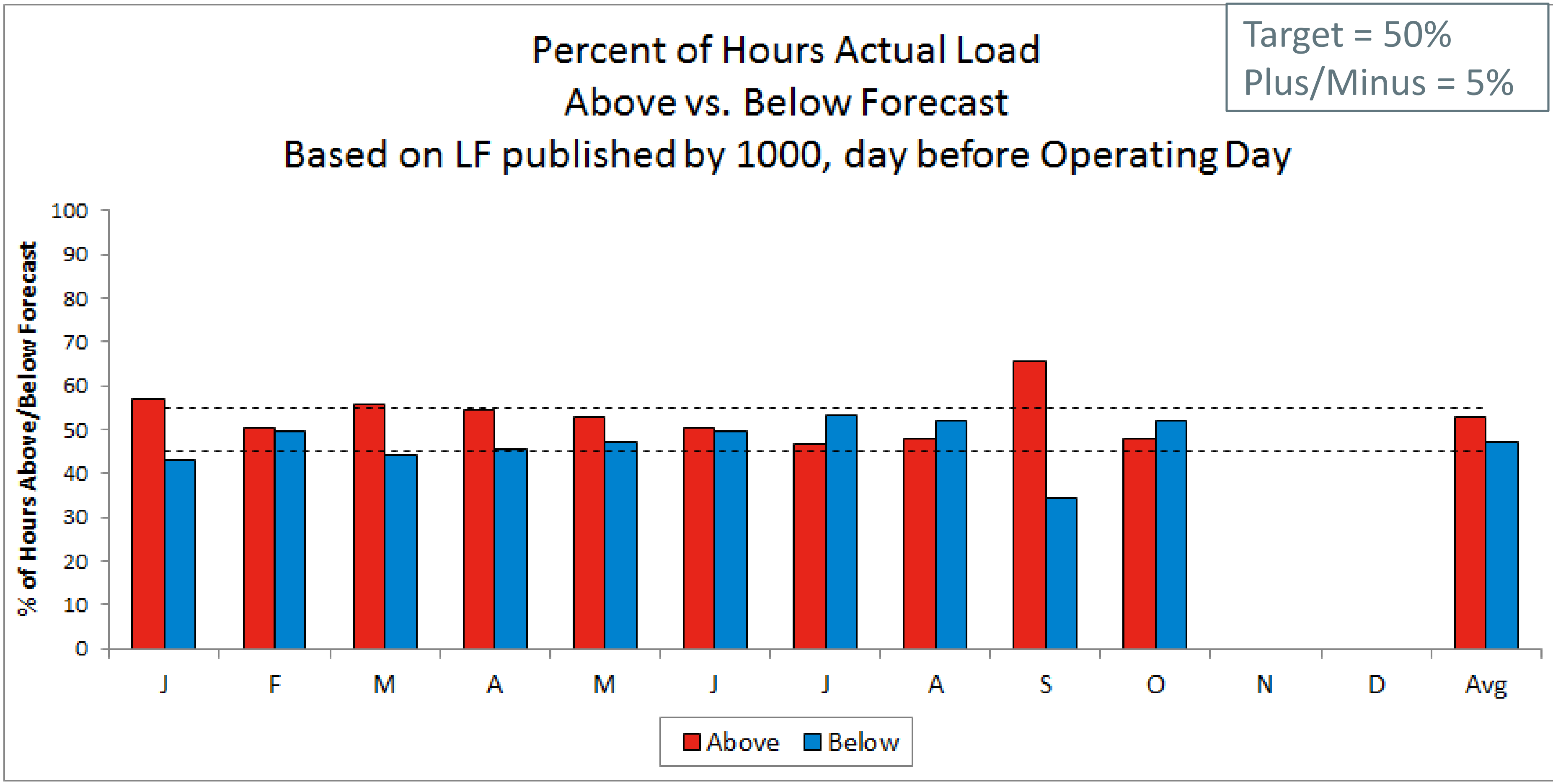
2021 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



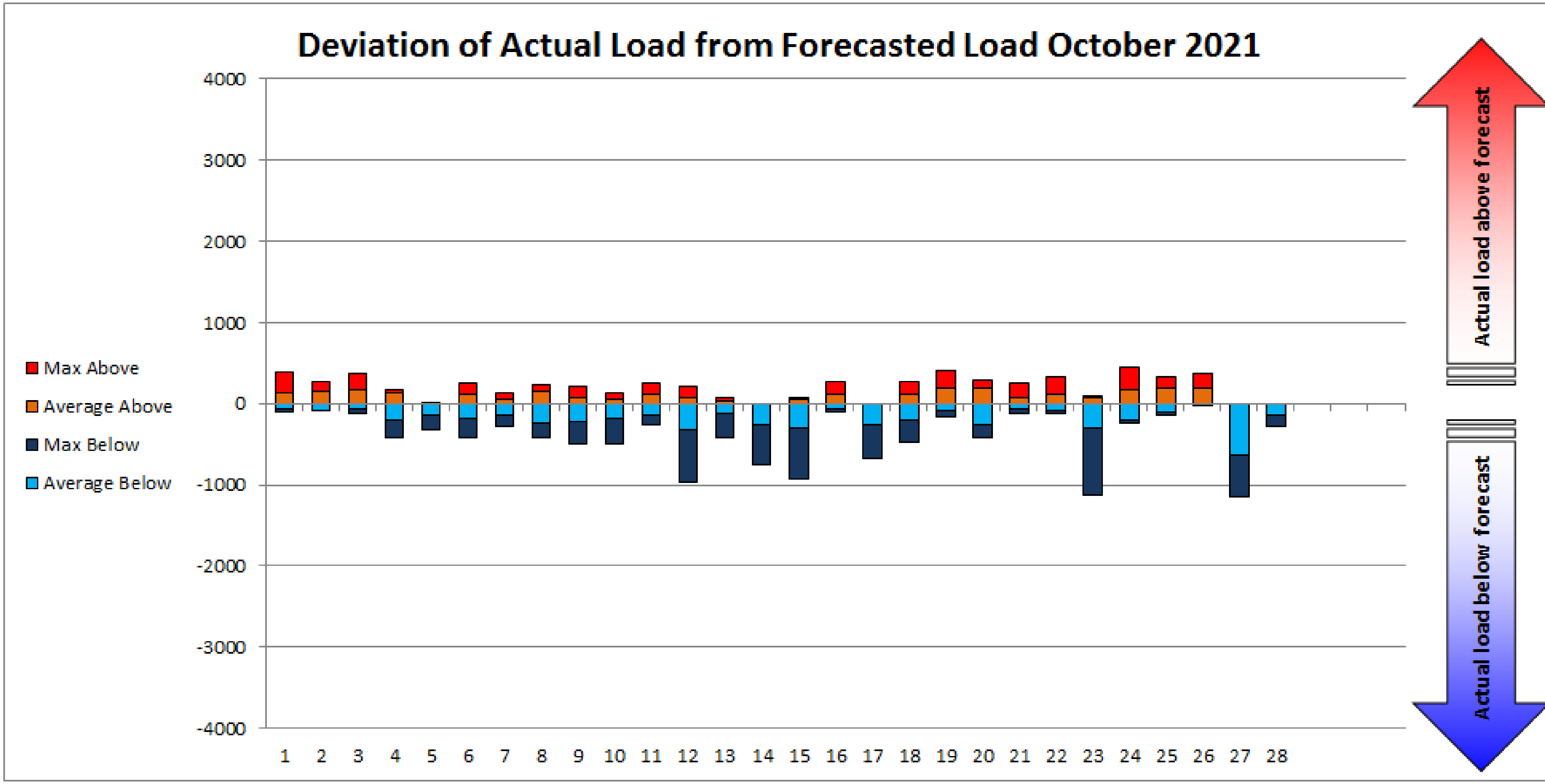
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	3.61	3.03	4.47	5.19	5.31	11.76	10.75	10.54	11.13	5.79			11.76
Day Min	0.02	0.06	0.08	0.03	0.11	0.04	0.05	0.01	0.17	0.09			0.01
MAPE	1.26	1.18	1.48	1.66	1.60	2.79	2.78	2.86	2.76	1.39			1.98
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60	2.60	2.00	1.80			

2021 System Operations - Load Forecast Accuracy cont.

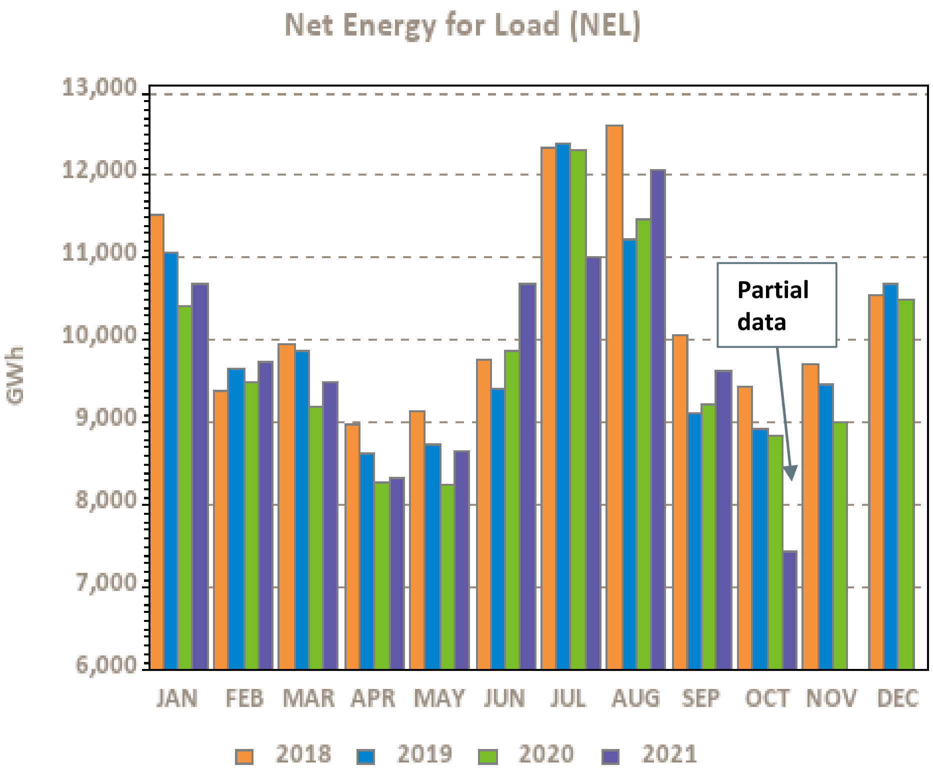


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	57.1	50.4	55.6	54.4	52.8	50.3	46.9	47.8	65.4	47.9			53
Below %	42.9	49.6	44.4	45.6	47.2	49.7	53.1	52.2	34.6	52.1			47
Avg Above	209.5	166.7	185.4	206.1	227.4	233.1	214.5	227	263.1	86.7			263
Avg Below	-147.6	-216.4	-188.0	-167.9	-146.8	-309.1	-348.1	-307.5	-196.2	-163.6			-348
Avg All	60	-25	30	40	61	-48	-122	-79	102	-58			-4

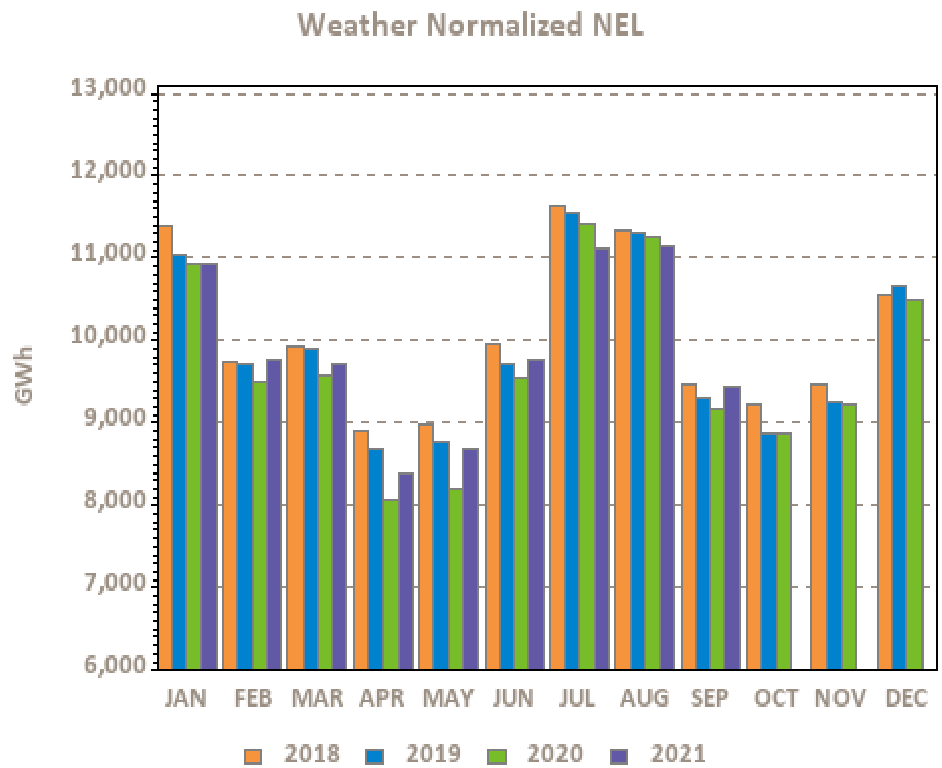
2021 System Operations - Load Forecast Accuracy cont.



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



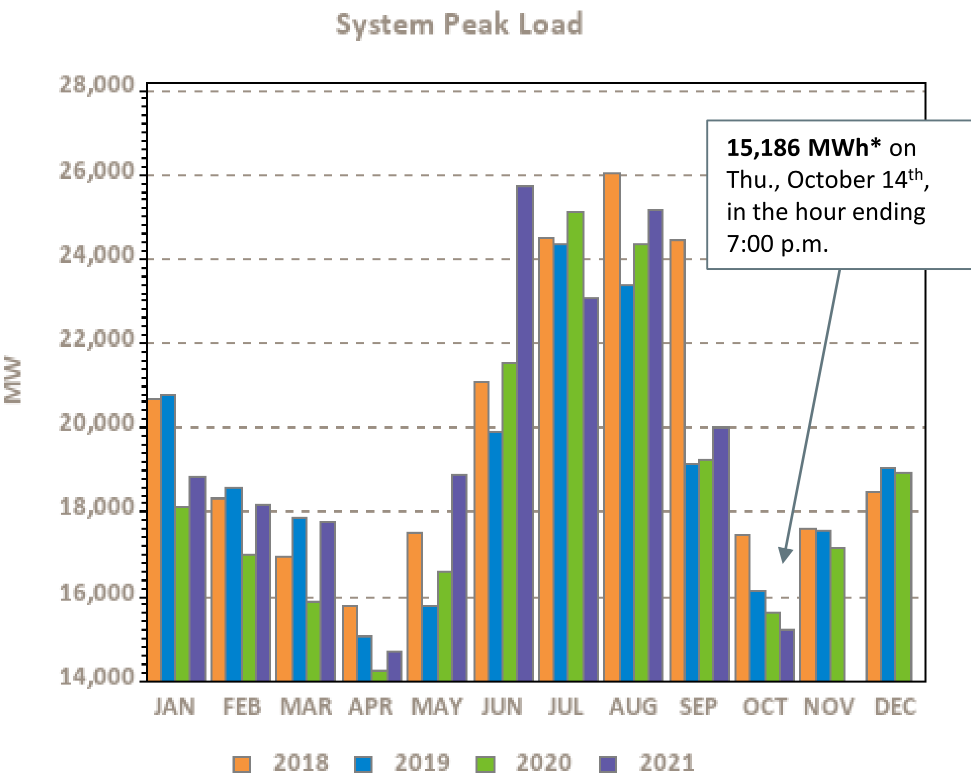
Ann Tot (TWh): 123.5 119.2 116.9 97.7



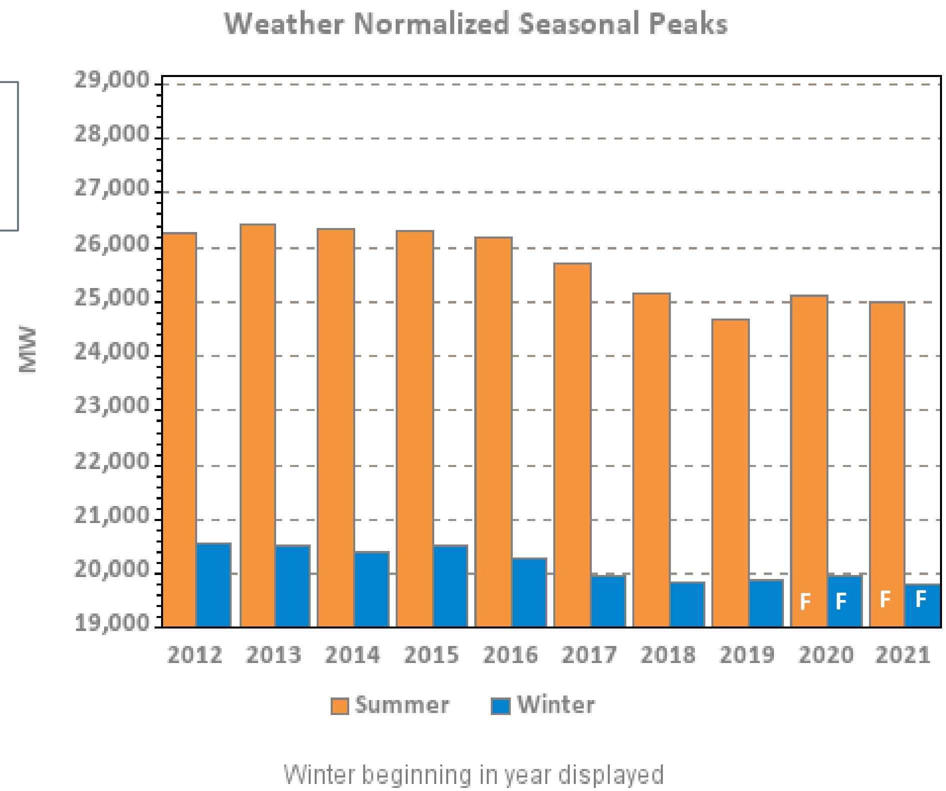
Ann Tot (TWh): 120.6 118.8 116.3 89.0

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



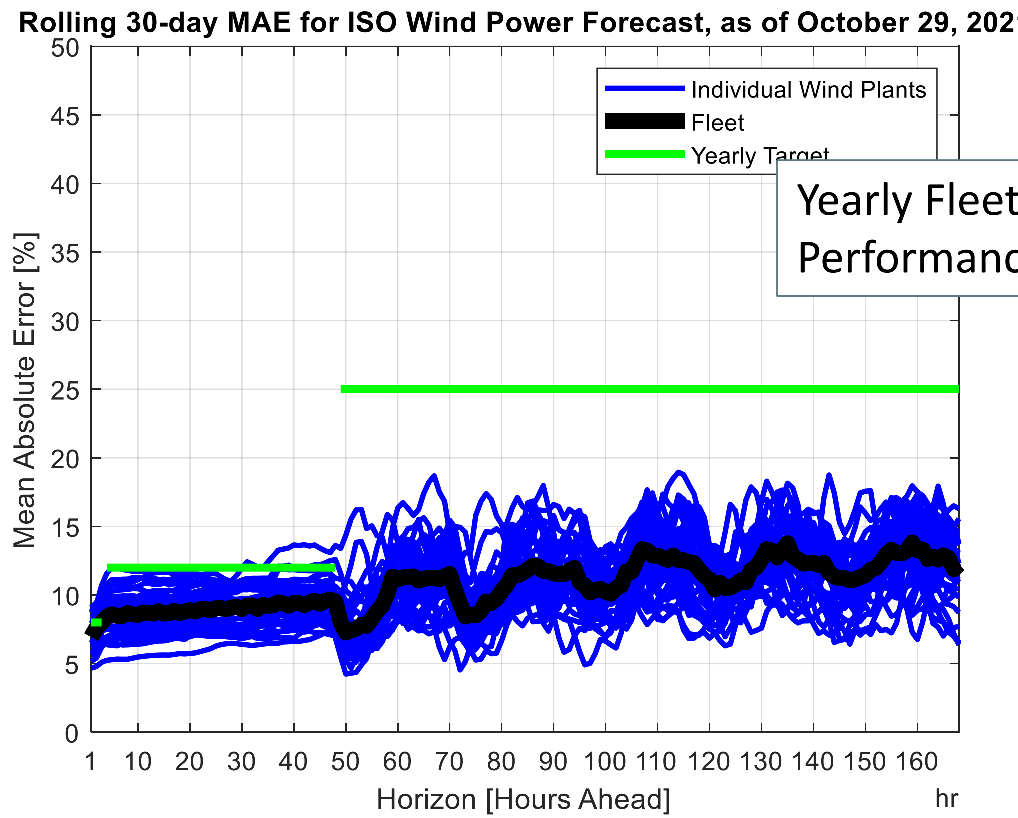
*Revenue quality metered value



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

Dashboard Indicator

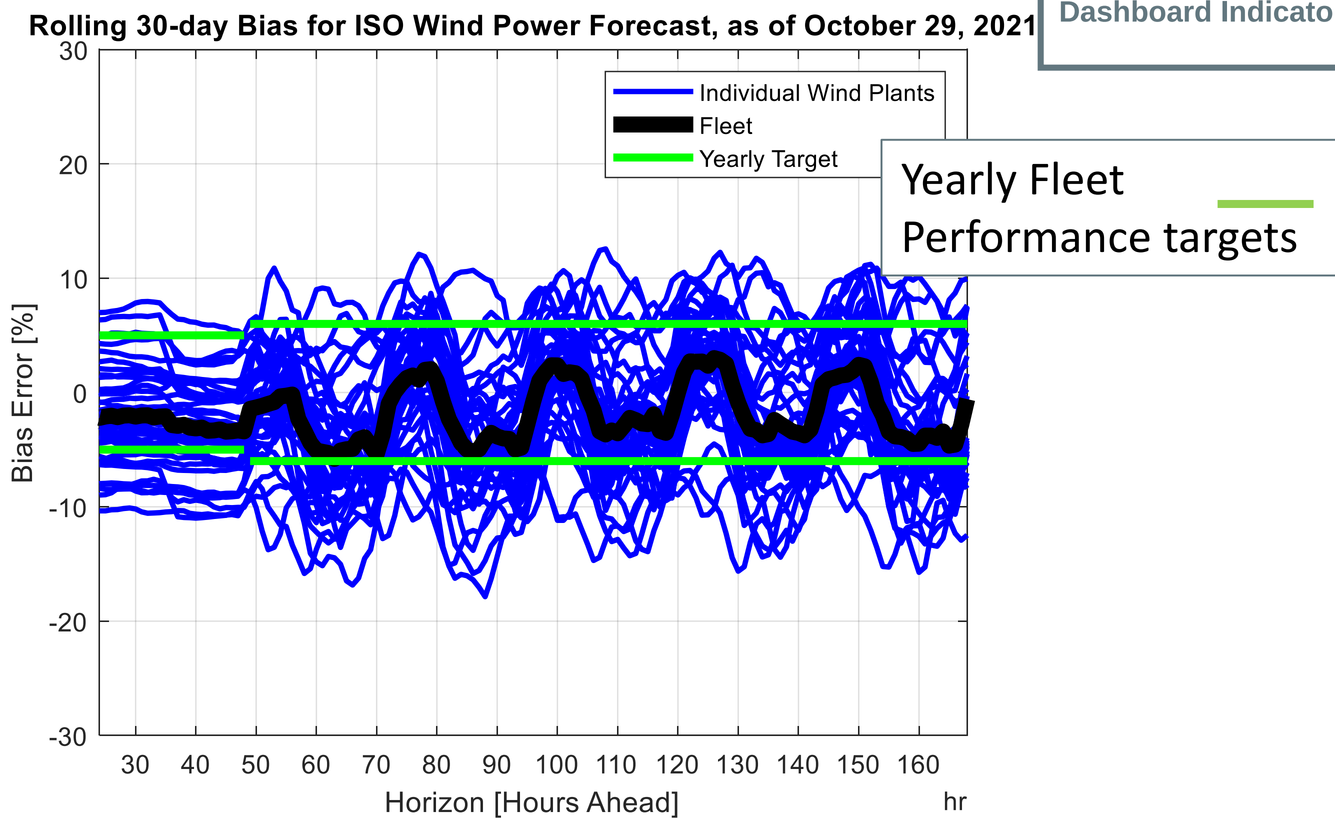


Yearly Fleet Performance targets

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

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

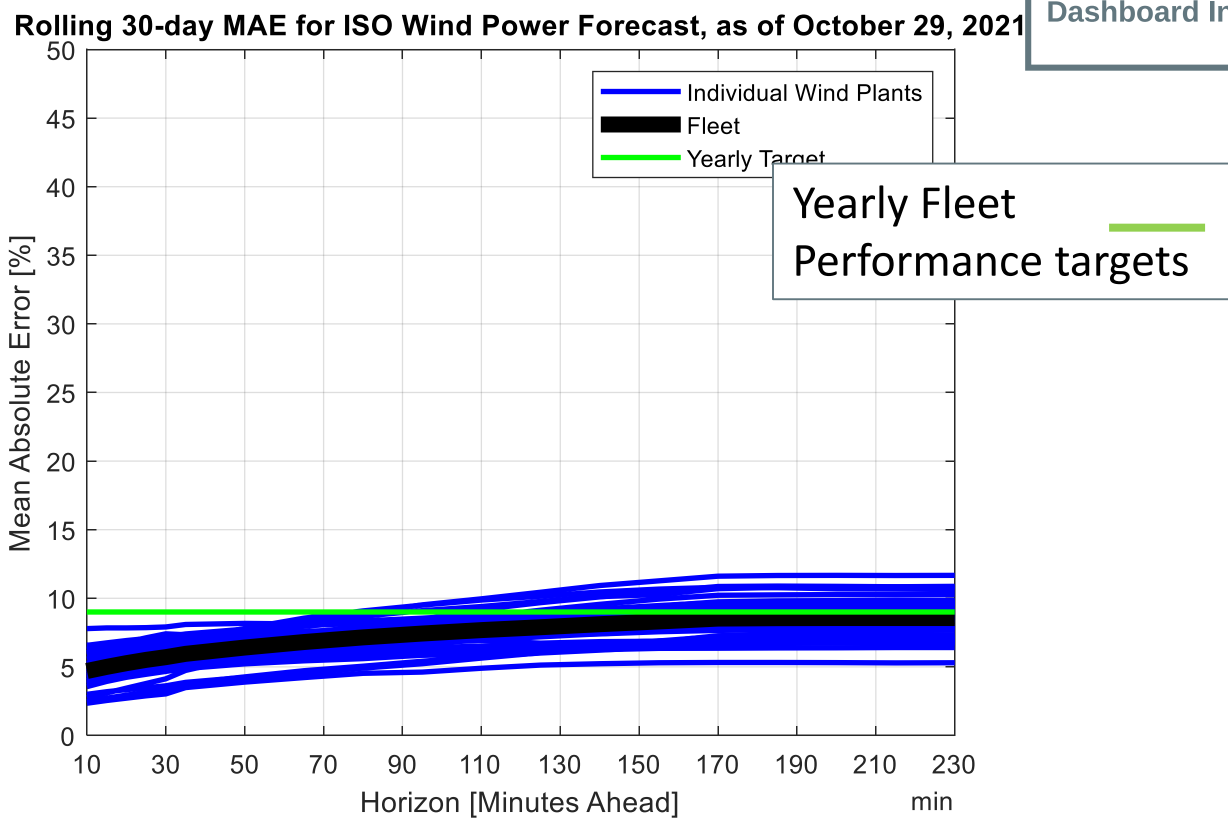
Dashboard Indicator



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

Wind Power Forecast Error Statistics: Short Term Forecast MAE

Dashboard Indicator



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Wind Power Forecast Error Statistics: Short Term Forecast Bias

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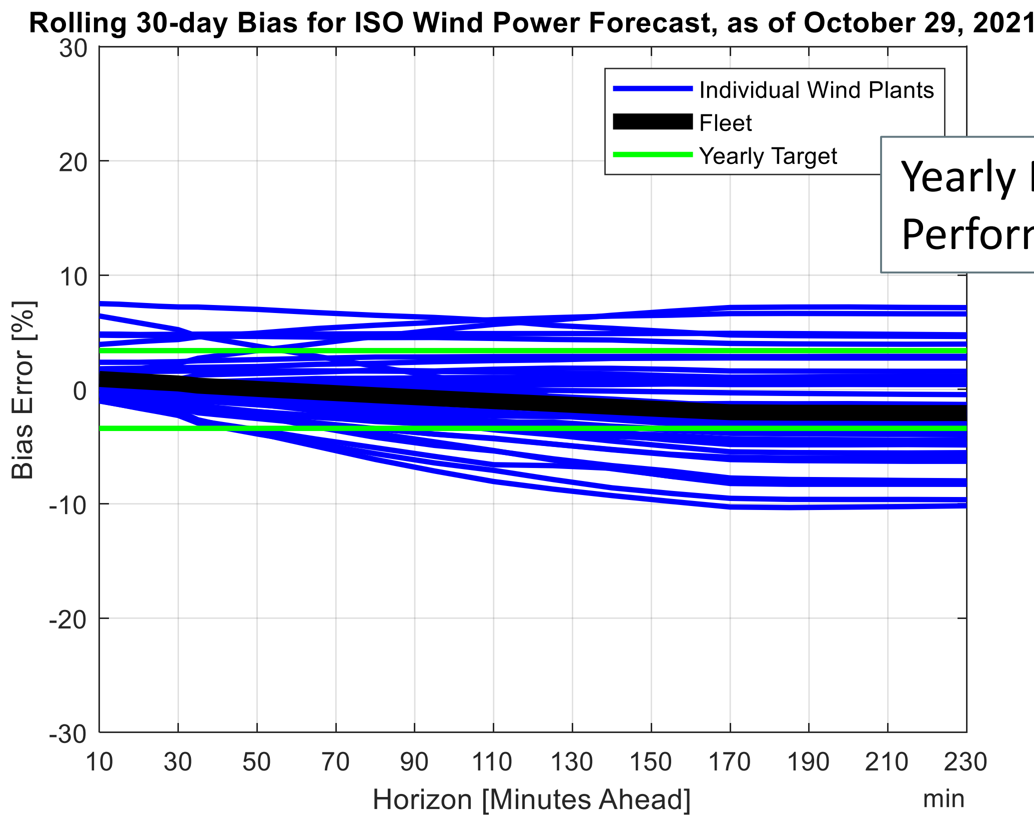

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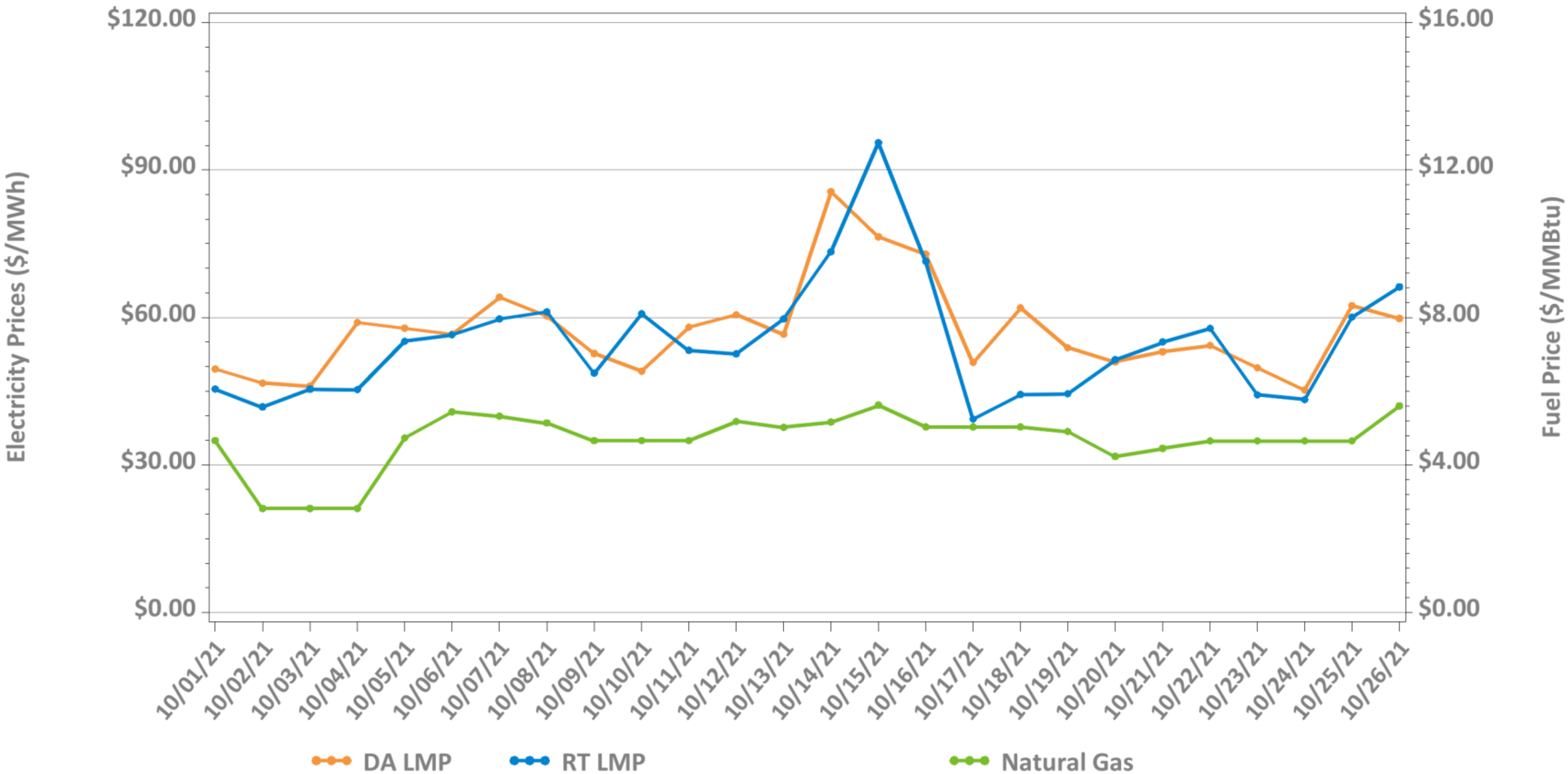
MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: October 1-26, 2021

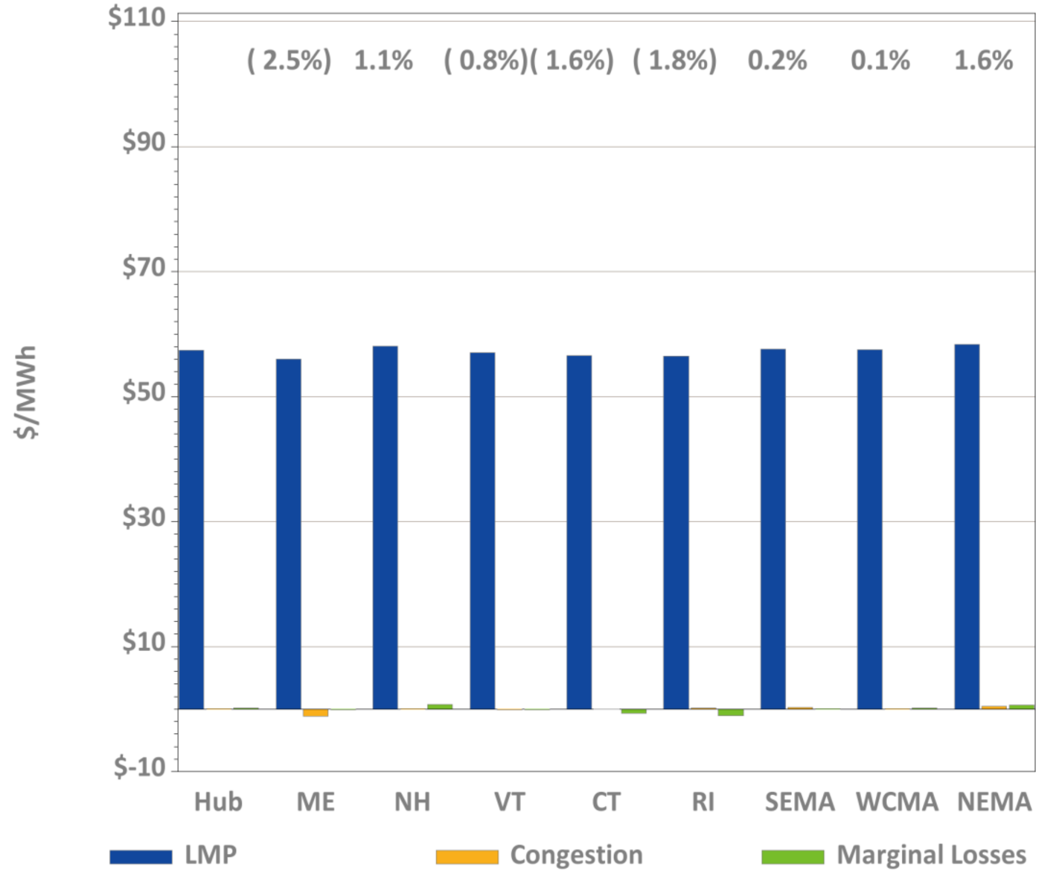


Underlying natural gas data furnished by:

ICE Global markets in clear view

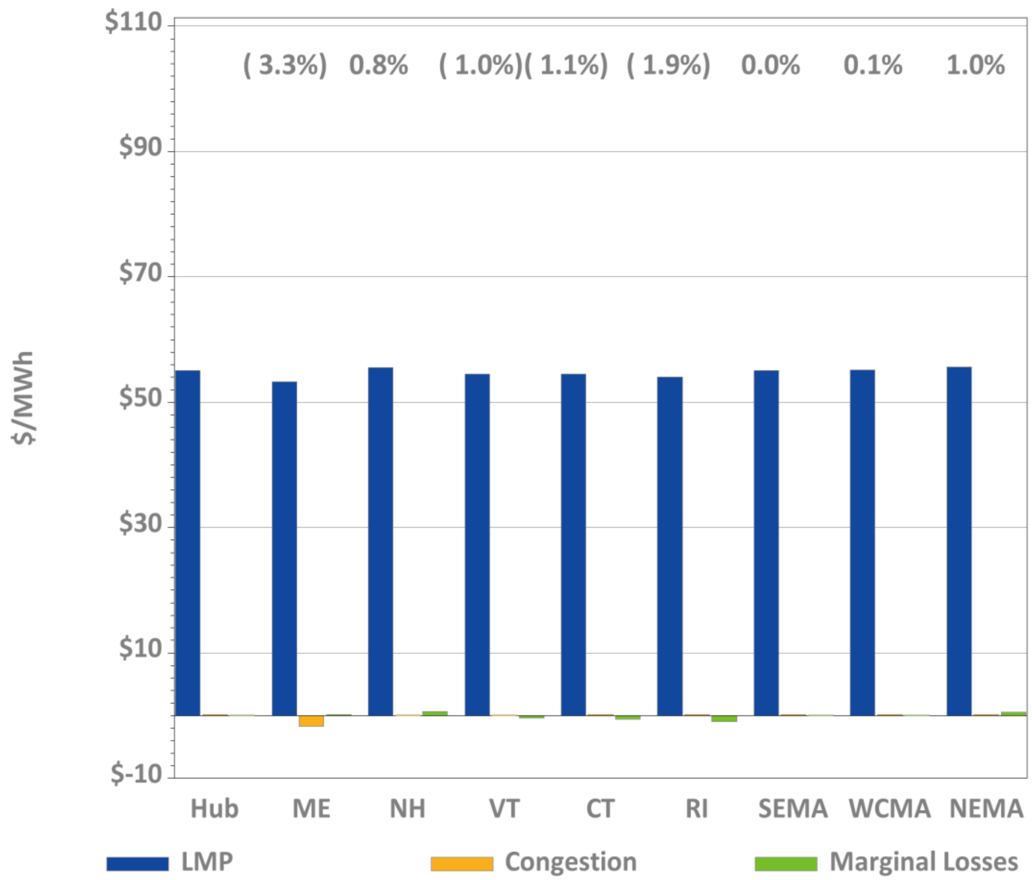
Average price difference over this period (DA-RT): $2.38
Average price difference over this period ABS(DA-RT): $6.01
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 11%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, October 2021



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

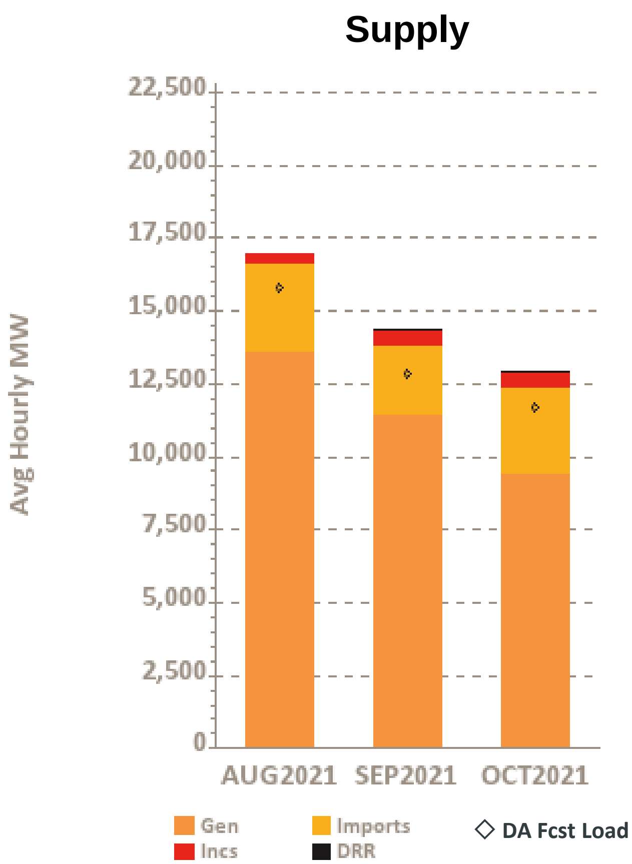
RT LMPs Average by Zone & Hub, October 2021

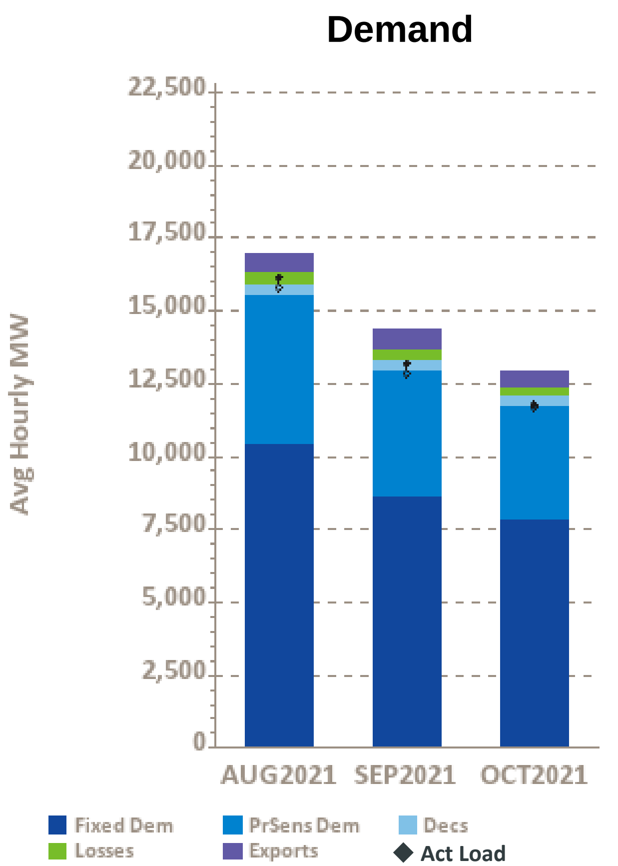


Definitions

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

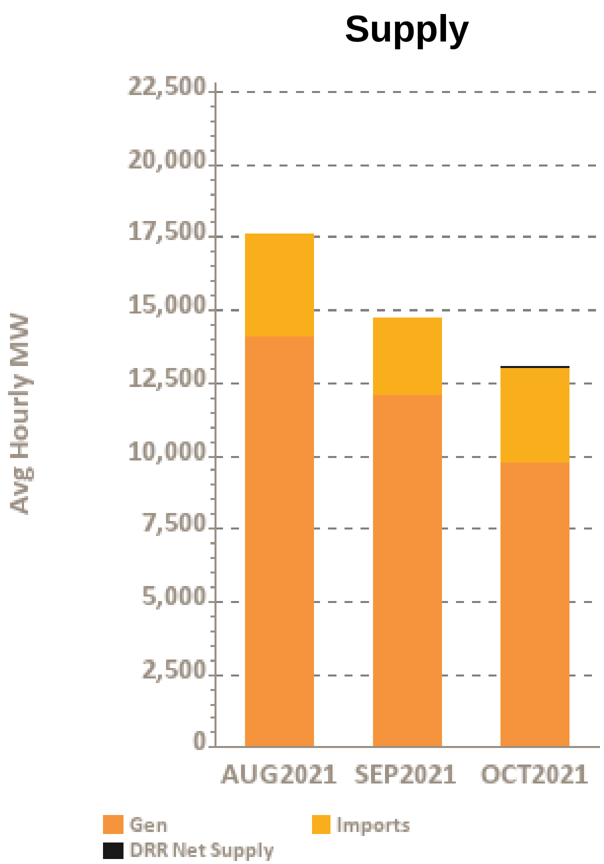


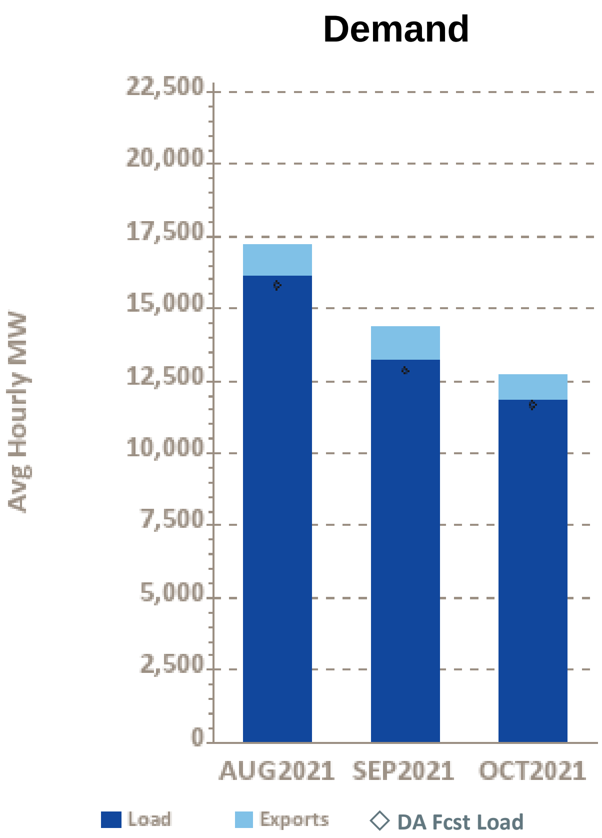


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

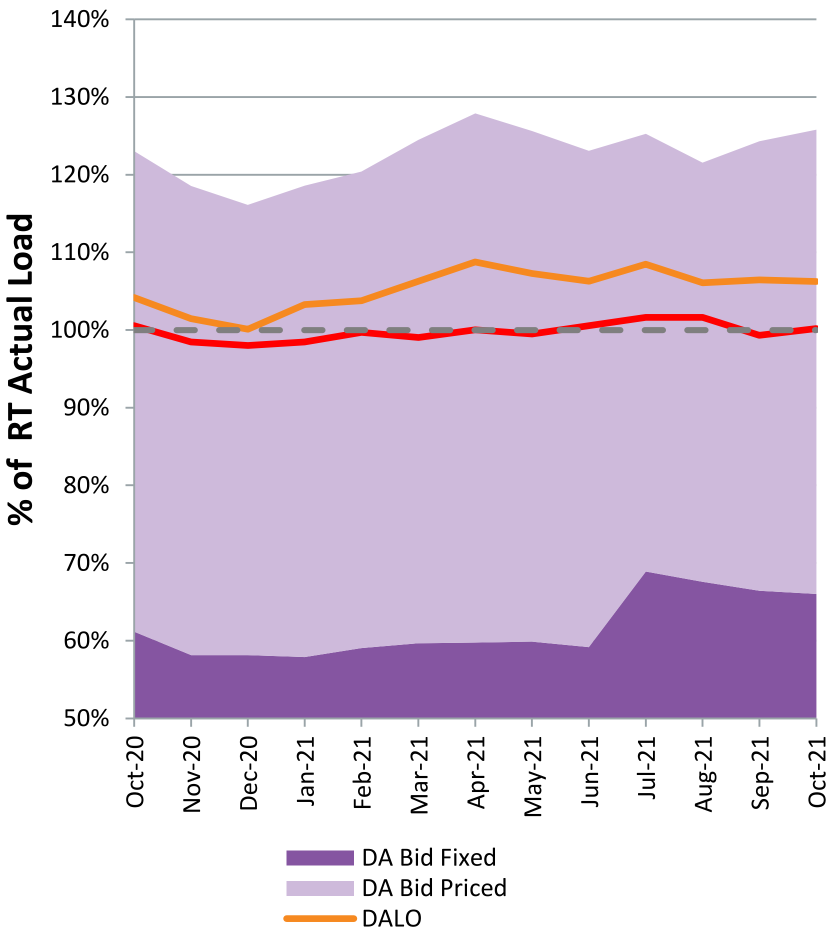
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

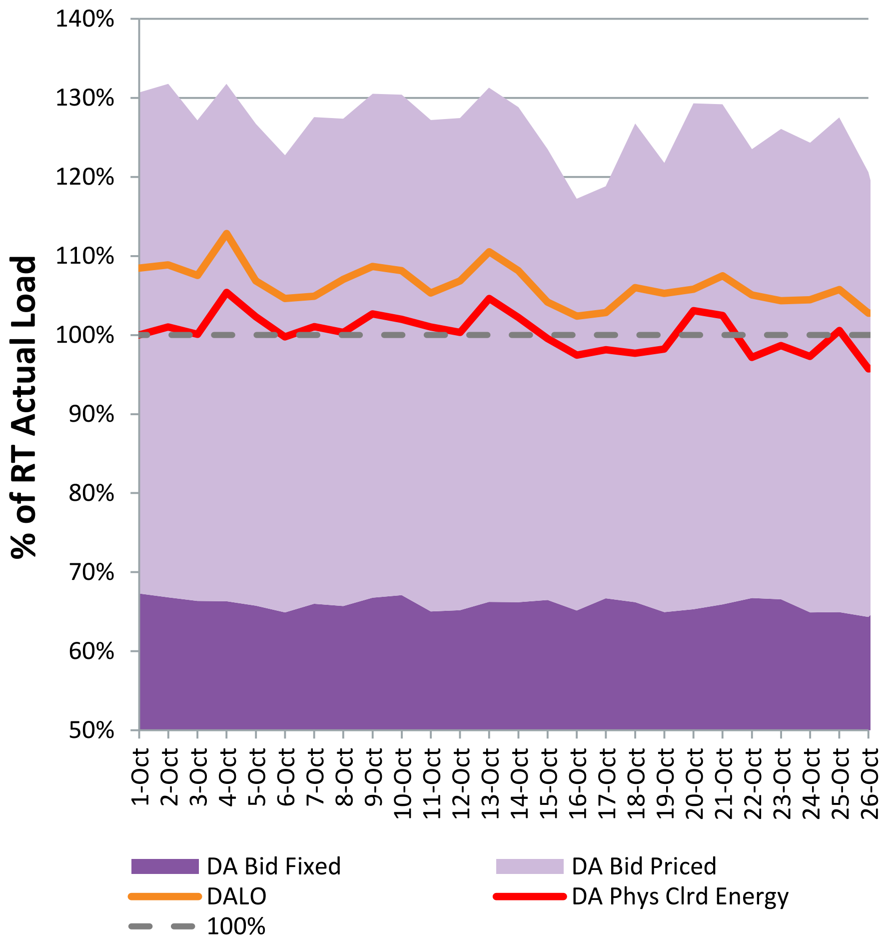
Components of RT Supply and Demand – Last Three Months





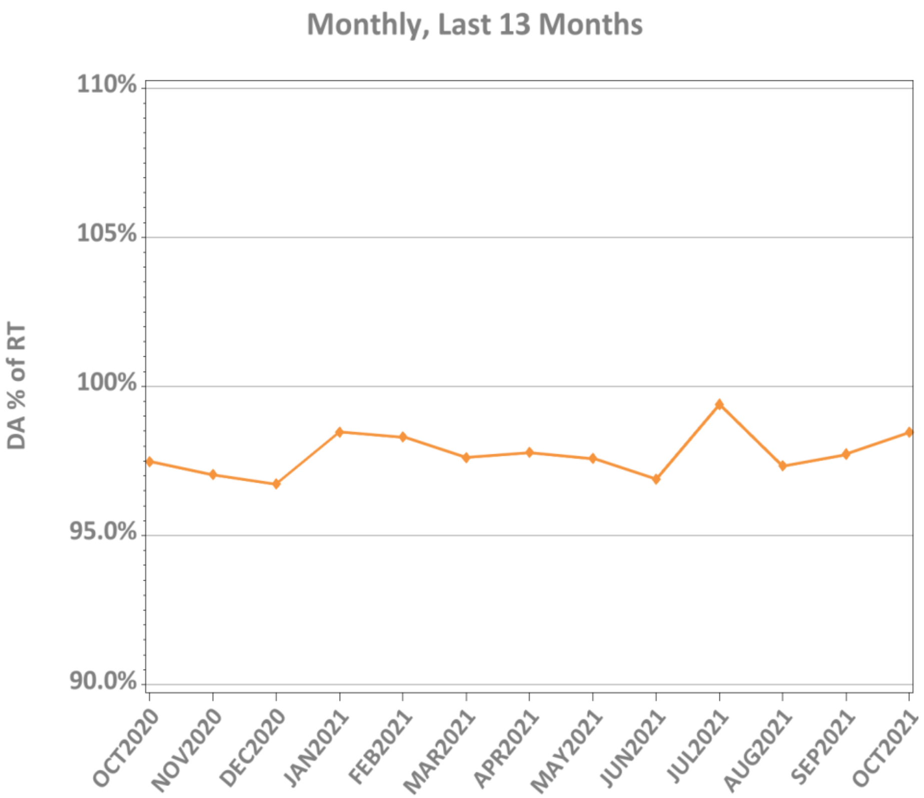
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

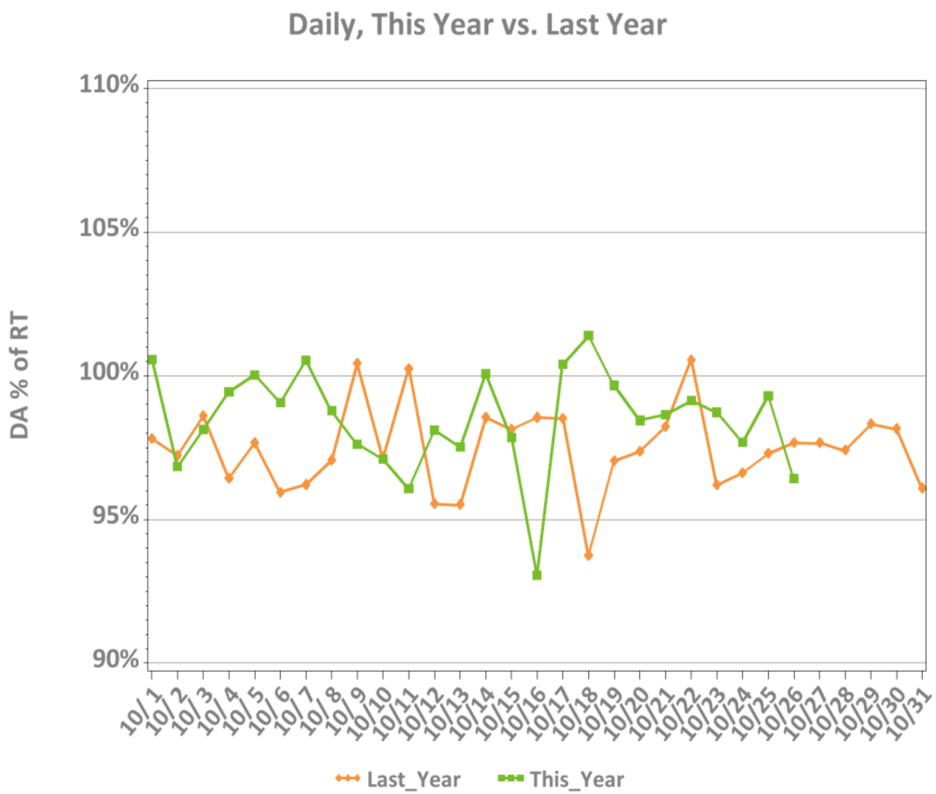




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

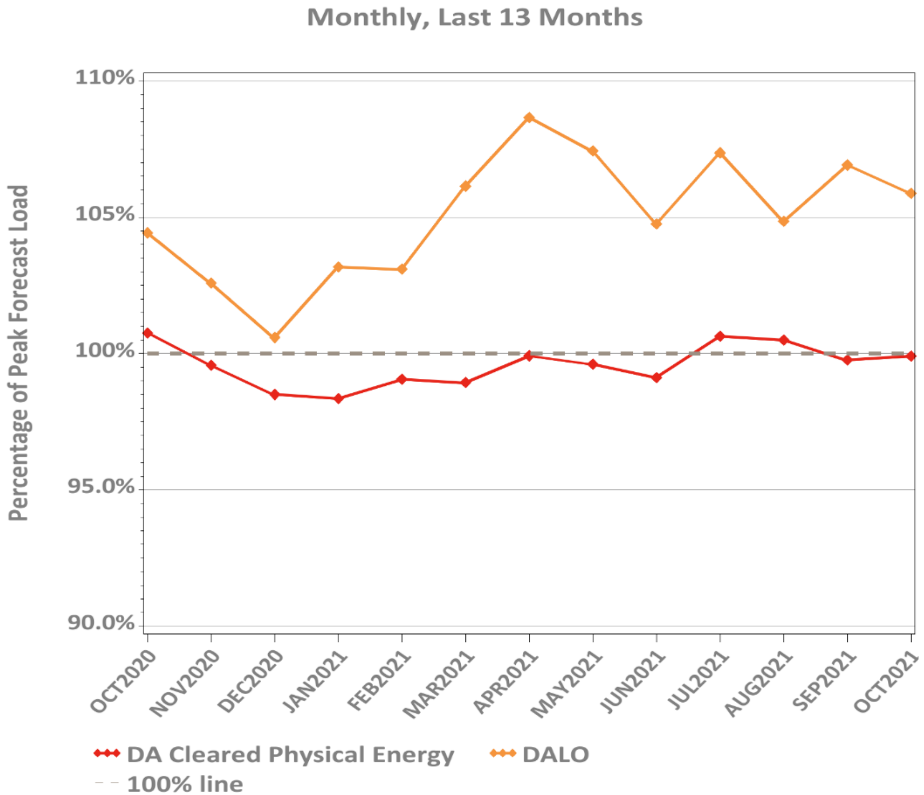
DA vs. RT Load Obligation: October, This Year vs. Last Year

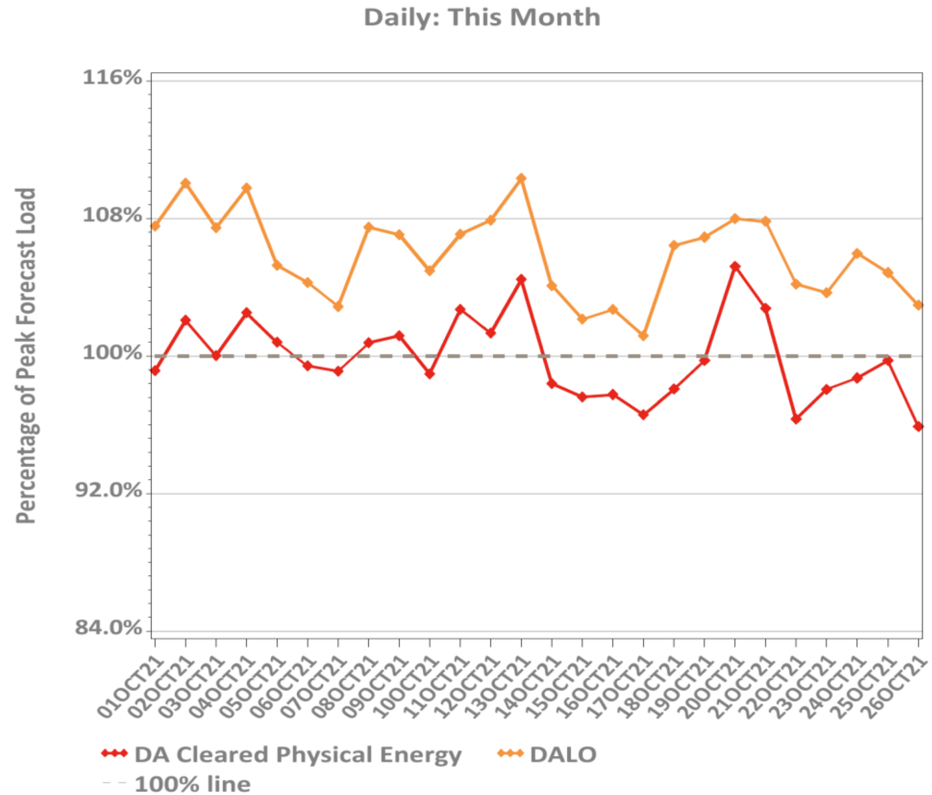




*Hourly average values

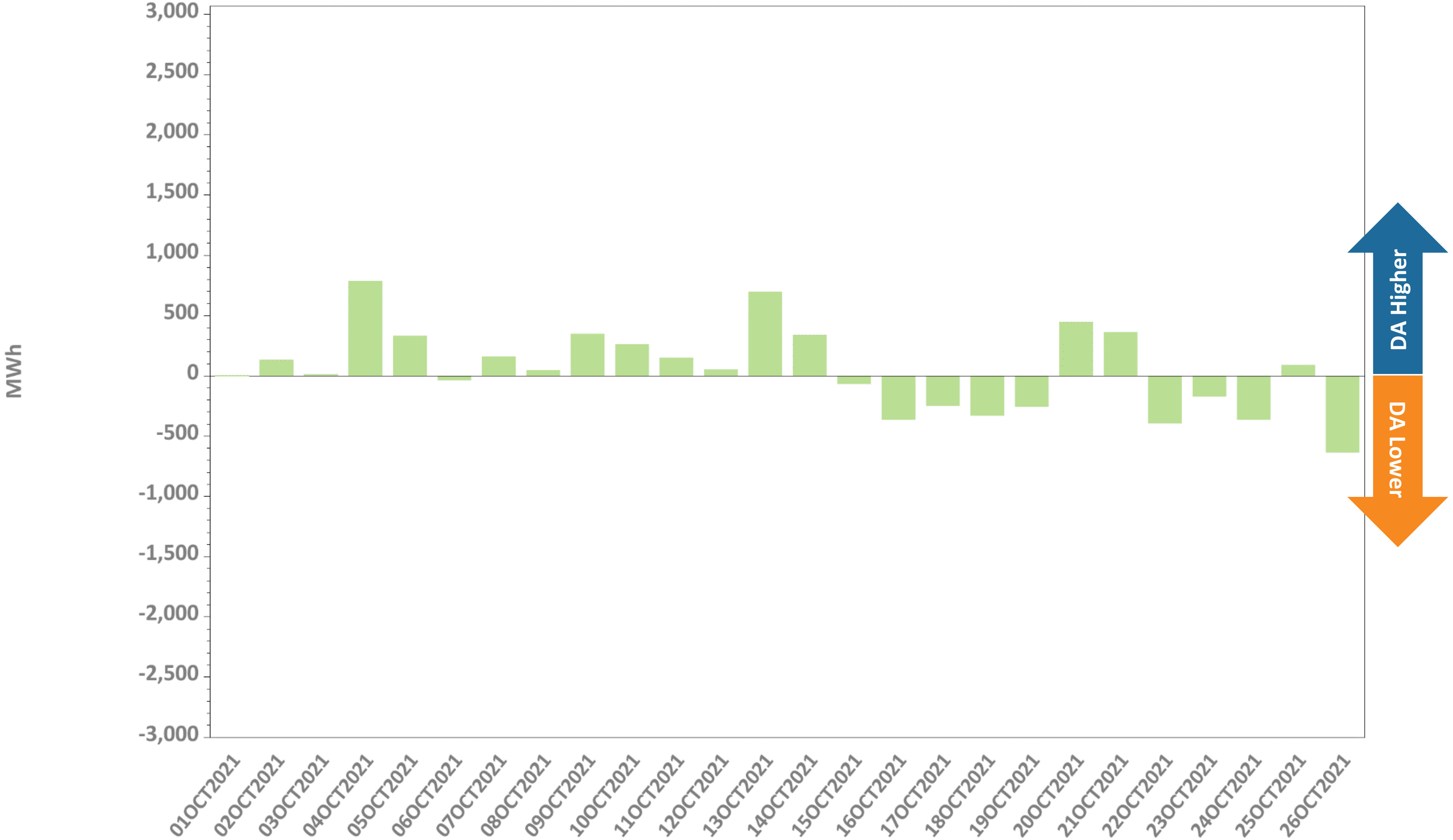
DA Volumes as % of Forecast in Peak Hour





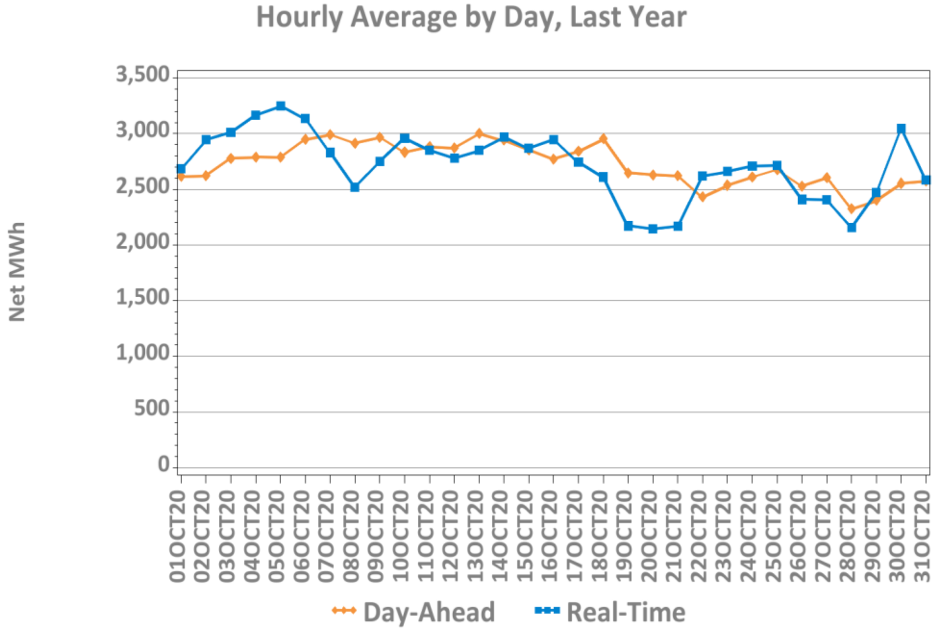
Note: There were several system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during the month.

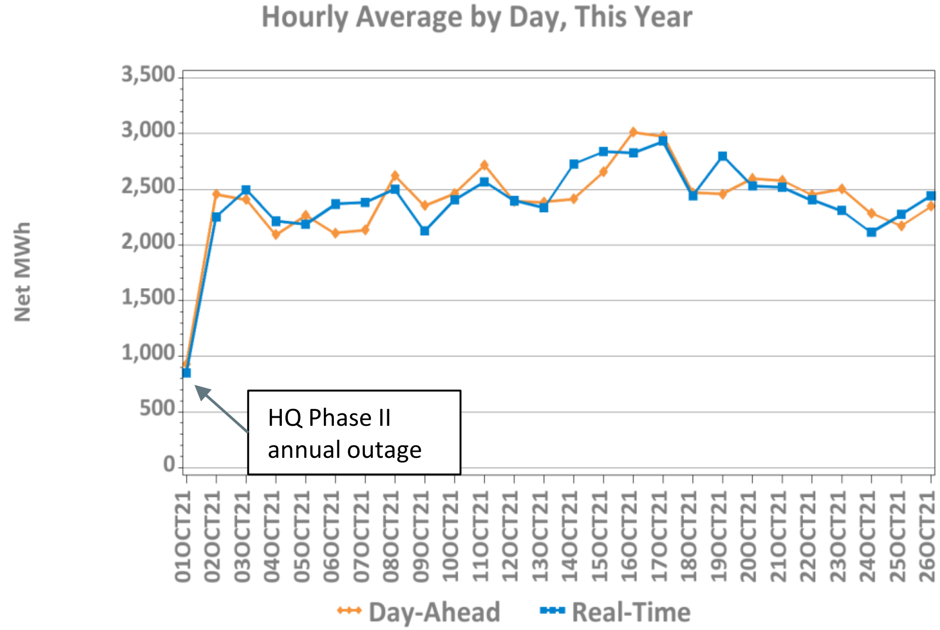
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



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

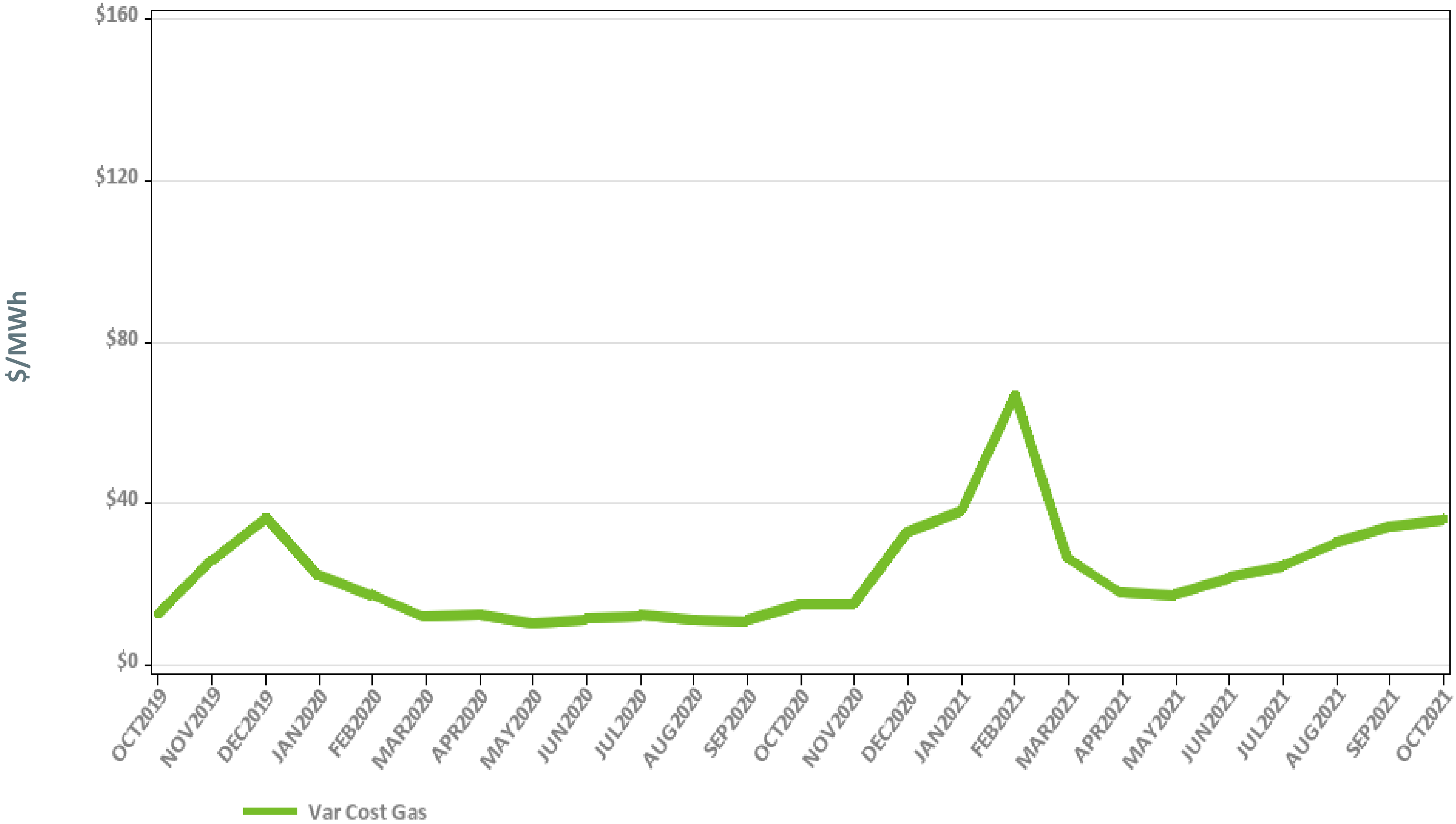
DA vs. RT Net Interchange October 2020 vs. October 2021





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

Variable Production Cost of Natural Gas: Monthly

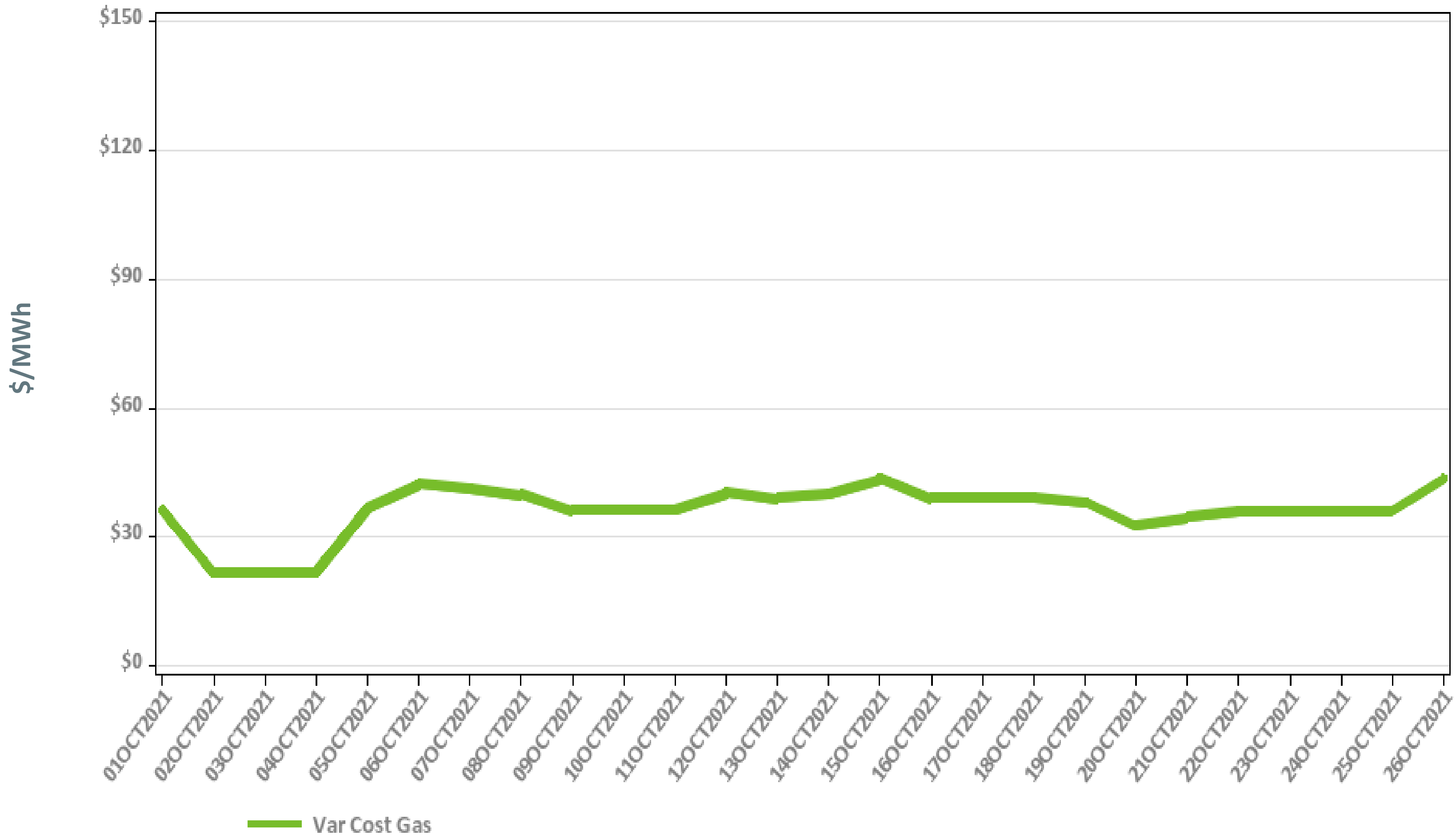


Underlying natural gas data furnished by:

ice Global markets in clear view

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

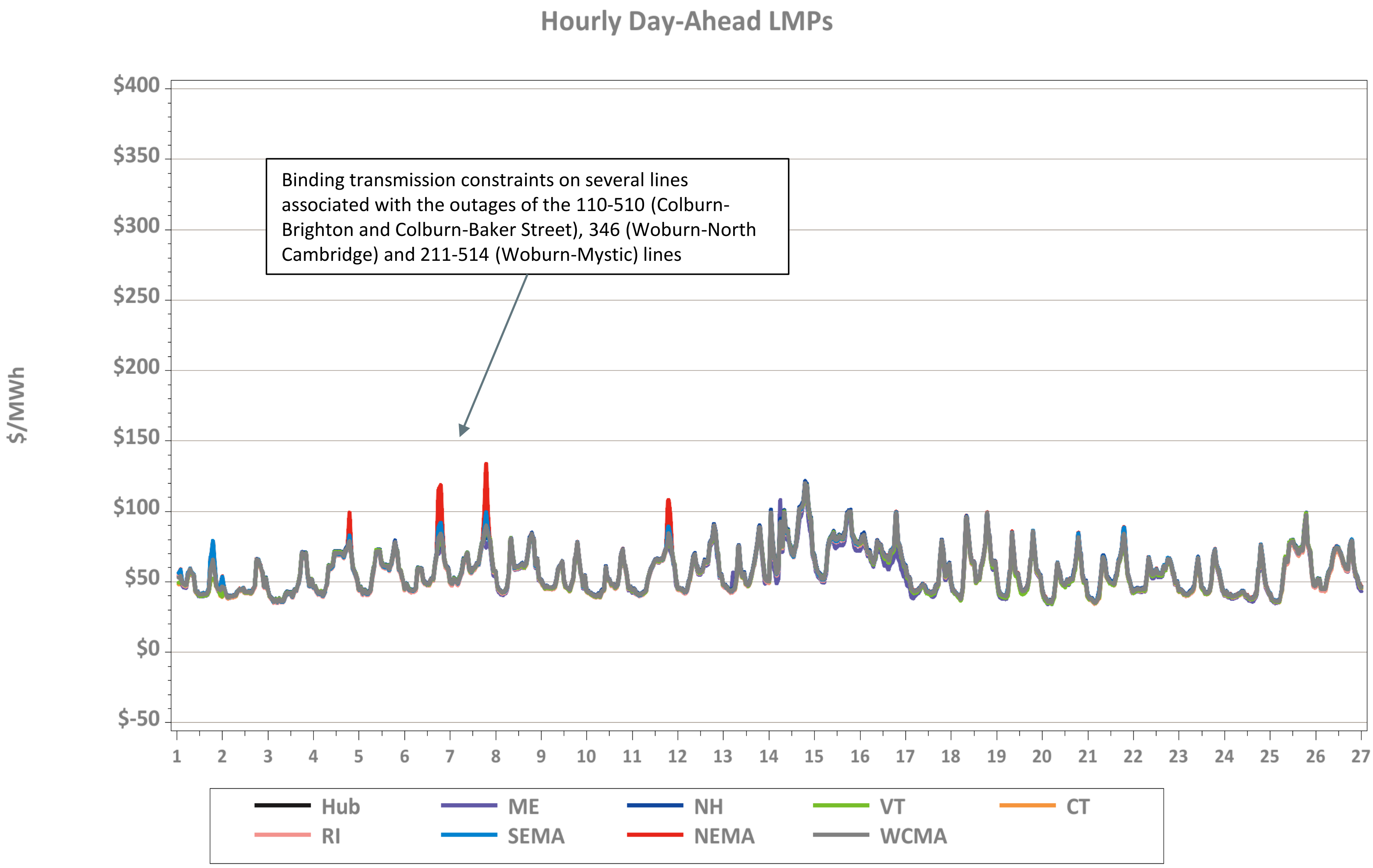
Variable Production Cost of Natural Gas: Daily



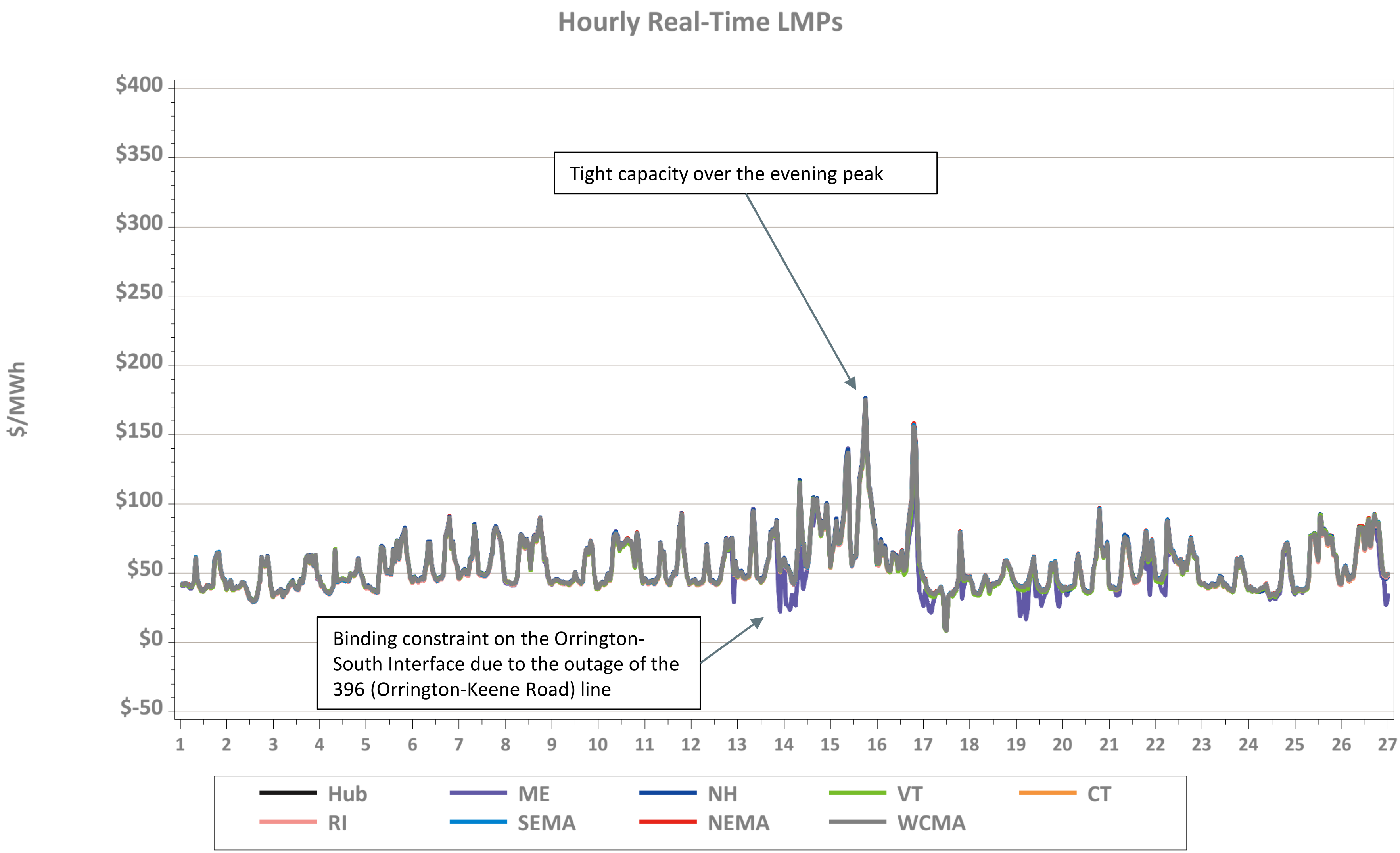
Underlying natural gas data furnished by:

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

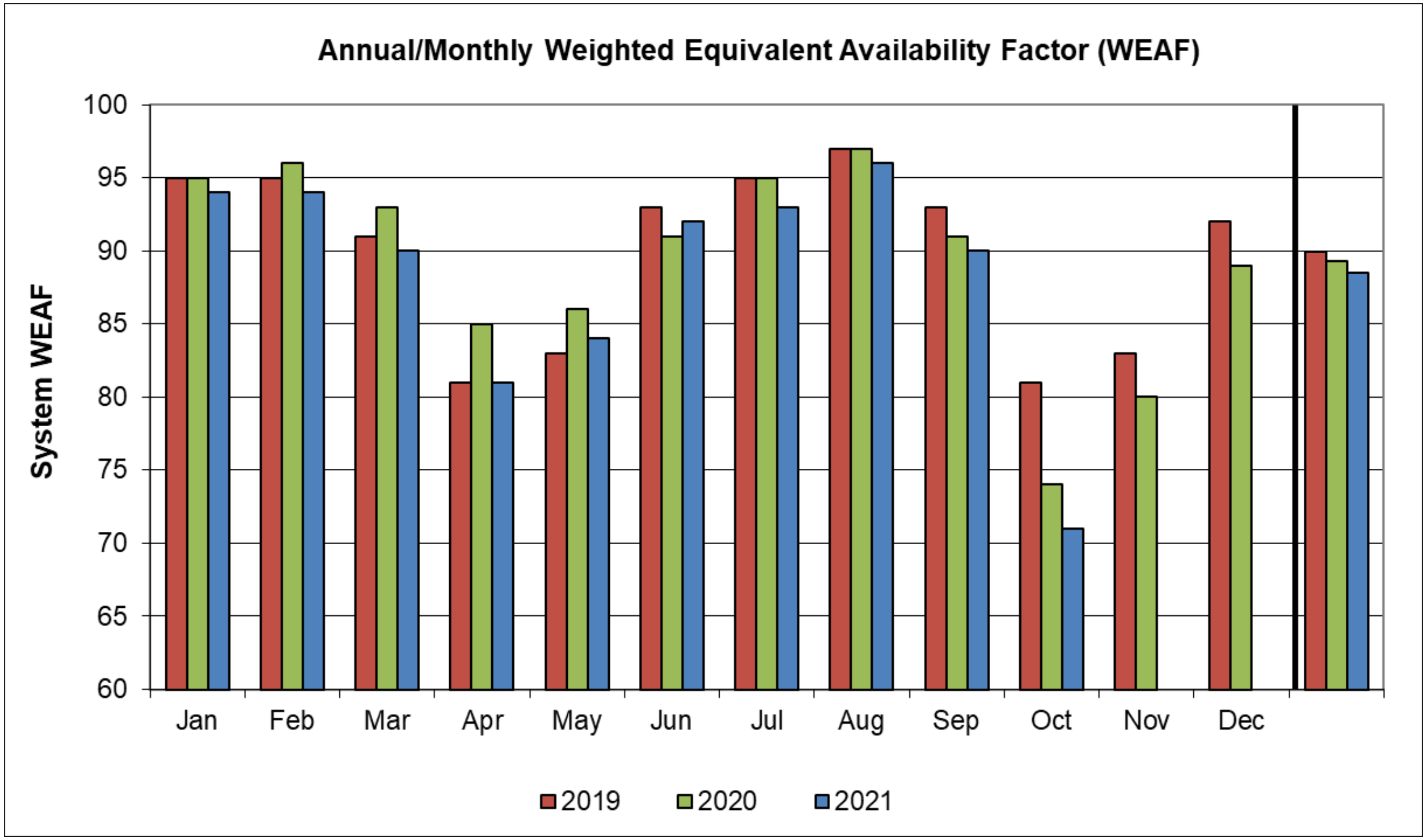
Hourly DA LMPs, October 1-26, 2021



Hourly RT LMPs, October 1-26, 2021



System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2021	94	94	90	81	84	92	93	96	90	71			89
2020	95	96	93	85	86	91	95	97	91	74	80	89	89
2019	95	95	91	81	83	93	95	97	93	81	83	92	90

Data as of 10/26/2021

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for November 2021

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	82.3	202.5	0.0	284.8
NH	40.7	147.6	0.0	188.2
VT	33.4	125.6	0.0	159.0
CT	136.6	120.1	614.8	871.5
RI	39.2	323.4	0.0	362.6
SEMA	43.9	485.2	0.0	529.2
WCMA	78.8	530.4	18.0	627.1
NEMA	59.1	841.7	0.0	900.8
Total	**514.0**	**2,776.5**	**632.8**	**3,923.3**

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

NEW GENERATION

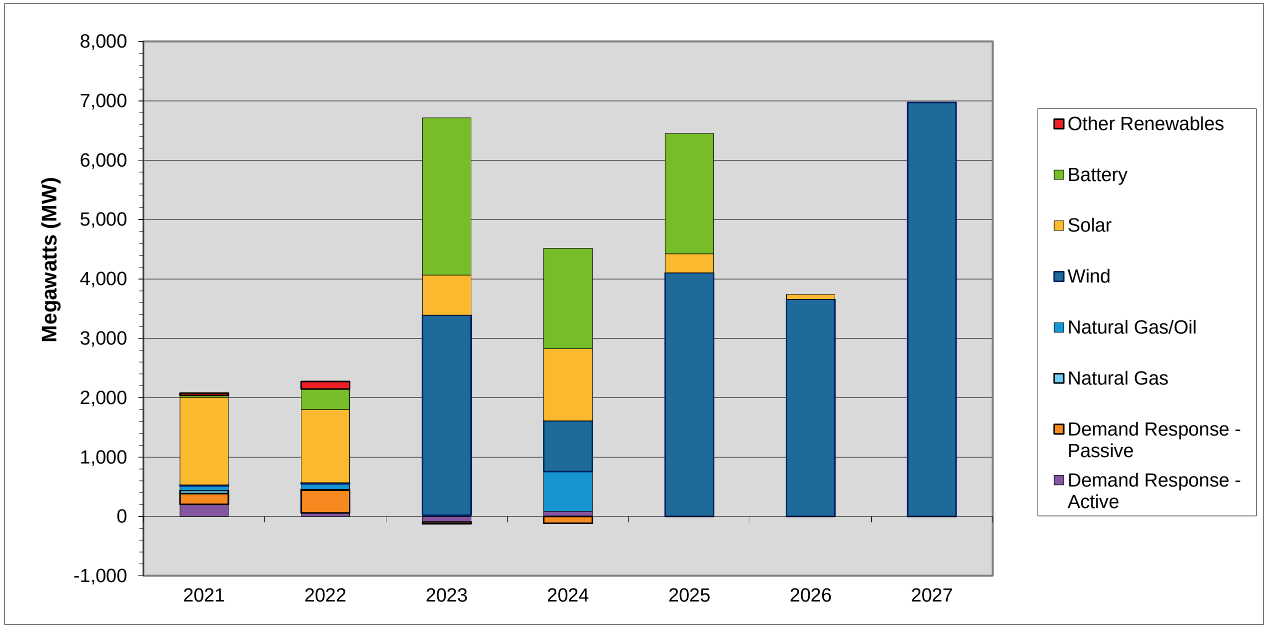
New Generation Update

Based on Queue as of 10/28/21

- Twenty six new projects totaling 587 MW were added to the interconnection queue since the last update
  - They consist of battery and solar-with-battery projects, along with a wind project and a fuel cell project, with in-service dates ranging from 2022 to 2025
- Twelve projects were marked commercial and six projects were withdrawn
- In total, 302 generation projects are currently being tracked by the ISO, totaling approximately 31,837 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



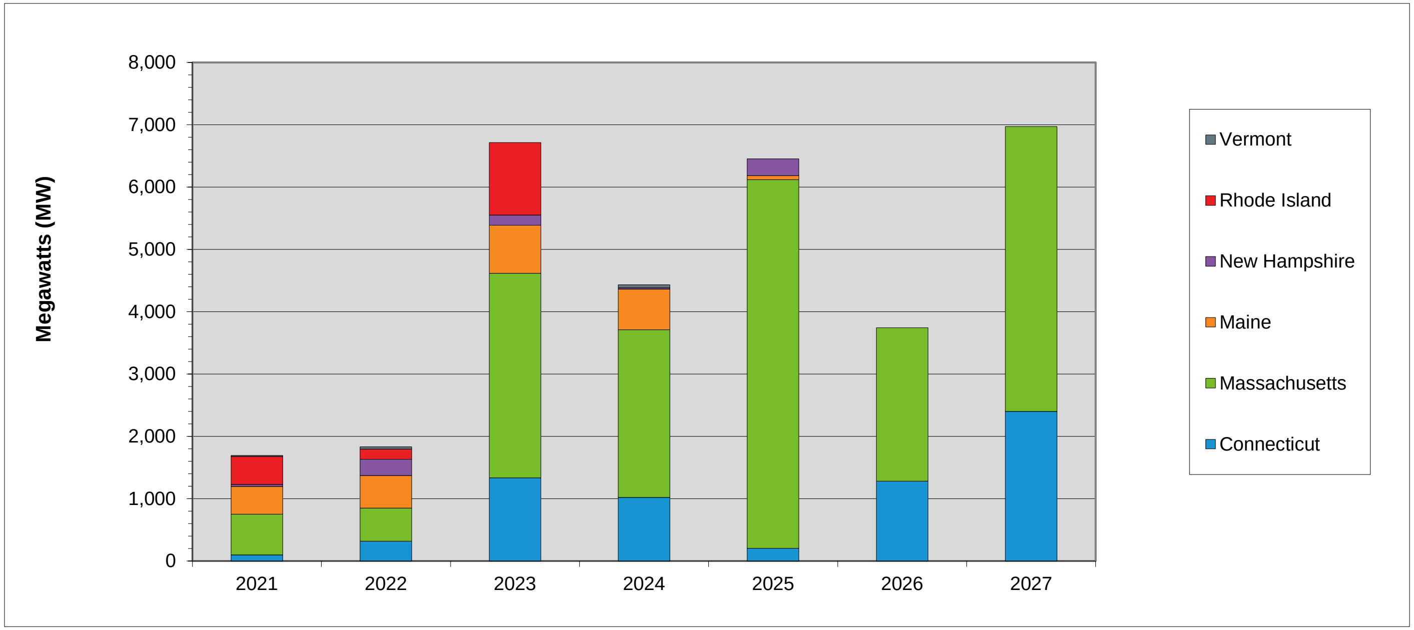
	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Other Renewables	38	128	0	0	0	0	0	166	0.5
Battery	34	347	2,644	1,690	2,030	0	0	6,745	20.7
Solar[2]	1,476	1,232	679	1,218	316	83	0	5,004	15.4
Wind	19	20	3,367	852	4,107	3,658	6,972	18,995	58.4
Natural Gas/Oil[3]	76	89	23	672	0	0	0	860	2.6
Natural Gas	49	18	0	0	0	0	0	67	0.2
Demand Response - Passive	184	380	-28	-114	0	0	0	422	1.3
Demand Response - Active	204	62	-94	86	0	0	0	258	0.8
Totals	**2,080**	**2,276**	**6,591**	**4,404**	**6,453**	**3,741**	**6,972**	**32,517**	**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



	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Vermont	15	40	0	50	0	0	0	105	0.3
Rhode Island	450	160	1,161	0	0	0	0	1,771	5.6
New Hampshire	30	261	164	20	272	0	0	747	2.3
Maine	448	525	774	654	64	0	0	2,465	7.7
Massachusetts	650	531	3,278	2,687	5,912	2,458	4,572	20,088	63.1
Connecticut	99	317	1,336	1,021	205	1,283	2,400	6,661	20.9
Totals	**1,692**	**1,834**	**6,713**	**4,432**	**6,453**	**3,741**	**6,972**	**31,837**	**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	42	6,745	0	0	42	6,745
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	7	860	1	14	6	846
Nuclear	1	37	0	0	1	37
Solar	210	5,004	18	238	192	4,766
Wind	30	18,995	1	15	29	18,980
Total	302	31,837	22	338	280	31,499

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

New Generation Projection

By Operating Type

	Total		Green		Yellow	
Operating Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	6	107	1	5	5	102
Intermediate	8	818	1	14	7	804
Peaker	258	11,917	19	304	239	11,613
Wind Turbine	30	18,995	1	15	29	18,980
Total	302	31,837	22	338	280	31,499

- 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	42	6,745	0	0	0	0	42	6,745	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	7	860	0	0	5	775	2	85	0	0
Nuclear	1	37	1	37	0	0	0	0	0	0
Solar	210	5,004	0	0	0	0	210	5,004	0	0
Wind	30	18,995	0	0	0	0	0	0	30	18,995
Total	302	31,837	6	107	8	818	258	11,917	30	18,995

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation (CSO) FCA 12

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*	624.445	659.137	34.692	603.776	-55.361	587.270	-16.506
	Passive Demand	2,975.36	3,045.073	69.713	3,123.232	78.159	3,322.722	199.490
Demand Total		**3,599.81**	**3,704.21**	**104.4**	**3,727.008**	**22.798**	**3,909.992**	**182.984**
Generator	*Non-Intermittent*	29,130.75	29,244.404	113.654	28,620.245	-624.159	28,941.276	321.031
	Intermittent	880.317	806.609	-73.708	660.932	-145.677	663.179	2.247
Generator Total		**30,011.07**	**30,051.013**	**39.943**	**29,281.177**	**-769.836**	**29,604.455**	**323.278**
Import Total		**1,217**	**1,305.487**	**88.487**	**1,307.587**	**2.10**	**1207.78**	**-99.807**
Grand Total*		**34,827.88**	**35,060.710**	**232.83**	**34,315.772**	**-744.94**	**34,722.227**	**406.455**
Net ICR (NICR)		**33,725**	**33,550**	**-175**	**32,230**	**-1,320**	**32,925**	**695**

* 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
FCA – Forward Capacity Auction
ICR – Installed Capacity Requirement

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		
	Passive Demand	3,354.69	3,407.507	52.817	3,450.899	43.392		
Demand Total		**4,040.244**	**4,090.623**	**50.38**	**4,109.558**	**18.935**		
Generator	*Non-Intermittent*	28,586.498	27,868.341	-718.157	28,105.411	237.07		
	Intermittent	1,024.792	901.672	-123.12	896.285	-5.387		
Generator Total		**2,9611.29**	**28,770.013**	**-841.28**	**29,001.696**	**231.683**		
Import Total		**1,187.69**	**1,292.41**	**104.72**	**1,292.41**	**0**		
Grand Total*		**34,839.224**	**34,153.046**	**-686.18**	**34,403.664**	**250.618**		
Net ICR (NICR)		**33,750**	**32,465**	**-1,285**	**32,765**	**300**		

* 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 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						
	Passive Demand	3,212.865						
Demand Total		**3,890.538**						
Generator	*Non-Intermittent*	28,154.203						
	Intermittent	1,089.265						
Generator Total		**29,243.468**						
Import Total		**1,487.059**						
Grand Total*		**34,621.065**						
Net ICR (NICR)		**33,270**						

* 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	**2375.422**	**370.734**	**2746.156**
2020-21	Active	334.634	85.294	419.928
	Passive	2,236.73	554.292	2,791.02
	Grand Total	**2571.361**	**639.586**	**3210.947**
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	**3085.734**	**514.072**	**3599.806**
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	**3386.703**	**653.541**	**4040.244**
2023-24	Active	560.55	31.493	592.043
	Passive	3,035.51	291.565	3,327.07
	Grand Total	**3596.056**	**323.058**	**3919.114**
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**

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

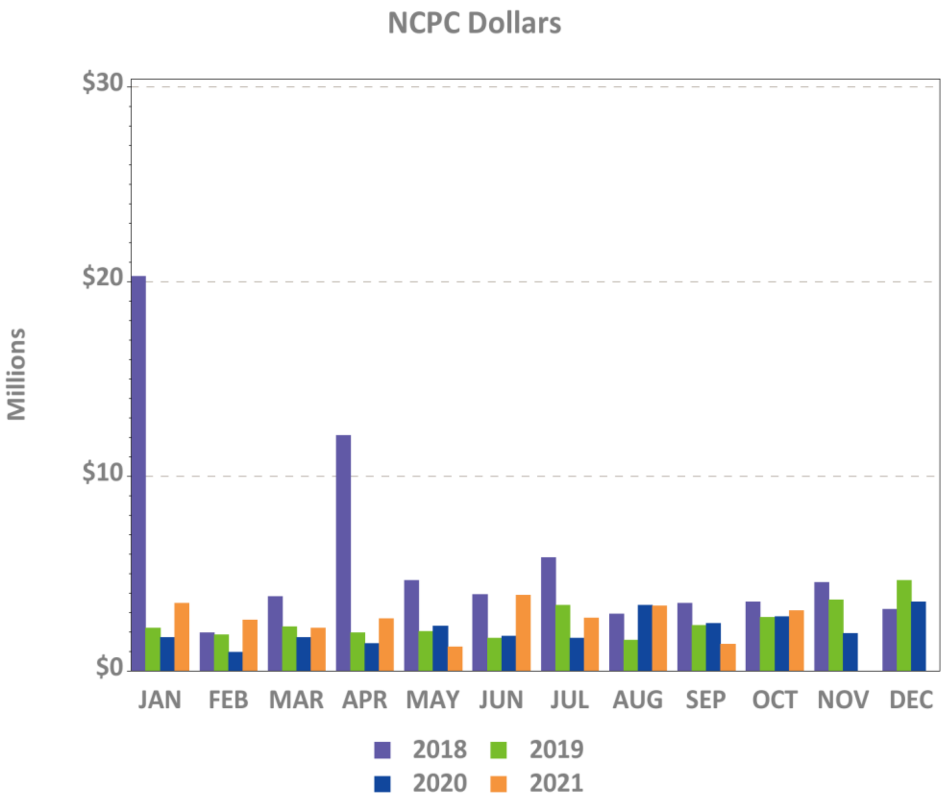
Definitions

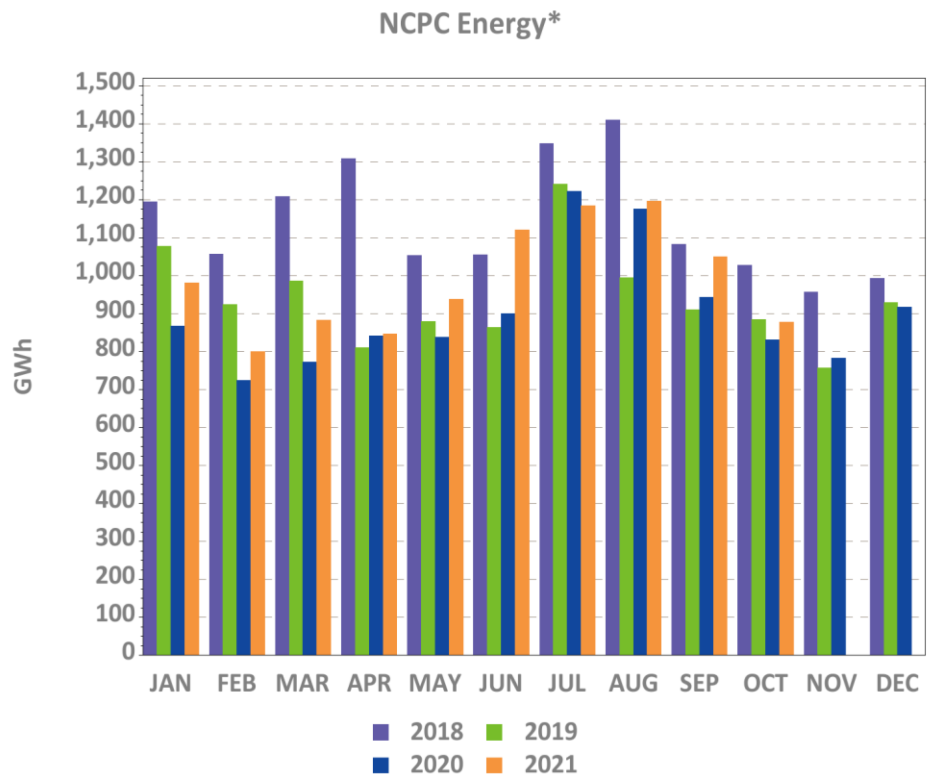
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

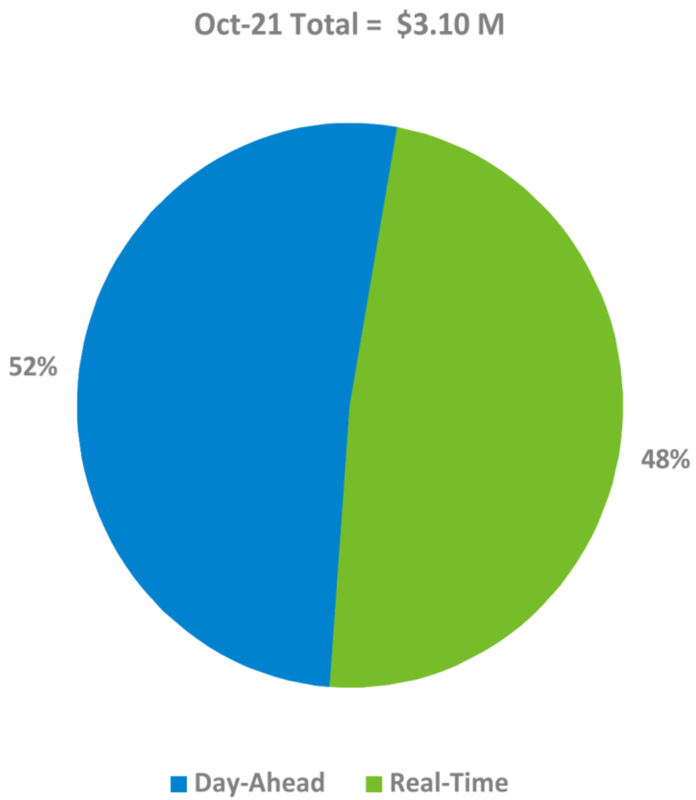
Year-Over-Year Total NCPC Dollars and Energy

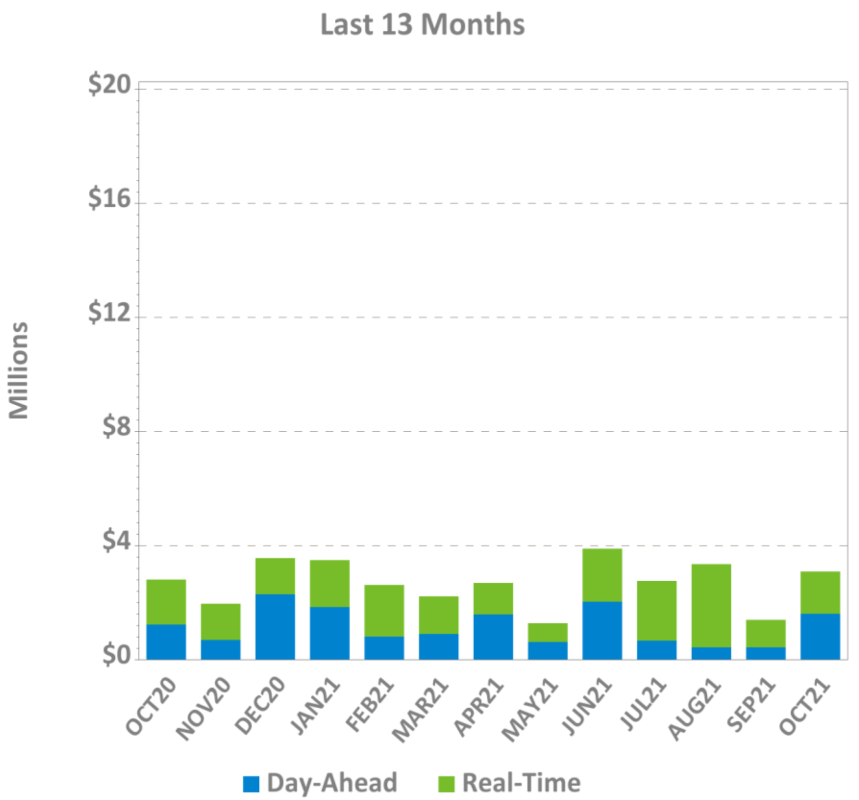




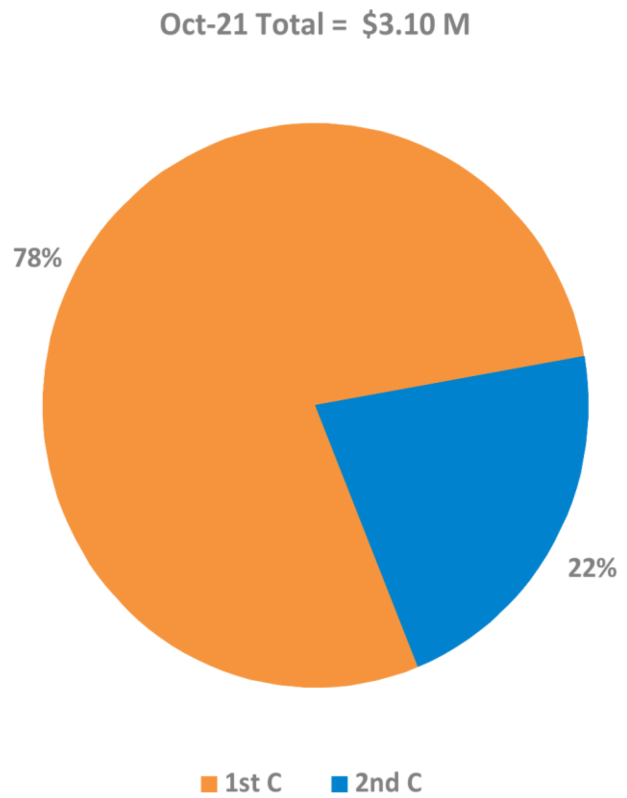
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

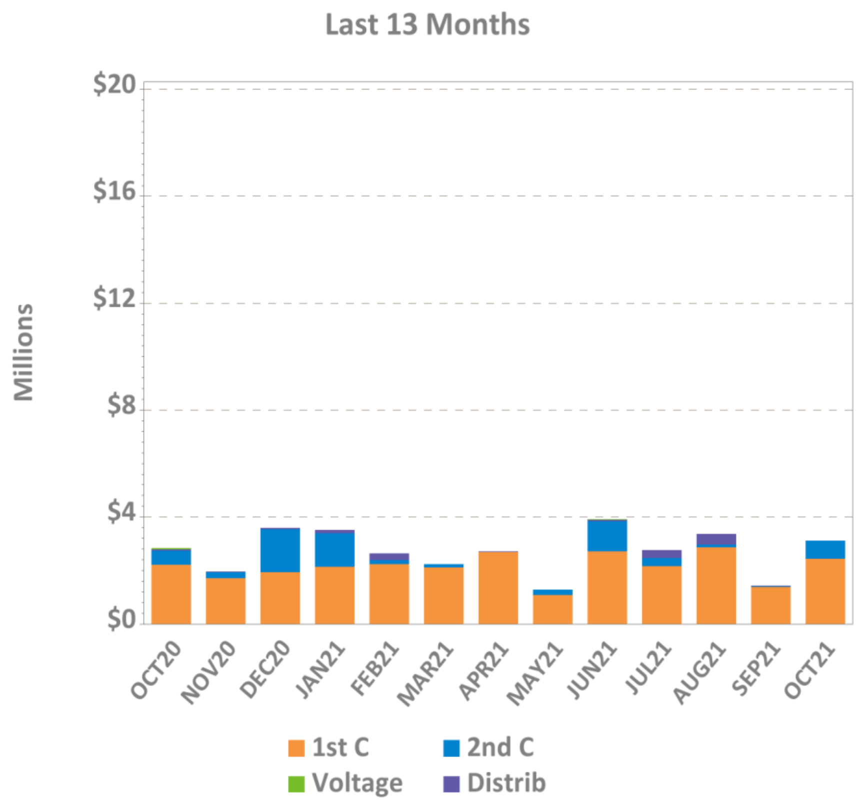
DA and RT NCPC Charges





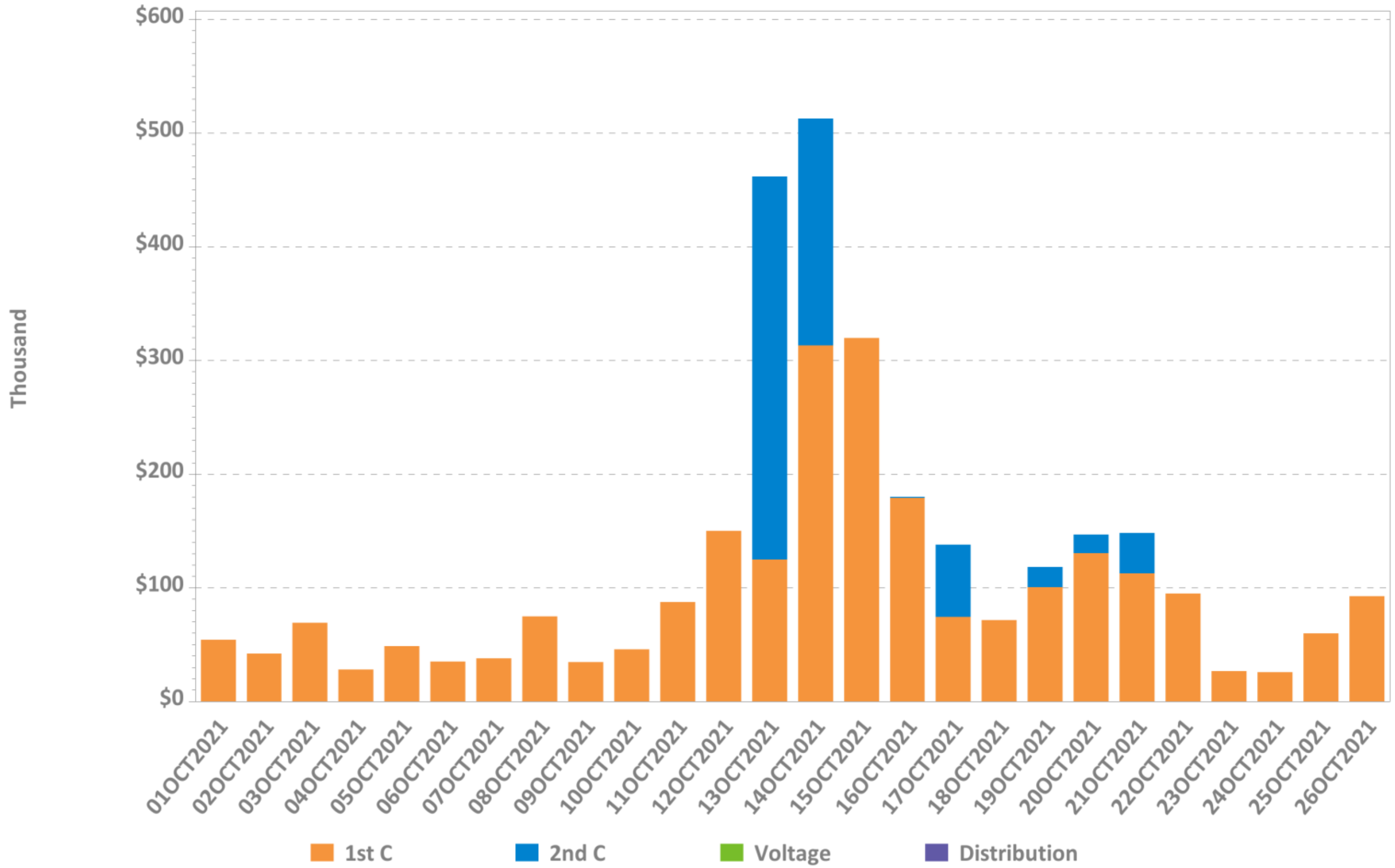
NCPC Charges by Type



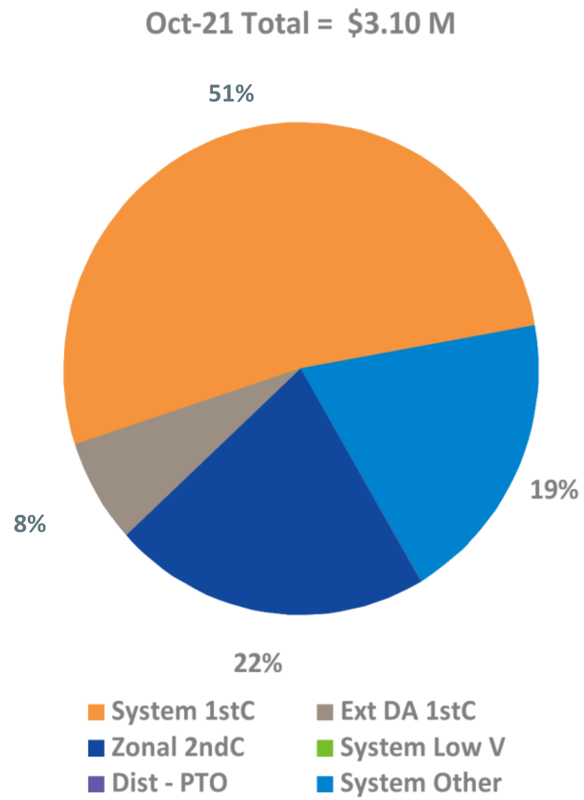


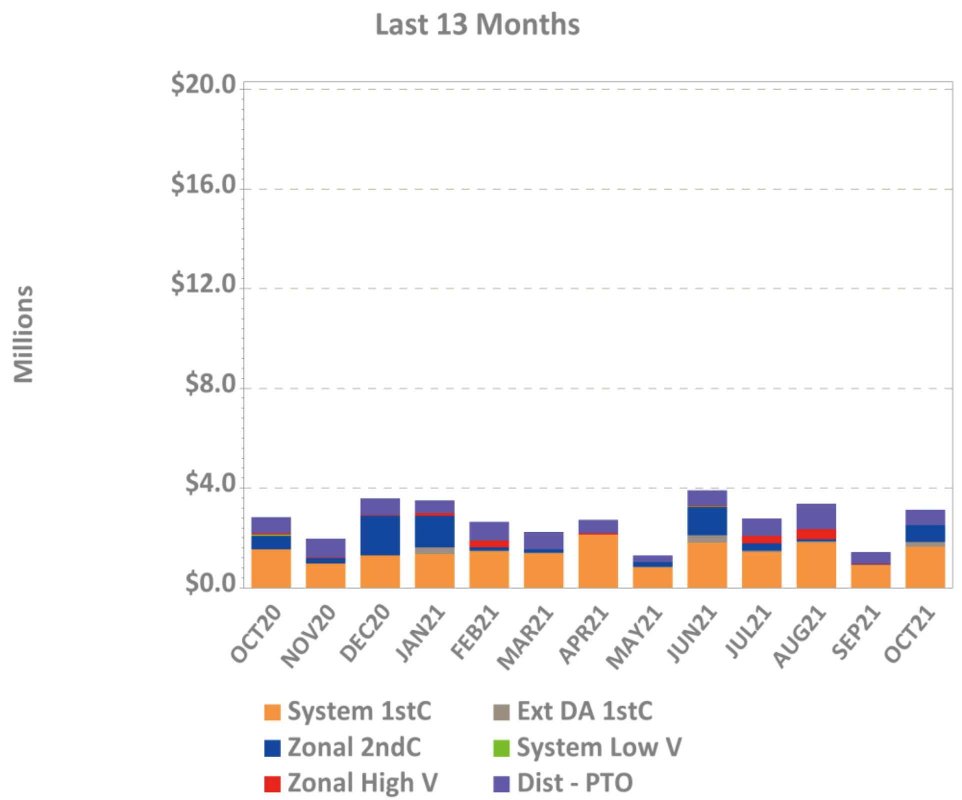
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



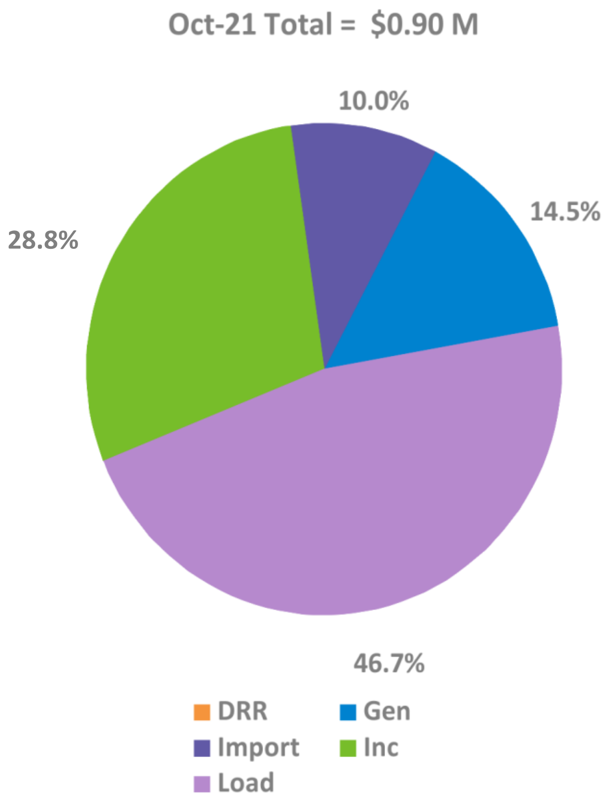
NCPC Charges by Allocation

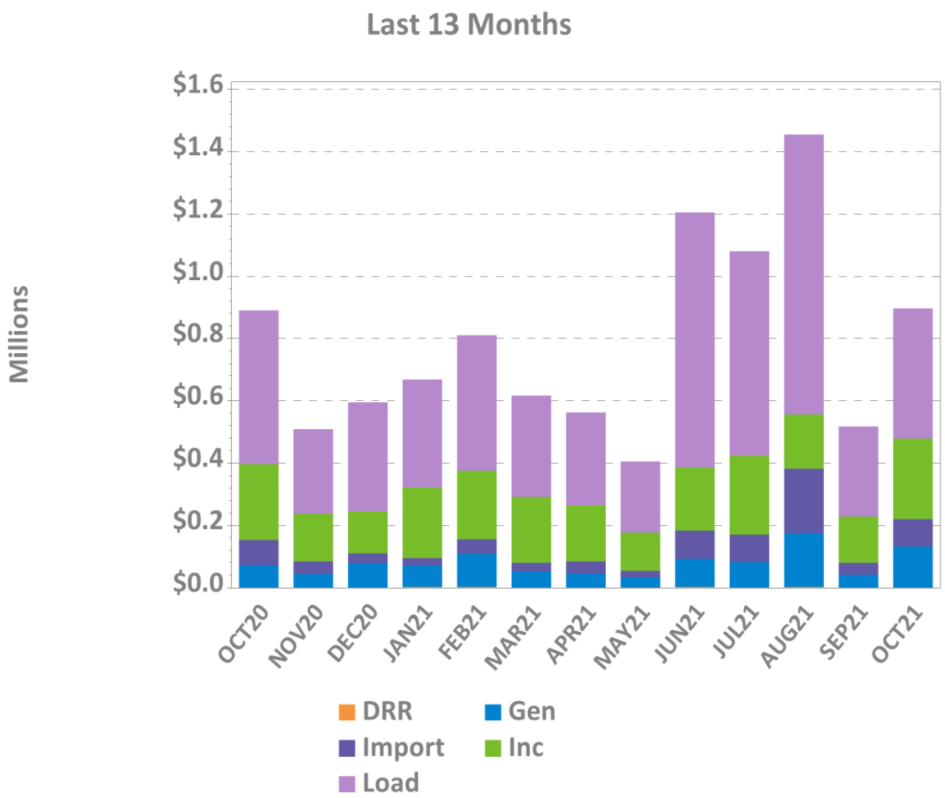




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

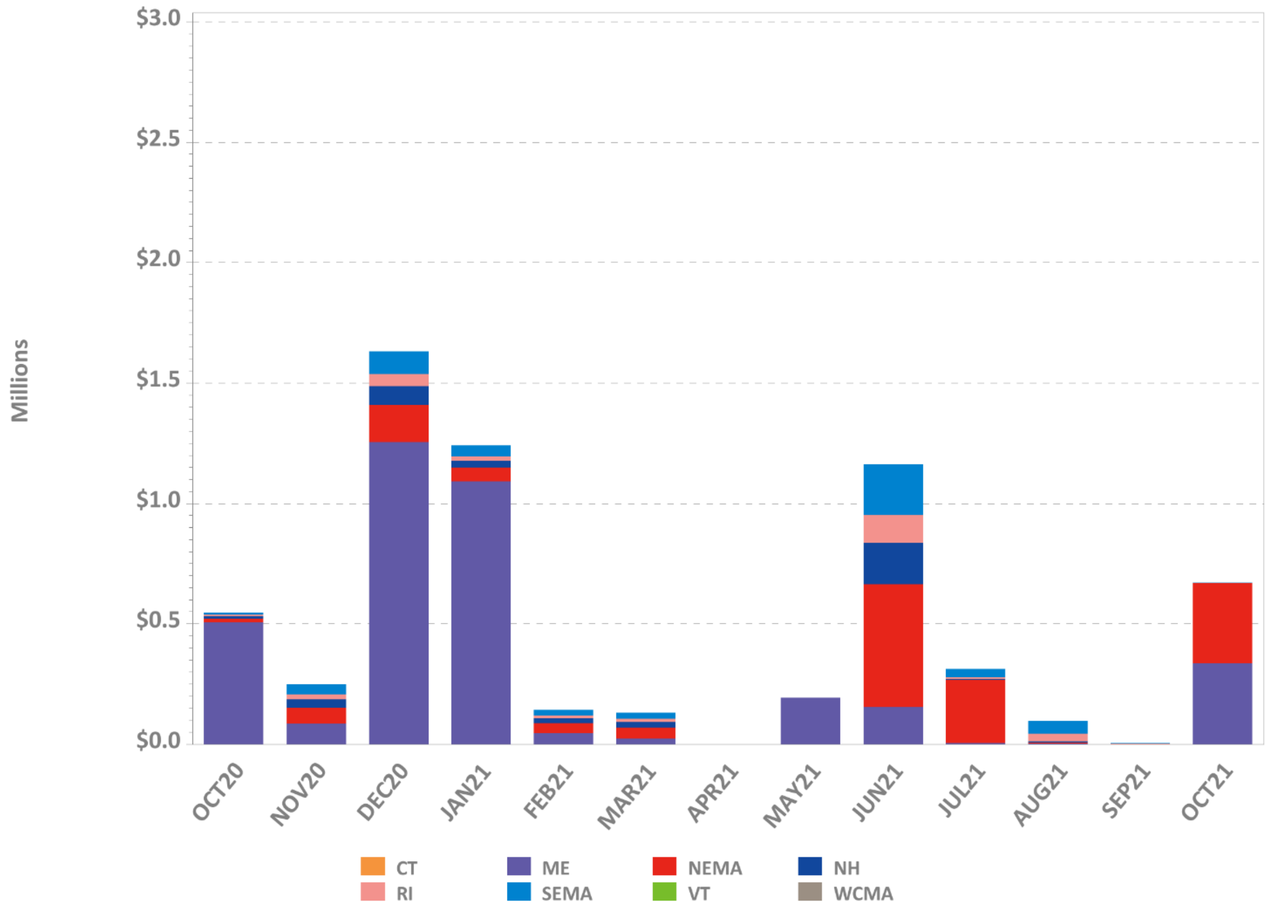
RT First Contingency Charges by Deviation Type





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

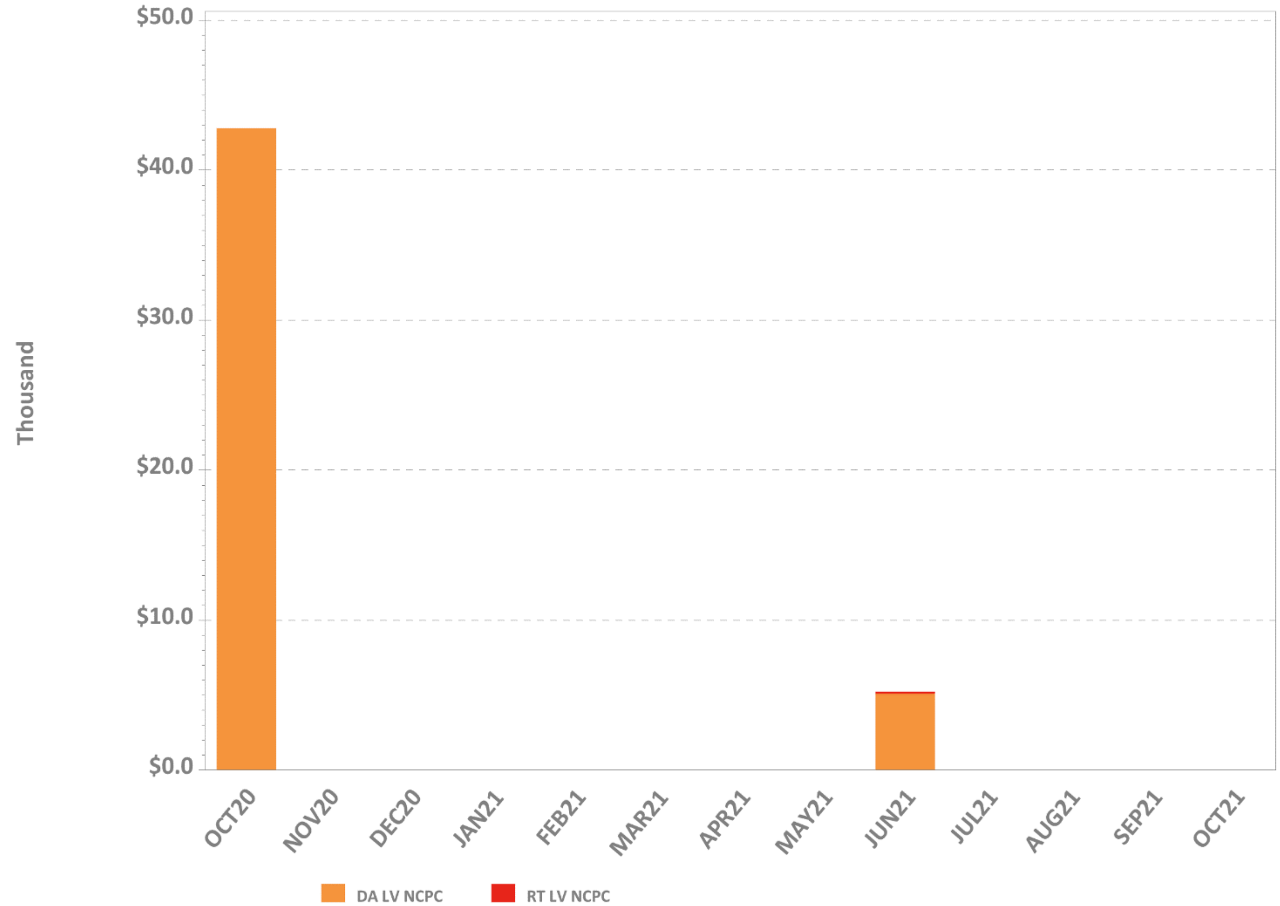
LSCPR Charges by Reliability Region



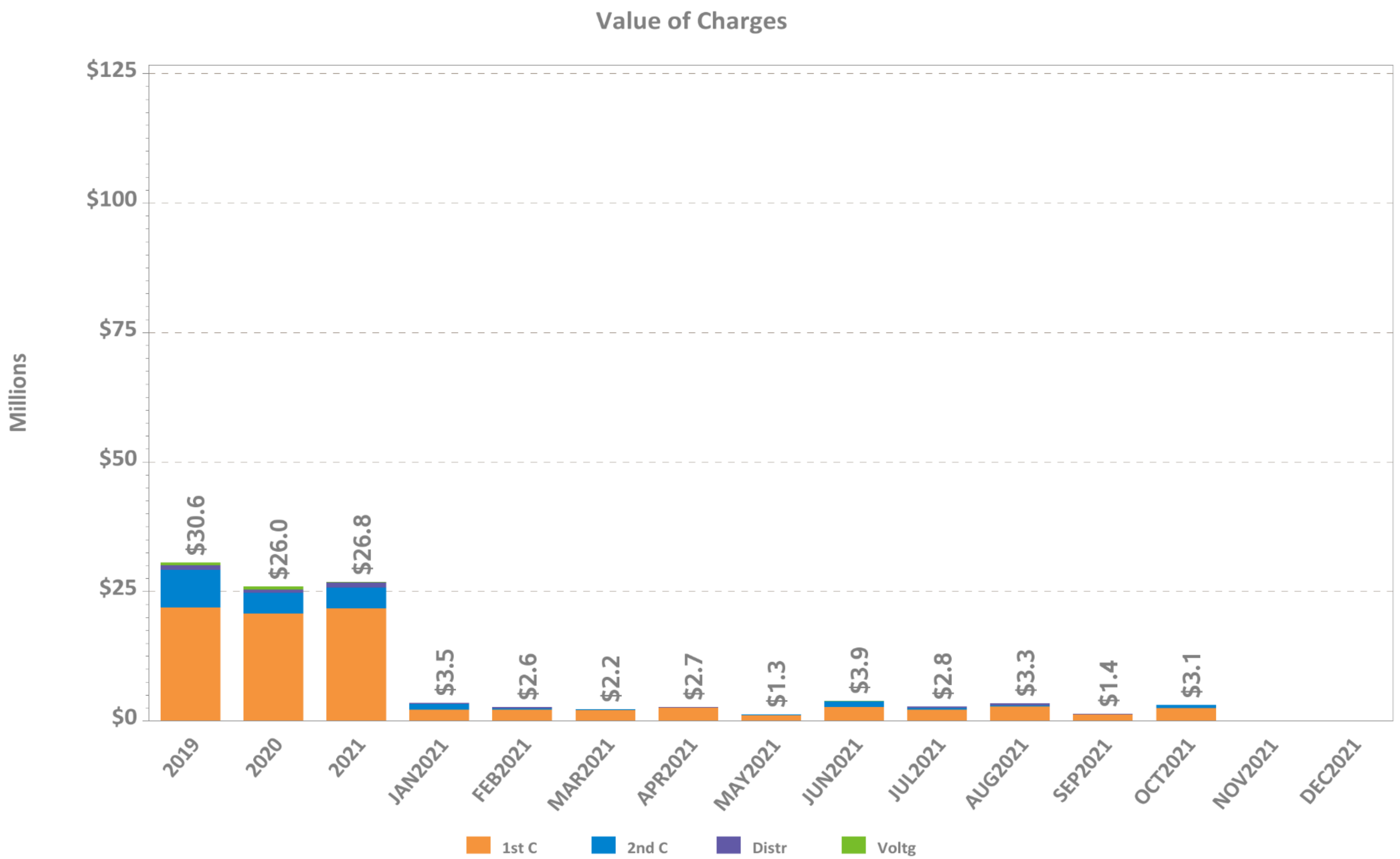
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

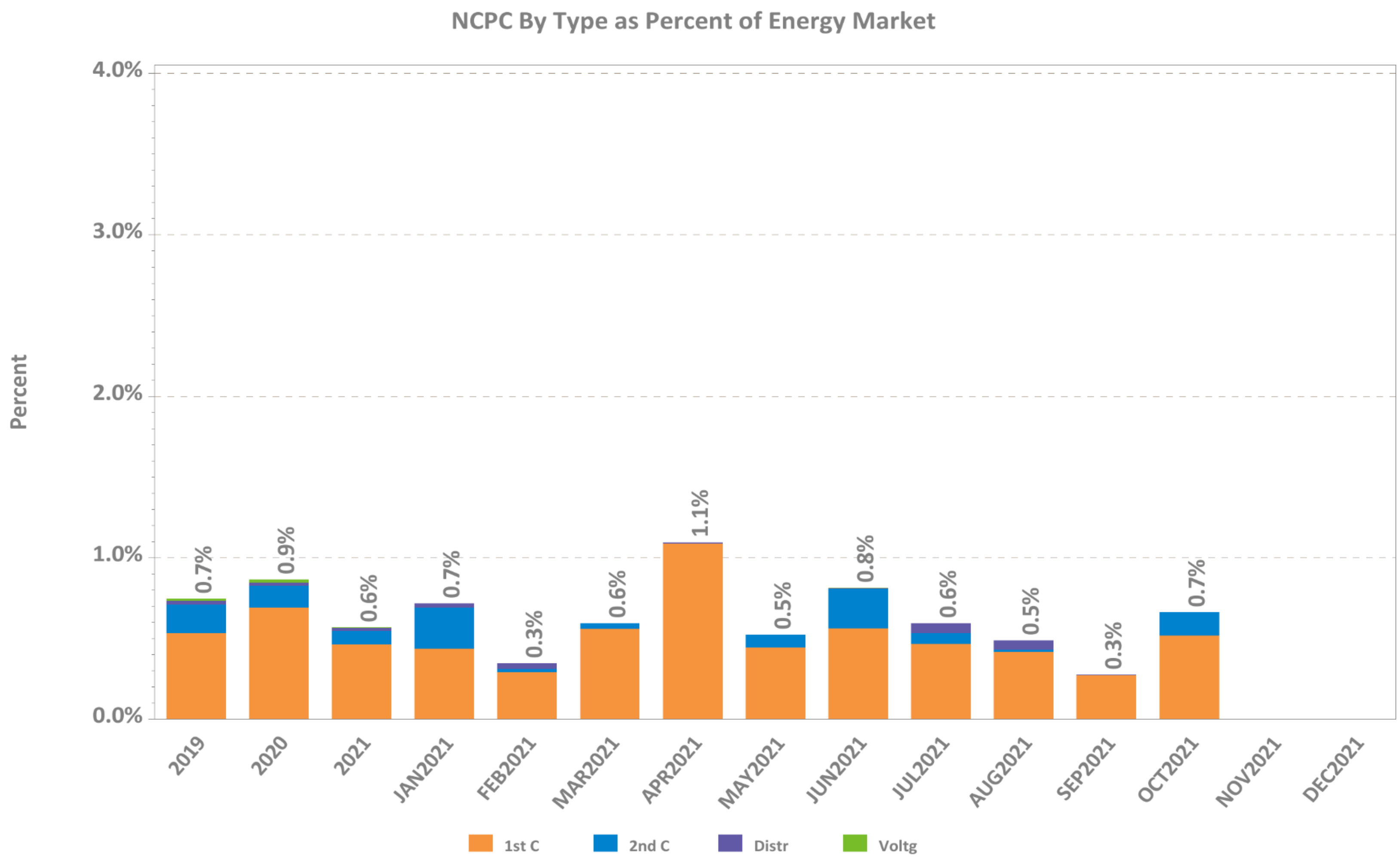
NCPC Charges for Voltage Support and High Voltage Control



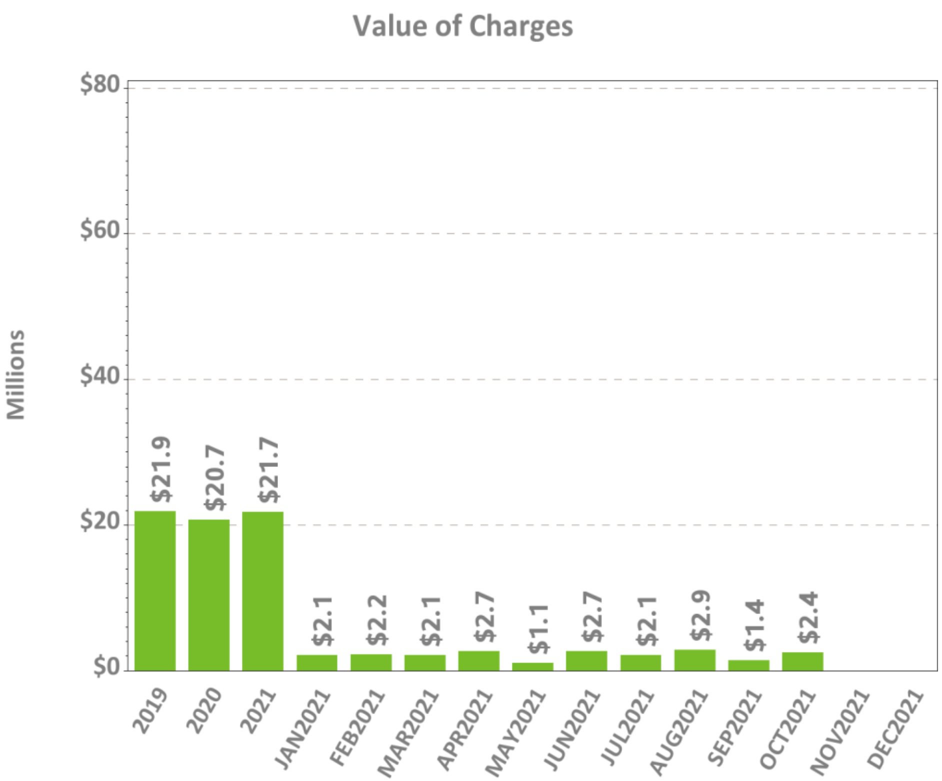
NCPC Charges by Type

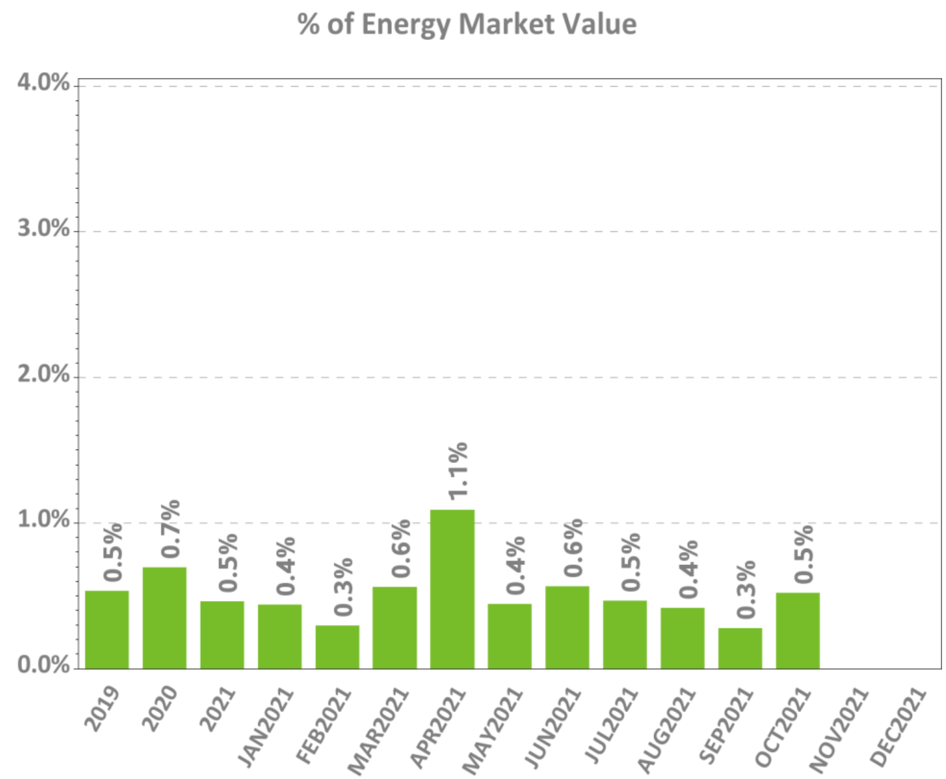


NCPC Charges as Percent of Energy Market



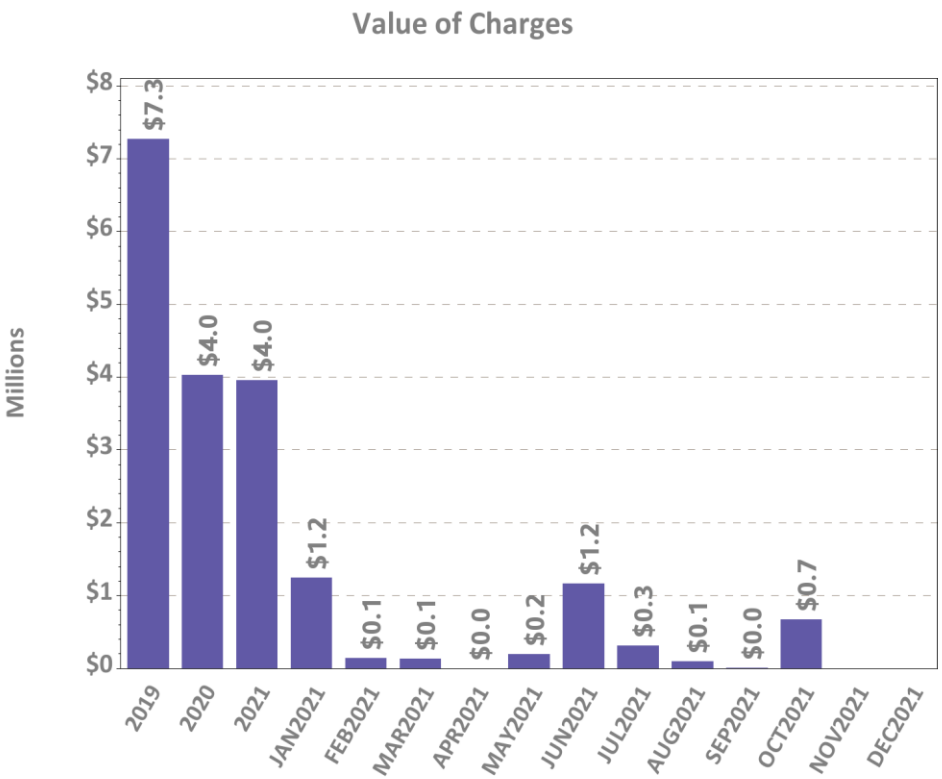
First Contingency NCPC Charges

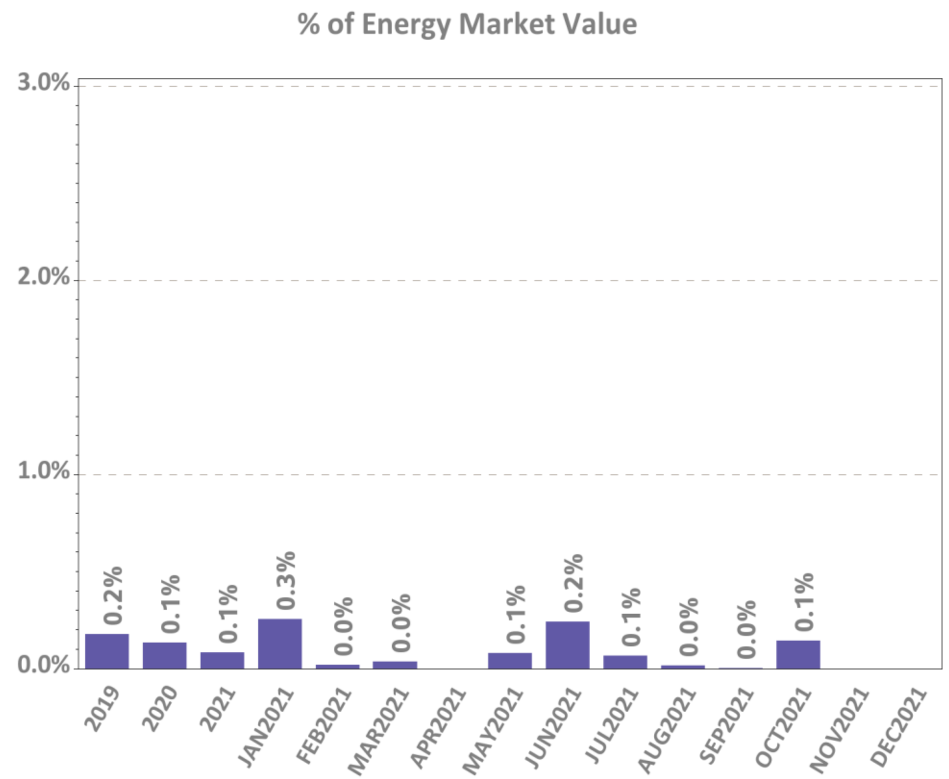




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

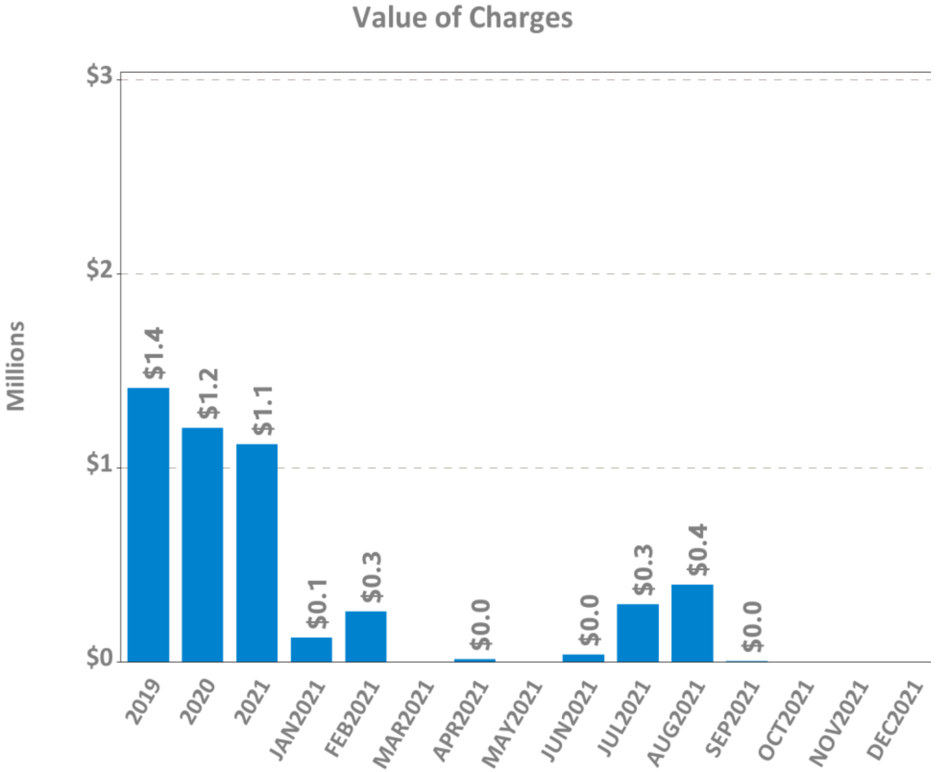
Second Contingency NCPC Charges

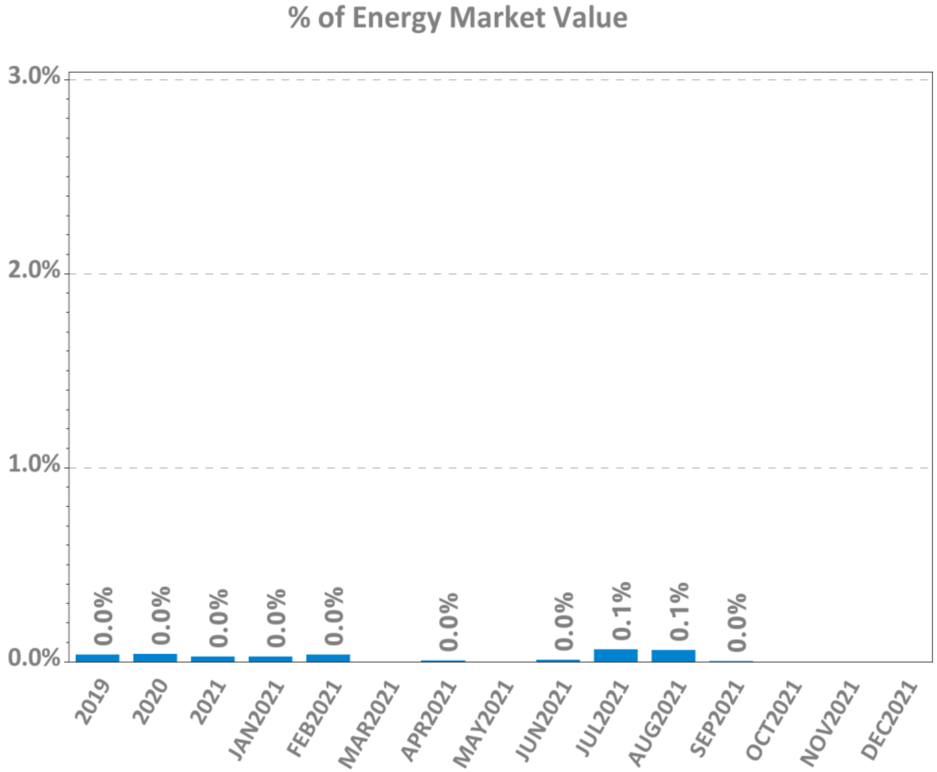




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

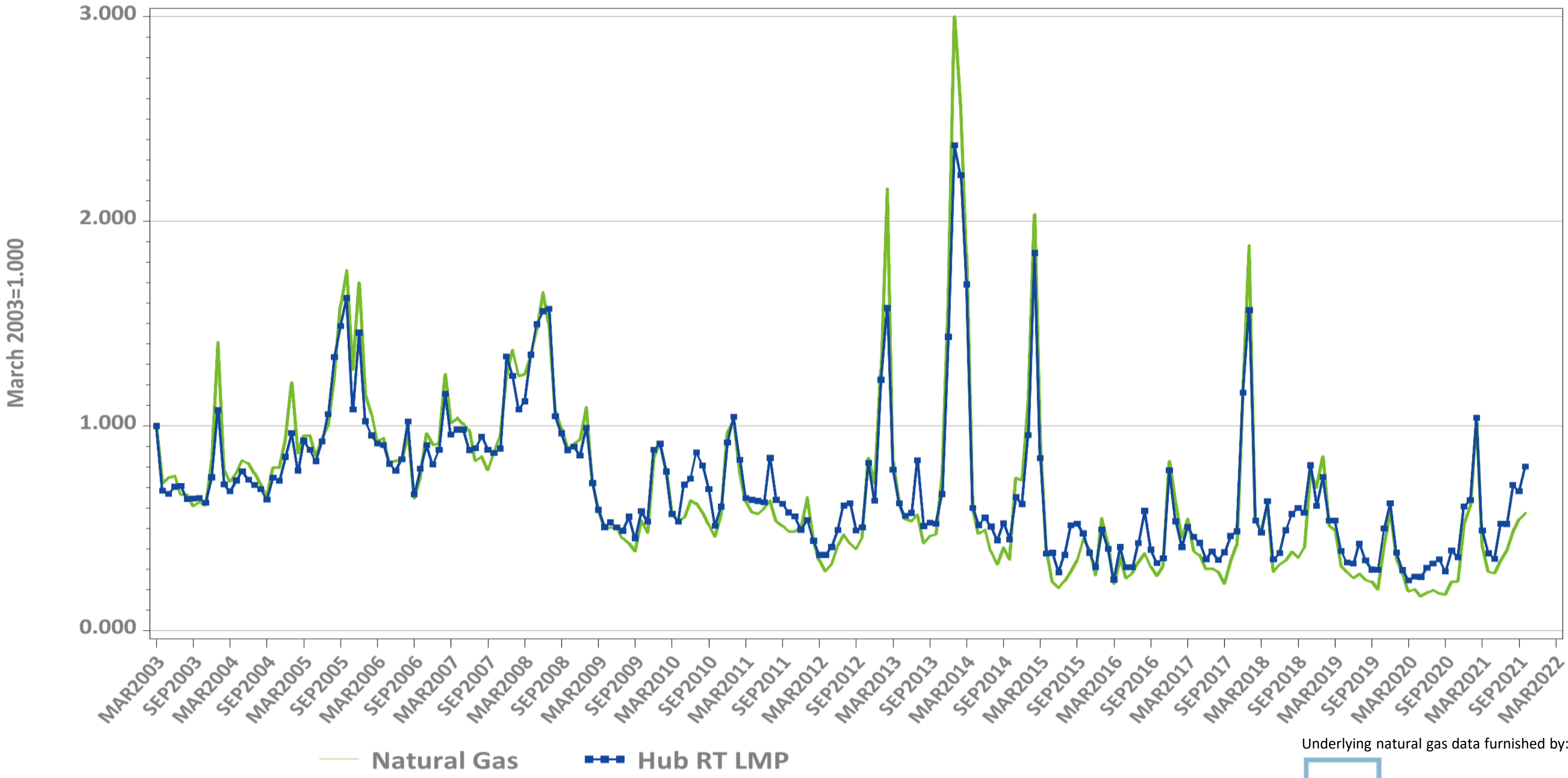
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2019	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$31.54	$30.72	$30.76	$31.20	$30.67	$31.19	$31.51	$31.24	$31.22
Real-Time	$30.92	$30.26	$30.12	$30.70	$30.05	$30.61	$30.80	$30.68	$30.67
RT Delta %	-2.0%	-1.5%	-2.1%	-1.6%	-2.0%	-1.9%	-2.2%	-1.8%	-1.8%
Year 2020	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$23.62	$22.59	$23.27	$23.50	$22.76	$23.27	$23.57	$23.30	$23.32
Real-Time	$23.62	$22.91	$23.23	$23.54	$22.90	$23.29	$23.56	$23.37	$23.38
RT Delta %	0.0%	1.4%	-0.2%	0.2%	0.6%	0.1%	-0.1%	0.3%	0.3%

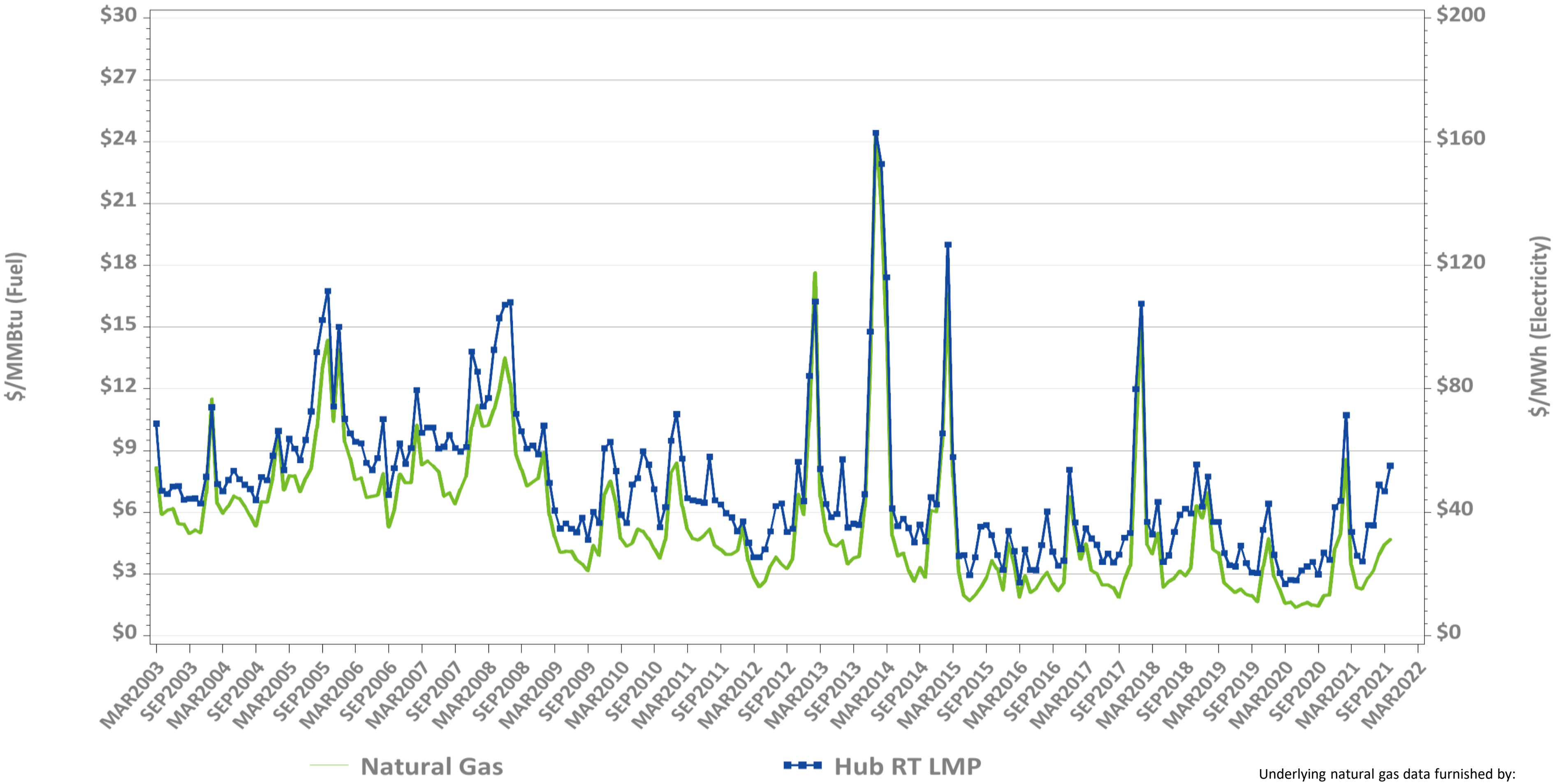
October-20	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$25.04	$24.33	$24.78	$24.95	$24.16	$24.60	$24.91	$24.79	$24.78
Real-Time	$27.09	$26.54	$26.97	$27.16	$26.22	$26.69	$26.97	$26.88	$26.87
RT Delta %	8.2%	9.1%	8.8%	8.8%	8.5%	8.5%	8.3%	8.4%	8.4%
October-21	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$58.53	$56.73	$56.07	$58.22	$57.22	$56.61	$57.75	$57.71	$57.64
Real-Time	$55.77	$54.60	$53.12	$55.66	$54.72	$54.20	$55.25	$55.28	$55.24
RT Delta %	-4.7%	-3.7%	-5.2%	-4.4%	-4.4%	-4.2%	-4.3%	-4.2%	-4.2%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	133.8%	133.1%	126.3%	133.3%	136.8%	130.1%	131.9%	132.8%	132.6%
Yr over Yr RT	105.9%	105.8%	97.0%	105.0%	108.7%	103.1%	104.9%	105.7%	105.6%

Monthly Average Fuel Price and RT Hub LMP Indexes



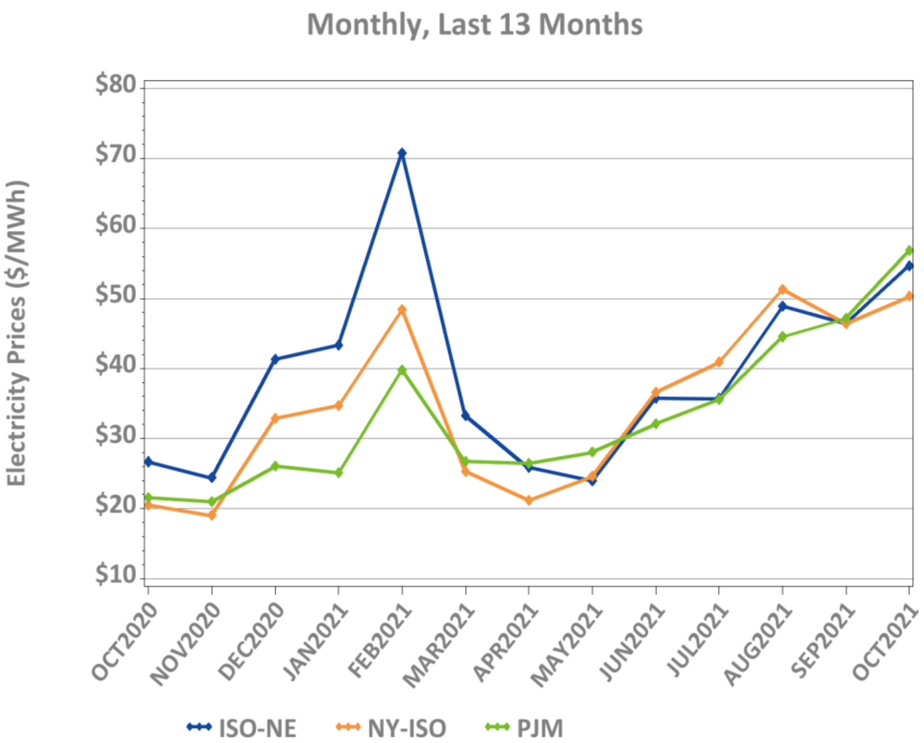
Underlying natural gas data furnished by: ICE Global markets in clear view

Monthly Average Fuel Price and RT Hub LMP

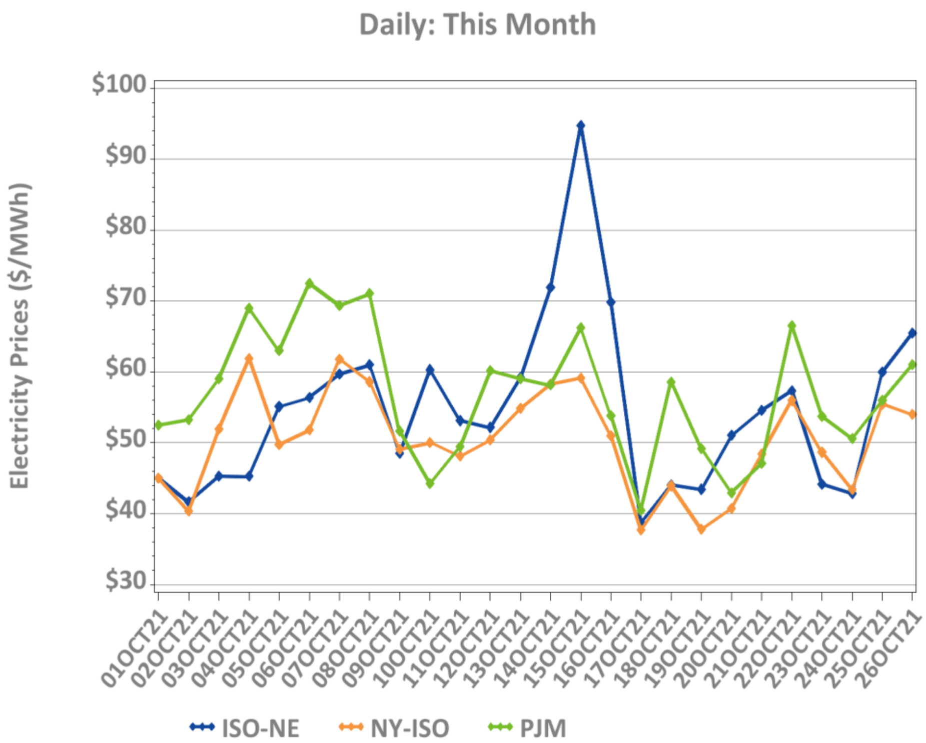


Underlying natural gas data furnished by: ICE Global markets in clear view

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

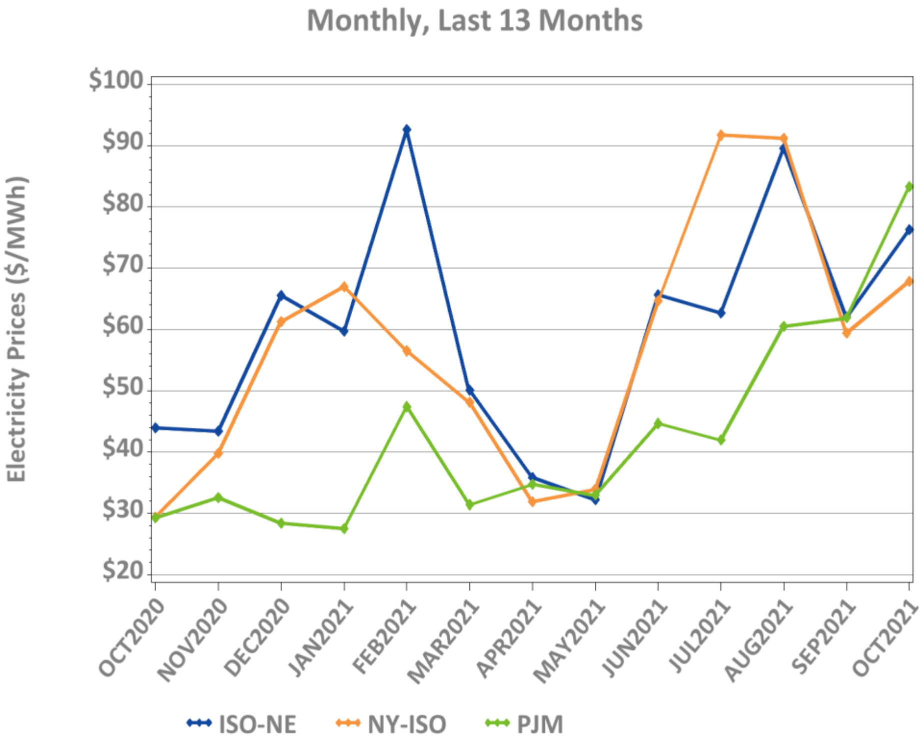


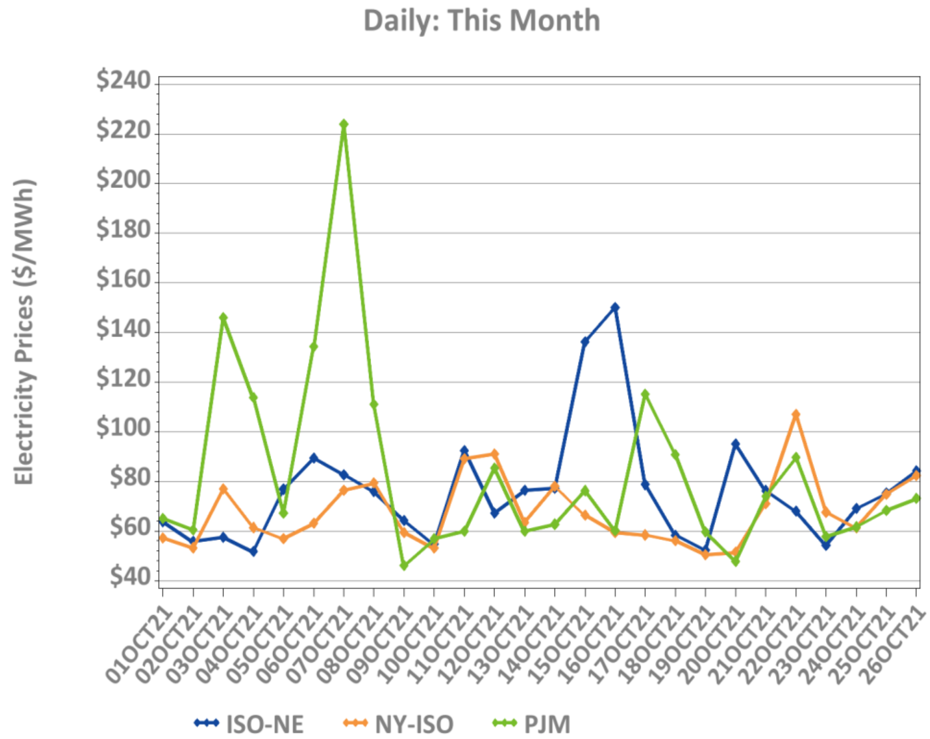
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





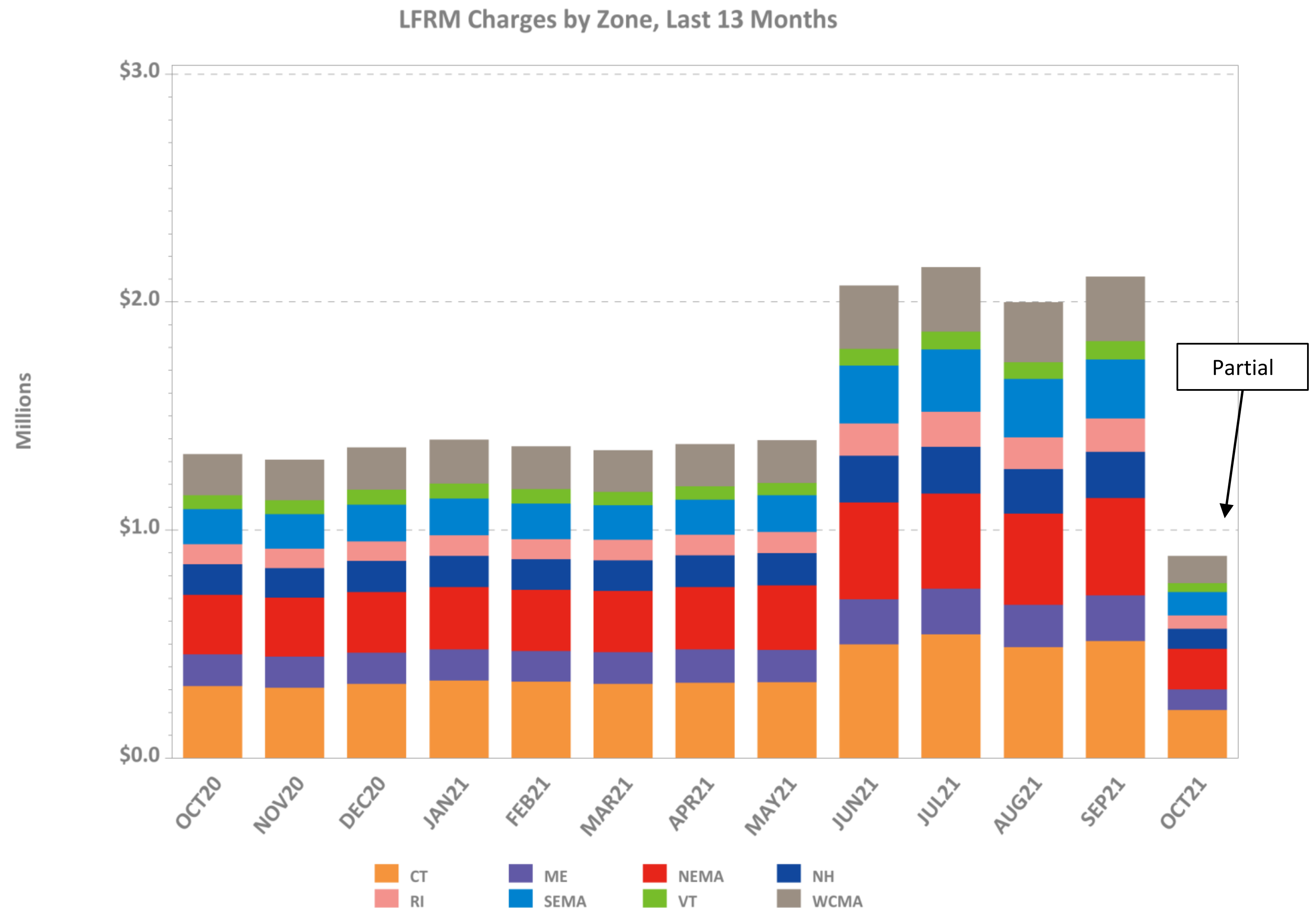
***Forecasted New England daily peak hours reflected**

Reserve Market Results – October 2021

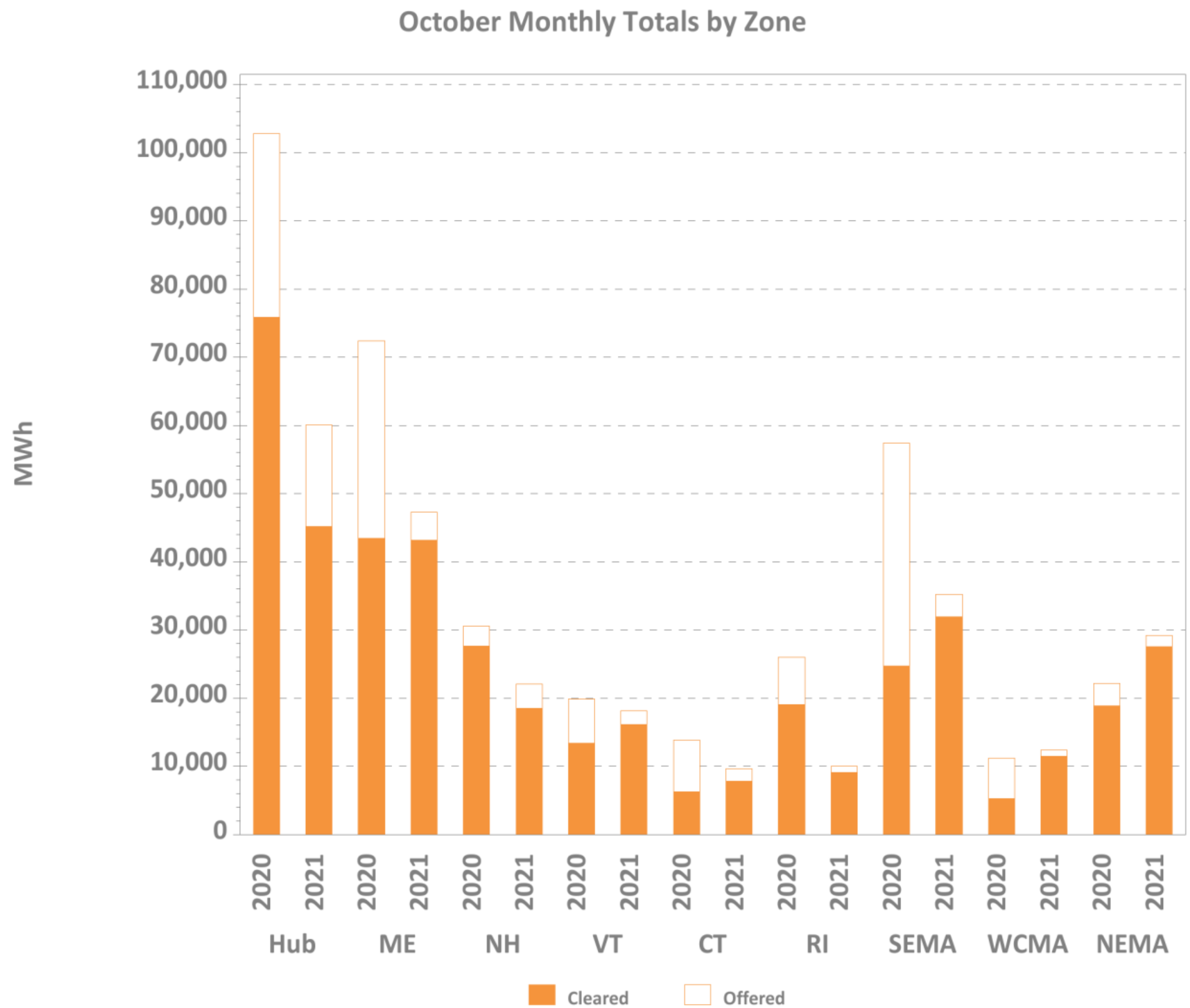
- Maximum potential Forward Reserve Market payments of $1.2M were reduced by credit reductions of $128K, failure-to-reserve penalties of $192K and no failure-to-activate penalties, resulting in a net payout of $0.8M or 72% of maximum
  - Rest of System: $0.58M/0.89M (66%)
  - Southwest Connecticut: $0.03M/0.03M (83%)
  - Connecticut: $0.27M/0.29M (96%)
  - NEMA: $0.02/$0.043M (46%)
- $599K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of $599K in Real-Time Reserve payments
  - Rest of System: 254 hours, $483K
  - Southwest Connecticut: 254 hours, $40K
  - Connecticut: 254 hours, $47K
  - NEMA: 254 hours, $28K

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

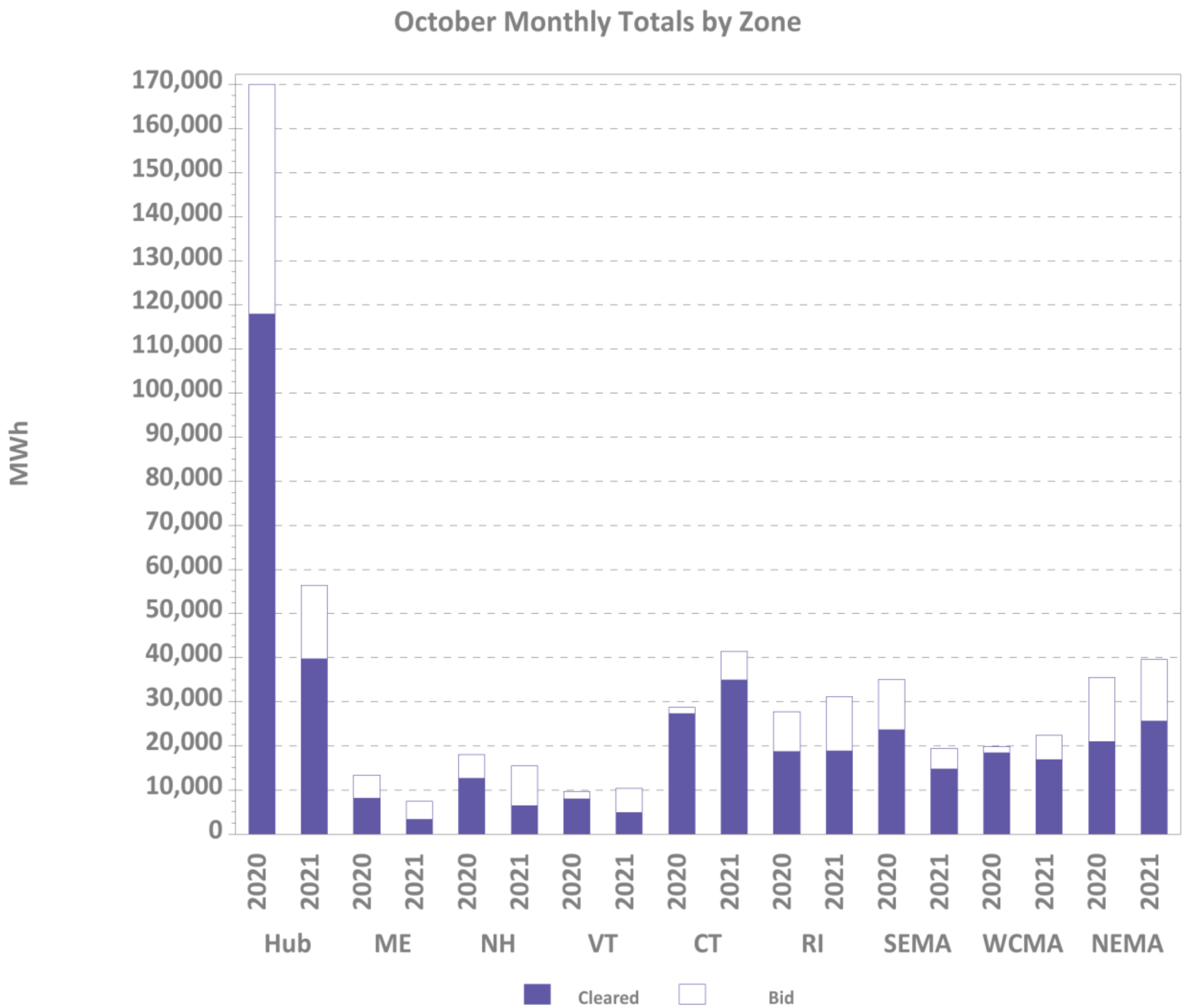
LFRM Charges to Load by Load Zone ($)



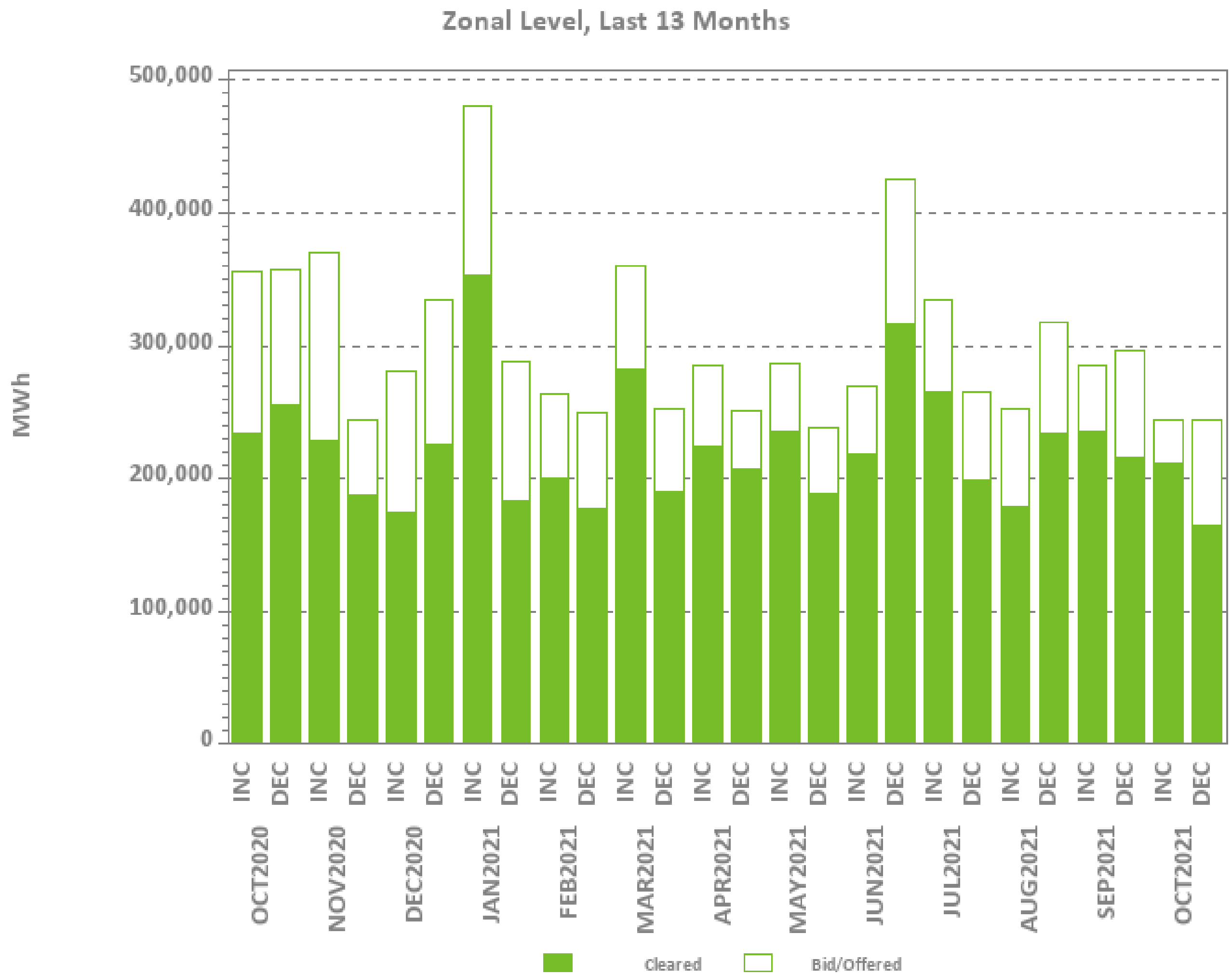
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

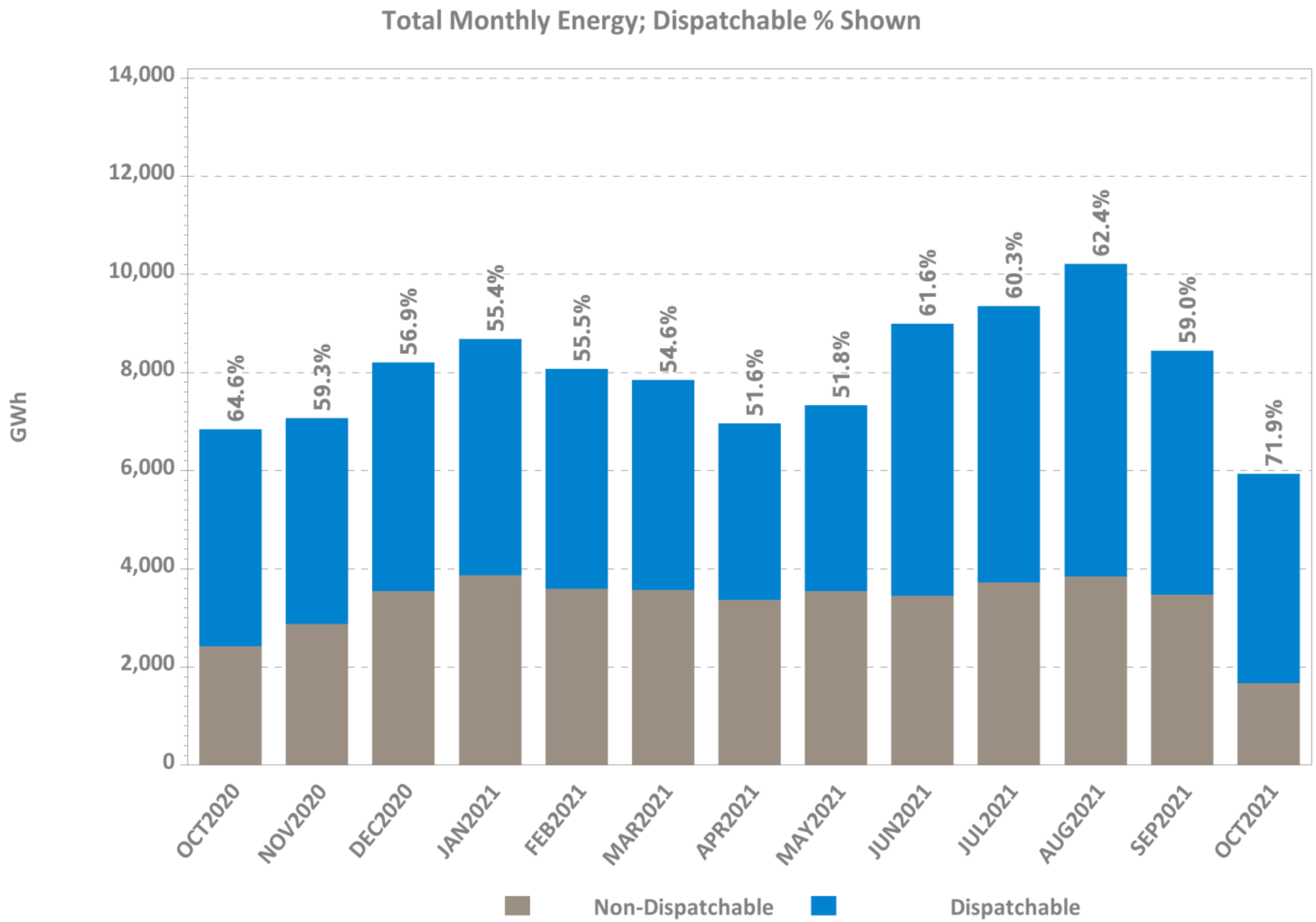


Total Increment Offers and Decrement Bids



Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



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

REGIONAL SYSTEM PLAN (RSP)

Regional System Plan (RSP)

- ISO-NE Board is reviewing the report for final approval within the next several weeks
- Final version of RSP21 will be available on the ISO-NE website
  - https://www.iso-ne.com/system-planning/system-plans-studies/rsp

Planning Advisory Committee (PAC)

- November 17 PAC Meeting Agenda Topics*
  - 2021 Economic Study: Future Grid Reliability Study
    - Ancillary Services Analysis Results - Part 3
    - Study High-Level Transmission Analysis - Part 2
    - Probabilistic Resource Availability Analysis Assumptions - Part 3
  - 2050 Transmission Study
    - Preliminary Assumptions and Methodology for the 2050 Transmission Study Scope of Work
  - FCA 17 Capacity Zone Development Preview
  - Vernon #13 Substation Asset Replacements

* 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

- 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 PAC meeting 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
- An overview of the system conditions and dispatch assumptions for the pilot study was discussed at the 12/16/20 and 1/21/21 PAC meetings
- 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; full written report on the pilot study is expected to be released in late 2021
- Future testing will focus on transient stability modeling and performance criteria

2050 Transmission Study

- A meeting with the states was held on 10/15/21 to review the draft study scope
- The study scope is expected to be discussed with the PAC in November, depending on the extent of state feedback

Economic Studies

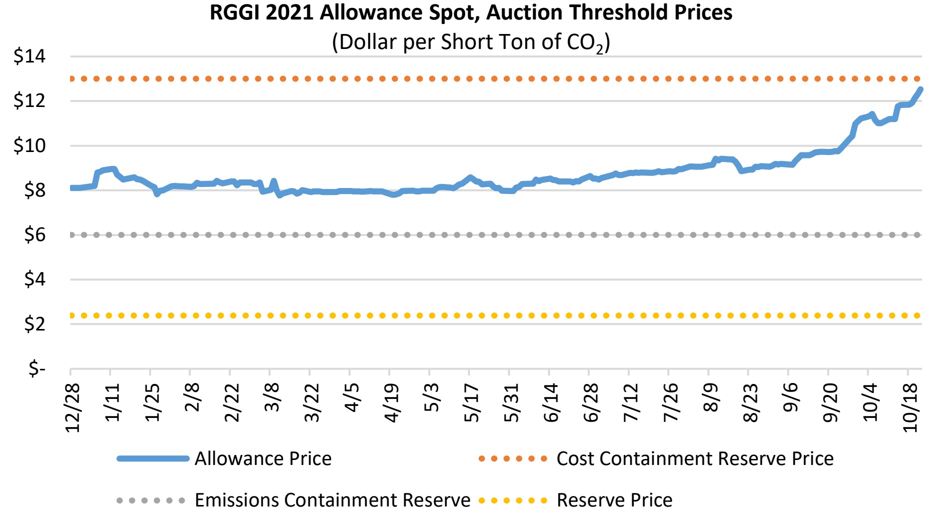
- 2020 Economic Study Request
  - Study proponent is National Grid
  - Study simulations are complete, and results have been presented to PAC
    - Draft report to be completed by the end of 2021
- 2021 Economic Study Request
  - Also known as Future Grid Reliability Study – Phase 1 (FGRS)
  - Study proponent is NEPOOL
  - The ISO presented a revised scope of analysis to the joint MC/RC on October 19 and, after some minor revisions from stakeholders, the revisions were accepted by consensus
  - High-level transmission and ancillary services were discussed at the October 20 PAC meeting

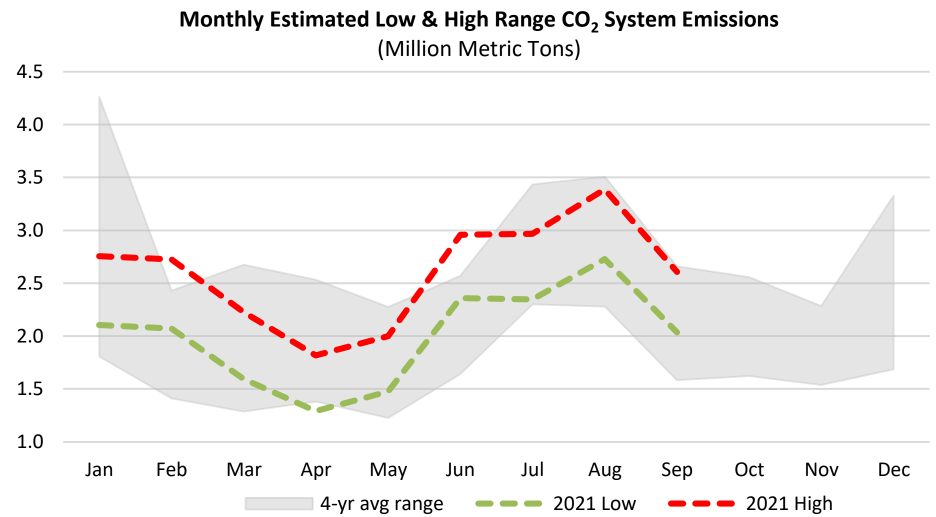
Future Grid Reliability Study (FGRS)

- Phase 1
  - Studies include: Production Cost Simulations; Ancillary Services Simulations; Resource Adequacy Screen; and Probabilistic Resource Availability Analysis
  - Framework Document and supporting assumptions table, which describe study scenarios and objectives, have been developed by stakeholders
  - Phase 1 work was submitted as the only 2021 economic study
- Phase 2
  - Studies include: Revenue Sufficiency Analysis and Transmission Security
  - Studies will be delayed as the Pathways and 2050 Transmission studies are further defined
  - Studies likely to be performed by a consultant
  - Embellishment of the study scope continues at the MC/RC

Environmental Matters – System CO_2 Emissions Up, Compliance Cost Trends Higher

- RGGI allowance prices at highest point since program began in 2009
  - Up 55% since December 2020 ($8.11) to $12.53 (as of 10/25/21)
  - Higher natural gas prices; purchasing by Virginia RGGI generators and outside investors (latter also buying up California/Quebec allowances) cited as factors
  - Ample supply of allowances already in circulation; 143 million allowances in circulation (short tons)
  - RGGI will auction off 23 million more allowances in 2021
  - If auction clears >$13, 12 million extra allowances (cost containment reserve) would be added to December 2021 auction, for a total of 35 million allowances
- New England January - September 2021 estimated system CO_2 emissions range between 18.0 and 23.4 million metric tons (MMT)
  - January - September four-year average (2017-2020) CO_2 emissions range between 15 and 26.3 MMT





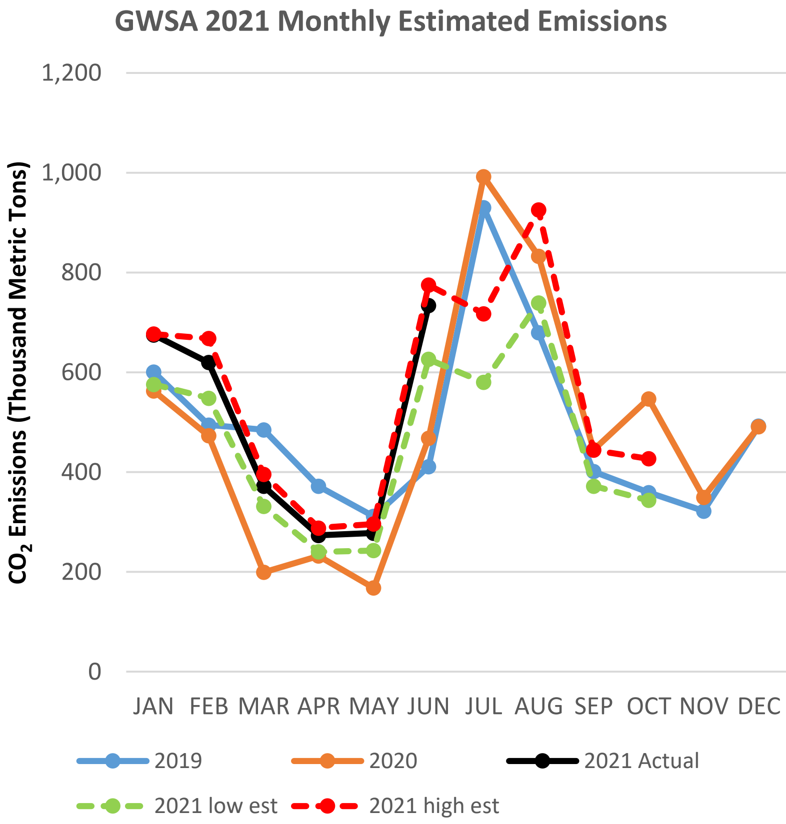
RGGI – Regional Greenhouse Gas Initiative

Environmental Matters – Massachusetts CO_2 Generator Emissions Cap

2021 CO_2 Emissions, Allowance Prices Trending Higher vs. 2020

- As of 10/24/21, estimated GWSA CO_2 emissions range between 4.60 and 5.61 MMT:
  - 56% to 68% of the 8.23 MMT 2021 cap
- 9/15/21 GWSA auction cleared at $10 per metric ton. Using latest clearing price, IMM estimated compliance costs by fuel type (based average GWSA emission/heat rates):
  - No. 2 fuel oil - $8.54/MWh
  - No. 6 fuel oil - $8.29/MWh
  - Natural gas - $2.39/MWh
- Affected generators have access to banked allowances in excess of expected 2021 emissions

2019-2021 Estimated Monthly Emissions (Thousand Metric Tons)



GWSA - Global Warming Solutions Act

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 10/21/2021

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 10/21/2021

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 10/21/2021

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 10/21/2021

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 10/21/2021

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 10/21/2021

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 10/21/2021

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	3
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-23	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Cancelled*	N/A

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

SEMA/RI Reliability Projects, cont.

Status as of 10/21/2021

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	3
1727	Retire the Barnstable SPS	Dec-21	3
1728	Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Dec-22	1
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Dec-22	1
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-23	1

SEMA/RI Reliability Projects, cont.

Status as of 10/21/2021

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	3
1732	Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Jan-23	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 10/21/2021

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	Jun-22	2
1724	Replace the Kent County 345/115 kV transformer	Mar-22	2
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 10/21/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1815	Reconductor the L190-4 and L190-5 line sections	Dec-24	2
1850	Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation	Mar-23	2
1851	Upgrade Card 115 kV to BPS standards	Mar-23	2
1852	Install one 115 kV circuit breaker in series with Card substation 4T	Mar-23	2
1853	Convert Gales Ferry substation from 69 kV to 115 kV	Dec-23	1
1854	Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Dec-22	1

Eastern CT Reliability Projects, cont.

Status as of 10/21/2021

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	1
1856	Rebuild 400-1 Line section to allow operation at 115 kV (Tunnel to Ledyard Jct.)	Dec-22	1
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	1
1858	Rebuild 400-2 Line section to allow operation at 115 kV (Ledyard Jct. to Border Bus with CMEEC)	Dec-21	3
1859	Rebuild the 400-3 Line Section to allow operation at 115 kV (Gales Ferry to Ledyard Jct.)	Dec-22	1
1860	Install a 25.2 MVAR 115 kV capacitor and one capacitor breaker at Killingly	Mar-22	2

Eastern CT Reliability Projects, cont.

Status as of 10/21/2021

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	June-22	2
1862	Install a 50 MVAR synchronous condenser with two 115 kV breakers at Shunock	Dec-24	1
1863	Install a 1% series reactor with bypass switch at Mystic, CT on the 1465 Line	Dec-22	1
1864	Convert the 400-2 Line Section to 115 kV (Border Bus to Buddington), convert Buddington to 115 kV	Dec-23	1

Boston Area Optimized Solution Projects

Status as of 10/21/2021

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	Jun-22	3
1875	Install a direct transfer trip (DTT) scheme between Ward Hill and West Amesbury Substations for Line 394	Jan-23	2
1876	Install one +/- 167 MVAR STATCOM at Tewksbury 345 kV Substation	Oct-23	2

New Hampshire Solution Projects

Status as of 10/21/2021

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	2
1879	Install a +50/-25 MVAR synchronous condenser at Huckins Hill 115 kV Substation with a 115 kV breaker	Aug-23	2
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	Nov-23	1

Upper Maine Solution Projects

Status as of 10/21/2021

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1882	Rebuild 21.7 miles of the existing 115 kV line Section 80 Highland – Coopers Mills 115 kV line	Dec-27	1
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	Dec-25	1

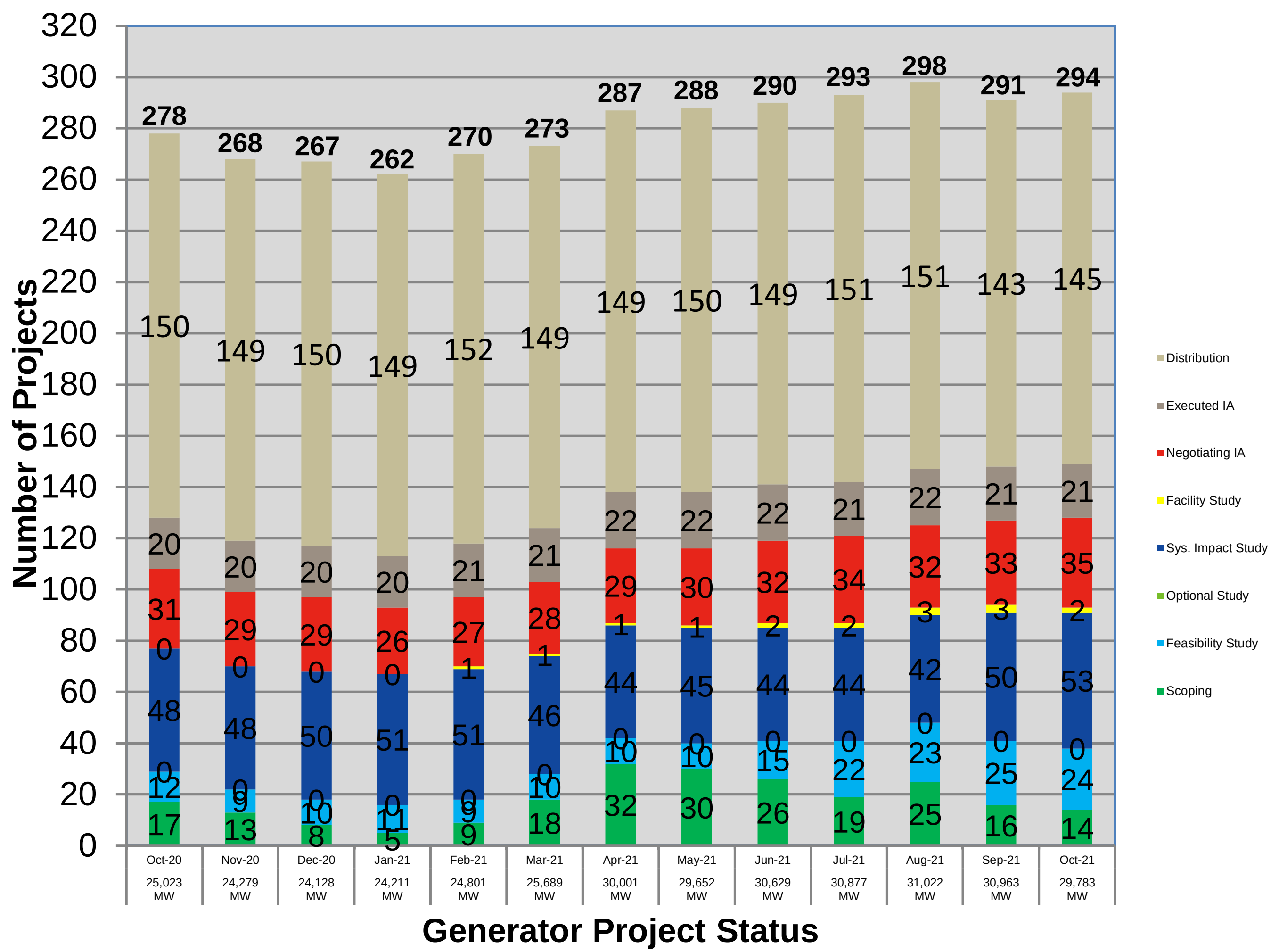
Upper Maine Solution Projects, cont.

Status as of 10/21/2021

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	Dec-25	1
1888	Install 10 MVAR reactor at Keene Road 115 kV substation	Dec-23	1
1889	Install three remotely monitored and controlled switches to split the existing Orrington reactors between the two Orrington 345/115 kV autotransformers	Dec-23	1

Status of Tariff Studies



Note: October 2021 is based on partial data.

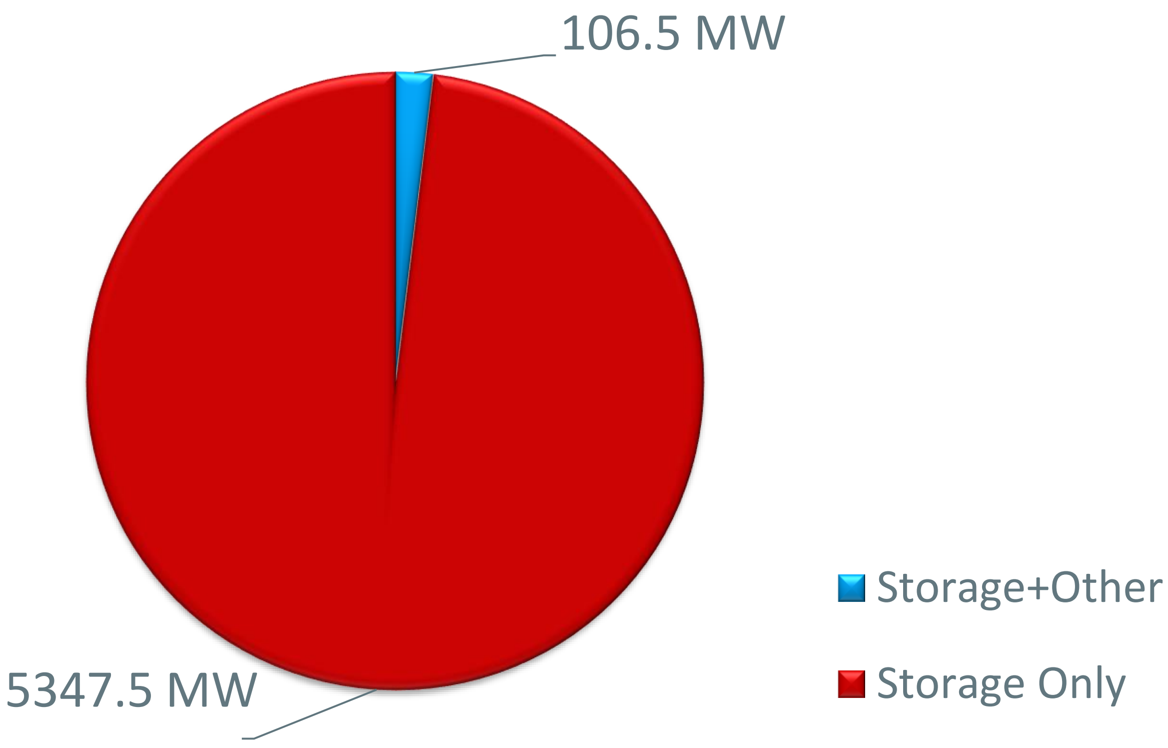
As of October 2021: 3 ETUs in Scoping, 0 in FS, 1 in SIS, 0 in OIS, 1 in FAC, 1 Negotiating IA, and 2 with Executed IA

Transmission Service Requests needing study: 1 in Scoping

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

What is in the Queue (as of October 25, 2021)

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



OPERABLE CAPACITY ANALYSIS

Fall 2021 Analysis

Fall 2021 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Nov. - 2021[2] CSO (MW)	Nov. - 2021[2] SCC (MW)
Operable Capacity MW [1]	29,967	32,086
Active Demand Capacity Resource (+) [5]	476	399
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	917	917
Non Commercial Capacity (+)	32	32
Non Gas-fired Planned Outage MW (-)	2,243	2,650
Gas Generator Outages MW (-)	1,512	1,785
Allowance for Unplanned Outages (-) [4]	3,600	3,600
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	24,037	25,399
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	17,517	17,517
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	19,822	19,822
Operable Capacity Margin	4,214	5,577

[1] Operable Capacity is based on data as of **October 27, 2021** 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 **October 27, 2021.**

[2] Load forecast that is based on the 2021 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **November 20, 2021.**

[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 2021 Operable Capacity Analysis

90/10 Load Forecast	Nov. - 2021[2] CSO (MW)	Nov. - 2021[2] SCC (MW)
Operable Capacity MW [1]	29,967	32,086
Active Demand Capacity Resource (+) [5]	476	399
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	917	917
Non Commercial Capacity (+)	32	32
Non Gas-fired Planned Outage MW (-)	2,243	2,650
Gas Generator Outages MW (-)	1,512	1,785
Allowance for Unplanned Outages (-) [4]	3,600	3,600
Generation at Risk Due to Gas Supply (-) [3]	793	861
Net Capacity (NET OPCAP SUPPLY MW)	23,244	24,538
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	18,098	18,098
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	20,403	20,403
Operable Capacity Margin	2,840	4,135

[1]Operable Capacity is based on data as of **October 27, 2021** 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 **October 27, 2021.**

[2] Load forecast that is based on the 2021 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **November 20, 2021.**

[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 2021 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

October 29, 2021 - 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 June, July, August, and Mid September.

Report created: 10/28/2021

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
11/13/2021	29967	476	917	32	2862	1452	3600	0	23479	16780	2305	19085	4393	N	Fall 2021
11/20/2021	**29967**	**476**	**917**	**32**	**2243**	**1512**	**3600**	**0**	**24037**	**17517**	**2305**	**19822**	**4214**	**Y**	**Fall 2021**

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 2021 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 2021 Operable Capacity Analysis 90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

October 29, 2021 - 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 December, January, February, March and April.

Report created: 10/28/2021

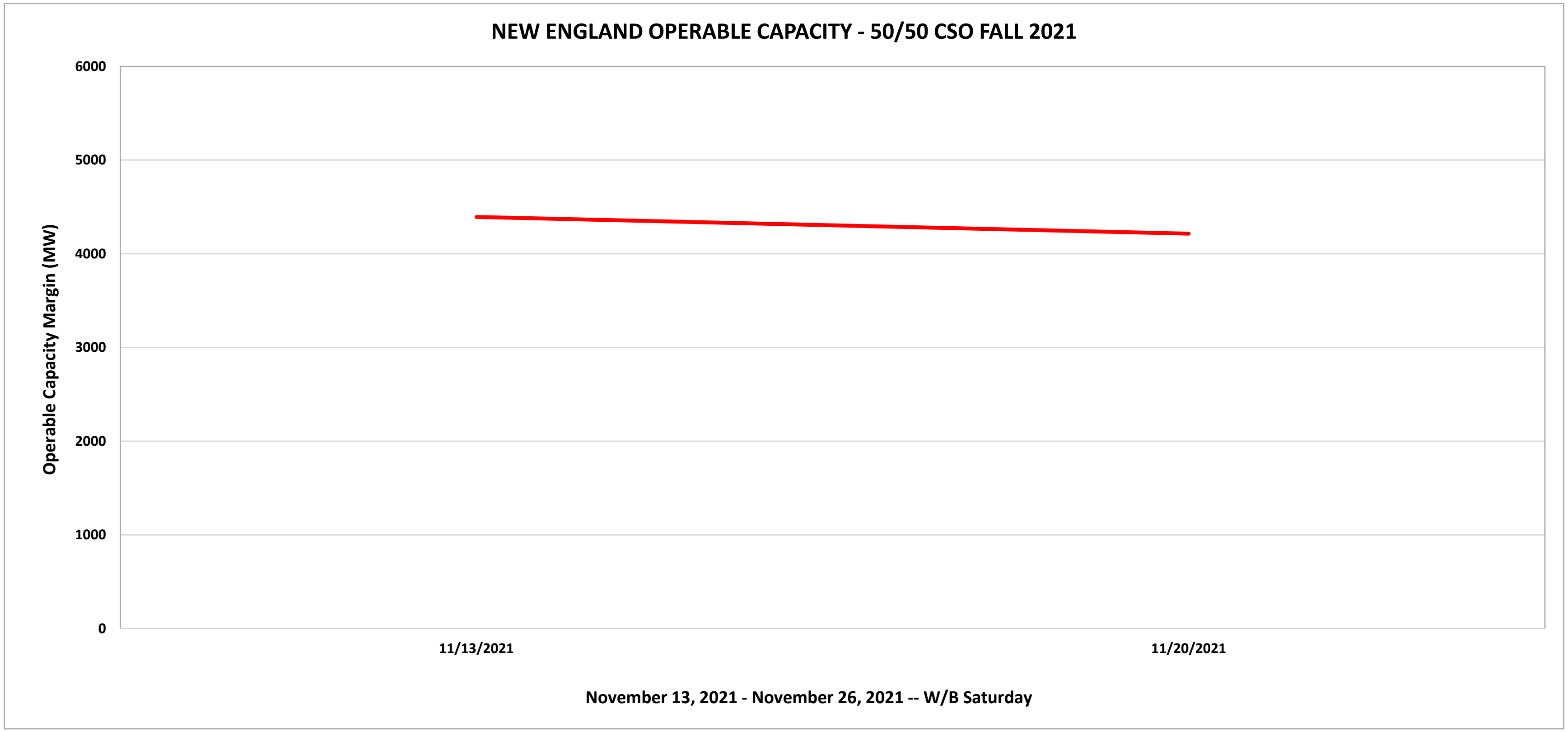
Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due 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
11/13/2021	29967	476	917	32	2862	1452	3600	83	23395	17339	2305	19644	3751	N	Fall 2021
11/20/2021	**29967**	**476**	**917**	**32**	**2243**	**1512**	**3600**	**793**	**23244**	**18098**	**2305**	**20403**	**2840**	**Y**	**Fall 2021**

Column Definitions

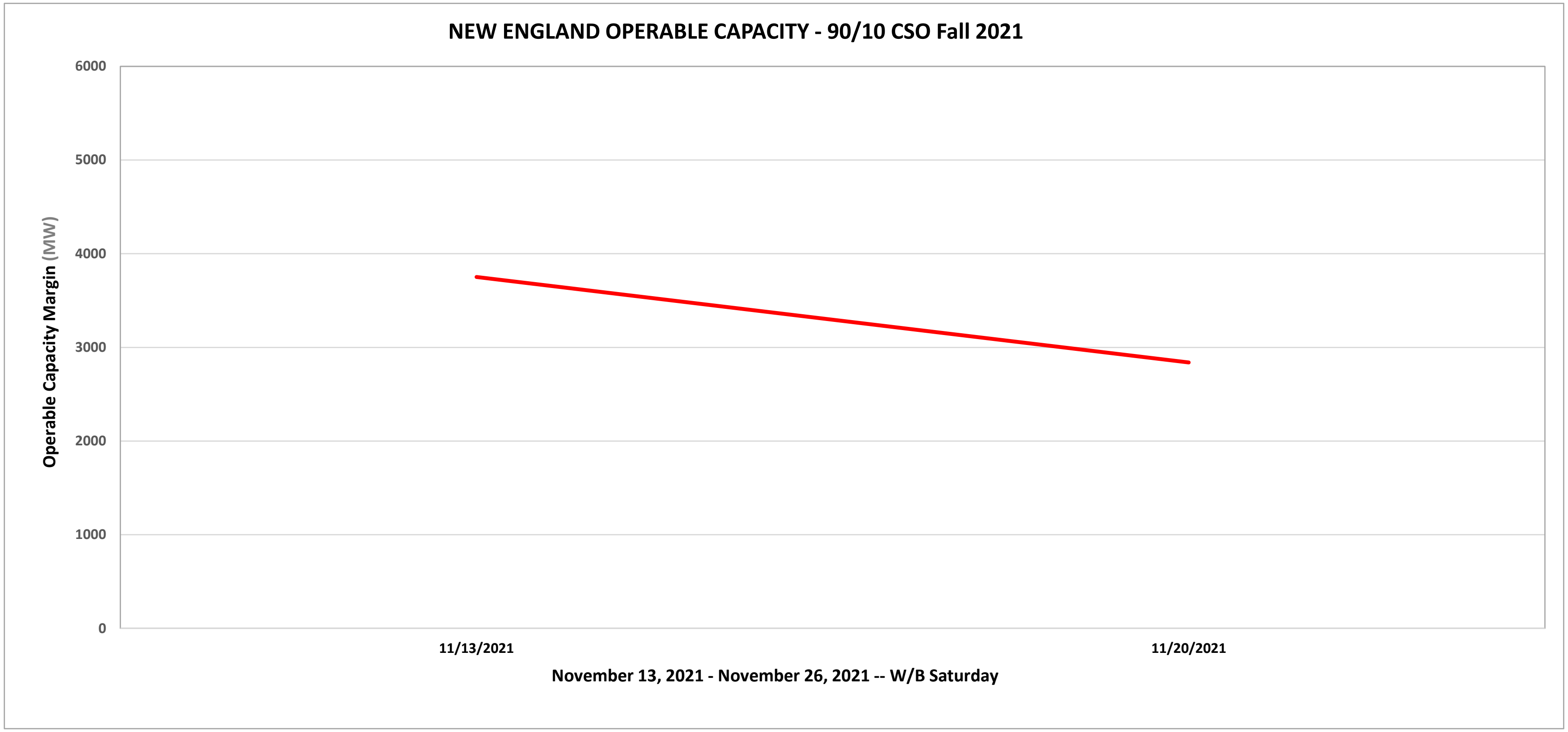
1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can 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 2021 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 2021 Operable Capacity Analysis
50/50 Forecast (Reference)



Fall 2021 Operable Capacity Analysis
90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Winter 2021/22 Analysis

Winter 2021/22 Operable Capacity Analysis

50/50 Load Forecast (Reference)	Jan. - 2022[2] CSO (MW)	Jan. - 2022[2] SCC (MW)
Operable Capacity MW [1]	29,784	32,086
Active Demand Capacity Resource (+) [5]	541	399
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,135	1,135
Non Commercial Capacity (+)	40	40
Non Gas-fired Planned Outage MW (-)	318	423
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	3,735	4,287
Net Capacity (NET OPCAP SUPPLY MW)	24,647	26,150
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,710	19,710
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,015	22,015
Operable Capacity Margin	2,632	4,135

[1] Operable Capacity is based on data as of **October 27, 2021** 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 **October 27, 2021.**

[2] Load forecast that is based on the 2021 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 8, 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.

Winter 2021/22 Operable Capacity Analysis

90/10 Load Forecast	Jan. - 2022[2] CSO (MW)	Jan. - 2022[2] SCC (MW)
Operable Capacity MW [1]	29,784	32,086
Active Demand Capacity Resource (+) [5]	541	399
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,135	1,135
Non Commercial Capacity (+)	40	40
Non Gas-fired Planned Outage MW (-)	318	423
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	4,546	5,217
Net Capacity (NET OPCAP SUPPLY MW)	23,836	25,220
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,349	20,349
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,654	22,654
Operable Capacity Margin	1,182	2,566

[1] Operable Capacity is based on data as of **October 27, 2021** 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 **October 27, 2021.**

[2] Load forecast that is based on the 2021 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **January 8, 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.

Winter 2021/22 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

October 29, 2021 - 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 June, July, August, and Mid September.

Report created: 10/28/2021

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
11/27/2021	29967	476	917	32	1728	96	3600	1862	24106	18237	2305	20542	3564	N	Winter 2021/2022
12/4/2021	29726	474	1143	33	474	748	3200	1634	25320	18611	2305	20916	4404	N	Winter 2021/2022
12/11/2021	29726	474	1143	33	388	298	3200	2283	25207	18900	2305	21205	4002	N	Winter 2021/2022
12/18/2021	29726	474	1143	33	312	102	3200	2692	25069	18911	2305	21216	3853	N	Winter 2021/2022
12/25/2021	29726	474	1143	33	312	93	3200	3048	24722	18973	2305	21278	3444	N	Winter 2021/2022
1/1/2022	29784	541	1135	40	382	0	2800	3740	24578	19246	2305	21551	3027	N	Winter 2021/2022
1/8/2022	**29784**	**541**	**1135**	**40**	**318**	**0**	**2800**	**3735**	**24647**	**19710**	**2305**	**22015**	**2632**	**Y**	**Winter 2021/2022**
1/15/2022	29784	541	1135	40	318	0	2800	3590	24792	19710	2305	22015	2777	N	Winter 2021/2022
1/22/2022	29784	541	1135	40	318	0	2800	3141	25241	19710	2305	22015	3226	N	Winter 2021/2022
1/29/2022	29784	541	1135	40	318	0	3100	2842	25240	19488	2305	21793	3447	N	Winter 2021/2022
2/5/2022	29784	541	1135	40	311	0	3100	2543	25546	19222	2305	21527	4019	N	Winter 2021/2022
2/12/2022	29784	541	1135	40	304	0	3100	2244	25852	19193	2305	21498	4354	N	Winter 2021/2022
2/19/2022	29784	541	1135	40	306	18	3100	1777	26299	18931	2305	21236	5063	N	Winter 2021/2022
2/26/2022	29784	541	1135	40	361	18	3100	1478	26543	17944	2305	20249	6294	N	Winter 2021/2022
3/5/2022	29784	541	1135	40	365	270	2200	927	27738	17596	2305	19901	7837	N	Winter 2021/2022
3/12/2022	29784	541	1135	40	649	718	2200	0	27934	17400	2305	19705	8229	N	Winter 2021/2022
3/19/2022	29784	541	1135	40	1073	1120	2200	0	27107	17036	2305	19341	7766	N	Winter 2021/2022
3/26/2022	29760	540	1135	40	1713	757	2700	0	26305	16472	2305	18777	7528	N	Winter 2021/2022

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 2021 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.

Winter 2021/22 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

October 29, 2021 - 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 December, January, February, March and April.

Report created: 10/28/2021

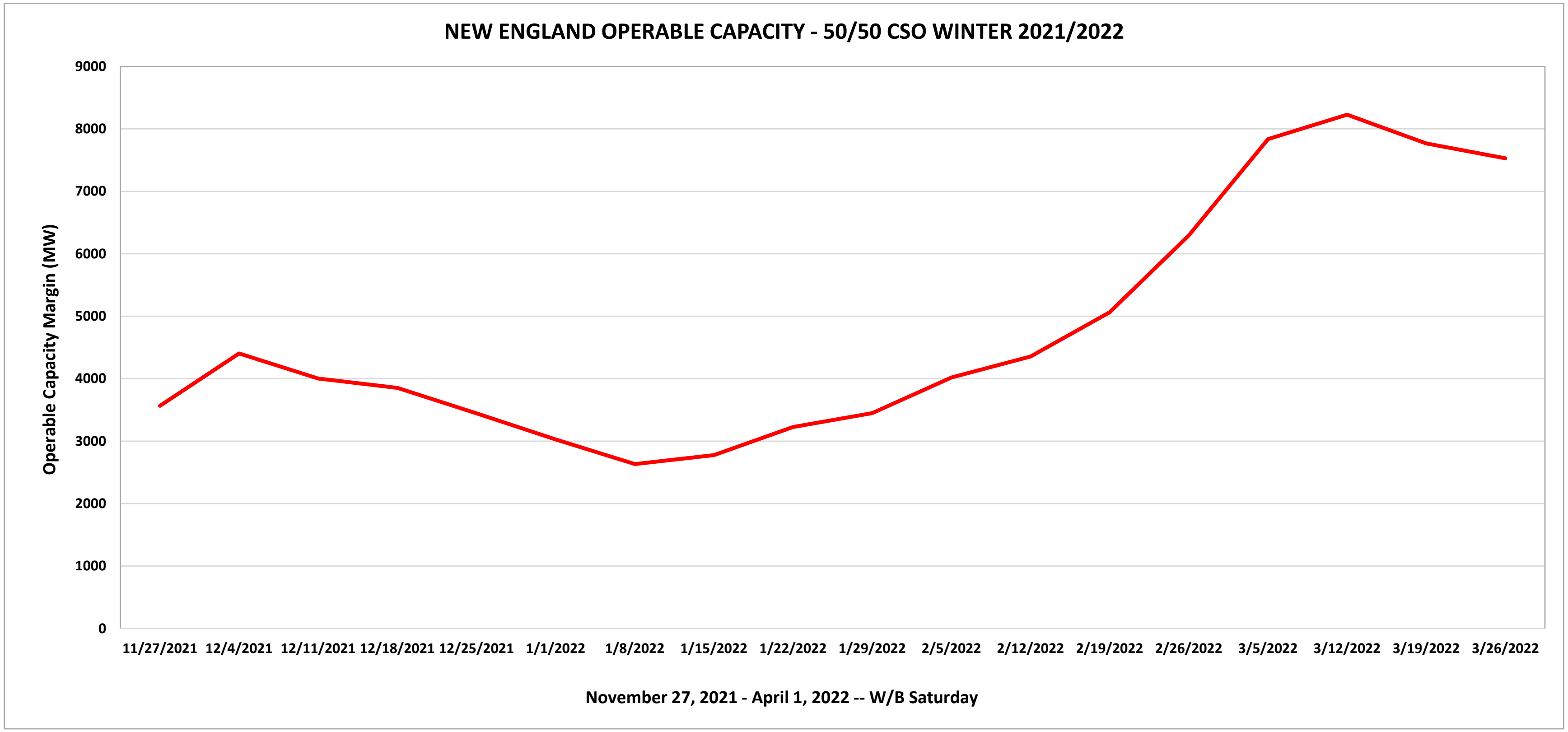
Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due 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
11/27/2021	29967	476	917	32	1728	96	3600	2776	23192	18838	2305	21143	2049	N	Winter 2021/2022
12/4/2021	29726	474	1143	33	474	748	3200	2622	24332	19218	2305	21523	2809	N	Winter 2021/2022
12/11/2021	29726	474	1143	33	388	298	3200	3270	24220	19515	2305	21820	2400	N	Winter 2021/2022
12/18/2021	29726	474	1143	33	312	102	3200	3811	23950	19527	2305	21832	2118	N	Winter 2021/2022
12/25/2021	29726	474	1143	33	312	93	3200	4194	23576	19591	2305	21896	1680	N	Winter 2021/2022
1/1/2022	29784	541	1135	40	382	0	2800	4415	23903	19872	2305	22177	1726	N	Winter 2021/2022
1/8/2022	**29784**	**541**	**1135**	**40**	**318**	**0**	**2800**	**4546**	**23836**	**20349**	**2305**	**22654**	**1182**	**Y**	**Winter 2021/2022**
1/15/2022	29784	541	1135	40	318	0	2800	4338	24044	20349	2305	22654	1390	N	Winter 2021/2022
1/22/2022	29784	541	1135	40	318	0	2800	4039	24343	20349	2305	22654	1689	N	Winter 2021/2022
1/29/2022	29784	541	1135	40	318	0	3100	4039	24043	20121	2305	22426	1617	N	Winter 2021/2022
2/5/2022	29784	541	1135	40	311	0	3100	3590	24499	19847	2305	22152	2347	N	Winter 2021/2022
2/12/2022	29784	541	1135	40	304	0	3100	3291	24805	19817	2305	22122	2683	N	Winter 2021/2022
2/19/2022	29784	541	1135	40	306	18	3100	2675	25401	19547	2305	21852	3549	N	Winter 2021/2022
2/26/2022	29784	541	1135	40	361	18	3100	2226	25795	18533	2305	20838	4957	N	Winter 2021/2022
3/5/2022	29784	541	1135	40	365	270	2200	1824	26841	18174	2305	20479	6362	N	Winter 2021/2022
3/12/2022	29784	541	1135	40	649	718	2200	778	27155	17973	2305	20278	6877	N	Winter 2021/2022
3/19/2022	29784	541	1135	40	1073	1120	2200	0	27107	17598	2305	19903	7204	N	Winter 2021/2022
3/26/2022	29760	540	1135	40	1713	757	2700	0	26305	17017	2305	19322	6983	N	Winter 2021/2022

Column Definitions

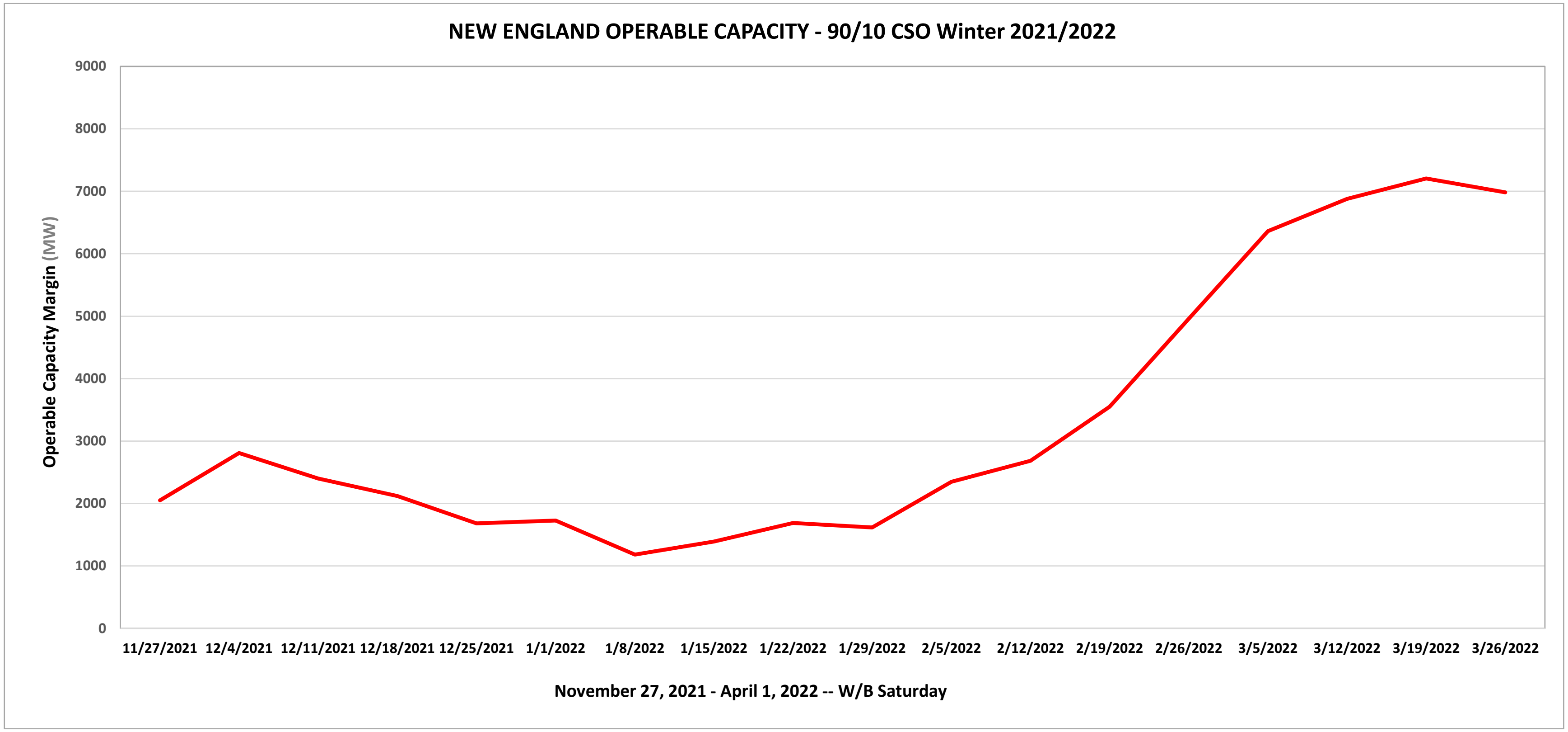
1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can 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 2021 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**

Winter 2021/22 Operable Capacity Analysis
50/50 Forecast (Reference)



Winter 2021/22 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

OCTOBER 7 | BOSTON, MA

Operational Impact of Extreme Weather Events

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Operational Impact of Extreme Weather Events – Introduction

- Recent experiences in Texas and California with extreme weather events have emphasized the importance of a comprehensive energy/resource adequacy assessment that covers a wide range of operating conditions
- The objective of this project is to conduct a probabilistic energy security study for the New England region in the operational time frame under extreme weather events

Operational Impact of Extreme Weather Events – Introduction

- The ISO will work with EPRI on this project
- The ISO effort will leverage the ongoing "Resource Adequacy for a Decarbonized Future" project by EPRI
- There are three major steps to this effort
  - Step 1: Extreme Weather Modeling (performed by EPRI)
  - Step 2: Risk Model Development and Scenario Generation (performed by EPRI)
  - Step 3: Energy security/adequacy assessments (performed by the ISO)
- Each of these major steps will be discussed with stakeholders
- This project is expected to take 15-18 months and will continue through the end of 2022/early 2023

Scope of Work – Step 1: Extreme Weather Modeling

- The objective of this step is to identify extreme weather events of interest, summer and winter, using probabilistic modeling
- This analysis begins with the acquisition and interpretation of locationally-specific climate data, both historical and projections
  - EPRI has developed and is expanding a repository of historical and projection climate data that includes multiple models and sources
  - This data repository will be used to characterize and visualize trends, including uncertainty, in the mean and extremes for different climate variables of interest

Scope of Work – Step 1: Extreme Weather Modeling, continued

- EPRI will incorporate future changes in weather variables
  - Future changes will be based on calculated trends for the near-term (next 20 years) and integrated with localized CMIP6 climate change projections (~2050 timeframe) to provide an appropriate margin or range of outcomes for the next 4 decades
- As part of this analysis, EPRI will summarize a number of possible extreme weather events in the New England region
  - For example, this could be for single day, 3-day or 5-day events by mean temperature, at an aggregate or city level
- Final deliverable for this task will include extreme weather events to model, and associated probabilistic distributions

Scope of Work – Step 2: Scenario Generation

- The objective of this step is to identify power system scenarios of interest using probabilistic techniques
- Key inputs for this phase include the following:
  - Agreement on macro assumptions about future energy mix, demand composition and other high-level factors
  - Identification of risk factors associated with each resource type (e.g., wind speed, temperature and age for wind power, streamflow for hydro, outages for synchronous machines, availability of natural gas etc.)
- For each of these risk factors, a model will be developed that suitably characterizes the risk associated with that risk factor (e.g., wind power conversion curve, forced outage failure rates)

Scope of Work – Step 2: Scenario Generation, continued

- Data from weather modeling, together with additional power system data, will be translated to various power system variables – wind/solar output, load, generator availability
  - This will include impact of extreme weather on output of resources
- The various power system variables, along with the risk models will be used to develop scenarios of interest, using Monte Carlo simulation
- These scenarios will be developed via a ‘scenario engine’ tool that will be built by EPRI

Scope of Work – Step 3: Assessing Energy Security/Adequacy

- Initially as part of this project, the ISO will use its 21 day Energy Security Analysis tool to assess operational impacts
- By limiting the analysis to 21 days, and furthermore, applying the probabilistic scenarios developed in the prior step, the ISO expects to quantify the operational impact of extreme weather events using probabilistic risk metrics, reducing the use of engineering judgement
- As a longer term effort (beyond 18 months), to provide a comprehensive assessment of energy adequacy for different time frames and weather conditions, new adequacy study methodologies are required
- These changes are a key focus of EPRI's "Resource Adequacy for a Decarbonized Future" supplemental project, which plans to develop methods to better account for tail risk in adequacy studies
  - For example, this may include methods to run Monte Carlo simulations and make appropriate draws to ensure such events are included in chronological adequacy studies using production cost modeling approaches

Draft Timeline

- This is a draft timeline, and subject to other priorities over the course of the next year
  - Feedback may add to the scope of work, which will likely extend the timeline into early 2023
- Q4 2021 – Initiate project
- Q1 2022 – Initiate stakeholder process on Extreme Weather Modeling
- Q2 2022 – Finalize Weather Modeling scenarios
- Q2 2022 – Initiate stakeholder process on Study Scenarios
- Q4 2022 – Finalize Scenarios for operational assessment
- Q4 2022 – Preliminary results of operational assessment

MEMORANDUM

TO: NEPOOL Participants Committee

FROM: Eric Runge, NEPOOL Counsel

DATE: October 27, 2021

RE: Vote on Participant Proposal to Change Schedule 11 Cost Allocation

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At the November 3, 2021 meeting of the Participants Committee you will be asked to vote on a proposal from NextEra on behalf of RENEW Northeast to revise Schedule 11 of Section II of the ISO New England Inc. ("ISO-NE") Transmission, Markets and Services Tariff.[1] The proposal would revise Schedule 11 so that annual costs associated with Distribution Upgrades, Stand Alone Network Upgrades and Network Upgrades would no longer be allocated to Interconnection Customers, but instead would be recovered from Transmission Customers ("Schedule 11 Revisions"). Background materials explaining the proposal and showing the proposed Tariff revision are linked below and have been included with this memo.[2]

The Transmission Committee considered the Schedule 11 Revisions proposal over the course of four meetings and, at its October 26, 2021 meeting, voted on the proposal. The Transmission Committee did not recommend Participants Committee support of the Schedule 11 Revisions, with a vote of 55.47% in favor.[3]

The following resolution could be used for the Participants Committee vote on this item:

> *Resolved* that the Participants Committee supports the proposed Schedule 11 Revisions as proposed by NextEra on behalf of RENEW and as included with the materials for the November 3, 2021 Participants Committee meeting, together with [any changes agreed to at the meeting, and]any non-substantive changes agreed to by the Chair of the Participants Committee after the meeting.

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[1] The Participating Transmission Owners have Section 205 filing rights over Schedule 11 cost allocation revisions. The Participating Transmission Owners Administrative Committee has not voted to support the proposal. To date, ISO-NE has not expressed an opinion on the Schedule 11 Revisions.

[2] The RENEW presentation from the October 26 Transmission Committee meeting is available here: https://www.iso-ne.com/static-assets/documents/2021/10/a05_tc_2021_10_26_renew_presentation.pdf. The marked Schedule 11 Revisions are available here: https://www.iso-ne.com/static-assets/documents/2021/10/a05_tc_2021_10_26_tc_sched_11_revs.pdf

[3] To pass, the motion to recommend Participants Committee support required a two-thirds vote in favor by the Transmission Committee. The Transmission Committee roll call vote was 55.47% in favor, with individual Sector votes as follows: Generation (16.70% in favor, 0.00% opposed, 0 abstentions), Transmission (0.00% in favor, 16.70% opposed, 1 abstention), Supplier (16.70% in favor, 0.00% opposed, 2 abstentions), Publicly Owned Entity (0.00% in favor, 16.70% opposed, 2 abstentions), Alternative Resources (16.50% in favor, 0.00% opposed, 1 abstention), and End User (5.57% in favor, 11.13% opposed, 2 abstentions).

Annual Charges Related to Interconnection Upgrades

RENEW Northeast

For NEPOOL TRANSMISSION COMMITTEE | OCTOBER 26, 2021

About RENEW Northeast

Overview of Presentation

RENEW is seeking to revise the OATT to remove the ability of Transmission Owners to directly assign to interconnection customers ongoing “annual costs” associated with interconnection-related Network Upgrades

- Review of RENEW Proposal
- Tariff Language and redlines
  - <u>One minor change to incorporate all resources</u>
- Request submitted to PTO-AC for annual cost information
- Impact on Regional Rates
- Next Steps

With the exception of the one minor tariff change, the RENEW Proposal and this presentation is the same as what was presented in September

RECAP: RENEW Proposal

Recap: Annual Costs Related to Interconnection Upgrades and Facilities

- Interconnection Customers are charged "annual costs" by PTOs in ISO-NE in the form of a carrying charge
- The carrying charge is a rate calculated annually by each PTO that is equivalent to the sum of certain PTO revenue requirement components (e.g., O&M, A&G, property taxes, income taxes, etc.) divided by their total gross transmission plant value
  - The rate is an average of the PTO's annual costs per dollar of transmission plant on their system
  - Each PTO calculates this rate slightly differently
  - Customers do not have a choice in New England of paying the actual cost instead of this formula rate
- The annual charge to an Interconnection Customer would be the product of that rate and the total cost of the Interconnecting Transmission Owner's Interconnection Facilities, Network Upgrades, and Distribution Upgrades

Recap: Annual Costs Related to Interconnection Upgrades and Facilities (cont'd)

- These annual charges are unique to New England
  - Many Interconnection Customers without prior development experience in New England do not find out about these annual charges, or what the rate is, until receiving their draft LGIA/SGIA and/or a bill following COD
  - Even when developers are aware of these charges and the current rate, they cannot know what future rates will be
- Annual charges to Interconnection Customers likely exceed actual costs related to their specific Network Upgrades
  - The Network Upgrades are the newest additions to the system and likely have the lowest cost to maintain, but the customer is charged the system-wide average rate.
  - The identical transmission facility would cost more to build today than it did twenty years ago. Because the rate is charged per dollar of capital cost, the annual charges related to the new facility would exceed the charges to the older facility even though the older facility likely costs more to maintain.

Recap: Annual Costs Related to Interconnection Upgrades and Facilities (cont'd)

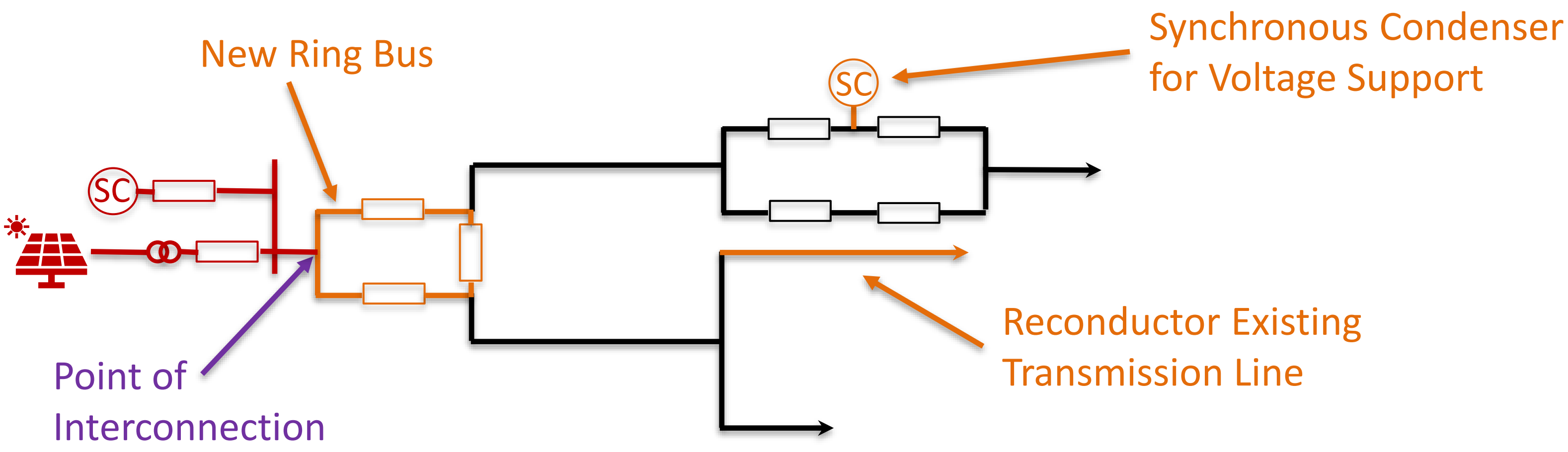
- Annual charges may shift existing costs to Interconnection Customers when Network Upgrades do not result in actual incremental costs
  - Reconductoring an existing transmission line
  - Replacing an existing circuit breaker or transformer with a new higher-rated one
  - Rebuilding an existing transmission line
  - Rebuilding an existing substation
- Network Upgrades may provide benefits to future interconnection customers through creation of headroom or to load through reduced congestion and increased reliability
  - The original Interconnection Customer is currently responsible for all annual charges regardless of the benefits provided to other such parties

Interconnection Facilities vs. Network Upgrades

Definitions from Schedule 22:

"Interconnection Facilities shall mean the Interconnecting Transmission Owner's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include **all facilities and equipment between the Generating Facility and the Point of Interconnection**, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Administered Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades."

"Network Upgrades shall mean the additions, modifications, and upgrades to the New England Transmission System required **at or beyond the Point of Interconnection** to accommodate the interconnection of the Large Generating Facility to the Administered Transmission System"



Proposed Change for Upgrades Beyond the Point of Interconnection

- RENEW is proposing that annual costs associated with upgrades to the system beyond the customer's point of interconnection be recovered by Transmission Owners through regional rates
  - This applies to Distribution Upgrades, Stand Alone Network Upgrades, and Network Upgrades (referred to generally as Network Upgrades in this presentation)
  - Annual costs associated with Interconnection Facilities would continue to be charged to Interconnection Customers
- Under the RENEW proposal, Interconnection Customers remain responsible for the initial capital cost of all identified Interconnection Facilities, Distribution Upgrades, Stand Alone Network Upgrades, and Network Upgrades
  - RENEW does not propose any changes to allocation of capital costs

Proposal to Reform Treatment of O&M Costs: Tariff changes

RENEW is seeking to revise the fourth paragraph in Schedule 11(5) of the OATT as follows:

Following completion of the construction or modification, the Generator Owner or ETU IC shall be obligated to pay all (or, in the case of an Upgrade identified under Clustering, its share) of the annual costs (including federal and state income taxes, O&M and A&G expenses, annual property taxes and other related costs) which are allocable to the Upgrade <u>but excluding annual costs associated with Distribution Upgrades, Stand Alone Network Upgrades, and Network Upgrades</u>, pursuant to the interconnection agreement (or support agreement) with the individual PTO or its designee which is responsible for the construction or modification, and such agreement may be filed with the Commission by the PTO, either signed or unsigned, on its own or at the request of the Generator Owner or ETU IC.

Proposal to Reform Treatment of O&M Costs: Additional Tariff change added to extend treatment to all resources

RENEW is seeking to revise Schedule 11(3)(d) of the OATT ("Categories A and B") as follows:

One-half of the Shared Amount (as defined below) of the capital cost of the PTF upgrade shall constitute Pool Supported PTF and be included in Annual Transmission Revenue Requirements under Attachment F to this OATT…. Following completion of the construction or modification of the Generator Interconnection Related Upgrade, the Generator Owner shall be obligated to pay its pro rata share of all of the annual costs (including cost of capital, federal and state income taxes, O&M and A&G expenses, annual property taxes and other related costs) which are allocable to such upgrade, but excluding annual costs associated with Distribution Upgrades, Stand Alone Network Upgrades, and Network Upgrades, pursuant to the interconnection agreement with the individual PTO or its designee…

Proposal to Reform Treatment of O&M Costs - Summary

- Under this proposal:
  - Interconnection Facilities
    - Interconnection customer continues to pay the capital cost (no change)
    - Interconnection customer continues to pay the annual cost in the form of a calculated rate (no change)
  - Network Upgrades
    - Interconnection customer continues to pay the capital cost (no change)
    - Interconnection customer no longer pays annual cost
    - PTOs would recover their **actual** annual costs in the same way that they recover these costs for the remainder of their transmission network
      - This actual cost is likely less than what the annual charge to Interconnection Customers in the form of a calculated rate would have been

Impact on Transmission Rates

O&M Charges Paid by Interconnection Customers Credited Against Transmission Owner Revenue Requirement

- O&M charges collected from Interconnection Customers are, we believe, credited against the Transmission Owners' Revenue Requirement prior to calculating the RNS and LNS Rates
- Reducing this credit against the revenue requirement increases the total amount recovered through RNS rates

Reminder: This is a calculated rate, not the actual cost related to the particular facilities funded by the Interconnection Customer. This charge may exceed the actual cost of O&M for these particular facilities.

Simplified Example to Illustrate Concept		
	Current Practice	RENEW Proposal
Total Revenue Requirement	$1,000,000	$1,000,000
Credit for O&M Charges Collected from Interconnection Customers for Network Upgrades	($10,000)	N/A
Credit for O&M Charge Collected from Interconnection Customers for Interconnection Facilities	($10,000)	($10,000)
Revenue Requirement Recovered Through Network Service Rate	$980,000	$990,000
Total Load	100,000 kW	100,000 kW
Network Service Rate	$9.80/kW-yr	$9.90/kW-yr

Request Submitted to PTO-AC for O&M Cost Information

- Key takeaway from the June TC meeting was the request for an assessment of the impact of our proposal on RNS rates
- After attempting to estimate this impact, we determined that we did not have sufficient information
  - On July 16 RENEW sent a letter to the PTO-AC requesting the carrying charges for each PTO in order to complete this assessment
  - RENEW discussed this proposal and information request with the PTO-AC at is July 29 meeting and also requested they provide the total amount of annual charges collected from Interconnection Customers
  - The PTO-AC provided this information on August 24, updated on September 20
    - Summarized on the next slide
  - The PTO-AC clarified on September 20 that the total charges collected from Interconnection Customers reflects charges for both Interconnection Facilities and Network Upgrades

Annual Transmission Charges to Interconnection Customers

Transmission Owner		Annual Charge Rate	Rate Effective Date	Total Annual Charges Collected from Interconnection Customers in CY 2020
Avangrid	Central Maine Power	3.02%	6/1/2021	$1,785,000
	United Illuminating	4.531%		$264,000
Eversource	CL&P	3.92%	6/1/2021	$9,109,000
	NSTAR – West	4.31%	6/1/2021	$615,000
	NSTAR – East	3.24%	6/1/2021	$236,000
	PSC of NH	4.43%	6/1/2021	$2,898,000
New England Power Company		4.99%	1/1/2021	$3,900,000
Vermont Transco		7.25%	2/28/2018	$231,000
Versant Power		2.09%		$128,000
	Average:	**4.02%**	Total:	**$19,166,000**

This data was provided by PTO-AC 8/24/2021, updated 9/20/2021

Reflects Interconnection Facilities and Network Upgrades
Reflects charges credited to RNS and LNS

Clarifying Questions Posed Back to PTO-AC (1 of 2)

- After reviewing the data on the prior slide, we realized we still did not have sufficient information to be able to estimate the rate impact of this proposal
- RENEW requested additional information from the PTO-AC on 9/20 and received the following responses on 9/23:
  - Q - Our understanding is that the annual charges collected from Interconnection Customers are credited against each TO's revenue requirement in the process of calculating the RNS and LNS rates. Is this an accurate description of how these revenues flow through to rates?
    - A - Yes, the revenues are credited in transmission rates

Clarifying Questions Posed Back to PTO-AC (2 of 2)

- Q - What portion of annual charges on the prior slide was related to Network Upgrades and what portion was related to Interconnection Facilities?
  - A – see below
- Q - What portion of the charges collected in CY2020 from Interconnection Customers related to Network Upgrades did each TO apply as a credit to their RNS Revenue Requirement versus their LNS Revenue Requirement?
  - A – see below
- Q - We are having difficulty determining the rate impact on our own, can the TOs tell us approximately what the impact would be on the 6/1/2021 RNS (and each TO's LNS) rate if the revenues attributable to Network upgrades were not collected from Interconnection Customers?
  - A - These are these are not simple questions to answer. To develop a response will require considerable time and effort on the part of PTO's. Unfortunately, this is something that PTO's cannot commit to at this time.

- Where we are now: <u>we do not actually know</u> what portion of the $19.2M collected in CY 2020…
  - Was related to Network Upgrades
  - Was related to actual incremental cost increases associated with the Network Upgrades
  - Was credited towards the RNS Revenue Requirement or LNS Revenue Requirement

Impact on RNS Rates

	Current Calculation of June 1, 2021 RNS Rate	Hypothetical Impact of RENEW Proposal on June 1, 2021 RNS Rate
Total NE RNS Rev Req	$2,572,018,870	+$7,187,250
Total NE Load (kW)	18,243,688	18,243,688
Total NE RNS ($ / kW-yr)	$140.981	+$0.394

*https://www.iso-ne.com/static-assets/documents/2021/05/jun21_sch_9_060121_v01.xlsx

- If we assume hypothetically that 75% of the $19.2M was related to Network Upgrades and 50% was credited towards the RNS Revenue Requirement we could say that:
  - Adding $**7.2** M to the Total NE RNS Revenue Requirement would have increased 6/1/2021 RNS rates by about **0.28**% ($0.394/kW-year)
  - This reflects elimination of the likely RNS subsidy that Interconnection Customers have been paying due to the calculated rate exceeding actual incremental costs (unknown portion of the above).
  - Because the actual incremental costs are unknown, difficult to project the impact from future interconnection related Network Upgrades
- Note that LNS rates would also be impacted by this proposal

Next Steps

- May 27: Initial TC presentation
- July 29: PTO-AC Presentation
- August 24: TC Presentation
- September 28: TC Presentation and Tariff Language
- October 26: TC Presentation and Vote
- November 3: Vote at the Participants Committee

Please note that the PTO AC has filing rights over Schedule 11 and we will continue to work with them on scheduling <u>and may make adjustments to the timing</u>.

THANK YOU.

SCHEDULE 11

GENERATOR INTERCONNECTION RELATED UPGRADE AND ELECTIVE TRANSMISSION INTERCONNECTION RELATED UPGRADE COSTS

(1)

Classification of Generating Projects. The treatment for purposes of this OATT of the Generator Interconnection Related Upgrade costs with respect to the facilities needed for the interconnection of a particular new or modified generating unit project in accordance with Section II.47 of this OATT depends on whether the project is a Category A Project, a Category B Project or a Category C Project, as follows:

(a) A Category A Project is one whose Generator Owner committed to pay for upgrade costs on or after October 1, 1998 and prior to October 29, 1998 and has filed a petition with the Commission requesting that the costs associated with the interconnection of its generation project be determined in accordance with Schedule 11 of this OATT, as evidenced either by the filing of an executed Transmission Service Agreement or by the filing of an unexecuted Transmission Service Agreement.

(b) A Category B Project is any one whose Generator Owner committed to pay for upgrade costs on or after October 29, 1998 and prior to June 22, 1999, as evidenced either by the filing of an executed Transmission Service Agreement or by the filing of an unexecuted Transmission Service Agreement. To the extent not otherwise covered by the preceding sentence, a Category B Project includes any one (other than a Category A Project) on which the Generator Owner had expended at least $5,000,000, including amounts due under irrevocable commitments, as of June 22, 1999. Category B Projects are those projects listed as Category A Projects in Section 1(a) of this Schedule 11, but no longer qualify as Category A Projects, that had expended at least $5,000,000 (including amounts due under irrevocable commitments) as of June 22, 1999, as reasonably determined by the ISO, as well as the following projects:

Sithe, Mystic Station Expansion

Sithe Edgar Station Expansion, Fore River

Sithe, West Medway

PG&E, Generating Lake Road Generating

PDC, Milford Power

PDC, Meriden Power

Reliant Energy, Hope Rhode Island

IDC FPL, Bellingham

Constellation, Merrimack (Nickel Hill) Energy Project

SEI, Canal Re-powering

ANP, Bellingham

ANP, Blackstone

Cabot, Island End

Calpine, Westbrook Power

HQ, Bucksport

AES, Londonderry

ConEd, Newington

Mirant, Kendall Repowering Project

(c) A Category C Project is any project which is not a Category A Project or a Category B Project.

(2)

Direct Interconnection Transmission Costs. Direct Interconnection Transmission Costs shall mean the cost of facilities constructed for sole use of the Generator Owner that are not PTF. One hundred percent of Direct Interconnection Transmission Costs shall be the responsibility of the Generator Owner whether the Generator Owner's project is a Category A Project, a Category B Project or a Category C Project.

(3)

Treatment of Category A Project Transmission Costs. The allocation of costs of Generator Interconnection Related Upgrades for Category A Projects will be determined as follows:

(d) One-half of the Shared Amount (as defined below) of the capital cost of the PTF upgrade shall constitute Pool Supported PTF and be included in Annual Transmission Revenue Requirements under Attachment F to this OATT. The Generator Owner shall be obligated to pay, in addition to the Direct Interconnection Transmission Costs, the other half of the Shared Amount of the capital cost of the PTF upgrade and all of the capital costs in excess Effective Date: 11/1/17 - Docket # ER17-2421-000 of the Shared Amount, and any applicable tax gross-up amounts, and such amounts to be paid by the Generator Owner shall not be included in Annual Transmission Revenue Requirements under Attachment F to this OATT. Following completion of the construction or modification of the Generator Interconnection Related Upgrade, the Generator Owner shall be obligated to pay its pro rata share of all of the annual costs (including cost of capital, federal and state income taxes, O&M and A&G expenses, annual property taxes and other related costs) which are allocable to such upgrade, but excluding annual costs associated with Distribution Upgrades, Stand Alone Network Upgrades, and Network Upgrades, pursuant to the interconnection agreement with the individual PTO or its designee which is responsible for the construction or modification, and such agreement may be filed with the Commission by the PTO, either signed or unsigned, on its own or at the request of the Generator Owner.

(4)

Treatment of Category B Project Transmission Costs. The costs of Generator Interconnection Related Upgrades in connection with a Category B Project shall be allocated in the same way as Generator Interconnection Related Upgrades for Category A projects

(5)

Treatment of Category C Project Transmission Costs. If a Generator Interconnection Related Upgrade or an Elective Transmission Upgrade Interconnection Related Upgrade (collectively, "Upgrade") is required in order to satisfy the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard (or its predecessor standard) in connection with a Category C Project, the Generator Owner or Elective Transmission Upgrade Interconnection Customer ("ETU IC"), as applicable, shall be obligated to pay all of the cost of such Upgrade, including all Direct Interconnection Transmission Costs and any applicable tax gross-up amounts, to the extent such costs would not have been incurred but for the interconnection; provided that, if the ISO determines that a particular Upgrade provides benefits to the system as a whole as well as to particular parties, then the cost of such Upgrade shall be allocated in the same way as Reliability Transmission Upgrades. If the Upgrade consists of Interconnecting Transmission Owner's Interconnection Facilities, Network Upgrades, or Distribution Upgrades, including a Cluster Enabling Transmission Upgrade, that were identified under Clustering and are not included in Direct Interconnection Transmission Costs, then the costs to be paid by each Generator Owner or ETU IC (that is not the ETU IC for an ETU that is taking the place of a CETU, or portion thereof, pursuant to Section 4.2.3.4 of Schedule 22, Section 1.5.3.3.3.4 of Schedule 23, or Section 4.2.3.4 of Schedule 25, Section II of the Tariff) with an Interconnection Request included in the cluster shall be the total costs of such Upgrade multiplied by the ratio of the Generator Owner or ETU IC's respective distribution impact divided by the total distribution impact of the entire cluster based on the following distribution factor cost allocation methodology.

Distribution Factor Cost Allocation Methodology: The distribution factor is the measure of responsiveness or change in electrical loading on system facilities due to a change in electric power transfer from one part of the electric system to another, expressed in percent of the change in power transfer. The calculation of the distribution factor for each of the eligible Upgrades shall: (i) use the final CSIS Study Case for summer peak load conditions; (ii) use the pre-contingency condition (i.e., no contingencies will be modeled); and, (iii) be conducted using a transfer from the injection point associated with the respective Generator Owner or ETU IC's facility to New England Control Area load. The distribution impact of each Generator Owner or ETU IC with an Interconnection Request included in the cluster shall be determined by multiplying the Generator Owner or ETU IC's respective distribution factor, as calculated above, by the Summer Network Resource Capability in the case of a Generating Facility or the absolute value of the higher of the requested bidirectional capability that results in a positive distribution factor in the case of an Elective Transmission Upgrade. The total distribution impact of the entire cluster shall be the sum of all of the individual distribution impacts for the Generator Owners and ETU ICs with Interconnection Requests included in the cluster.

Where cost allocation for an Upgrade identified under Clustering cannot be determined using the distribution factor cost allocation methodology (e.g., a dynamic reactive device), each Generator Owner or ETU IC with an Interconnection Request included in the cluster shall be obligated to pay the costs of such Upgrade based upon its pro rata megawatt share of the Interconnection Requests included in the cluster study to be determined using the Summer Network Resource Capability in the case of a Generating Facility and the absolute value of the higher of the requested bidirectional capability in the case of an Elective Transmission Upgrade.

Following completion of the construction or modification, the Generator Owner or ETU IC shall be obligated to pay all (or, in the case of an Upgrade identified under Clustering, its share) of the annual costs (including federal and state income taxes, O&M and A&G expenses, annual property taxes and other related costs) which are allocable to the Upgrade but excluding annual costs associated with Distribution Upgrades, Stand Alone Network Upgrades, and Network Upgrades, pursuant to the interconnection agreement (or support agreement) with the individual PTO or its designee which is responsible for the construction or modification, and such agreement may be filed with the Commission by the PTO, either signed or unsigned, on its own or at the request of the Generator Owner or ETU IC.

A Generator Owner with a Generating Facility or ETU IC with an Elective Transmission Upgrade that achieves Commercial Operation within ten years of the In-Service Date of a Cluster Enabling Transmission Upgrade (to be referred to as a “Late Comer Project”) shall reimburse the entities (i.e., Generator Owner or ETU IC) that have contributed to the costs of the Cluster Enabling Transmission Upgrade by the amount of said entities’ corresponding reduction in Cluster Enabling Transmission Upgrade costs based on the comparison of the Cluster Enabling Transmission Upgrade cost allocation with and without the added Late Comer Project, if the Late Comer Project: (i) interconnects directly to the Cluster Enabling Transmission Upgrade, (ii) connects to a substation where the Cluster Enabling Transmission Upgrade terminates, or (iii) (a) is greater than five megawatt and is greater than one percent of the Cluster Enabling Transmission Upgrade normal rating, and (b) (1) has an impact on the Cluster Enabling Transmission Upgrade that is greater than five percent of the Cluster Enabling Transmission Upgrade normal rating or (2) has a distribution factor on the Cluster Enabling Transmission Upgrade that is greater than or equal to 20 percent using the distribution factor methodology described above. A Generator Owner or ETU IC that has contributed to the costs of the Cluster Enabling Transmission Upgrade shall have the payments associated with the Cluster Enabling Transmission Upgrade adjusted based on the depreciation schedule that is being used for the Cluster Enabling Transmission Upgrade.

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of November 2, 2021

The following activity, as more fully described in the attached litigation report, has occurred since the report dated October 5, 2021 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

COVID-19

No Activity to Report

I. Complaints/Section 206 Proceedings

	3	Green Development DAF Charges Complaint Against National Grid (EL21-47)	Oct 25	Green Development requests partial rehearing of the Sep 23 *Complaint Order*; FERC action required on or before ***Nov 24, 2021***
	3	NECEC/Avangrid Complaint Against NextEra/Seabrook (EL21-6)	Oct 7	ISO-NE, Avangrid, NextEra, MA AG, NEPGA/EPSA, MA DOER file initial briefs
			Oct 22	Avangrid, NextEra, ISO-NE file reply briefs

II. Rate, ICR, FCA, Cost Recovery Filings

*	8	2022 NESCOE Budget (ER22-117)	Oct 15	ISO-NE files materials for funding NESCOE's 2022 operations; comment date Nov 5
			Oct 18	NESCOE intervenes
*	8	2022 ISO-NE Administrative Costs and Capital Budgets (ER22-113)	Oct 15	ISO-NE files its 2022 administrative costs and capital budgets; comment date Nov 5
			Oct 21-27	NEPOOL, NRG intervene
			Nov 1	NEPOOL files comments supporting ISO-NE 2022 Budgets
	9	CSC CIP IROL Cost Recovery: Pre-Jun 1, 2021 Regulatory Asset Cost Recovery (ER21-2334)	Nov 1	FERC issues a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration" of CSC's request for rehearing of the *August 31 Order*
	10	Mystic 8/9 Cost of Service Agreement (ER18-1639)	Oct 8	Mystic appeals *Mystic ROE Order* and *September 13 Notice*
			Oct 15	ENECOS and NESCOE submit formal challenges to Mystic's 2021 Capital Expenditures Informational Filing; comment deadline ***Nov 17, 2021***

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

*	11	Waiver Request: FCA16 Qualification (Andro Hydro) (ER22-174)	Oct 21	Andro Hydro requests waiver of qualification rules in connection with FCA16; comment deadline ***Nov 10, 2021***
	11	eTariff § III.3.1 Corrections (ER21-2850)	Oct 25	ISO-NE supplements record to correct a docket reference in the Sep 8 transmittal letter

IV. OATT Amendments / TOAs / Coordination Agreements

	12	TOs *Order 676-I* Compliance Filing (ER21-2529-001)	Oct 22	PTO AC submits amendment to Jul 27, 2021 compliance filing to include in Schedules 20A-Common and 21-Common revised and new WEQ standards that should have been incorporated by reference; comment deadline ***Nov 12, 2021***

	12	BTM Generation Proposal (ER21-2337)	Oct 12	NEPGA files amended protest and comments in response to deficiency letter response
			Oct 27	PTO AC answers NEPGA Oct 12 protest and comments
	12	CSC Schedule 18 *Order 676-I* Compliance Filing (ER21-2509-001)	Oct 27	ISO-NE and CSC submit amendments to the Jul 26, 2021 compliance filing to include in Schedule 18 references to revised and new WEQ standards that should have been incorporated by reference; comment deadline ***Nov 17, 2021***
	13	ISO-NE/NEPOOL *Order 676-I* Compliance Filing (ER21-941-001)	Oct 22	ISO-NE and NEPOOL submit amendments to the Jan 26, 2021 compliance filing to include in Schedule 24 references to revised and new WEQ standards that should have been incorporated by reference; comment deadline ***Nov 12, 2021***

V. Financial Assurance/Billing Policy Amendments

*	13	Removal of FAP Notarization Requirements (ER22-213)	Oct 27	ISO-NE and NEPOOL jointly file FAP Revisions; comment deadline ***Nov 17, 2021***
*	14	eTariff FAP Attachment 3 Corrections (ER21-2815)	Oct 19	FERC accepts corrections, eff. Sep 10, 2020

VI. Schedule 20/21/22/23 Changes

*	14	Schedule 21-NEP: Sterling LSA (ER22-97)	Oct 13	National Grid files LSA with Sterling Municipal; comment deadline ***Nov 3, 2021***
	14	Schedule 20A-UI: Vitol Phase I/II HVDC-TF Service Agreement (ER21-2662)	Oct 7	FERC accepts UI Service Agreement, eff. Nov 1, 2020
	14	Schedule 20A-CMP: Vitol Phase I/II HVDC-TF Service Agreement (ER21-2661)	Oct 7	FERC accepts CMP Service Agreement, eff. Nov 1, 2020

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

*	16	Capital Projects Report - 2021 Q3 (ER22-125)	Oct 15	ISO-NE files 2021 Q3 Report; comment deadline ***Nov 5, 2021***
			Oct 27-Nov 1	NEPOOL, NESCOE intervene
			Nov 1	NEPOOL files comments supporting Q3 Report
*	16	LFTR Implementation: 52nd Quarterly Status Report (ER07-476)	Oct 15	ISO-NE files its 52nd quarterly report

IX. Membership Filings

	17	Sep 2021 Membership Filing (ER21-2802)	Oct 28	FERC accepts (i) the memberships of Gravel Pit Solar, Tyr Energy and Walden Renewables Development; and (ii) the termination of the Participant status of: Brookfield Energy Marketing Inc., HIKO Energy and Perigee Energy
	17	Suspension Notice – Manchester Methane, LLC (not docketed)	Oct 18	ISO-NE files notice of suspension of Manchester Methane, LLC from the New England Markets

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

	19	Rules of Procedure Changes (CMEP Risk-Based Approach Enhancements) (RR21-10)	Oct 20	Public Utility District No. 1 of Chelan County and APPA/LPPC/TAPS file comments

XI. Misc. - of Regional Interest

*	21	203 Application: Castleton Commodities/Atlas Power (GSP companies) (EC22-7)	Oct 20	Atlas and GSP Holdings request authorization to acquire the remaining 50% of GSP Holdings from an indirect subsidiary of Castleton Commodities; comment deadline ***Nov 10, 2021***
*	21	203 Application: Hull Street/CMEEC (EC22-3)	Oct 15	MPH AL Pierce, LLC, indirectly owned by affiliates of Hull Street Energy, requests FERC authorization to acquire 100 % of the interests in CMEEC's 84 MW Wallingford facility; comment deadline ***Nov 5, 2021***
	21	203 Application: Valcour Wind Energy/AES (EC21-114)	Oct 15	FERC authorizes transaction, which when consummated, will make will AES Renewable Holdings and Valcour Wind Energy Related Persons
	22	203 Application: Covanta/EQT (EC21-113)	Oct 18	FERC authorizes transaction, which when consummated, will make Covanta and Cypress Creek Renewables Related Persons
	22	203 Application: Cypress Creek/EQT (EC21-108)	Oct 8 Oct 15	Transaction consummated Cypress Creek files notice that transaction was consummated
*	23	D&E Agreement Cancellation: NSTAR/Cranberry Storage (ER22-214)	Oct 27	NSTAR submits notice of cancellation of D&E Agreement; comment deadline ***Nov 17, 2021***
*	23	Cost Reimbursement Agreement Cancellation: National Grid/GRS (ER22-129)	Oct 18	National Grid files notice of cancellation of Cost Reimbursement Agreement; comment deadline ***Nov 8, 2021***
	23	IA Termination: CL&P/Sterling Property (ER21-2860)	Oct 15 Oct 25	CL&P answers Sterling Property's protest Sterling Property answers CL&P's answer
	24	TSAs: Third Amendments to NECEC Transmission TSAs (ER21-2738 et al.)	Oct 21	FERC accepts third amendments to TSAs, eff. Aug 24, 2021
	24	ISA: NSTAR/Servistar (ER21-2696)	Oct 14	FERC accepts ISA, eff. Aug 17, 2021
	25	D&E Agreement: NSTAR/Medway Grid II (ER21-2684)	Oct 14	FERC accepts D&E Agreement II, eff. Aug 17, 2021
	25	*Orders 864/864-A* (Public Util. Trans. ADIT Rate Changes): New England Compliance Filings (various)	Oct 19 Oct 21	*ER20-2429-001 (CMP)*. CMP requests 2nd extension of time to respond to second deficiency letter *ER20-2429-001 (CMP)*. FERC grants extension of time to respond to second deficiency letter to ***Nov 8, 2021***

XII. Misc. - Administrative & Rulemaking Proceedings

26	Joint Federal-State Task Force on Electric Transmission (AD21-15)	Oct 27	FERC issues notice of, and agenda for, ***Nov 10, 2021*** meeting
27	Climate Change, Extreme Weather, and Elec. Sys. Reliability: Jun 1-2 Tech. Conf. (AD21-13)	Oct 14	Entergy answers comments submitted by City of New Orleans
28	Modernizing Electricity Market Design - Energy and Ancillary Service Markets (AD21-10)	Oct 7 Oct 12 Oct 14	FERC issues supplemental notice of Oct 12 tech conf FERC holds the second of the 2 staff-led tech confs FERC posts transcript of Sep 15 tech conf in eLibrary

29	Office of Public Participation (AD21-9)	Oct 12 Oct 12-29	Elin Katz announced as OPP Director Individual ratepayers submit comments
30	Hybrid Resources (AD20-9)	Oct 20	NYISO submits comments in response to issues raised in earlier comments
31	ANOPR: Transmission Planning and Allocation and Generator Interconnection (RM21-17)	Oct 8-18	Comments 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, R Street Institute; reply comment deadline ***Nov 30, 2021*** ***Nov 15, 2021*** staff-led, remote technical conference regarding regional transmission planning
33	NOPR: Electric Transmission Incentives Policy (RM20-10)	Oct 13 Oct 18	FERC posts transcript of Sep 10 workshop in eLibrary FERC issues notice inviting comments; comment deadline ***Jan 14, 2022***

XIII. FERC Enforcement Proceedings

39	GreenHat (IN18-9)	Oct 6 Oct 8	OE answers Kittel motion Kittel's widow submits statement
41	Total Gas & Power North America, Inc. et al. (IN12-17)	Oct 15 Oct 18 Oct 18 Oct 19 Oct 25 Nov 1	First settlement conf Second settlement conf scheduled for ***Oct 25, 2021*** Respondents and OE Staff move to suspend and extend the procedural schedule Parties jointly submit status report Second settlement conf held; third conf scheduled for ***Nov 1, 2021*** Third settlement conf held Hearing commencement and initial decision deadlines ***Sep 26, 2022*** and ***Feb 20, 2023***, respectively
40	Powhatan Energy, HEEP Fund, CU Fund, and Chen (IN15-3)	Oct 29	FERC approves Stipulation and Consent Agreement; Chen Defendents to disgorge ***$600,000*** to resolve its part in the *Powhatan Penalties Order* and the federal court lawsuit seeking an order affirming that *Order*; federal court proceedings against Powhatan continue

XIV. Natural Gas Proceedings

42	Iroquois ExC Project (CP20-48)	Oct 15	Iroquois submits supplemental Life Cycle Greenhouse Gas Analysis Report; final EIS Report to be issued ***Nov 12, 2021***

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

* 46	Mystic ROE (21-1198)	Oct 8 Oct 14 Oct 29	Petition for Review filed Clerk issues order directing filing of initial submissions Mystic files initial Statements and underlying decision
48	CASPR (20-1333, 20-1331) (consolidated)**	Oct 22 Oct 25	Sierra Club, NRDC, Renew Northeast, and CLF moved to hold this matter further in abeyance until Jun 1, 2022 Court grants Oct 22 motion

49	2013/14 Winter Reliability Program Order on Compliance and Remand (20-1289, 20-1366) (consol.)	Oct 15	Oral argument held before Judges Srinivasan, Henderson and Edwards
49	ISO-NE's Inventoried Energy Program Proposal (19-1224 et al.)	Oct 21	Oral argument held before Judges Wilkins, Katsas and Jackson
50	*Order 872* (20-72788 et al.) (9th Cir.)		Respondent's brief filed
51	*Opinion 569/569-A*: FERC's Base ROE Methodology (16-1325 et al.) (consol.)	Oct 29	Court allots time limits for oral arguments; oral argument ***Nov 18, 2021*** before Judges Srinivasan, Katsas and Walker

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: November 3, 2021

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 November 2, 2021. If you have questions, please contact us.

COVID-19

- **Remote ALJ Hearings (AD20-12)**

All hearings before Administrative Law Judges ("ALJs") are being held remotely through video conference software (WebEx and SharePoint) until further notice.[2] The Presiding Judge in each remote hearing will ensure that the participants have access to an "IT Day" prior to the hearing to allow all participants, witnesses, and the public who will attend the hearing to learn more about the remote hearing software and to get their technical questions answered by the appropriate FERC staff. Uniform Hearing Rules for all Office of the ALJ hearings were adopted effective September 15, 2020.[3] The "Remote Hearing Guidance for Participants" was revised on May 18, 2021 to make two additional changes.[4] The Uniform Hearing Rules and Remote Hearing Guidance for Participants are publicly available in this proceeding in eLibrary and on the FERC's Administrative Litigation webpage.

- **Extension of Filing Deadlines (AD20-11)**

On July 26, 2021, the wavier of FERC regulations that require that filings with the FERC be notarized or supported by sworn declarations was ***extended for an additional six months, through January 1, 2022***.[5] The July 26 notice extended the waiver first noticed in May[6] for a third time.[7] As previously reported, Entities may also seek waiver of FERC orders, regulations, tariffs and rate schedules, including motions for waiver of

[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] *Chief Administrative Law Judge's Notices to the Public*, Docket No. AD20-12 (June 17, 2020).

[3] *Chief Administrative Law Judge's Notices to the Public*, Docket No. AD20-12 (Sep. 1, 2020).

[4] *Chief Administrative Law Judge's Notices to the Public*, Docket No. AD20-12 (May 18, 2021) (requiring that only attorneys may access Live Litigation (§VI(a)(vii)) and encouraging that privileged sessions be limited and revising guidance on privileged versus public session management (§VI(k)).

[5] *See Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (July 26, 2021) ("Third Extension").

[6] *Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (May 8, 2020)("First Extension"); *Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (Jan. 25, 2021) ("Second Extension").

[7] *See Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (Aug. 20, 2020).

regulations that govern the form of filings, as appropriate, to address needs resulting from steps they have taken in response to the coronavirus.[8]

- **Blanket Waiver of ISO/RTO Tariff In-Person Meeting and Notarization Requirements (EL20-37)**

In light of the continuing nature of the COVID-19 National Emergency, the FERC extended on July 26, 2021, ***for an additional 6 months, through January 1, 2022***, the blanket waivers of ISO/RTO Tariff *in-person*[9] meeting and notarization requirements.[10] The July 26 order extended for a third time the blanket waivers first granted in the FERC's April 2, 2020 order and extended in orders issued August 20, 2020 and January 25, 2021.[11]

I. Complaints/Section 206 Proceedings

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

On September 7, 2021, the FERC instituted a proceeding under FPA Section 206 to consider whether Schedule 25 and Tariff section I.3.10 may be unjust and unreasonable.[12] This proceeding arises out of issues raised in the 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.[13]

Accordingly, the FERC directed ISO-NE to: (1) show cause as to why Schedule 25 and Tariff section I.3.10 remain just and reasonable or (2) explain what changes to Schedule 25 and/or Tariff section I.3.10 it believes would remedy the identified concerns if the FERC were to determine that Schedule 25 and/or Tariff section I.3.10 has become unjust and unreasonable and proceeds to establish a replacement rate. ISO-NE's response is due on or before November 8, 2021. ISO-NE may make its filing pursuant to FPA section 206 (in which case interested parties would have 60 days (or 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) or, should it prefer, pursuant to its applicable FPA section 205 filing rights (in which case comments from interested parties would be due in accordance with the usual 21-day deadlines set for such proceedings). The FERC noted its expectation that, if ISO-NE files changes to Schedule 25 and/or Tariff section I.3.10 that it believes would remedy the identified concerns within 60 days of the date of the *Sep 7 Order*, it would issue a final order within three months of ISO-NE's response.[14] On September 8, the FERC issued a notice of the proceeding and of the refund

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8 *Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (Apr. 2, 2020).

9 The waiver only applies to a specific requirement that meetings be held *in person*. Other than the in-person requirement, such meetings must still be held consistent with the tariff, but should be conducted by other means (e.g. telephonically).

10 *Temporary Action to Facilitate Social Distancing*, 176 FERC ¶ 61,044 (July 26, 2021).

11 *Temporary Action to Facilitate Social Distancing*, 171 FERC ¶ 61,004 (Apr. 2, 2020) (waiving notarization requirements through Sep. 1, 2020, contained in any tariff, rate schedule, service agreement, or contract subject to the FERC's jurisdiction under the Federal Power Act ("FPA"), the Natural Gas Act ("NGA"), or the Interstate Commerce Act); *Temporary Action to Facilitate Social Distancing*, 172 FERC ¶ 61,151 (Aug. 20, 2020) (extending the waivers through Jan. 29, 2021); *Temporary Action to Facilitate Social Distancing*, 174 FERC ¶ 61,047 (Jan. 25, 2021) (extending the waivers through July 31, 2021).

12 *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*").

13 *Id.* at P 20.

14 *Id.* at P 26.

effective date, which will be October 13, 2020 (the date the NECEC/Avangrid Complaint Against NextEra/Seabrook was filed). Those interested in participating in this proceeding were required to intervene on or before October 5, 2021.[15] NEPOOL, NESCOE, Brookfield, Calpine, Dominion, Eversource, HQ US, LS Power, MA AG, MMWEC, National Grid, NECEC Transmission, NEPGA, NextEra, NRG, CT DEEP, MA DOER, American Clean Power Association ("ACPA"), EPSA, RENEW Northeast, and Public Citizen intervened. While a few parties submitted their comments directly related to the NECEC/Avangrid Complaint against NextEra/Seabrook (EL21-6) also in this proceeding, there was no activity specific to this proceeding since the last Report. As noted above, ISO-NE's response is due November 8, 2021. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com). If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Green Development DAF Charges Complaint Against National Grid (EL21-47)**

As previously reported, on September 23, 2021, the FERC denied in part, but granted in part, the complaint ("Complaint")[16] by Green Development, LLC ("Green Development") against New England Power Company and Narragansett Electric Company (together, "National Grid" or "Grid").[17] The *Complaint Order* partially denied the Complaint, finding that Green Development did not meet its burden of proof that the assignment of Direct Assignment Facility ("DAF") charges violated the first part of the ISO-NE Tariff definition of Direct Assignment Facilities (requiring that the facilities be constructed for the sole use/benefit of a particular Transmission Customer requesting service under the ISO-NE Tariff).[18] However, the *Complaint Order* found that Green Development demonstrated a failure by National Grid to comply with the requirement that the facilities be "specified in a separate agreement among ISO-NE, the Interconnection Customer and the Transmission Customer, as applicable, and the Transmission Owner whose transmission system is to be modified."[19] As a result, National Grid is not permitted, unless and until it complies with that part of the definition, to assess DAF charges to Narragansett in association with the upgrades necessary for the Projects.[20]

Request for Partial Rehearing. On October 25, 2021, Green Development requested partial rehearing of the *Green Development Complaint Order*, asking the FERC to reverse its finding that Green Development did not meet its burden of proof that the assignment of DAF charges violated the first part of the ISO-NE Tariff definition of DAF (requiring that the facilities be constructed for the sole use/benefit of a particular Transmission Customer requesting service under the ISO-NE Tariff), and grant its Complaint in full. Green Development's request for partial rehearing is pending before the FERC, with FERC action required on or before November 24, 2021, or the request will be deemed denied by operation of law. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

As previously reported, NECEC Transmission LLC ("NECEC") and Avangrid Inc. (together, "Avangrid") filed a complaint (the "Complaint") on October 13, 2020 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[21] and direct NextEra to immediately commence engineering, design, planning

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

[16] The Complaint requested a finding that Grid's assessment of Direct Assignment Facility ("DAF") charges for Green Development's projects is unauthorized under the ISO-NE Tariff (the "Complaint").

[17] Green Development, LLC v. New England Power Co. and Narragansett Elec. Co., 176 FERC ¶ 61,193 (Sep. 23, 2021) ("*Green Development Complaint Order*" or "*Complaint Order*")).

[18] *Id.* at PP 54-55, 59-60.

[19] *Id.* at PP 54, 61-62.

[20] *Id.* at P 62.

[21] 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

and procurement activities that are necessary for NextEra to construct the generator owned transmission upgrades during Seabrook Station's Planned 2021 Outage. NextEra submitted an answer to the October 13 Complaint (requesting the FERC dismiss or deny the Complaint) and National Grid filed comments. Doc-less interventions were filed by Dominion, Eversource, Calpine, Exelon, HQ US, MA AG, MMWEC National Grid, NESCOE, NRG, and Public Citizen. Avangrid answered NextEra's answer and NextEra answered Avangrid's November 17 answer ("supplemental answer"), repeating its request that the FERC dismiss or deny the Complaint. Avangrid also answered the supplemental answer.

Avangrid amended the Complaint on March 26, 2021 to reflect that aspects of the relief originally requested in the Complaint are no longer feasible within the timeline previously sought. Avangrid continues 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.

Order Establishing 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).[22] Specifically, with respect to this proceeding, the FERC requested additional briefing from the Parties, as well as from ISO-NE, on the following issues:

- Whether or not Seabrook's breaker is properly identified as a part of Seabrook's generating facility.
- 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.
- 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.
- Whether there exists any solution for the interconnection of the NECEC Project that may be implemented without the replacement of Seabrook's breaker.
- 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.

Additional Briefing. Initial briefs were due on or before October 7, 2021, and were filed by ISO-NE, Avangrid, NextEra, MA AG, NEPGA/EPSA, MA DOER. Reply briefs are due on or before October 22, 2021, and were filed by Avangrid, NextEra, ISO-NE. With briefing complete, this matter is again before the FERC, which is expected to issue an order within 90 days.

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

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regulations and to initiate an investigation and require NextEra to preserve and provide documents related to the interconnection of the NECEC Project.

[22] *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).

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

In a related matter, initiated a week earlier than the Avangrid Complaint, NextEra Energy Seabrook, LLC ("Seabrook") filed a Petition for a Declaratory Order ("Petition") "by which it seeks to understand the scope of its FERC-jurisdictional regulatory obligations with respect to the project ("NECEC Elective Upgrade"), and to resolve its dispute with NECEC". 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 Seabrook's Petition were filed by Eversource, MMWEC and NEPGA. Avangrid and NECEC Transmission ("Avangrid") protested the Declaratory Order Petition. Doc-less interventions were filed by Avangrid, 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. There has been no activity in this proceeding since the last Report and this matter also remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

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

  - ***Base ROE Complaint I (EL11-66)***. In the first Base ROE Complaint proceeding, the FERC concluded that the TOs' ROE had become unjust and unreasonable,[23] 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*).[24] However, the FERC's orders were challenged, and in *Emera Maine,*[25] the 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.

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[23] 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*")).

[24] *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*").

[25] *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).

- ***Base ROE Complaints II & III (EL13-33 and EL14-86) (consolidated)***. The second (EL13-33)[26] and third (EL14-86)[27] 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.[28] 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[29] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[30] 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.[31] 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.[32] 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*[33] (EL14-12; EL15-45) in

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

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

[28] *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*").

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

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

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

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

[33] *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

Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[34]

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

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

The FERC provided preliminary analysis of how it would apply the proposed methodology in the Base ROE I Complaint, suggesting that it would affirm its holding that an 11.14% Base ROE is unjust and unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[35] 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[36] 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, 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.

Opinion 569; and (iv) calculating the zone of reasonableness in equal thirds, instead of using the quartile approach that was applied in *Opinion 569*.

[34] *Id.* at P 19.

[35] *Id.* at P 59.

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

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*[37] 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

- **2022 NESCOE Budget (ER22-117)**

This proceeding was initiated by ISO-NE's October 15, 2021 filing of the budget for funding NESCOE's 2022 operations. The 2022 Operating Expense Budget for NESCOE is $2,485,156. The amount to be recovered reflects true-ups from 2021 (over-collections of $781,482). Accordingly, if accepted, the NESCOE budget will result in a charge of $0.00736 per kilowatt ("kW") of Monthly Network Load (a $0.00110/kW increase over 2021). The 2022 NESCOE budget was supported by the Participants Committee at its October 7, 2021 meeting. Comments and any interventions are due on or before November 5. Thus far, NESCOE submitted a doc-less intervention. If there are any questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **2022 ISO-NE Administrative Costs and Capital Budgets (ER22-113)**

On October 15, 2021, ISO-NE filed for recovery of its 2022 administrative costs (the "2022 Revenue Requirement") and submitted its capital budget and supporting materials for calendar year 2022 ("2022 Capital Budget", and together with the 2022 Revenue Requirement, the "2022 ISO Budgets"). The 2022 ISO-NE Budgets were filed together pursuant to the Settlement Agreement entered into to resolve challenges to the 2013 ISO-NE Budgets. In the October 15 filing, ISO-NE reported that the 2022 Revenue Requirement is $215.1 million (a $10.1 million or 4.9% increase over 2021), which increases to $216.1 million after the under-collection for 2020 is added. Of that total, ISO-NE's administrative costs (i.e., the 2022 Core Operating Budget) comprise $189.1 million; depreciation and amortization of regulatory assets, $26 million; and a $1.1 million true-up for 2020 under-collections.

ISO-NE further reported that the 2022 Capital Budget is $32 million, a $4 million increase over 2021, and is comprised of the following (with 2022 projected costs and target completion dates, if available, in parentheses):

- nGem Market Clearing Engine Implementation (Mar 2023) ($4.4 million)
- nGem Hardware Phase II (Dec 2022) ($3 million)
- Cyber Security Improvements (Dec 2022) ($2 million)
- MOPR (Dec 2023) ($1.5 million)
- CIP Electronic Security Perimeter Redesign Phase II ($1 million)
- nGem Software Development Part II (Dec 2022) ($2.8 million)
- Forward Capacity Tracking System Infrastructure Conversation Part III (Dec 2022) ($2.9 million)
- 2022 Issue Resolution Projects (June 2022 and Dec 2022) ($1.5 million)
- Amazon Web Services Cloud Foundation (Apr 2022) ($1 million)
- IMM Data Analysis Phase III (Dec 2022) ($900,000)

[37] *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).

- IMM Data Analysis Phase III (Dec 2022) ($900,000)
- Solar Do Not Exceed Dispatch (Sep 2022) ($500,000)
- Integrated Market Simulator Phase I (Jun 2022) ($400,000)
- Identity and Access Management – Phase III (Dec 2022) ($400,000)
- Windows Server 2019 R2 Deployment (Jun 2023) ($400,000)
- Forward Capacity Market Cost Allocation & Accelerated Billing (May 2022) ($300,000)
- TTC Calculator Redesign (May 2022) ($300,000)
- TranSMART Technical Architecture Update (Jun 2022) ($300,000)
- Forecast Enhancements (Jun 2020) ($200,000)
- LMP Monitor Replacement (Apr 2022) ($100,000)
- Linear State Estimator (Oct 2022) ($500,000)
- Enterprise Application Integration Phase III (Nov 2022) ($500,000)
- External Website Migration to Cloud (Oct 2022) ($400,000)
- Integrated Market Simulator Phase I (Jun 2022) ($400,000)
- Security Information and Event Management Log Monitoring Replacement (Jul 2022) ($300,000)
- Security Information and Event Management Log Monitoring Replacement (Jul 2022) ($300,000)
- TranSMART Technical Architecture Update (Jun 2022) ($300,000)
- E-mail List Server Technology Refresh (Jan 2023) ($300,000)
- Capitalized Interest ($500,000)
- Non-Project Capital Expenditures ($3 million)
- Other Emerging Work ($2.4 million)

The 2022 ISO-NE Budgets were supported by the Participants Committee at its October 7, 2021 meeting. Comments on this filing are due November 5, 2021. NEPOOL filed comments supporting the 2022 Budgets on November 1. NRG filed a doc-less intervention. If there are any questions on this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **CSC Request for Regulatory Asset Recovery of Previously-Incurred CIP IROL Costs (ER21-2334)**

On August 31, 2021, the FERC denied the request by Cross-Sound Cable Company LLC ("CSC") for authorization to establish a regulatory asset that would include all CIP-IROL Costs[38] that CSC prudently incurred between January 1, 2016 and May 31, 2021 ($1.324 million) and recover those costs under Schedule 17 (from all ISO-NE transmission customers) over a five-year period (beginning on the date the FERC makes this rate treatment and related cost recovery effective).[39] Relying on its *Schedule 17 Orders*,[40] which found that Schedule 17 permits recovery only of CIP-IROL costs incurred on or after the effective date of a FPA section 205 filing made by an IROL-Critical Facility owner to recover such costs, and recovery of CIP-IROL costs incurred prior to the effective date of any relevant, individual FPA section 205 filing would violate the rule

[38] Interconnection Reliability Operating Limits ("IROL") Critical Infrastructure Protection ("CIP") costs under Schedule 17 of the ISO-NE Tariff.

[39] *Cross-Sound Cable Co., LLC*, 176 FERC ¶ 61,073 (Aug. 31, 2021) ("*August 31 Order*").

[40] *ISO New England Inc.,* 171 FERC ¶ 61,160 ("*Schedule 17 Order*"), *order on reh'g*, 172 FERC ¶ 61,251 (2020) ("*Schedule 17 Rehearing Order*") (collectively, "*Schedule 17 Orders*"), *appeal pending sub nom.*, *Cogentrix Energy Power Mgmt., LLC v. FERC*, D.C. Cir. No. 20-1389 (filed Oct. 14, 2020) (*see* Section XVI).

against retroactive ratemaking, the FERC found that permitting the recovery here proposed by CSC would violate the filed rate doctrine.[41] The FERC rejected the alternative bases for FERC approval proposed by CSC.[42]

CSC Request for Rehearing Denied by Operation of Law. On November 1, 2021, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[43] The Notice confirmed that the 60-day period during which a petition for review of the *Mystic ROE Order* can be filed with an appropriate federal court was triggered when the FERC did not act on CSC's request for rehearing of the *August 31 Order*. The Notice also indicated that the FERC would address, as is its right, the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper."

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

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

As previously reported, the FERC issued four orders in this proceeding in July 2020 (three on July 17 (together, the "*July 17 Orders*"); one on July 28, 2020). Each of the orders addressed in part or in whole the Cost-of-Service Agreement ("COS Agreement")[44] among Constellation Mystic Power ("Mystic"), Exelon Generation Company ("ExGen") and ISO-NE, which is to provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024. As noted in Section XVI below, each of the *July 17 Orders*[45] (and the earlier, underlying orders) as well as the FERC order setting the base ROE for the Mystic COS Agreement at 9.33%,[46] have been appealed to the U.S. Court of Appeals for the D.C. Circuit ("DC Circuit"). Activity since the last Report includes:

Requests for Rehearing of the Mystic ROE Order Denied by Operation of Law (-010, -011). On September 13, 2021, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[47] The Notice confirmed that the 60-day period during which a petition for review of the *Mystic ROE Order* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests

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41 *August 31 Order* at P 33.

42 *Id.* at PP 33-37. As previously reported, CSC proposed three alternative bases upon which the FERC could grant its request to use a regulatory asset for CIP IROL cost recovery and rate treatment: (i) FPA section 219 and Order 679 (incentive rate framework); FPA section 205 (in furtherance of the FERC's expressed policy of ensuring reliability of the BES in response to cybersecurity threats); or (iii) FPA section 309 (FERC's remedial authority). In the *August 31 Order*, the FERC rejected each of these in turn.

43 *Cross-Sound Cable Co., LLC*, 177 FERC ¶ 62,064 (Nov. 1, 2021) (Notice of Denial By Operation of Law of Rehearings of *August 31 Order*).

44 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, and on the continued provision of surplus LNG from Distrigas to third parties.

45 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).

46 *Constellation Mystic Power, LLC,* 176 FERC ¶ 61,019 (July 15, 2021) ("*Mystic ROE Order*").

47 *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).

for rehearing of the *Mystic ROE Order* filed by Mystic, CT Parties,[48] ENECOS,[49] and the MA AG. The Notice also indicated that the FERC would address, as is its right, the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper." As more fully described in Section VXI below, the *Mystic ROE Order* and the *September 13 Notice* have been appealed to and are now pending before the DC Circuit on appeal.

ROE (Fifth) Compliance Filing (-012). On October 28, 2021, the FERC accepted Mystic's fifth compliance filing[50] -- a revised COS Agreement – submitted in response to the *Mystic ROE Order.* The compliance filing: (1) changed the Cost of Common Equity figures from 10.71% to 9.33% in Schedule C of the Methodology, for both Mystic 8&9 and Everett Marine Terminal ("Everett"); and (ii) reduced the Annual Fixed Revenue Requirements ("AFRR") to $170,605,963 for the 2022/2023 Capacity Commitment Period ("CCP") and to $139,668,204 for the 2023/2024 CCP.

2021 Capital Expenditures Informational 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 "2021 Filing" 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 ("2022 CapEx Projects"). Formal challenges to the September 15 filing were submitted by the Eastern New England Customer-Owned Systems ("ENECOS") and NESCOE. Comments on the formal challenges are due on or before November 17, 2021.

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).

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

- **Waiver Request: FCA16 Qualification (Andro Hydro) (ER22-174)**

On October 20, 2021, as supplemented on October 26, Andro Hydro LLC ("Andro Hydro") requested a one-time waiver of the FCM qualification rules to allow Andro Hydro's Riley-Jay-Otis-Livermore hydroelectric generating resource to participate in the sixteenth Forward Capacity Auction ("FCA16") at a reduced qualification level (8 MW rather than 12.884 MW). Andro Hydro states that ISO-NE informed it of its determination just one day ahead of the Tariff deadline to reduce the capacity amount for which FCA16 qualification sought, insufficient time for it to understand and address ISO-NE's determination.[51] Andro Hydro seeks all necessary waivers to allow it to lower the FCA16 MWs for its resource (avoiding any concerns regarding required upgrades), and thereby make it possible for its resource to participate in FCA16. Comments on Andro Hydro's waiver request are due on or before November 10, 2021. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **eTariff § III.3.1 Corrections (ER21-2850)**

On September 8, ISO-NE filed conforming changes to eTariff § III.3.1 to ensure that the eTariff Viewer reflects changes accepted in ER21-1974 (Solar Data Requirements & Relocation of Wind Data Requirements) but inadvertently omitted in later changes filed in ER21-2220 (Removal of Appendix B from Market Rule 1; Deletion of

[48] "CT Parties" are: the Conn. Pub. Utils. Reg. Authority ("CT PURA"), the Conn. Dept. of Energy and Environ. Protection ("CT DEEP"), and the Conn. Office of Consumer Counsel ("CT OCC").

[49] As noted in previous Reports, "ENECOS" are Braintree, Concord, Georgetown, Hingham, Littleton Electric Light & Water, Middleborough, Middleton, Norwood, Pascoag, Reading, Taunton, and Wellesley.

[50] *Constellation Mystic, LLC*, Docket No. ER18-1639-012 (October 28, 2021) (unpublished letter order) (accepting Mystic's 5th compliance filing).

[51] ISO-NE determined that Andro Hydro's resource did not qualify to participate in FCA16 because a portion of the administered transmission system owned by CMP would require upgrades (not expected to be upgraded before the 2025-2026 Capacity Commitment Period ("CCP")) to allow the Resource to supply capacity.

Assoc. Tariff Provisions). Comments on the corrections were due on or before September 29, 2021; none were filed. NEPOOL filed a doc-less intervention. On October 25, 2021, ISO-NE supplemented record to correct a docket reference in the footnote 4 to the September 8 transmittal letter. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

- **BTM Generation Proposal (ER21-2337)**

On July 1, 2021, ISO-NE and the Participating Transmission Owners Administrative Committee ("PTO AC") jointly filed revisions to Tariff sections I and II to clarify that the calculation of Monthly Regional Network Load excludes load served by behind-the-meter ("BTM") generation, which does not participate in the New England wholesale markets as a Generator Asset, as well as the portions of a Generator Asset utilized to net load at the same retail meter ("BTM Generation Proposal"). The Participants Committee supported the BTM Generation Proposal at its June 3, 2021 meeting (Consent Agenda Items #3 and 4). Comments on this filing were due on or before July 22, 2021. Comments and protests were filed by NEPOOL, the ISO-NE IMM, AEE, IECG, NECOS/ENE, NEPGA, Public Systems, MPUC/CT PURA/MA DPU, and the VT PUC. Doc-less interventions were filed by Calpine, EMI, IECG, National Grid, NESCOE, and NRG. The PTO AC answered the NEPGA protest on August 6, 2021. Answers to the PTO AC Answer were filed by NEPGA and the IMM on August 13 and August 16, respectively. Since the last Report, IECG filed an answer to the NEPGA and IMM answers.

Deficiency Letter. On August 20, 2021, the FERC issued a deficiency letter, directing ISO-NE to provide within 30 days additional information and clarifications. The responses to the Deficiency Letter were due and were filed by ISO-NE on September 20, 2021. The responses to the deficiency letter re-set the 60-day deadline for FERC action on this filing. Comments on ISO-NE's deficiency letter responses were due on or before October 12, 2021, and NEPGA filed an amended protest and comments on that day. On October 27, the PTO AC answered NEPGA's amended protest and comments. 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).

- **TOs *Order 676-I* Compliance Filing (ER21-2529)**

On July 27, 2021, the PTO AC, ISO-NE, Schedule 20A Service Providers, GMP, and VTransco filed revisions to ISO-NE Tariff Schedule 21-Common and Schedule 20A-Common in accordance with *Order 676-I*. The revisions include certain updated business practice standards (Version 003.2) adopted by the Wholesale Electric Quadrant ("WEQ") of the North American Energy Standards Board ("NAESB") and incorporated by reference in the FERC's regulations through *Order 676-I*. Comments on this filing were due on or before August 19, 2021; none were filed. National Grid filed a doc-less intervention on August 13, 2021.

Amended Revisions (ER21-2529-001). On October 22, 2021, the PTO AC submitted amendments to the July 27 compliance filing to include in Schedules 20A-Common and 21-Common revised and new WEQ standards identified in the FERC's March 3, 2020 errata notice to *Order 676-I* ("*Order 676-I Errata Notice*") but not included in the July 27, 2021 filing. Any comments on the errata filing are due on or before November 12, 2021.

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

- **CSC Schedule 18 *Order 676-I* Compliance Filing (ER21-2509)**

On July 26, 2021, CSC and ISO-NE filed revisions to ISO-NE Tariff Schedule 18-Attachment Z in accordance with *Order 676-I*. The revisions include certain updated business practice standards (Version

003.2) adopted by NAESB's Wholesale Electric Quadrant and incorporated by reference in the FERC's regulations through *Order 676-I*. Comments on this filing were due on or before August 16, 2021; none were filed. National Grid and CSC filed doc-less interventions on August 13, 2021 and August 16, 2021, respectively.

Amended Revisions (ER21-2509-001). On October 27, 2021, ISO-NE and CSC submitted amendments to the July 26 compliance filing to include in Schedule 18 revised and new WEQ standards identified in the FERC's *Order 676-I Errata Notice* but not included in the July 26, 2021 filing. Any comments on the errata filing are due on or before November 17, 2021.

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

- **ISO-NE/NEPOOL *Order 676-I* Compliance Filing (ER21-941)**

On January 26, 2021, ISO-NE and NEPOOL, in response to *Order 676-I*, jointly filed changes to incorporate by reference in Schedule 24 of the OATT the latest version (Version 003.2) of certain Standards for Business Practices and Communication Protocols for Public Utilities adopted by NAESB's Wholesale Electric Quadrant. The Participants Committee unanimously supported the *Order 676-I* revisions at its May 7, 2020 meeting. Comments on this filing were due on or before February 16, 2021; none were filed.

Amended Revisions (ER21-941-001). On October 22, 2021, ISO-NE and NEPOOL submitted amendments to the January 26 compliance filing to include in Schedule 24 revised and new WEQ standards identified in the *Order 676-I Errata Notice* to but not included in the July 26, 2021 filing. Any comments on the errata filing are due on or before November 12, 2021.

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

V. Financial Assurance/Billing Policy Amendments

- **Removal of FAP Notarization Requirements (ER22-213)**

On October 27, ISO-NE and NEPOOL jointly filed changes to the ISO-NE Financial Assurance Policy ("FAP") to remove the notarization requirement from the FAP officer certification forms and to add a statement of acknowledgment of the Senior Officer executing the officer certification forms ("FAP Revisions"). The FAP Revisions were unanimously approved at the October 7 Participants Committee meeting. ISO-NE requested a January 1, 2022 effective date for the FAP Revisions, which dovetails with the expiration of the FERC's blanket waiver of Tariff notarization requirements described in Section I above. Comments on the FAP Revisions are due on or before November 17, 2021. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **eTariff FAP Attachment 3 Corrections (ER21-2815)**

On October 19, 2021, the FERC accepted[52] the corrections filed by ISO-NE to its eTariff to reinstate in Attachment 3 to the FAP previously-accepted[53] text (footnote 1)[54] which was omitted in two subsequent filings.[55] Unless the October 19 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VI. Schedule 20/21/22/23 Changes

- **Schedule 21-NEP: Sterling Municipal LSA (ER22-97)**

On October 13, 2021, National Grid filed a non-conforming Local Service Agreement ("LSA") with Sterling Municipal Light Department ("Sterling Municipal") to extend the term of service to Sterling Municipal and to include the other new provisions, particularly those related to the DAF Charge that Sterling Municipal is required to pay pursuant to the LSA. Since the LSA covers an existing, interconnected facility, a new three-party interconnection agreement (that would include ISO-NE) was not required. A December 13, 2021 effective was requested. Comments on this filing are due on or before November 3, 2021. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 20A-UI: Vitol Phase I/II HVDC-TF Service Agreement (ER21-2662)**

On October 7, 2021, the FERC accepted the new Phase I/II HVDC-TF Service Agreement between UI and Vitol Inc. ("Vitol") under Schedule 20A-UI for 1 MW of firm service over the Phase I/II HVDC transmission facilities ("Phase I/II HVDC-TF").[56] The Service Agreement was ace[ted effective November 20, 2020, as requested (the date on which monthly firm service began). Unless the October 7 UI 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 20A-CMP: Vitol Phase I/II HVDC-TF Service Agreement (ER21-2661)**

Also on October 7, 2021, the FERC accepted a similar Phase I/II HVDC-TF Service Agreement between Central Maine Power ("CMP") and Vitol under Schedule 20A-CMP for 1 MW of firm service over the Phase I/II HVDC-TF. The CMP Service Agreement was also accepted effective as of November 1, 2020, as requested (the date on which monthly firm service began). Unless the October 7 CMP 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-VP: Recovery of Bangor Hydro/Maine Public Service Merger-Related Costs (ER15-1434-001 *et al.*)**

Still pending before the FERC is the MPS Merger Cost Recovery Settlement, filed by Emera Maine on May 8, 2018 to resolve all issues pending before the FERC in the consolidated proceedings set for hearing in the *MPS*

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[52] *ISO New England Inc.*, Docket No. ER21-2815 (Oct. 19, 2021) (unpublished letter order).

[53] *See ISO New England Inc.*, Docket No. ER20-2145 (Sep. 2, 2020) (unpublished letter order).

[54] Footnote 1 reads: As used in this certification, a Certifying Entity's "independent risk management function" can include appropriate corporate persons or bodies that are independent of the Certifying Entity's trading functions, such as a risk management committee, a risk officer, a Certifying Entity's board or board committee, or a board or committee of the Certifying Entity's parent company."

[55] *See* Revisions Related to Disclosure Information Under the FAP, *ISO New England Inc. and the New England Power Pool Participants Comm.*, Docket No. ER21-816 (filed Jan. 6, 2021; corrected Feb. 23, 2021); Revisions to Obligations of Energy Efficiency Resources Under PFP, *ISO New England Inc.*, Docket No. ER21-943 (filed Jan. 26, 2021).

[56] *The United Illuminating Co.*, Docket No. ER21-2662 (Oct. 7, 2021) (unpublished letter order).

Merger-Related Costs Order,[57] and certified by Settlement Judge Dring[58] to the Commission.[59] As previously reported, under the Settlement, permitted cost recovery over a period from June 1, 2018 to May 31, 2021 will be $390,000 under Attachment P of the BHD OATT and $260,000 under the MPD OATT. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

- **Waiver Agreement: PA Board Provisions (not docketed)**

On September 24, 2021, NEPOOL and ISO-NE submitted an informational filing advising the FERC of the waiver of sections 9.2.2 and 9.2.3(a) of the Participants Agreement (related to the size of the ISO Board and the term length of one new Board member) that was required to seat the four-person slate of candidates for election to the ISO Board of Directors. The Waiver Agreement was unanimously approved by the Participants Committee in balloting and approved by the ISO Board. This filing was not docketed and will not be noticed by the FERC for public comment. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VIII. Regional Reports

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

FG&E's 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*[60] *and 531-B*[61] also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

[57] *Emera Maine and BHE Holdings*, 155 FERC ¶ 61,230 (June 2, 2016) ("*MPS Merger-Related Costs Order*"). In the *MPS Merger-Related Costs Order*, the FERC accepted, but established hearing and settlement judge procedures for, filings by Emera Maine seeking authorization to recover certain merger-related costs viewed by the FERC's Office of Enforcement's Division of Audits and Accounting ("DAA") to be subject to the conditions of the orders authorizing Emera Maine's acquisition of, and ultimate merger with, Maine Public Service ("Merger Conditions"). The Merger Conditions imposed a hold harmless requirement, and required a compliance filing demonstrating fulfillment of that requirement, should Emera Maine seek to recover transaction-related costs through any transmission rate. Following an audit of Emera Maine, DAA found that Emera Maine "inappropriately included the costs of four merger-related capital initiatives in its formula rate recovery mechanisms" and "did not properly record certain merger-related expenses incurred to consummate the merger transaction to appropriate non-operating expense accounts as required by [FERC] regulations [and] inappropriately included costs of merger-related activities through its formula rate recovery mechanisms" without first making a compliance filing as required by the merger orders. The *MPS Merger-Related Costs Order* set resolution of the issues of material fact for hearing and settlement judge procedures, consolidating the separate compliance filing dockets.

[58] ALJ John Dring was the settlement judge for these proceedings. There were five settlement conferences -- three in 2016 and two in 2017. With the Settlement pending before the FERC, settlement judge procedures, for now, have not been terminated.

[59] *Emera Maine and BHE Holdings*, 163 FERC ¶ 63,018 (June 11, 2018).

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

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

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

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

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

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

- **Capital Projects Report - 2021 Q3 (ER22-125)**

On October 15, 2021, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the third quarter ("Q3") of calendar year 2021 (the "Report").[62] Report highlights included the following new projects: (i) E-Mail List Server Technology Refresh ($769,000); and (ii) Total Transfer Capability ("TTC") Calculator Redesign ($492,400). Projects with a significant changes (with amounts returned to the Emerging Work Fund following in parentheses) were (i) Secure Lightweight Directory Access Protocol ("LDAP") Channel Binding Adaption ($100,000); and (ii) 2021 Issue Resolution Project ($100,000). Comments on the 2021 Q3 Report are due on or before November 5, 2021. NEPOOL filed comments supporting the 2021 Q3 Report on November 1, 2021. Also on November 1, 2021, NESCOE filed a doc-less motion to intervene. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **LFTR Implementation: 52nd Quarterly Status Report (ER07-476; RM06-08)**

ISO-NE filed the 52nd of its quarterly status reports regarding LFTR implementation on October 15, 2021. ISO-NE reported that it implemented monthly reconfiguration auctions (accepted in ER12-2122) beginning with the month of October 2019. ISO-NE further reported that, while it will continue to evaluate its as-filed LFTR design and financial assurance issues, including an ongoing evaluation of the FTR market and risk associated with FTRs and LFTRs, it is currently focused on higher priority market-design initiatives. ISO-NE concluded its report by describing the 18-month implementation that would be required once the LFTR financial assurance issues are resolved. These status reports are not noticed for public comment.

- **Reserve Market Compliance (31st) Semi-Annual Report (ER06-613)**

As directed by the original ASM II Order,[63] as modified,[64] ISO-NE submitted its 31st semi-annual reserve market compliance report on October 1, 2021. In the 31st report, ISO-NE stated that "is currently re-evaluating approaches to forward reserve products and will keep the Commission apprised of any plans with respect to a forward TMSR market in future reports in this docket." The October 1 report was not noticed for public comment. If there are questions on this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com).

IX. Membership Filings

- **October 2021 Membership Filing (ER21-2985)**

On September 30, 2021, NEPOOL requested that the FERC accept (i) the memberships of CPV Valley, LLC [Related Person to CPV Towantic (Generation Sector)]; Generation Bridge Connecticut Holdings, LLC (Provisional Group Member) ("GB CT"); Generation Bridge M&M Holdings, LLC [Related Person to Generation Bridge CT [(Provisional Group Member)] ("GB M&M"); J.P. Morgan Ventures Energy Corporation (Supplier Sector)

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[62] *ISO New England Inc.*, Docket No. ER21-2632 (Oct. 1, 2021) (unpublished letter order).

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

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

("JPMVEC"); Oxford Energy Center, LLC (Provisional Group Member); Naugatuck Avenue Storage LLC [Related Person to Jupiter Power (Provisional Group Member)]; Norman Street ES LLC [Related Person to Jupiter Power (Provisional Group Member)]; and Westfield ESS LLC [Related Person to Jupiter Power (Provisional Group Member)]; and (ii) the name change of Rhode Island Bioenergy Facility, LLC (f/k/a Orbit Energy Rhode Island, LLC). Comments on this filing were due on or before October 21, 2021; none were filed. This proceeding is pending before the FERC.

- **September 2021 Membership Filing (ER21-2802)**

On October 28, 2021, the FERC accepted (i) the memberships of Gravel Pit Solar, LLC [Related Person to DWW Solar II and Fusion Solar Center, LLC (AR Sector, Large RG Group Member)]; Tyr Energy (Supplier Sector); and Walden Renewables Development LLC (Provisional Member); and (ii) the termination of the Participant status of: Brookfield Energy Marketing Inc. [Related Person to Brookfield companies (Supplier Sector)]; and HIKO Energy and Perigee Energy [Related Persons to Spark Energy (Supplier Sector)].[65] Unless the October 28 order is challenged, this proceeding will be concluded.

- **Suspension Notice (not docketed)**

Since the last Report, ISO-NE filed, pursuant to Section 2.3 of the Information Policy, a notice with the FERC noting that the following Market Participant was suspended from the New England Markets on the date indicated (at 8:30 a.m.) due to a Financial Assurance Default:

Date of Suspension/ FERC Notice	***Participant Name***	***Default Type***	***Date Reinstated***
Oct 14/18	Manchester Methane, LLC	Financial Assurance	not yet

Suspension notices are for the FERC's information only and are not docketed or noticed for public comment.

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).

- **Revised Reliability Standards: CIP-004-7, CIP-011-3 (RD21-6)**

On September 15, 2021, NERC filed for approval proposed changes to Reliability Standards CIP-004-7 (Cyber Security – Personnel & Training) and CIP-011-3 (Cyber Security – Information Protection). The changes clarify the protections required for the use of third-party solutions (e.g. cloud services, which depend less on the actual storage location of the information and more on file-level rights and permissions) for BES Cyber System Information ("BCSI"). NERC asked that the changes become effective (and the currently effective versions be retired) on the first day of the first calendar quarter that is 24 months following FERC approval. Comments on the changes were due on or before October 6, 2021; none were filed. This matter is pending before the FERC.

- **Revised Reliability Standards (SOL Changes): FAC-003-5, 011-4, 014-3; IRO-008-3; PRC 002-3, 023-5, -026-2; and TOP-001-6 (RM21-19)**

On June 28, 2021, NERC filed for approval proposed changes to the following Reliability Standards related to establishing and communicating System Operating Limits ("SOLs", and together the "SOL Changes"):

- ♦ FAC-011-4 (System Operating Limits Methodology for the Operations Horizon)
- ♦ FAC-014-3 (Establish and Communicate System Operating Limits)

[65] *New England Power Pool Participants Committee*, Docket No. ER21-2802 (Oct. 28, 2021) (unpublished letter order).

- FAC-003-5 (Transmission Vegetation Management)
- IRO-008-3 (Reliability Coordinator Operational Analyses and Real-time Assessments)
- PRC-002-3 (Disturbance Monitoring and Reporting Requirements)
- PRC-023-5 (Transmission Relay Loadability)
- PRC-026-2 (Relay Performance During Stable Power Swings)
- TOP-001-6 (Transmission Operations)

NERC also requested the retirement of Reliability Standard FAC-010-3 (System Operating Limits Methodology for the Planning Horizon) and modifications to NERC's Glossary of Terms to revise the definition for System Operating Limit and to include "System Voltage Limit". The SOL Changes (NERC Project 2015-09) were developed in response to recommendations from a periodic review of the FAC-010, FAC-011, and FAC-014 Reliability Standards. NERC asked that revised Reliability Standards become effective (and the currently effective versions be retired) on the first day of the first calendar quarter that is 24 months following FERC approval. The SOL Changes have not yet been noticed for public comment.

- **NOI: Enhancements to CIP Standards (RM20-12)**

On June 18, 2020, the FERC issued a notice of inquiry ("NOI") seeking comments on certain potential enhancements to the currently-effective CIP Reliability Standards. In particular, the FERC asked for comments on whether the CIP Standards adequately address: (i) cybersecurity risks pertaining to data security, (ii) detection of anomalies and events, and (iii) mitigation of cybersecurity events. In addition, the FERC asked for comments on the potential risk of a coordinated cyberattack on geographically distributed targets and whether FERC action including potential modifications to the CIP Standards would be appropriate to address such risk.

Comments were filed by NERC, the ISO/RTO Council ("IRC"), American Public Power Association ("APPA")/ Large Public Power Council ("LPPC"), Canadian Electricity Assoc. ("CEA"), Cogentrix, EEI/EPSA, Forescout Technologies, MISO TOs, NJ BPU, NRECA, Reliable Energy Analytics, Southwestern Power Administration, SEIA, Siemen's Energy, Southern Companies, the Transmission Access Policy Study Group ("TAPS"), U.S. Bureau of Reclamation, U.S Corp of Army Engineers, Western Area Power Administration ("WAPA"), Wolverine Power Supply Cooperative, XTec, and J. Applebaum, J. Christopher/T. Conway, and G. Cotter. No reply comments were filed. This matter is pending before the FERC.

- **NOI: Virtualization and Cloud Computing Services in BES Operations (RM20-8)**

On February 20, 2020, the FERC issued a NOI seeking comments on (i) the potential benefits and risks associated with the use of virtualization and cloud computing services in association with bulk electric system ("BES") operations; and (ii) whether the CIP Reliability Standards impede the voluntary adoption of virtualization or cloud computing services.[66] On March 25, 2020, Joint Associations[67] requested an extension of time to submit comments and reply comments. On April 2, the FERC granted Joint Associations' request and extended the deadline for initial comments on the NOI to July 1, 2020; the deadline for reply comments, July 31, 2020. Comments were filed by NERC, the IRC, Accenture, Amazon Web Services ("Amazon"), Bonneville, the Bureau of Reclamation, Barry Jones, Georgia System Operations, GridBright, Idaho Power, Microsoft, MISO, MISO Transmission Owners, Siemens Energy Management, Tri-State Generation and Transmission Association, VMware, Inc., AEE, American Association for Laboratory Accreditation ("A2LA"), APPA, Canadian Electricity Assoc., EEI, NRECA, and Waterfall Security Solutions. Reply comments were due on or before July 31, 2020, and were filed by AEE, Amazon and Microsoft.

[66] *Virtualization and Cloud Computing Services*, 170 FERC ¶ 61,110 (Feb. 20, 2020).

[67] "Joint Associations" are for purposes of this proceeding: EEI, APPA, NRECA, and LPPC.

In part in response to the comments filed, the FERC, in a December 17, 2020 order,[68] directed NERC to begin a formal process to assess, and to make an informational filing in a little over one year (January 1, 2022) that addresses, the feasibility of voluntarily conducting BES operations in the cloud in a secure manner, as well as the status and schedule for any plans to modify the standards.

- ***Order 873*** **- Retirement of Reliability Standard Requirements (Standards Efficiency Review) (RM19-17; RM19-16)**

On September 17, 2020, the FERC approved the retirement of the 18 Reliability Standard requirements through the retirement of four Reliability Standards and the modification of five Reliability Standards,[69] concluding that the 18 requirements "(1) provide little or no reliability benefit; (2) are administrative in nature or relate expressly to commercial or business practices; or (3) are redundant with other Reliability Standards."[70] The FERC also approved the associated violation risk factors, violation severity levels, implementation plan, and effective dates proposed by NERC. Because it was not persuaded by NERC's justification for the retirement of FAC-008-4 requirement R8, the FERC remanded the retirement of requirements R7 and R8 to NERC for further consideration.[71]

The FERC left for another day its final action on the remaining 56 requirements for which the FERC proposed to approve retirement in the *Retirements NOPR*[72] (the "MOD A Reliability Standards"). The FERC intends to coordinate the effective dates for the retirement of the MOD A Reliability Standards with successor North American Energy Standards Board ("NAESB") business practice standards (v. 003.3) that include Modeling business practices, which were just accepted in *Order 676-J* (*see* Section XII below).

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

On September 29, 2021, NERC filed for approval changes to sections 400 (Compliance Monitoring and Enforcement) and 1500 (Confidential Information), Appendix 2 (Definitions) and Appendix 4C (Compliance Monitoring and Enforcement Program) of the NERC Rules of Procedure ("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"). Comments on this filing were due on or before October 20, 2021. Comments were filed by Public Utility District No. 1 of Chelan County and jointly by APPA/LPPC/TAPS. This matter is pending before the FERC.

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[68] *Virtualization and Cloud Computing Services*, 173 FERC ¶ 61,243 (Dec. 17, 2020) ("*Order Directing Jan 2022 Info. Filing*").

[69] *Elec. Rel. Org. Proposal to Retire Reqs. in Rel. Standards Under the NERC Standards Efficiency Review*, Order No. 873, 172 FERC ¶ 61,225 (Sep. 17, 2020) ("*Order 873*"). The four Reliability Standards being eliminated in their entirety are FAC-013-2 (Assessment of Transfer Capability for the Near-term Transmission Planning Horizon), INT-004-3.1 (Dynamic Transfers), INT-010-2.1 (Interchange Initiation and Modification for Reliability), MOD-020-0 (Providing Interruptible Demands and Direct Control Load Management Data to System Operations and Reliability Coordinators). The five modified Reliability Standards are INT-006-5 (Evaluation of Interchange Transactions), INT-009-3 (Implementation of Interchange) and PRC-004-6 (Protection System Misoperation Identification and Correction), IRO-002-7 (Reliability Coordination—Monitoring and Analysis), TOP-001-5 (Transmission Operations).

[70] *Order 873* at P 2.

[71] *Order 873* at P 5. Pursuant to FPA section 215(d)(4), if the FERC disapproves a modification to a Reliability Standard in whole or in part, it must remand the entire Reliability Standard to NERC for further consideration. Accordingly, although it was satisfied here with the justification for the retirement of R7, the FERC was required to remand both R7 and R8 so that its concerns with the retirement of Requirement R8 could be addressed.

[72] *Electric Reliability Organization Proposal to Retire Requirements in Rel. Standards Under the NERC Standards Efficiency Review*, 170 FERC ¶ 61,032 (Jan. 23, 2020) ("*Retirements NOPR*") (proposing to approve the retirement of 74 of 77 Reliability Standard requirements requested to be retired by NERC in these two dockets in connection with the first phase of work under NERC's Standards Efficiency Review, an initiative begun in 2017 that reviewed the body of NERC Reliability Standards to identify those Reliability Standards and requirements that were administrative in nature, duplicative to other standards, or provided no benefit to reliability). As previously reported, NERC withdrew its proposed changes to VAR-001-6 on May 14, 2020, reducing to 76 the number of requirements proposed to be retired.

- **2022 NERC/NPCC Business Plans and Budgets (RR21-9)**

On August 24, 2021, NERC submitted its proposed Business Plan and Budget, as well as the Business Plans and Budgets for the Regional Entities, including NPCC, for 2022. FERC regulations[73] 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 2022 funding requirement represents an overall increase of approximately 6.2% over NERC's 2021 funding requirement. The NPCC U.S. allocation of NERC's net funding requirement is $9.44 million. NPCC has requested $17.5 million in statutory funding (a U.S. assessment per kWh (2020 NEL) of $0.0000540) and $1 million for non-statutory functions. Comments on this filing were due on or before September 14, 2021; none were filed.

On September 29, 2021, NERC amended its August 24 filing to include additional Fixed Asset expenditures NERC expects to incur in 2022 in connection with its anticipated move to a new headquarters office location in the Atlanta, Georgia, area ("Budget Amendment"). The Budget Amendment does not provide for any increase from the Original Budget in NERC's 2022 statutory assessments, nor is there any change proposed to any Regional Entity's 2022 Business Plan and Budget. Comments on the Budget Amendment were due on or before October 12, 2021; none were filed. This matter is pending before the FERC.

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

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

- **Report of Comparisons of 2020 Budgeted to Actual Costs for NERC and the Regional Entities (RR21-5)**

On June 1, 2021, NERC filed comparisons of actual to budgeted costs for 2020 for NERC and the six Regional Entities operating in 2020, including NPCC. The Report includes comparisons of actual funding received and costs incurred, with explanations of significant actual cost-to-budget variances, audited financial statements, and tables showing metrics concerning NERC and Regional Entity administrative costs in their 2020 budgets and actual results. Comments on this filing were due on or before June 22, 2021; none were filed. This matter is pending before the FERC.

- **SolarWinds and Related Supply Chain Compromise White Paper (not docketed)**

On July 7, 2021, FERC staff and E-ISAC released a joint white paper emphasizing the need for continued vigilance by the electricity industry related to supply chain compromises and incidents and recommending specific cybersecurity mitigation actions to better ensure the security of the bulk-power system ("BPS"). View the Report here.

- **FERC/NERC Joint Report on Real Time Assessments (not docketed)**

On July 8, 2021, FERC Staff, together with staff from NERC and its regional entities issued a report outlining recommendations for real-time assessments of grid operating conditions.[74] The report concluded that

[73] 18 CFR § 39.4(b) (2014).

[74] Real-time assessments evaluate system conditions using real-time data to measure existing and potential operating conditions to ensure continued reliable operation of the bulk electric system. The joint staff review focuses on strategies and techniques used by reliability coordinators and transmission operators to perform these assessments following a loss or degradation of data or tools used to

system operators are prepared to manage limited impairments of their primary assessment tools or data through system redundancy and redundant data sources. However, infrequent events involving significant real-time data loss or the failure of primary analysis tools lasting more than two hours require the development of alternative data sources, tools, and analyses work to mitigate the potential loss of visibility and control resulting from the impairment of their primary tools. The report addressed the following seven technical areas related to Real-Time assessments, including observations, conclusions, and recommendations for each: (i) Real-Time Assessment Tools Under Normal Operating Conditions; (ii) Real-Time Data and Data Quality; (iii) Real-Time Data Loss Management; (iv) Alternative Real-Time Assessment and Study Tools; (v) Model Management; (vi) Control Center Hardware Configuration; and (vii) Major System Upgrades/Vendor Changes. View the Report here.

XI. Misc. - of Regional Interest

- **203 Application: Castleton Commodities/Atlas Power (GSP companies) (EC22-7)**

On October 20, 2021, ACR II Granite Shore Power Holdings LLC, an Atlas Capital Resources affiliate (together, "Atlas"), and 50% of owner of Granite Shore Power Holdings LLC ("GSP Holdings"), requested authorization to acquire the remaining 50% of GSP Holdings from CCI PAH II, an indirect subsidiary of Castleton Commodities International LLC ("CCI"). Following consummation of the transaction, Atlas will wholly own GSP Holdings, the indirect owner of NEPOOL members GSP Lost Nation LLC, GSP Merrimack LLC, GSP Newington LLC, GSP Schiller LLC, and GSP White Lake LLC. Comments on this application are due on or before November 10, 2021. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Hull Street/CMEEC (EC22-3)**

On October 15, 2021, MPH AL Pierce, LLC, indirectly owned by affiliates of Hull Street Energy, requested FERC authorization to acquire 100 % of the interests in CMEEC's 84 MW Wallingford electric generating facility. Comments on this application are due on or before November 5, 2021. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: PSEG/Generation Bridge II (ArcLight) (EC21-125)**

On September 2, 2021, PSEG Project Companies[75] and Generation Bridge II, LLC ("Purchaser") requested authorization for a transaction pursuant to which 100% of the membership interests in the PSEG Project Companies will be sold to Generation Bridge II, a wholly-owned, indirect subsidiary of ArcLight Fund VII, which is itself affiliated with Great River Hydro. On September 28, 2021, applicants submitted revised pages of an affidavit included in the original filing to correct statements regarding the ownership of certain assets. Applicants stated that the correction did not affect the analysis or conclusions presented in the original filing. Comments on the correction were due on or before November 2, 2021; none were filed. This application is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Valcour Wind Energy/AES (EC21-114)**

On October 15, 2021, the FERC authorized a transaction pursuant to which Valcour Wind Energy, LLC ("Valcour") will become a Related Person of AES Corporation (and AES Distributed Energy, Inc.).[76] Challenges, if any, to the October 15 order are due on or before November 15, 2021. Pursuant to the October 15 order, AES must file a notice within 10 days of consummation of the transaction, which as of the date of this Report has not

maintain situational awareness. The review included on-site discussions with representatives of nine participating reliability coordinators and transmission operators.

[75] The "PSEG Project Companies" are: PSEG New Haven LLC ("PSEG New Haven"), PSEG Power Connecticut LLC ("PSEG Power CT"), PSEG Power New York LLC ("PSEG Power NY").

[76] *The AES Corp.*, 177 FERC ¶ 62,026 (Oct. 15, 2021).

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

- **203 Application: Covanta/EQT (EC21-113)**

On October 18, 2021, the FERC authorized a transaction pursuant to which Covanta Holding Corporation and its public utility subsidiaries, including NEPOOL member Covanta Energy Marketing, LLC (together, "Covanta"), will become a wholly-owned subsidiary Covert Intermediate, Inc., itself an indirectly, wholly-owned affiliate of EQT AB ("EQT").[77] Consummation of this and the Cypress Creek Holdings transaction summarized just below, will make Covanta and Cypress Creek Renewables Related Persons. Pursuant to the October 18 order, Covanta must file a notice within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Cypress Creek/EQT (EC21-108)**

On October 1, 2021, the FERC authorized a transaction pursuant to which Cypress Creek Renewables, LLC, among others, will become a wholly-owned subsidiary Catalyst AcquisitionCo, Inc. ("Catalyst"), itself an indirectly, wholly-owned affiliate of EQT.[78] Consummation of this and the Covanta transaction summarized just above, will make Cypress Creek Renewables and Covanta Energy Marketing Related Persons. On October 15, 2021, Cypress Creek Renewables filed a notice that the authorized transaction was consummated on October 8, 2021. Reporting on this proceeding is now concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: PPL/Narragansett (EC21-87)**

On September 23, 2021, the FERC authorized a transaction pursuant to which a wholly-owned subsidiary of PPL Corporation will acquire 100% of the outstanding shares of common stock of The Narragansett Electric Company ("Narragansett").[79] This transaction is expected to close in the fourth quarter of 2021. Pursuant to the September 23 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 concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: NRG/Generation Bridge (ArcLight) (EC21-74)**

On August 18, 2021, the FERC authorized a transaction pursuant to which 100% of the membership interest in certain NRG Project Companies[80] will be sold to Generation Bridge Acquisition, LLC ("Purchaser"), a wholly-owned, indirect subsidiary of ArcLight Fund VI, which is itself affiliated with Great River Hydro.[81] Pursuant to the August 18 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 concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Exelon Generation (EC21-57)**

On August 24, 2021, the FERC authorized a "spin" transaction in which, after completion of an internal reorganization, the ownership of the public utility subsidiaries ("ExGen Utility Subsidiaries") of Exelon Generation Company, LLC ("ExGen") intermediate holding company owner, HoldCo, will be distributed to the shareholders of

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[77] *Covanta Holding Corp*., 177 FERC ¶ 62,031 (Oct. 18, 2021).

[78] *Cypress Creek Holdings, LLC*, 177 FERC ¶ 62,003 (Oct. 1, 2021).

[79] *PPL Corp. and The Narragansett Elec. Co.*, 176 FERC ¶ 61,175 (Sep. 23, 2021).

[80] The New England "NRG Project Companies" are Connecticut Jet Power LLC ("Connecticut Jet"), Devon Power LLC ("Devon"), Middletown Power LLC ("Middletown"), and Montville Power LLC ("Montville").

[81] *Arthur Kill Power LLC et al.*, 176 FERC ¶ 62,086 (Aug. 18, 2021).

Applicants' current ultimate upstream owner, Exelon Corporation (the "Transaction").[82] Following the Transaction, Exelon Corporation and its remaining subsidiaries will retain no interest in or affiliation with ExGen or the ExGen Utility Subsidiaries; Exelon Corporation and HoldCo will be separate publicly-traded companies. 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 concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement Cancellation: NSTAR/Cranberry Storage (ER22-214)**

On October 27, 2021, NSTAR filed a notice of cancellation of the Engineering, Design, and Procurement Agreement ("D&E Agreement") with Cranberry Point Energy Storage, LLC ("Cranberry Storage"). The D&E Agreement set forth the terms and conditions under which Cranberry Storage reimbursed NSTAR for costs associated with advancing certain design and engineering activities for upgrades that were identified in the applicable ISO-NE) studies, prior to execution of an LGIA. The D&E Agreement terminated by its terms when an LGIA was executed on October 8, 2021. An October 27, 2021 effective date was requested. Comments on this filing are due on or before November 17, 2021. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Cost Reimbursement Agreement Cancellation: National Grid/GRS (ER22-129)**

On October 18, 2021, National Grid filed a notice of cancellation of its Cost Reimbursement Agreement with Gas Recovery Systems ("GRS"). Performance under the Agreement has been completed, all amounts due and owing have been paid in full, and a new interconnection agreement between National Grid and GRS has been accepted and is currently in effect. A December 18, 2021 effective date was requested. Comments on this filing are due on or before November 8, 2021. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **CL&P/EIP E&P Agreement (ER21-2880)**

On September 13, 2021, CL&P filed an Engineering, Design & Procurement Agreement ("E&P Agreement") between itself and EIP Investments, LLC ("EIP"). The E&P Agreement (designated as Service Agreement IA-ESCLP-009) provides the terms and conditions under which CL&P will undertake certain engineering and design services for the upgrades identified in the System Impact Study for the interconnection to CL&P's 69 kV transmission line connected to CL&P's Black Rock substation located in New Britain, Connecticut. A September 14, 2021 effective date was requested. Comments on this filing were due on or before October 5, 2021; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA Termination: CL&P / Sterling Property (ER21-2860)**

On September 9, 2021, CL&P filed a notice of termination of a 2002 Interconnection Agreement ("IA") governing interconnection service to a since-decommissioned 26 MW waste-tire fueled generator located in Sterling, Connecticut (the "Facility").[83] The IA was accepted in Docket No. ER03-434,[84] and according to CL&P can be terminated under Section 2 of the IA because the Facility has been decommissioned. A November 8, 2021 effective date was requested. Comments on the notice were due on or before September 30, 2021. On September 30, Sterling Property, LLC ("Sterling"), owner of the Facility, filed a protest, asserting that the facility has not been decommissioned, and the regulatory proceeding before the Connecticut Department of Energy and the Environment ("CT DEEP") referenced in CL&P's termination notice, remains open and ongoing. Sterling stated that the FERC should "decline to exercise primary jurisdiction over this matter, given that the

[82] *Exelon Generation Co., LLC*, 176 FERC ¶ 61,121 (Aug. 24, 2021).

[83] The IA originally was between CL&P and Exeter Energy Limited Partnership ("Exeter"). The IA was assumed by Exeter's successor-in-interest, EmpireCo Limited Partnership ("EmpireCo"), who later assigned the IA to Sterling Property, LLC.

[84] *Northeast Utils. Serv. Co.*, Docket No. ER03-434 (Mar. 17, 2003) (unpublished letter order).

parties' dispute involves a factual dispute regarding a state regulatory proceeding, and further involves issues of contract interpretation that do not require the [FERC]'s specialized expertise to resolve or implicate the [FERC]'s regulatory responsibilities". On October 15, 2021, CL&P answered Sterling's protest; Sterling answered CL&P's answer on October 25. Brookfield submitted a doc-less intervention. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **TSAs: Third Amendments to NECEC Transmission TSAs (ER21-2738 et al.)**

On October 21, 2021, the FERC accepted third amendments to 7 of NECEC Transmission's previously-filed and accepted, cost-based transmission service agreements ("TSAs")[85] with the participants that will fund the construction, operation and maintenance of the New England Clean Energy Connect Project.[86] The amendments are intended to (i) clarify the scope of the NECEC Project, specifically the Network Upgrades needed to interconnect the project to the New England Transmission System, based on the results of the applicable ISO-NE system impact studies; and (ii) allow NECEC Transmission to certify achievement of certain critical milestones related to construction authorizations and other approvals from governmental organizations and ISO-NE, based on the clarified scope. The TSAs were accepted effective as of August 24, 2021, as requested. Unless the October 21 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).

- **Seabrook/NECEC E&P Agreement (ER21-2719)**

On October 4, 2021, the FERC accepted an Engineering & Procurement Agreement ("E&P Agreement") between NextEra Energy Seabrook, LLC ("Seabrook") and NECEC Transmission, LLC.[87] As previously reported, the E&P Agreement (designated as Seabrook Rate Schedule No. 2) provides the terms and conditions "concerning the engineering and procurement of long lead-time items" associated with work to be engaged in by Seabrook at NECEC's request "for the design, engineering, planning, permitting, and procurement of material and equipment" necessary to address the Significant Adverse Impact on Seabrook. Seabrook reported that all of the terms and conditions of the E&P Agreement had been mutually agreed upon. The E&P Agreement was accepted effective August 20, 2021, as requested. Unless the October 4 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **ISA: NSTAR/Servistar (ER21-2696)**

On October 14, 2021, the FERC accepted an interconnection study agreement ("ISA") between NSTAR and Servistar LLC ("Servistar").[88] As previously reported, Servistar is proposing to interconnect a 150 MW data center facility to Eversource's 1293 and 1302 115 kV transmission lines (ISO-NE queue position #1140). The ISA sets forth the terms and conditions under which NSTAR will study the feasibility of the project's interconnection ahead of the commencement of the ISO-NE study to give a preliminary review of possible adverse impacts to the system which the project will be responsible to mitigate. The ISA was accepted effective as of August 17, 2021, as requested. Unless the October 14 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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[85] *NECEC Transmission LLC*, Docket Nos. ER21-2738 et al. (Oct. 21, 2021) (unpublished letter order).

[86] The third amendments to the 7 TSAs were separately docketed as follows: Eversource (ER21-2738); National Grid (ER21-2739); Unitil (ER21-2742); HQUS/Eversource (ER21-2743); HQUS/National Grid (ER21-2744); HQUS/Unitil (ER21-2745); and HQUS Additional (ER21-2747).

[87] *NextEra Energy Seabrook, LLC*, Docket No. ER21-2719 (Oct. 4, 2021) (unpublished letter order).

[88] *NSTAR Electric Co.*, Docket No. ER21-2696 (Oct. 14, 2021) (unpublished letter order).

- **D&E Agreement: NSTAR/Medway Grid II (ER21-2684)**

Also on October 14, 2021, the FERC accepted a second D&E Agreement between NSTAR and Medway Grid, LLC ("Medway").[89] The second Medway D&E Agreement sets forth the terms and conditions under which NSTAR will undertake certain preliminary design and engineering activities related to the upgrades identified in the System Impact Study for queue position #844, Medway's request to interconnect to NSTAR's 3445 kV West Medway Substation. The D&E Agreement was accepted effective as of August 17, 2021, as requested. Unless the October 14 order in this proceeding 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).

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

On July 23, 2021, Versant Power filed proposed revisions to Section 4 of the Versant Power Open Access Transmission Tariff For Maine Public District (the "MPD OATT") to incorporate by reference certain of the revisions required by *Order 676-I* and requested waiver of certain of those standards that are not applicable to MPD and/or the MPD OATT. Comments on this filing were due on or before August 13, 2021; none were filed. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- ***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 public utilities with transmission have submitted their *Order 864* compliance filings, with the specific dockets and filing dates identified in the following table (all remain pending):

Date Filed	Docket	Transmission Provider	Date Accepted
Mar 11, 2021	ER21-1325	NHT	pending
Mar 8, 2021	ER21-1295	Eversource (CL&P, PSNH, NSTAR)	pending
Feb 16, 2021	ER21-1154	Fitchburg Gas & Electric ("FG&E")	pending
Oct 30, 2020 Apr 16, 2021	ER21-311 ER21-1694	Green Mountain Power	pending pending
Aug 5, 2020	ER20-2614	New England Power AC Support Agreement	pending
Aug 5, 2020	ER20-2610	CL&P	pending
Aug 5, 2020	ER20-2609 ER21-1650	NSTAR	pending pending
Aug 5, 2020	ER20-2608	PSNH	pending
Aug 4, 2020	ER20-2607	NEP – Seabrook Transmission Support Agreement	pending
Jul 31, 2020	ER20-2594 ER21-1709	VTransco	pending pending
Jul 30, 2020	ER20-2572 ER21-1130	New England TOs	pending

[89] *NSTAR Electric Co.*, Docket No. ER21-2684 (Oct. 14, 2021) (unpublished letter order) (accepting the NSTAR/Medway Grid D&E Agreement II).

[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 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.

[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*").

Jul 30, 2020	ER20-2553	NEP – LSA with MECO/Nantucket	pending
Jul 30, 2020	ER20-2551	New England Power	pending
Jul 15, 2020	ER20-2429 ER21-1702	CMP	pending pending
Jun 29, 2020	ER20-2219	New England Power	pending
Jun 23, 2020 Mar 22, 2021	ER20-2133 -001	Versant Power	pending
May 18, 2020 Jan 7, 2021	ER20-1839	VETCO	pending
Feb 26, 2020 Dec 11, 2020	ER20-1089	New England Elec. Trans. Corp.	pending
Feb 26, 2020 Dec 11, 2020	ER20-1088	New England Hydro Trans. Elec. Co.	pending
Feb 26, 2020 Dec 11, 2020	ER20-1087	New England Hydro Trans. Corp.	pending

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

♦ ***ER20-2429 (CMP)***. As previously reported, the FERC issued a second deficiency letter on September 15, 2021. Following two extensions ranted at CMP's request (including an October 19 request), CMP's responses to the second deficiency letter are now due November 8, 2021.

XII. Misc. - Administrative & Rulemaking Proceedings

- **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").[92] The Transmission Task Force will be 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 will be open to the public for listening and observing and on the record. The Transmission Task Force will focus on "topics related to efficiently and fairly planning and paying for transmission, including transmission to facilitate generator interconnection, that provides benefits from a federal and state perspective."[93] On July 19, 2021, NARUC nominated the 10 state commissioners to the Transmission Task Force, including New England Commissioners Riley Allen (VT PUC) and Matt Nelson (Chair, MA DPU).

On August 30, 2021, the FERC issued an order listing the 10 state commissioner members (confirming the nominations of Commissioner Allen and Chairman Nelson), announcing the first public meeting of the Task Force (to be held Wednesday, November 10, 2021, from approximately 1:00 pm to 6:00 p.m., in Louisville, Kentucky, in

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

[93] 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.

conjunction with the NARUC meeting scheduled to be held there), and inviting agenda topics (all interested persons, including all state commissions, were invited to file comments in this docket on agenda topics for the first public meeting on or before September 10, 2021).[94] Comments on the agenda were filed by AEP, APPA, the Environmental Law and Policy Center and National Audubon Society, ITC, NYU's Institute for Policy Integrity, Shell, Southern Company Services, Wires.

On October 27, 2021, the FERC issued a notice of, and attached an agenda for, the Wednesday, November 10 meeting. While the meeting will be open to the public for listening and observing and on the record, including limited in person seating, the public was encouraged to attend via audio Webcast given continuing COVID-19 concerns. This conference will be transcribed and will address incorporating state perspectives into regional transmission planning.

- **Climate Change, Extreme Weather, and Electric Sys. Reliability: Jun 1-2 Technical Conference (AD21-13)**

On June 1-2, 2021, FERC staff convened a technical conference to discuss issues surrounding the threat to electric system reliability posed by climate change and extreme weather events. This technical conference addressed (i) concerns that, because extreme weather events are increasing in frequency, intensity, geographic expanse, and duration, the number and severity of weather-induced events in the electric power industry may also increase; and (ii) specific challenges posed to electric system reliability by climate change and extreme weather, which may vary by region. The FERC seeks to understand the near, medium and long-term challenges facing the regions of the country; how decision makers in the regions are evaluating and addressing those challenges; and whether further FERC action is needed to help achieve an electric system that can withstand, respond to, and recover from extreme weather events. Pre-technical conference comments were due on or before April 15, 2021 and were filed by, among others, ISO-NE, AEE, Dominion, EDF, Eversource, Exelon, LS Power, National Grid, PSEG, Vistra, APPA, Capital Power, EEI, NARUC, NEI, NERC, NRECA, and the R Street Institute. Speaker materials were posted in eLibrary on June 3, 2021; transcripts of the June 1-2 days, July 22, 2021.

On August 11, 2021, the FERC issued a notice inviting post-technical conference comments. Comments could address the questions raised in the notice, as well as any other issues raised during the technical conference or identified in the Supplemental Notices of Technical Conference issued March 15 and May 21, 2021. Comments were due on or before September 27, 2021 and were filed by: CAISO; MISO; NYISO; PJM; AEP; City of New Orleans; City of New York; Columbia Law School's Sabin Center for Climate Change Law; EDF and Sabin Center for Climate Change Law; EEI; EPSA; Eversource; Exelon, Jupiter Intelligence; Louisville Gas and Electric Company and Kentucky Utilities Company; MI PSC; NRDC, Sierra Club, Sustainable FERC Project, and UCS; Old Dominion Electric Cooperative ("ODEC"); NERC; and C. Wright. On October 14, Entergy answered the comments submitted by City of New Orleans. This matter is pending before the FERC.

- **Electrification and the Grid of the Future: Apr 29 Technical Conference (AD21-12)**

The FERC convened a Commissioner-led technical conference on April 29, 2021 to discuss electrification—the shift from non-electric to electric sources of energy at the point of final consumption (e.g., to fuel vehicles, heat and cool homes and businesses, and provide process heat at industrial facilities). The purpose of the technical conference was to "initiate a dialog between Commissioners and stakeholders on how to prepare for an increasingly electrified future." Panel discussions addressed (1) projections, drivers, and risks of electrification; (2) infrastructure requirements of electrification (the extent to which electrification may influence or necessitate additional transmission and generation infrastructure); (3) transmission and distribution system services provided by flexible demand (how newly electrified sources of energy demand (e.g., electric vehicles, smart thermostats, etc.) could provide grid services and enhance reliability); and (4) the role of local, state, and federal coordination as electrification advances. A transcript of the technical conference is posted in eLibrary. On May 17, the FERC

[94] *Joint Federal-State Task Force on Electric Transmission*, 176 FERC ¶ 61,131 (Aug. 30, 2021).

issued a notice inviting the submission of post-technical conference comments, on or before July 1, 2021. Nearly 20 sets of comments were filed, including comments by: AGA, CAISO, EEI, IL ICC, MISO, MISO TOs, Organization of MISO States, NEMA, NRECA, Chargepoint, CTC Global, Electrify America, Entergy, Environmental Defense Fund, ITC Holdings, Prairie Power, National Grid, and R Street Institute. This matter remains pending before the FERC.

- **Reliability Technical Conference (Sep 30) (AD21-11)**

On September 30, 2021, the FERC convened its annual Commissioner-led technical conference to discuss policy issues related to the reliability of the Bulk-Power System ("BPS"). Panel discussions addressed: (1) BPS reliability and security (current state, challenges and initiatives); (2) extreme weather, risks and challenges); (3) managing cyber risks in the electric power sector; and (4) maintaining electric reliability with changing resource mix. A detailed final agenda, identifying the presenters and panelists, is available here. Speaker materials have been posted to eLibrary.

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

March 23 Tech Conf (PJM). The FERC convened a Commissioner-led technical conference was on March 23, 2021 to provide input to the Commission on resource adequacy in the evolving electricity sector. Speaker materials from the March 23 technical conference have been posted to eLibrary. On March 29, Ohio PUC Commission Dan Conway submitted written comments. On April 5, the FERC issued a notice inviting post-technical conference comments on specific PJM-specific questions. Initial comments were due on or before April 26, 2021; reply comments must be submitted on or before May 10, 2021. More than 45 sets of 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, some of which addressed issues to be discussed in the May 25 New England technical conference (identified immediately below). On May 10, 2021, 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").

May 25 Tech Conf (New England). On May 25, 2021, the FERC held a Commissioner-led technical conference regarding the wholesale markets administered by ISO New England Inc. Supplemental notices of the technical conference were issued on May 3 and May 17. The May 17 supplemental notice identified panelists and topics/questions for discussion for the technical conference. Panel discussions included: (1) a Commissioner-led discussion of the relationship between state policies and the New England Markets; (2) a Staff-led discussion of short-term options and complementary potential market changes to accommodate state policies in New England; and (3) a Staff-led discussion of long-term options and centralized procurement of clean energy.

Post (New England) Tech Conf Comments. On June 4, 2021, the FERC issued a notice inviting post-technical conference comments on the issues raised during the technical conference, including the questions listed in the May 17, 2021 supplemental notice. Post-technical conference comments were due on or before ***July 19, 2021*** and were filed by: AEE, Calpine, CT Parties, Dominion, Eversource, MMWEC, NESCOE, NEPGA, NextEra, NRG, Public Interest Orgs, Vistra, AEMA, EPSA, RENEW.

- **Modernizing Electricity Market Design - Energy and Ancillary Service Markets (AD21-10)**

Tech Conf I (Sep 14). On September 14, 2021, the FERC held the first of two staff-led technical conferences addressing ISO/RTO energy and ancillary services markets (including potential energy and ancillary services market reforms, such as market reforms to increase operational flexibility, that may be needed as the resource fleet and load profiles change over time). In an August 17, 2021 supplemental notice the FERC identified the following four panels and the topics and questions to be discussed: (1) Understanding the Need for Additional Operational Flexibility in RTO/ISO Energy and Ancillary Services Markets; (2) Revising Existing Operating Reserve Demand Curves ("ORDCs") to Address Operational Flexibility Needs in RTOs/ISOs; (3) Creating New Products to Address Operational Flexibility Needs in RTOs/ISOs; and (4) Market Design Issues and Tradeoffs to Consider in Reforms to Increase Operational Flexibility in RTO/ISO Energy and Ancillary Services Markets. Speakers were identified in a second supplemental notice issued on September 3, 2021. A transcript of the September 14 technical conference was posted in eLibrary on October 14, 2021.

Tech Conf II (Oct 12). A second full-day technical conference was convened on October 12, 2021. An October 7 supplemental notice identified the speakers and the following four panels and topics to be discussed: (1) Incenting Resources to Reflect Their Full Operational Flexibility in Energy and Ancillary Services Offers; (2) Maximizing the Operational Flexibility Available from New and Emerging Resource Types; (3) Revising RTO/ISO Market Models, Optimization, and Other Software Elements to Address Operational Flexibility Needs; and (4) Out-of-Market Operator Actions Used to Manage Net Load Variability and Uncertainty.

White Paper. On September 7, 2021, FERC staff issued a White Paper entitled "Energy and Ancillary Services Market Reforms to Address Changing System Needs". The White Paper summarizes recent energy and ancillary services markets reforms as well as reforms currently under consideration and was prepared in an effort to frame discussions at the two technical conferences.

- **Office of Public Participation (AD21-9)**

On June 24, 2021, the FERC issued a report in which it detailed the forthcoming creation of the Office of Public Participation ("OPP"), which it intends to grow over the course of a four-year period before OPP reaches its full operating status by the close of Fiscal Year ("FY") 2024. By the end of FY2021, the FERC plans to hire the OPP Director (which it has done – *see* below), as well as the Deputy Director and an administrative staff member. The FERC plans to assess OPP's workload and reevaluate needed resources for additional growth into and beyond FY2024 to ensure meaningful and consistent compliance with FPA section 319. A report, prepared by M.J. Bradley & Associates for NRDC's Sustainable FERC Project, summarizing stakeholder feedback provided to the FERC through listening sessions and written comments, was posted to the FERC's eLibrary on August 3, 2021.

The FERC held on October 7. 2021 a virtual workshop to discuss technical assistance in electric proceedings, solicit public input on their technical assistance needs, and explore ways OPP could work with external entities to facilitate technical assistance to interested parties. Further details on the agenda, including registration information, can be found on the U.S. Department of Energy's ("DOE") Pacific Northwest National Laboratory ("PNNL") website. Information on this technical workshop was also posted on the Calendar of Events on the FERC's website, www.ferc.gov.

On October 12, 2021, FERC Chairman Glick announced that Elin Katz, the former head of the Connecticut Office of Consumer Counsel ("CT OCC") and president of the National Association of State Utility Consumer Advocates ("NASUCA"), will lead OPP. She will assume her role as the Director of OPP in late November.

Since the last Report, nearly 25 sets of comments were filed by individual New England (New Hampshire) ratepayers requesting OPP's assistance and support on New England issues, including FCM Market reforms, the shutdown of Merrimack Station, and requiring "ISO New England make their plan for grid transition transparent to the community."

- **ISO/RTO Credit Principles and Practices (AD21-6)**

On February 25-26, 2021, the FERC held a technical conference to discuss principles and best practices for credit risk management in ISO/RTOs. Panel topics included: Credit Principles and Practices in ISOI/RTO Markets; RTO/ISO Comparison of Risk Management Structure, Credit Enhancements and Lessons Learned; Internal Resources and Expertise within RTOs/ISOs; Impact of Market Design on Credit Risk; Addressing Counterparty Risk: Minimum Participation Requirements and Know Your Customer Protocols; and Collateral, Initial and Variation Margining for FTR and non-FTR positions. Speaker materials and a transcript of the technical conference are posted in the FERC's eLibrary.

On April 21, 2021, the FERC issued a notice inviting post-technical conference comments on the issues raised during the technical conference, including the questions listed in the February 24, 2021 supplemental notice of the technical conference and in the attachment to the April 21 notice. Post-technical conference comments were due on or before June 7, 2021 and were filed by ISO-NE, Appian Way, Committee of Chief Risk Officers, CPV, DC Energy, Energy Trading Institute, EPSA, Financial Marketers Coalition, ISO/RTO Council, MISO, NYISO, PJM, SPP, and Vitol. On July 6, NEPOOL filed comments in response to the IRC comments that, to the extent Tariff changes are to be proposed, the Tariff changes be vetted first pursuant to the Participant Processes set forth in the Participants Agreement. This matter is pending before the FERC.

- **Offshore Wind Integration in RTOs/ISOs Tech Conf (Oct 27, 2020) (AD20-18)**

On October 27, 2020, the FERC convened a staff-led technical conference to consider whether and how existing RTO and ISO interconnection, merchant transmission and transmission planning frameworks can accommodate anticipated growth in offshore wind generation in an efficient or cost-effective manner that safeguards open access transmission principles. The conference also provided an opportunity for participants to discuss possible changes or improvements to the current regulatory frameworks that may accommodate such growth. Speaker materials and a transcript of the technical conference are posted in eLibrary. Since the last Report, Advanced Power Alliance filed comments requesting that the FERC issue a notice providing an opportunity for interested persons to submit post-conference comments and to thereafter “take action to facilitate transmission planning and interconnection policies that will enable construction of the cost-effective, efficient, resilient and environmentally-sound transmission infrastructure needed to connect new offshore wind generation to the onshore grid.”

On March 11, 2021, the FERC issued a notice inviting interested persons to file, on or before May 10, 2021, post-technical conference comments on the questions listed in the attachment to its Notice or to the questions outlined in the October 22, 2020 supplemental notice of technical conference. Post-technical conference comments were filed by over 30 parties, including: ISO-NE, NESCOE, Anbaric, ConEd, Eversource, National Grid, NRDC et al., Orsted, Shell, CT DEEP, EEI, MA DOER, RENEW et al., and RWE Renewables Americas. This matter is pending before the FERC.

- **Hybrid Resources (AD20-9)**

As previously reported, the FERC convened a July 23, 2020 technical conference to discuss technical and market issues prompted by growing interest in projects that are comprised of more than one resource type at the same plant location (“hybrid resources”). The focus was on generation resources and electric storage resources paired together as hybrid resources. Speaker materials and a transcript of the technical conference have been posted to the FERC’s eLibrary. Post-technical conference comments were filed by ISO-NE, CAISO, MISO, NYISO, PJM, Enel, American Council on Renewable Energy, AWEA, EEI, EPRI, R Street Institute, Savion, and SEIA.

On January 19, 2021, the FERC issued an order directing each ISO/RTO to submit, within 6 months (or before July 19, 2021), a report that provides: (a) a description of its current practices related to each of the following four hybrid resource issues: (1) terminology; (2) interconnection; (3) market participation; and (4) capacity valuation (collectively, the “Issues”); (b) an update on the status of any ongoing efforts to develop reforms related to each of the Issues; and (c) responses to the specific requests for information contained in the order. The ISO/RTO Reports, including ISO-NE’s, were filed on July 19, 2021. Public comments in response to the ISO/RTO reports are now due September 20, 2021.[95]

Hybrid Resources White Paper. On May 26, 2021, the FERC issued a white paper that discusses the hybrid resources technical conference, as well as information learned in post-technical conference comments. Interested

[95] Public comments were initially due August 18, 2021. However, in response to a request by the Energy Storage Association (“ESA”), the American Clean Power Association (“ACP”), and Solar Energy Industry Association (“SEIA”), the FERC granted a 30-day extension of time, to September 20, 2021, to file comments in response to the ISO/RTO reports.

persons were invited to submit comments on the white paper and encouraged to jointly respond to both the white paper and RTO/ISO informational reports where applicable to avoid duplicate comments. Comments on the white paper will also be due on September 20, 2021.

Comments. Comments on the RTO filing and on the FERC's Hybrid Resources White Paper were submitted by the American Council on Renewable Energy ("ACRE"), Clean Grid Alliance, EEI, the City of New York, Hybrid Resource Coalition, NRECA, Pine Gate Renewables, PJM IMM, and UCS. On October 20, 2021, NYISO submitted comments in response to issues raised by those comments. These matters are now pending before the FERC.

- **ANOPR: Transmission Planning and Allocation and Generator Interconnection (RM21-17)**

On July 15, 2021, the FERC issued an advanced notice of proposed rulemaking ("ANOPR")[96] to consider whether there should be changes in the regional transmission planning and cost allocation and generator interconnection processes and, if so, which changes are necessary to ensure that transmission rates remain just and reasonable and not unduly discriminatory or preferential and that reliability is maintained. Specifically, the ANOPR discusses proposals or concepts for changes to existing processes in several broad categories: regional transmission planning, regional cost allocation, generator interconnection funding, generator interconnection queueing processes and consumer protection, and in several instances the ANOPR also offers a potential rationale or argument for potential proposals. The FERC seeks comments from the public on these proposals and welcomes commenters to offer additional or alternative proposals for consideration.

Since the last Report, 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. Reply comments are due on or before ***November 30, 2021.***

November 15, 2021 Tech Conf. On September 16, 2021, the FERC announced that it will convene remotely a staff-led technical conference regarding regional transmission planning on Monday, November 15, 2021. The technical conference will seek to examine in detail issues and potential reforms related to regional transmission planning as described in the July 15, 2021 ANOPR. Specifically, the technical conference will examine issues related to incorporating sufficiently long-term and comprehensive forecasts of future transmission needs during regional transmission planning processes, including considering the needs of anticipated future generation in identifying needed transmission facilities. This may include: approaches to planning regional transmission facilities that identify transmission needs for anticipated future generation, e.g., use in regional transmission planning of future scenarios or geographic zones where future generation is anticipated to locate; factors shaping future transmission needs that are appropriate to consider as inputs into transmission planning studies; and evaluation criteria used by the transmission planning regions to identify and select the more efficient or cost-effective regional transmission facilities.

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

On March 18, 2021, the FERC issued a NOI[97] 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

[96] *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*").

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

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.

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

On December 17, 2020, the FERC issued a NOPR[98] 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.,[99] 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[100] 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: Managing Transmission Line Ratings (RM20-16)**

On November 19, 2020, the FERC issued a NOPR[101] proposing to reform both the *pro forma* OATT and its regulations to improve the accuracy and transparency of transmission line ratings. Specifically, the NOPR proposes to require: transmission providers to implement ambient-adjusted ratings on the transmission lines over which they provide transmission service; ISO/RTOSs to establish and implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings at least hourly; and transmission owners to share transmission line ratings and transmission line rating methodologies with their respective transmission provider(s) and, in ISO/RTOs, with their respective market monitor(s). Comments on the *Managing Transmission Line Ratings NOPR* were due on or before March 22, 2021.[102] Comments were submitted by over 50 parties, including by ISO-NE, DC Energy, Dominion, EDF, ENEL/EnerNOC, Eversource, Exelon, NRDC, Vistra, EEI, EPRI, EPSA, New England State Agencies,[103] NRECA/LPPC, and Potomac Economics. Reply comments were submitted by the Enel Companies, EPSA, PJM, OMS, Potomac Economics, NRECA/LPCC, and ITC Holdings Corp and the Utah Division of Public Utilities. This matter is pending before the FERC.

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

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

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

[101] *Managing Transmission Line Ratings*, 173 FERC ¶ 61,165 (Nov. 19, 2020) ("*Managing Transmission Line Ratings NOPR*").

[102] The *Managing Transmission Line Ratings NOPR* was published in the *Fed. Reg.* on Jan. 21, 2021 (Vol. 86, No. 12) pp. 6,420-6,444.

[103] "New England State Agencies" are for purposes of this proceeding: CT Att'y Gen. William Tong, MA AG Maura Healey, the CT Dept. of Energy and Environ. Protection, the CT OCC, MOPA, NH OCA, Peter F. Neronha, RI AG, and Thomas J. Donovan, Jr., VT AG. The Feb 1 comments by the New England State Agencies broadly supported the FERC's proposals.

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

Supplemental NOPR. In light of comments already received in this proceeding,[104] the FERC issued on April 15, 2021 a *Supplemental NOPR*[105] 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 seeks 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*.[106] 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.[107] Since the last Report, reply comments were posted from New England State Parties,[108] Alliant/Consumers/DTE, AEP, Pacific Gas & Electric, Joint Consumer Advocates, and the American Clean Power Association.

September 10, 2021 Workshop. The FERC convened a workshop on September 10, 2021[109] to discuss certain performance-based ratemaking approaches, particularly shared savings, that may foster deployment of

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[104] 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.

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

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

- A shift from risks and challenges to a ***consumers'' benefits test*** that focuses on ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.
- ***ROEs incentive for Economic Benefits***. A 50-basis-point adder for transmission projects that meet an economic benefit-to-cost ratio in the top 75th percentile of transmission projects examined over a sample period 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.

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

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

[109] 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).

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 must be submitted on or before ***January 14, 2022***.

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

- ***Order 860/860-A*: Data Collection for Analytics & Surveillance and MBR Purposes (RM16-17)**

As previously reported, *Order 860,*[110] issued three years after the FERC's *Data Collection NOPR,*[111] (i) revises the FERC's MBR regulations by establishing a relational database of ownership and affiliate information for MBR Sellers (which, among other uses, will be used to create asset appendices and indicative screens), (ii) reduces the scope of information that must be provided in MBR filings, modifies the information required in, and format of, a MBR Seller's asset appendix, (iii) changes the process and timing of the requirements to advise the FERC of changes in status and affiliate information, and (iv) eliminates the requirement adopted in *Order 816* that MBR Sellers submit corporate organization charts. In addition, the FERC stated that it will not adopt the *Data Collection NOPR* proposal to collect Connected Entity data from MBR Sellers and entities trading virtuals or holding FTRs. The FERC has posted on its website high-level instructions that describe the mechanics of the relational database submission process and how to prepare filings that incorporate information that is submitted to the relational database. As recently extended (*see* below), *Order 860* became effective July 1, 2021, and submitters have until close of business on November 2, 2021 to make their initial baseline submissions. Submitters will be required to obtain FERC-generated IDs for reportable entities that do not have CIDs or LEIs, as well as Asset IDs for reportable generation assets without an EIA code so that every ultimate upstream affiliate or other reportable entity has a FERC-assigned company identifiers ("CID"), Legal Entity Identifier,[112] or FERC-generated ID and that all reportable generation assets have an code from the Energy Information Agency ("EIA") Form EIA-860 database or a FERC-assigned Asset ID. Requests for rehearing and/or clarification of *Order 860* were denied,[113] other than TAPS' request that the FERC clarify that the public will be able to access the relational database. On that point, the FERC clarified "that we will make available services through which the public will be able to access organizational charts, asset appendices, and other reports, as well as have access to the same historical data as Sellers, including all market-based rate information submitted into the database. We also clarify that the database will retain information submitted by Sellers and that historical data can be accessed by the public."

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110 *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 168 FERC ¶ 61,039 (July 18, 2019) ("*Order 860*"), *order on reh'g and clarif.*, 170 FERC ¶ 61,129 (Feb. 20, 2020).

111 *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 156 FERC ¶ 61,045 (July 21, 2016) ("*Data Collection NOPR*").

112 An LEI is a unique 20-digit alpha-numeric code assigned to a single entity. They are issued by the Local Operating Units of the Global LEI System.

113 *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, Order No. 860-A, 170 FERC ¶ 61,129 (Feb. 20, 2020) ("*Order 860-A*").

MBR Database. On January 10, 2020, the FERC issued a notice that updated versions of the XML, XSD, and MBR Data Dictionary are available on the FERC's website and that the test environment for the MBR Database is now available and can be accessed on the MBR Database webpage.

March 18 Notice. On March 18, 2021, the FERC issued a notice seeking comments on proposed changes to the MBR Data Dictionary to reflect the affiliations, or lack of affiliation, among Sellers for which their ultimate upstream affiliate is an institutional investor who acquired their securities pursuant to a section 203(a)(2) blanket authorization.[114] Specifically, the FERC proposes to update the MBR Data Dictionary and add the following three new attributes to the Entities table: the blanket authorization docket number, and the utility ID types and the utility IDs of the utilities whose securities were purchased under the corresponding blanket authorization docket number. Appropriate Sellers would be required to submit the docket number of the proceeding in which the FERC granted the section 203(a)(2) blanket authorization and the upstream affiliate whose securities were acquired pursuant to the section 203(a)(2) blanket authorization. Comments on the Notice were due on or before June 7, 2021,[115] and were filed by EEI, the Global LEI Foundation, TAPS, and XBRL US. In light of the proposed changes, the FERC deferred by three months the effective date of *Order 860* and its associated deadlines.

Effective Date: July 1, 2021; Baseline Submissions November 2, 2021; First change in Status Filings, November 30, 2021. On March 18, 2021, the FERC issued a notice extending the effective and associated implementation dates of *Order 860* by an additional *three* months. The new *Order 860* effective date was July 1, 2021, and the deadline for baseline submissions will be to and including November 2, 2021. First change in status filings under these new timelines will be due November 30, 2021.

Order Adopting Changes to MBR Database. On August 19, 2021, the FERC issued an order revising the MBR Data Dictionary as proposed in the March 18 Notice.[116] Specifically, Sellers whose ultimate upstream affiliate(s) own their voting securities pursuant to a section 203(a)(2) blanket authorization must provide, in the MBR Database, three additional data fields: (1) the docket number of the section 203(a)(2) blanket authorization, (2) the Utility_ID_Type_CD of the utility whose securities were acquired under the corresponding section 203(a)(2) blanket authorization docket number, and (3) the Utility ID of that utility.

- ***Order 676-J*: Incorporation of NAESB WEQ Standards v. 003.3 into FERC Regs (RM05-5-029, -030)**

On May 20, 2021, the FERC issued Order 676-J,[117] which revises 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 the Wholesale Electric Quadrant ("WEQ") of the North American Energy Standards Board ("NAESB"). 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. *Order 676-J* became effective August 2, 2021.[118] Public utilities must make a compliance filing to comply with the requirements of this final rule through eTariff 12

[114] *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 174 FERC ¶ 61,214 (Mar. 18, 2021).

[115] The Notice was published *Fed. Reg.* on Apr. 6, 2021 (Vol. 86, No. 64) pp. 17,823-17,828.

[116] *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, 176 FERC ¶ 61,109 (Aug. 19, 2021).

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

[118] *Order 676-J* was published *Fed. Reg.* on June 2, 2021 (Vol. 86, No. 104) pp. 29,491-29,503.

months after implementation of the WEQ Version 003.2 Standards. Compliance filings for cybersecurity and Parallel Flow Visualization standards are due March 2, 2022.

- **Waiver of Tariff Requirements (PL20-7)**

On May 21, 2020, the FERC issued a Proposed Policy Statement that would clarify its policy regarding requests for waiver of tariff provisions.[119] The *Proposed Policy Statement* sets forth the approach the FERC would take going forward to ensure compliance with the filed rate doctrine and the rule against retroactive making. The proposed policy will both clarify and modify waiver standards, and in some instances, make it harder to obtain waivers.

Specifically, the FERC proposed the following guidance on filing procedures to implement its new approach for granting waivers of tariff provisions and to no longer grant retroactive waivers except as consistent with the *Proposed Policy Statement*:

1. *Style Requests as Requests for Remedial Relief*. Filings seeking relief in connection with actions or omissions that have already occurred prior to the date relief is sought from the FERC would be characterized as a request for remedial relief (rather than as a request for a waiver). In response to such a request, the FERC will focus on what remedy, if any, is required to cure acknowledged or alleged deviations from a filed tariff. "Waiver" is to be limited to (a) requests for prospective relief when a requested future deviation from the filed tariff has not yet occurred at the time a request is filed; or (b) petitions for remedial relief when a tariff expressly authorizes regulated entities to seek a remedial waiver from the FERC for past non-compliance with the filed tariff.

2. *Form of Filing*. When the entity requesting remedial relief is the entity that acted (or believes it may have acted) in a manner inconsistent with the tariff, such requests should be filed as petitions for declaratory order under Rule 207 of the FERC's Rules of Practice and Procedure. When the filing entity alleges a different entity has acted in a manner inconsistent with the tariff, such requests should be filed as complaints under Rule 206. Given the filing fees associated with petitions for declaratory order, the industry was encouraged to directly address this aspect of the proposal.

3. *Expressly Request FERC Action pursuant to FPA section 309 or NGA section 16.4*. These provisions have been found to afford the FERC the latitude to remedy past non-compliance "provided the agency's action conforms with the purposes and policies of Congress and does not contravene any terms of the Act."

The FERC acknowledged that this Policy would represent a change from its past approach, particularly in situations where inadvertent failures to comply with ministerial tariff requirements have not been protested. The FERC suggested a few ways tariffs may be modified to avoid what may appear by comparison to be harsh outcomes, including expressly stating in the tariff that a failure to comply with a certain deadline may be waived by order of the FERC or by allowing various kinds of errors to be cured within a reasonable period of time after a default has occurred or an error has been discovered, but is difficult to imagine how feasible or how well these options might work in practice.

[119] *Waiver of Tariff Requirements*, 171 FERC ¶ 61,156 (May 21, 2020) ("*Proposed Policy Statement*").

The FERC proposed to incorporate its current four-part analysis[120] in considering both requests for prospective waiver and petitions for remedial relief, but cautioned that it would apply that analysis only in those limited circumstances where the request for remedial relief would not violate the filed rate doctrine or the rule against retroactive ratemaking due to adequate prior notice, or the requested relief is within the FERC's authority to grant under FPA section 309 or NGA section 16.

Finally, the FERC proposed requiring a stronger showing when a petitioner is seeking remedial relief for its own failure to comply with a tariff – petitions will be more compelling when the failure to comply was due to something more than inadvertent error or administrative oversight. Petitions for remedial relief will generally be denied when a protestor credibly contends, or the FERC independently determines, that the requested remedial relief will result in undesirable consequences (e.g. harm to third parties).

With respect to prospective requests to waive the 60-day prior notice requirement under FPA section 205(d) (or the 30-day prior notice requirement under NGA section 4(d)), which the FERC has discretion to waive "for good cause shown," the FERC proposes to leave in effect its policy of generally granting such waivers,[121] to the extent that entities seek an effective date no earlier than the day *after* the date a rate change is submitted to the FERC.

Comments on the Proposed Policy Statement were due on or before June 18, 2020 and were filed by the IRC, AEE, APPA, AWEA/SEIA, EEI, EPSA, Indicated Generators,[122] INGAA, Kansas Electric Power Coop. ("KEPC"), NGA, NGSA, NRECA, Public Citizen, Sunflower Electric Power, and TAPS. Reply comments were filed by APPA, Joint Trade Associations,[123] KEPC, and the Sustainable FERC Project. The proposed Policy Statement remains pending before the FERC.

- **FERC's ROE Policy for Natural Gas and Oil Pipelines (PL19-4)**

On May 21, 2020, the FERC issued a Policy Statement that applies to natural gas and oil pipelines, with certain exceptions to account for the statutory, operational, organizational and competitive differences among the electric, natural gas and oil pipeline industries, the FERC's ROE methodology adopted in *Opinion No. 569-A*.[124] Specifically, the FFERC revised its policy and will determine natural gas and oil pipeline ROEs by averaging the results of the DCF and CAPM, but will not use the risk premium model discussed in *Opinion 569/569-A* ("Risk Premium").[125] In addition, the FERC clarified its policies governing the formation of proxy groups and the treatment of outliers in proceedings addressing natural gas and oil pipeline ROEs. Finally, the FERC encouraged oil pipelines to file revised FERC Form No. 6, page 700s for 2019 reflecting the revised ROE

[120] Under current practice, the FERC grants tariff provision waivers where: (1) the underlying error was made in good faith; (2) the waiver is of limited scope; (3) the waiver addresses a concrete problem; and (4) the waiver does not have undesirable consequences, such as harming third parties.

[121] *See Cent. Hudson Gas & Elec. Corp.*, 60 FERC ¶ 61,106, *order on reh'g*, 61 FERC ¶ 61,089 (1992) ("*Central Hudson*"). Factors that will generally support a waiver of prior notice include: (1) uncontested filings that do not change rates; (2) filings that reduce rates and charges; and (3) filings that increase rates as prescribed by a previously accepted contract or settlement on file with the FERC.

[122] "Indicated Generators" are Vistra, NRG, FirstLight, Cogentrix, and LS Power.

[123] "Joint Trade Associations" are AEE, AWEA, EEI, EPSA, INGAA, NGSA, NRECA and SEIA.

[124] *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 FERC ¶ 61,155 (May 21, 2020) ("*Natural Gas and Oil Pipeline ROE Policy Statement*").

[125] As previously reported, the FERC issued a notice of inquiry on March 21, 2019 seeking information and views to help the FERC explore whether, and if so how, it should modify its policies concerning the determination of ROE to be used in designing jurisdictional rates charged by public utilities.[125] The FERC also sought comment on whether any changes to its policies concerning public utility ROEs should be applied to interstate natural gas and oil pipelines. This NOI followed *Emera Maine*, which reversed *Opinion 531*, and seeks to engage interests beyond those represented in the *Emera Maine* proceeding (see EL11-66 *et al.* in Section I above).

policy. This Policy Statement became effective May 27, 2020.[126] On July 7, the FERC issued a notice that pipelines choosing to file updated FERC Form No. 6, page 700 data consistent with the ROE Policy Statement should file such data on or before July 21, 2020.

Complainant-Aligned Parties[127] answered the New England TO's May 10 supplemental comments. On June 15, 2020, Joint Parties[128] submitted supplemental comments arguing that the FERC should use the midpoint, rather than the median, as the measure of central tendency for public utilities that file individually to establish a ROE. Joint Parties' comments were opposed by Six Cities.[129] WIRES submitted supplemental comments on June 18, 2020 requesting that the FERC take further action in this proceeding to "resolve the uncertainty surrounding its base ROE methodology and establish a policy consistent with the recommendations made in these comments" (recommending a framework that employs all four of the previously proposed ROE models, including the Expected Earnings model, along with certain modifications, to ensure that ROEs attract capital investment in needed transmission infrastructure). On June 24, EEI and WIRES requested the FERC issue a NOI regarding the FERC's policy for determining base ROE applicable to the electric industry as a whole. Six Cities answered Joint Parties on June 30. APPA answered EEI and WIRES' June 24 motion.

- **NOI: Certification of New Interstate Natural Gas Facilities (PL18-1)**

As previously reported, the FERC's February 18, 2021 notice of inquiry ("*2021 NOI*") sought new information and additional stakeholder perspectives to help the FERC explore whether it should revise its approach under the currently effective policy statement on the certification of new natural gas transportation facilities to determine whether a proposed natural gas project is or will be required by the public convenience and necessity, as that standard is established in NGA section 7.[130] The *2021 NOI* is to provide an opportunity for stakeholders to refresh the record and provide updated information and additional viewpoints to help the FERC assess its policy.[131] Comments on the *2021 NOI* were due May 26, 2021. In all, more than 130 sets of comments were filed, including a large number from concerned private citizens. This matter is pending before the FERC.

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- **PacifiCorp (IN21-6)**

On April 15, 2021, in the FERC's first-ever Show Cause Order addressing alleged violations of NERC Reliability Standards,[132] 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

[126] The *Natural Gas and Oil Pipeline ROE Policy Statement* was published *Fed. Reg.* on May 27, 2020 (Vol. 85, No. 102) pp. 31,760-31,773.

[127] For this purpose, "Complainant-Aligned Parties" are: Connecticut Public Utilities Regulatory Authority, Connecticut Office of the Attorney General, Connecticut Department of Energy and Environmental Protection, Connecticut Office of Consumer Counsel, Massachusetts Office of the Attorney General, Massachusetts Department of Public Utilities, Massachusetts Municipal Wholesale Electric Company, and New Hampshire Electric Cooperative.

[128] "Joint Parties" are: AEP, Avista, Evergy Companies, Entergy Services, Exelon, FirstEnergy, Portland Gen. Elec., PG&E, Corporation, Puget Sound Energy, PacifiCorp, Idaho Power, PSEG, So. Cal. Edison, and San Diego Gas & Elec.

[129] "Six Cities" are the Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California.

[130] *Certification of New Interstate Natural Gas Facilities*, 174 FERC ¶ 61,125 (Feb. 18, 2021) ("2021 NOI").

[131] *Id.* at P 3.

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

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. 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).

- **GreenHat (IN18-9)**

On May 20, 2021, the FERC directed GreenHat Energy, LLC ("GreenHat"), John Bartholomew, Kevin Ziegenhorn, and [Luan Troxel as the Executor for] the Estate of Andrew Kittell ("Kittell Estate") (collectively, "Respondents") to show cause why they should not be found to have violated FPA section 222, along with section 1c.2 of the FERC's regulations, PJM Tariff Attachment Q, Section B and section 15.1.3 of PJM's Operating Agreement, by engaging in a manipulative scheme in PJM's Financial Transmission Rights ("FTR") market which generated more than $13 million in unjust profits for Respondents and imposed approximately $179 million in losses on PJM Members.[133] The FERC directed GreenHat, Bartholomew, Ziegenhorn, and the Kittell Estate to show cause why they should not be required, jointly and severally, to disgorge unjust profits of just ***over $13 million***, plus interest, and directed GreenHat, Bartholomew, and Ziegenhorn (but not the Kittell Estate) to show cause why they should not be assessed civil penalties of ***$179 million***, ***$25 million***, and ***$25 million***, respectively.

Respondents answered the *GreenHat Show Cause Order* on July 6, 2021. On July 27, Enforcement Litigation Staff answered Respondents' July 6 answers. On August 23, 2021, the Estate of Andrew Kittell submitted a reply to Enforcement's July 27 answer. This matter is again before the FERC. As previously reported, should the FERC choose to pursue a civil penalty against Respondents for the alleged violations, Respondents have already exercised their right to adjudicate these allegations in federal district court. In September, OE issued a notice that, should the FERC decide to issue a penalty order, the date by which the FERC needs to do so to ensure that a lawsuit against the Kittell Estate will be timely is October 11, 2021. On October 1, 2021, OE lawyers reported on improper communications (forwarding some precedential decisions regarding statute of limitations) from a decisional staff member to another lawyer who is working on the GreenHat litigation. In response, the Kittell Estate requested on October 5, 2021 that the FERC drop all enforcement action against the Estate, ban OE staff Messrs. Tabackman and Olson from any future involvement, and order other offices within the FERC to investigate. On October 6, 2021, OE Staff answer the October 5 motion. In addition, on October 8, 2021, Andrew Kittel's widow submitted a statement. This matter remains pending before the FERC.

[133] *GreenHat Energy, LLC et al.*, 175 FERC ¶ 61,138 (May 20, 2021) ("*GreenHat Show Cause Order*").

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

- **Powhatan Energy, HEEP Fund, CU Fund, and Chen (IN15-3)**

On October 29, 2021, the FERC approved a Stipulation and Consent Agreement between OE and Houlian Chen, HEEP Fund, Inc. and CU Fund, Inc. (collectively, the "Chen Defendants").[134] This Agreement resolves (i) the FERC's claims against the Chen Defendants for violations of its Anti-Market Manipulation Rules[135] and (ii) the FERC's lawsuit in the United States District Court for the Eastern District of Virginia to request an order affirming the *Powhatan Penalties Order*, *FERC v. Powhatan Energy Fund LLC, et al.*, No 3:15-cv-00452 (MHL) as it pertains to the Chen Defendants (Federal Court Lawsuit). The Chen Defendants agreed to pay disgorgement of $600,000, without either admitting or denying the alleged violations. The FERC directed the Chen Defendants to make the disgorgement payment within 10 days of the Effective Date of the Agreement and directed PJM to allocate the disgorged funds in its discretion for the benefit of PJM customers.

Natural Gas-Related Enforcement Actions

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

On March 18, 2021, the FERC issued a show cause order[136] 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 under NGA section 7(c).[137] The FERC directed Respondents to show cause why they should not be assessed civil penalties in the amount of ***$20.16 million***. On April 5, 2021, the FERC extended by 60 days, to June 18, 2021, the deadline for Respondents' answer. On June 18, 2021, Rover and ETP answered the *Rover/ETP Show 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. This matter is pending before the FERC.

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[134] *Houlihan Chen et al.*, 177 FERC ¶ 61,076 (Oct. 29, 2021).

[135] The FERC found, in *Houlian Chen, Powhatan Energy Fund, LLC, HEEP Fund, LLC, and CU Fund, Inc.*, 151 FERC ¶ 61,179 (May 29, 2015) ("*Powhatan Penalties Order*"), that Houlian "Alan" Chen, HEEP Fund, Inc., CU Fund, Inc., and Powhatan Energy Fund, LLC (together, "Powhatan Respondents") violated the FERC's Anti-Manipulation Rules by engaging in fraudulent UTC transactions in PJM's energy markets. The FERC ordered the disgorgement of profits with interest and the assessment of civil penalties as follows: Powhatan Energy Fund ($16.8 million civil penalty; $3.47 million disgorgement); CU Fund: ($10.08 million civil penalty; $1.08 million disgorgement); HEEP Fund ($1.92 million civil penalty; $173,100 disgorgement); H. Chen ($1 million civil penalty for trades executed through and on behalf of Powhatan and the Funds). OE alleged that, between June and August 2010, Powhatan Respondents engaged in manipulative Up To Congestion trading in PJM, trades which amounted to wash trading, long prohibited by the FERC. Specifically, Staff alleged that the transactions were designed to falsely appear to be spread trades, as a vehicle for collecting Marginal Loss Surplus Allocation ("MLSA") payments from PJM, by placing millions of megawatt hours of offsetting trades between the same two trading points, in the same volumes and the same hours—an intentional effort to cancel out the financial consequences from any spread between the two trading points while capturing large amounts of MLSA payments.

[136] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 174 FERC ¶ 61,208 (Mar. 18, 2021) ("*Rover/ETP Show Cause Order*").

[137] Specifically, Rover stated that it was "committed to a solution that results in no adverse effects" to the Stoneman House, an 1843 farmstead located near Rover's largest proposed compressor station. In truth, the OE Staff Report alleges, Rover was simultaneously planning to purchase the house with the intent to demolish it, if necessary, to complete its pipeline. The OE Staff Report alleges that Rover purchased the house in May 2015 and demolished the house in May 2016. The OE Staff Report further finds that despite taking these actions during the year and a half that Rover's application was pending before the FERC, Rover did not notify the FERC that it purchased the Stoneman House, intended to destroy the Stoneman House, and did destroy the Stoneman House. The OE Staff Report therefore concludes that Rover violated section 157.5's requirement for full, complete and forthright applications, through its misrepresentations and omissions, when it decided not to tell FERC that it had purchased the house and was considering demolishing it, and when Rover demolished it in May 2016 without notifying FERC.

- ***BP (IN13-15)***

On December 17, 2020, the FERC issued *Opinion 549-A*,[138] a 159-page decision addressing arguments raised on rehearing requested of *Opinion 549.*[139] *Opinion 549-A* modifies the discussion in *Opinion 549*, but reaches the same the result (ultimately requiring BP to pay a ***$20.16 million civil penalty (roughly $24.4 million with accrued interest) and disgorge $207,169***). Of note, *Opinion 549-A* denied BP's motion to dismiss this enforcement action as time barred (by the five-year statute of limitations set forth in 28 U.S.C. § 2462), finding BP waived any statute of limitations defense by failing to raise it earlier in this proceeding.[140] 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.[141]

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[142] 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.[143]

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

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

[139] *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*")).

[140] *BP Penalties Allegheny Order* at P 1.

[141] *Id*. at P 319.

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

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

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.

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.[144] On July 27, Chief Judge Cintron designated Judge Suzanne Krolikowski as the Presiding ALJ and established an extended Track III Schedule[145] for the proceeding. Judge Krolikowski scheduled and convened on August 26, 2021 a prehearing conference in this proceeding.

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 described just below, Respondents and OE Staff moved to temporarily suspend the procedural schedule for about six weeks to "allow the Participants to direct all of their resources towards fully participating in settlement discussions." Chief Judge Cintron granted the motion, extending the hearing commencement and initial decision deadlines to September 26, 2022, and February 20, 2023, respectively.

Settlement Judge Procedures. On September 21, 2021, Chief Judge Cintron concurrently designated Judge Joel deJesus as Settlement Judge to explore the possibility of settlement. Three settlement conferences have been held (October 15, 25 and November 1); settlement discussions continue. In the meantime, the procedural deadlines in the hearing proceedings have been extended to support the settlement discussions.

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.
  - February 2, 2020 application for a certificate of public convenience and necessity pending; Iroquois requests on January 26, 2021 that the FERC act promptly and issue the certificate; National Grid and ConEd submit comments supporting Iroquois' application and request for action.
  - On May 27, 2021, FERC staff issued a notice that it will prepare an environmental impact statement ("EIS") for this Project, which will respond to comments filed on the Environmental Assessment, and plans to release that EIS on September 3, 3021.
  - On June 11, 2021, FERC staff issued a notice that it has prepared a draft EIS for this Project, which responds to comments on the September 30, 2020 Environmental Assessment, and with the exception of greenhouse gas ("GHG") emissions, concludes that approval of the proposed Project, with the mitigation measures recommended in the EIS, would not result in significant environmental impacts. FERC staff did not come to a determination of significance with regards to GHG emissions. Comments

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

[145] 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.

on the draft EIS were due on or before August 9, 2021. Since the last Report, 93 sets of individual comments were filed, bring to nearly 300 the number of individual comments have been filed. Algonquin responded to those comments on August 24, 2021.

- On September 2, 2021, FERC staff modified the issuance date of its final EIS for the Project, due to the "complexity of comments received on the draft EIS". Issuance of a final EIS is now expected on November 12, 2021; the 90-day Federal Authorization Decision Deadline, February 9, 2022.
- On September 3, 2021, FERC staff issued environmental information request #4, to which Iroquois responded on September 13, 2021.
- On October 15, 2021, Iroquois submitted a supplemental Life Cycle Greenhouse Gas Analysis Report.

- ***Atlantic Bridge Project (CP16-9)***
  - On February 24, 2020, the FERC authorized Algonquin Gas Transmission, LLC ("Algonquin") and Maritimes & Northeast Pipeline, LLC ("Maritimes") to place facilities associated with the Atlantic Bridge Project into service.[146] Rehearing of the *Authorization Order* was timely requested, but denied by operation of law.
  - *Briefing Order*. In a fairly unprecedented order issued February 18, 2021,[147] the FERC, expressing concerns regarding operation of the project, established briefing on the following matters:
    - In light of the concerns expressed regarding public safety, is it consistent with the FERC's responsibilities under the NGA to allow the Weymouth Compressor Station to enter and remain in service?
    - Should the Commission reconsider the current operation of the Weymouth Compressor Station in light of any changed circumstances since the project was authorized? For example, are there changes in the Weymouth Compressor Station's projected air emissions impacts or public safety impacts the Commission should consider? We encourage parties to address how any such changes affect the surrounding communities, including environmental justice communities.
    - Are there any additional mitigation measures the Commission should impose in response to air emissions or public safety concerns?
    - What would the consequences be if the Commission were to stay or reverse the *Authorization Order*?
  - Requests for rehearing of the *Briefing Order* were filed by Algonquin, NGSA and Center for Liquefied Natural Gas, and by America and Energy Infrastructure Council. Cheniere Energy submitted comments in support of the requests for rehearing. On April 19, 2021, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[148] The Notice confirmed that the 60-day period during which a petition for review of its *Briefing Order* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of the *Briefing Order*. The Notice also indicated that the FERC would address, as is its right, the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper." On May 19, the FERC issued that order,[149] dismissing the requests for rehearing of the *Briefing Order*, noting, over the objection of Commissioner Danly, that the *Briefing Order* was an exercise of the FERC's continuing oversight of the Project (meaning the claimed harms

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[146] *Algonquin Gas Transmission, LLC*, Docket No. CP16-9 at 1 (Sep. 24, 2020) (delegated order) ("*Authorization Order*").

[147] *Algonquin Gas Transmission, LLC and Maritimes & Northeast Pipeline, LLC*, 174 FERC ¶ 61,126 (Feb. 18, 2021) ("*Briefing Order*").

[148] *Algonquin Gas Transmission, LLC and Maritimes & Northeast Pipeline, LLC*, 175 FERC ¶ 62,022 (Apr. 19, 2021) ("*April 19 Notice of Denial of Rehearings by Operation of Law*").

[149] *Algonquin Gas Transmission, LLC and Maritimes & Northeast Pipeline, LLC*, 175 FERC ¶ 61,150 (May 19, 2021) ("*May 19 Order*").

would be speculative and premature) and Algonquin and Trade Associations will have an opportunity to submit, if they choose, in requests for rehearing of any final decision by the Commission in this proceeding. Algonquin petitioned the DC Circuit for review of the *Briefing Order* and the notice of denial by operation of law on May 3, 2021 (*see* Section XVI below).

- Requests for rehearing of the *May 19 Order* were filed by Algonquin and INGAA. On July 16, 2021, the FERC issued a Notice of Denial of Rehearings by Operation of Law of the requests for rehearing of the *May 19 Order*.
- Algonquin also petitioned the DC Circuit for review of the *Briefing Order*, *April 19 Notice of Denial of Rehearings by Operation of Law*, and the *May 19 Order*.[150]
- This matter is before the DC Circuit (*see* Section XVI below).

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.[151] 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*.[152] 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,[153] 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.[154] 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

[150] *Algonquin Gas Transmission, LLC and Maritimes & Northeast Pipeline, LLC*, 176 FERC ¶ 62,029 (July 16, 2021) ("*July 16 Notice of Denial of Rehearings by Operation of Law*").

[151] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 167 FERC ¶ 61,007 (Apr. 2, 2019).

[152] *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).

[153] 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).

[154] *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*").

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.[155] On February 2, 2019, the 2nd Circuit vacated the decision of the NY DEC and remanded the case with instructions for the NY DEC to more clearly articulate its basis for the denial and how that basis is connected to information in the existing administrative record. The matter is again before the NY DEC.

- On November 26, 2018, the Applicants filed a request at FERC for a 3-year extension of time, until February 3, 2022, to complete construction and to place the certificated facilities into service. The Applicants cited the fact that they "do not anticipate commencement of Project construction until early 2021 due to New York's continued legal actions and to time lines required for procurement of necessary pipe and compressor facility materials." The extension request was granted on January 31, 2019.
- On August 8, 2019, the NY DEC again denied Applicants request for a Water Quality Certification, and as directed by the Second Circuit,[156] 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.[157]
- 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, [158] 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.[159]

XV. State Proceedings & Federal Legislative Proceedings

- **New England States' Vision Statement**

In October 2020, the six New England states released their "Vision Statement", outlining their vision for "a clean, affordable, and reliable 21st century regional electric grid" and committing to engage in a collaborative and open process, supported by NESCOE, intended to advance the principles discussed in the Vision Statement. As part of that effort, the following series of online technical forums to discuss the issues presented in the Vision Statement were held:

Jan 13, 2021	Wholesale Market Reform
Jan 25, 2021	Wholesale Market Reform
Feb 2, 2021	Transmission Planning

155 *Nat'l Fuel Gas Supply Corp. v. NYSDEC et al*. (2d Cir., Case No. 17-1164).

156 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).

157 *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).

158 *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 173 FERC ¶ 61,197 (Dec. 1, 2020).

159 *Id.* at P 10.

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 Participants Committee meeting and is posted on the ISO-NE website here.

XVI. Federal Courts

The following are matters of interest, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the federal courts (unless otherwise noted, the cases are before the U.S. Court of Appeals for the District of Columbia Circuit ("DC Circuit")). An "**" following the Case No. indicates that NEPOOL has intervened or is a litigant in the appeal. The remaining matters are appeals as to which NEPOOL has no organizational interest but that may be of interest to Participants. For further information on any of these proceedings, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Mystic ROE (21-1198)**
  Underlying FERC Proceeding: EL18-1639-010, -011[160]
  Petitioners: Mystic
  Status: Filing of Initial Submissions Underway

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%. On October 14, 2021, the Court ordered Mystic to file, and Mystic filed on October 29, a Docketing Statement Form, a Statement of Intent to Utilize Deferred Joint Appendix, a Statement of Issues to be Raised, the Underlying Decision from which the appeal arises. Appearances and Procedural Motions, if any, are due on or before November 15, 2021. A Certified Index to the Record and Dispositive Motions, if any, are due November 29, 2021.

- **ISO-NE Implementation of Order 1000 Exemptions for Immediate Need Reliability Projects (20-1422)**
  Underlying FERC Proceeding: EL19-90[161]
  Petitioner: LS Power
  Status: Briefing Complete; Pending Court Action

On October 16, 2020, LSP Transmission Holdings II, LLC ("LS Power") petitioned the DC Circuit Court of Appeals for review of the FERC's orders addressing ISO-NE's implementation of the Order 1000 exemptions for

[160] *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).*

[161] *ISO New England Inc., 171 FERC ¶ 61,211 (June 18, 2020) ("Order Terminating Proceeding")* (finding (i) "insufficient evidence in the record to find under FPA section 206 that [ISO-NE's] implementation of the exemption for immediate need reliability projects is unjust, unreasonable, or unduly discriminatory or preferential; (ii) "insufficient evidence in the record to find that ISO-NE implemented the immediate need reliability project exemption in a manner that is inconsistent with or more expansive than [the FERC] directed"; and (iii) that ISO-NE complies with the five criteria established for the immediate need reliability project exemption); and *ISO New England Inc.,* 172

immediate need reliability projects. Since the last Report, MMWEC filed on July 8 a notice that it would not submit a Reply Brief. On July 9, 2021, LSP Transmission filed Petitioner's Reply Brief. LSP Transmission filed a Joint Appendix on July 16. On July 28, 2021, MMWEC filed an Intervenor for Petitioner Final Brief. Final Briefs were filed on July 30, 2021. Briefing is now complete and this matter is pending before the Court.

- **CIP IROL Cost Recovery Rules (20-1389)**
  Underlying FERC Proceeding: ER20-739[162]
  Petitioner: Cogentrix, Vistra
  Status: Briefing Complete; Oral Argument Scheduled for Nov 12

On September 25, 2020, Cogentrix and Vistra petitioned the DC Circuit Court of Appeals for review of the FERC's orders allowing for recovery of expenditures to comply with the IROL-CIP requirements, but only those costs incurred on or after the effective date of the relevant individual FPA section 205 filing, including undepreciated costs of any such past capital expenditures to comply with the IROL-CIP requirements. Cogentrix and Vistra filed a Deferred Appendix (July 16, 2021) and Final Briefs (from Petitioners and the FERC) were submitted on July 26, 2021. Briefing is now complete. On September 22, 2021, the Court scheduled oral argument for Friday, November 12, 2021. The argument panel will be comprised of Judges Srinivasan, Katsas and Randolph.

- **Mystic 8/9 Cost of Service Agreement (20-1343; 20-1361, 20-1362; 20-1365, 20-1368; 21-1067; 21-1070)(consolidated)**
  Underlying FERC Proceeding: EL18-1639[163]
  Petitioners: Mystic (20-1343), NESCOE (20-1361, 21-1067), MA AG (20-1362), CT Parties (20-1365, 20-1368, 21-1070)
  Status: Briefing Underway

Mystic, NESCOE, MA AG, and CT Parties have separately petitioned the DC Circuit Court of Appeals for review of the FERC's orders addressing the COS Agreement among Mystic, ExGen and ISO-NE.[164] The cases have been consolidated into Case No. 20-1343. On February 17 and 24, 2021, the Court consolidated with 20-1343 the most recent appeals in cases 21-1067 (NESCOE) and 21-1070 (CT Parties), respectively. On March 25, 2021, the Court issued an order returning this case to its active docket. On March 26, the Court granted the interventions by MMWEC/NHEC, NESCOE, and ENECOS. On April 16, 2021, the Court ordered the parties to file, and the parties did file, by May 17, 2021, proposed formats for the briefing of these cases.

On June 23, 2021, the Court established a briefing schedule. Thus far, FERC filed a Certified Index to the Record (on July 12, 2021); Mystic and State Petitioners filed Opening Briefs (September 7, 2021); and Intervenor for State Petitioners filed their Brief (September 21, 2021). Next up are Respondent's (FERC's) Brief (December 6, 2021); Intervenors for Respondents' Briefs (December 20, 2021); Reply Briefs (February 3, 2022); Joint Appendix (February 17, 2022); and Final Briefs (February 24, 2022). The date for oral argument and the composition of the merits panel will be identified at a later time.

FERC ¶ 61,293 (Sep. 29, 2020) *("Order 1000 Exemptions Allegheny Order")* (addressing arguments raised by request for rehearing denied by operation of law, modifying discussion in *Order Terminating Proceeding,* but reaching same result).

[162] *ISO New England Inc.*, 171 FERC ¶ 61,160 (May 26, 2020) ("*CIP IROL Cost Recovery Order*") and *ISO New England Inc.*, 172 FERC ¶ 61,251 (Sep. 17, 2020) ("*CIP IROL Allegheny Order*", and together with the CIP IROL Cost Recover Order, the "*CIP IROL Orders*").

[163] *July 2018 Order*; *July 2018 Rehearing Order*; *Dec 2018 Order*; *Dec 2018 Rehearing Order; Jul 17 Compliance Order*.

[164] 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.

- ***CASPR* (20-1333, 20-1331) (consolidated)****
  Underlying FERC Proceeding: ER18-619[165]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF
  Status: Being Held in Abeyance (until June 1, 2022)

On August 31, 2020, the Sierra Club, NRDC, RENEW Northeast, and CLF petitioned the DC Circuit Court of Appeals for review of the FERC's order accepting ISO-NE's CASPR revisions (which, under *Allegheny*, is ripe for review). On October 2, 2020, appearances, docketing statements, a statement of issues to be raised, and a statement of intent to utilize deferred joint appendix were filed. On October 19, 2020, the FERC moved to dismiss the case for a lack of jurisdiction (arguing that Petitioners missed their opportunity to timely file their Petition for review in 2018, and filing within 60 days of *Allegheny* did not make their Petition timely). Alternatively, the FERC asked that the case be held in abeyance for 60 days pending issuance of a further FERC order on this matter. On October 29, Petitioners opposed the FERC's motion. On November 5, 2020, the FERC filed a reply, indicated that an order on rehearing would be issued imminently and suggested that, if the Court declines to dismiss the petition, it should be held in abeyance until the Commission issues an order on rehearing. As noted above, the FERC issued the *CASPR Allegheny Order* on November 19, modifying the discussion in the *CASPR Order*, but reaching the same the result. The Sierra Club, NRDC and CLF also requested rehearing of the November 19 order.

On January 12, 2021, the Court dismissed as moot the FERC's October 19 motion to hold this proceeding in abeyance and ordered that the motion to dismiss be referred to the merits panel (Judges Pillard, Katsas and Walker) and addressed by the parties in their briefs. On January 25 and 26, CT Parties and MMWEC and NHEC filed statements of issues and notices that they intend to participate in support of Petitioners. On January 27, the Court ordered the parties to submit by February 26, 2021, proposed formats for the briefing of these cases. On March 24, 2021, the Court granted NEPOOL's intervention and established a briefing schedule that, as explained just below, has since been superseded.

On April 7, 2021, the Court granted Petitioners' motion to hold this matter in abeyance, pending further order of the Court. The parties were directed to file motions to govern future proceedings in these cases on or before October 22, 2021. On October 22, 2021, Petitioners Sierra Club, NRDC, Renew Northeast, Inc., and CLF moved the Court to hold this matter in abeyance until June 1, 2022. On October 25, 2021, the Court granted Petitioners' second motion to hold this matter in abeyance. The parties were directed to file motions to govern future proceedings in these cases on or before June 1, 2022.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[166]
  Petitioners: TOs' (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[167] 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*[168] decision. On September 22, 2020, the FERC submitted an unopposed motion to hold this proceeding in abeyance for four months to allow for the Commission to "a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the Commission." On October 2, 2020, the Court granted the FERC's motion, and directed the parties to file motions to govern future proceedings in this case by February 2, 2021. On January 25, 2021, the FERC requested that the Court continue to hold this

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

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

[167] 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.

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

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. On August 24, the FERC submitted a status report indicating that the proceedings before the Commission remain ongoing and that this appeal should continue to remain in abeyance.

- **2013/14 Winter Reliability Program Order on Compliance and Remand (20-1289, 20-1366) (consol.)**
  Underlying FERC Proceeding: ER13-2266[169]
  Petitioner: TransCanada
  Status: Briefing Complete; Oral Argument Held Oct 15

On July 30, 2020, TransCanada Power Marketing ("Petitioner" or "TransCanada") again petitioned the DC Circuit Court of Appeals for review of the FERC's action on the 2013/2014 Winter Reliability Program, this time in the FERC's April 1, 2020 *2013/14 Winter Reliability Program Order on Compliance and Remand*.[170] NEPGA intervened on October 15, 2020 (and its intervention granted on October 28). On October 16, TransCanada filed a docketing statement and statement of issues. On October 29, the FERC filed a certified index to the record and an unopposed motion for a 60-day briefing period. On December 2, 2020, the Court granted the FERC's October 29 motion. On January 11, 2021, TransCanada submitted its initial brief. On March 12, FERC filed its Respondent Brief. Since the last Report, TransCanada filed Petitioner's Reply Brief on April 9, 2021 and the Deferred Appendix on April 16. TransCanada filed its Final Brief on April 30, 2021. Briefing is now complete. Since the last Report, oral argument was held Friday, October 15, 2021 before Judges Srinivasan, Henderson and Edwards.

- **ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224***; 19-1247; 19-1252; 19-1253)(consolidated); Underlying FERC Proceeding: ER19-1428**[171]
  Petitioners: ENECOS (Belmont et al.) (19-1224); MA AG (19-1247); NH PUC/NH OCA (19-1252); Sierra Club/UCS (19-1253)
  Status: Briefing Complete; Oral Argument Held Oct 21

As previously reported, at the unopposed request of the FERC, the Court issued an order suspending the previous briefing schedule and remanding the record back to the FERC. Subsequently, the FERC issued its *IEP Remand Order* (June 18, 2020) and its Notice of Denial by Operation of Law of the requests for rehearing of its *IEP Remand Order* (August 20, 2020). As previously reported, each of the Petitioners filed amended petitions for review in the consolidated proceeding in order to bring the FERC's *IEP Remand Order* and the post-remand FERC record before the DC Circuit. On November 10, 2020, the Court ordered that the cases be removed from abeyance. Opening Briefs from Petitioners were filed on December 11, 2020. The FERC filed its Respondent Brief

[169] 171 FERC ¶ 61,003 (Apr. 1, 2020) ("*2013/14 Winter Reliability Program Order on Compliance and Remand*") (accepting ISO-NE's January 23, 2017 compliance filing, finding that the bid results from the 2013/14 Winter Reliability Program were just and reasonable, and providing for this finding the further reasoning requested by the DC Circuit in *TransCanada Power Mktg. Ltd. v. FERC*, 811 F.3d 1 (DC Cir. 2015) ("*TransCanada*").)

[170] In TransCanada, the DC Circuit granted TransCanada's prior petition in part, and directed the FERC to either better justify its determination or revise its disposition to ensure that the rates under the Program are just and reasonable. *TransCanada* at 1.

[171] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

on February 9. Intervenor for Respondent Briefs were filed on February 16 by ISO-NE and NEPGA. On February 24, the FERC filed an amended certified index to the record. Petitioners' Reply Brief was filed on March 30, 2021. The Deferred Appendix was filed on April 20, 2021. Final Briefs were filed on May 4, 2021. Briefing is now complete. Since the last Report, oral argument was held October 21, 2021 before Judges Wilkins, Katsas and Jackson.

Other Federal Court Activity of Interest

- ***Order 872*** **(20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[172]
  Petitioners: SEIA et al.
  Status: Briefing Again Underway

On September 17, 2020, SEIA petitioned the 9th Circuit Court of Appeals for review of *Order 872*.[173] On October 9, the FERC filed an unopposed motion for the Court to hold this appeal in abeyance, suspend filing of the certified index to the record, and issue a new briefing schedule after January 4, 2021. The abeyance was to permit the FERC to address the pending rehearing requests in a future order. On October 26, 2020, the Court granted the FERC's motion. On January 29, 2021, SEIA requested that this case be consolidated with the others, and that the abeyance period be extended to give the parties additional time to coordinate and develop a unified, efficient briefing schedule.

On March 25, 2021, the Court granted SEIA's unopposed March 5, 2021 motion to lift the stay in this proceeding. Briefing has resumed. On May 27, 2021, Petitioners' briefs were filed by SEIA and Other Petitioners.[174] On June 28, 2021, petitioner-intervenors filed their joint brief and (June 28, 2021); motions and associated briefs by amici curiae in support of petitioners were also filed on June 28, 2021. NewSun Energy filed an Intervenor Brief on July 28. Since the last Report, Respondent's brief was filed on September 27. Next up will be: joint brief of respondent-intervenors (October 27, 2021); motions and associated briefs by amici curiae in support of respondent (October 27, 2021); and any optional reply briefs (December 13, 2021).

- **PennEast Project (18-1128)**
  Underlying FERC Proceeding: CP15-558[175]
  Petitioners: NJ DEP, DE and Raritan Canal Commission, NJ Div. of Rate Counsel
  Status: Motion to Hold Proceedings in Abeyance Pending

The Supreme Court proceedings up on which abeyance in this proceeding had been based ended on August 2, 2021. The parties filed a motion to govern future proceedings on September 1, 2021, suggesting that supplemental briefing was in order. On September 13, 2021, the Court ordered that Petitioners and Respondents file supplemental briefs on November 12, 2021.

On October 29, FERC and Petitioners NJ DEP, DE and Raritan Canal Commission, NJ Conservation Foundation and The Watershed Institute, NJ Division of Rate Counsel, Township of Hopewell, NJ and ConEd (collectively, "Movants") requested that the Court suspend the supplemental briefing schedule entered on September 13, 2021 and hold this consolidated case in abeyance, with motions to govern due on February 18,

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

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

[174] "Other Petitioners" are Montana Environmental Information Center, Sierra Club, Center for Biological Diversity, Vote Solar, Appalachian Voices, Energy Alabama, Georgia Interfaith Power & Light, North Carolina Sustainable Energy Association, Upstate Forever, and Community Renewable Energy Association.

[175] *PennEast Pipeline Co., LLC*, 162 FERC ¶ 61,053 (Jan. 19, 2018), *reh'g denied*, 163 FERC ¶ 61,159 (May 30, 2018).

2022. That motion 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[176]
  Petitioners: MISO TOs, Transource Energy, Dec 23 Petitioners et al.
  Status: Briefing Complete; Oral Argument Scheduled for Nov 18

The MISO Transmission Owners (TOs), Transource and "Dec 23 Petitioners",[177] among others, have appealed *Opinion 569/569-A*. The MISO TOs' case has been consolidated with previous appeals that had been held in abeyance, with the lead case number assigned as 16-1325. The FERC filed a certified Index to the Record on December 3, 2020, the Parties filed a joint unopposed briefing schedule on December 23, 2020. Statements of issues were filed on February 8, 2021. Petitioners' Briefs were filed on March 10. On March 17, 2021, a motion to participate as amicus curiae was jointly filed by NEP, CPM, Eversource, Fitchburg and Unitil, NHT, VTransco, Versant Power, and UI ("New England Parties") (that motion was granted on April 30, 2021). On March 18, New England Parties submitted an amicus brief in support of Transmission Owning Petitioners. On March 24, 2021, Intervenors in Support of Petitioners[178] filed their Brief. FERC filed its Respondent brief on June 8 and Intervenors in Support of FERC their Joint Brief on June 22, 2021. Petitioners' and Joint Petitioners' Reply Briefs were filed on July 8, 2021; Intervenors in Support of Petitioners Reply Briefs, July 22, 2021. The Joint Deferred Appendix was filed on August 5, 2021; Final Briefs on August 19, 2021. Briefing is now complete. On September 22, 2021, the Court scheduled oral argument for November 18, 2021. On October 29, 2021, the Court allotted time limits for the November 18 oral argument before Judges Srinivasan, Katsas and Walker.

- **Algonquin Atlantic Bridge Project Briefing Order (21-1115*, 21-1138, 21-1153, 21-1155) (consol.);**
  Underlying FERC Proceeding: CP16-9-012[179]
  Petitioners: LS Power, Algonquin, INGA
  Status: Case Being Held in Abeyance

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 August 27, 2021, the Court granted a second abeyance motion by the FERC, directing the parties to file motions to govern future proceedings by October 29, 2021.

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[176] *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).

[177] "Dec 23 Petitioners" are: Assoc. of Bus. Advocating Tariff Equity; Coalition of MISO Transmission Customers: IL Industrial Energy Consumers; IN Industrial Energy Consumers, Inc.; MN Large Industrial Group; WI Industrial Energy Group; AMP; Cooperative Energy; Hoosier Energy Rural Elec. Coop.; MS Public Service Comm.; MO Public Service Comm.; MO Joint Municipal Electric Utility Comm.; Organization of MISO States, Inc.; Southwestern Elec. Coop., Inc.; and Wabash Valley Power Assoc.

[178] The Intervenors for Petitioners Brief was filed by Citizens Utility Board of Wisconsin, Illinois Citizens Utility Board, Indiana Office of Utility Consumer Counselor, Iowa Office of Consumer Advocate, Louisiana Public Service Commission, Michigan Citizens Against Rate Excess, Minnesota Department of Commerce, and Missouri Office of Public Council.

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

INDEX
Status Report of Current Regulatory and Legal Proceedings as of November 2, 2021

COVID-19

I. Complaints/Section 206 Proceedings

II. Rate, ICR, FCA, Cost Recovery Filings

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

IV. OATT Amendments/Coordination Agreements

V. Financial Assurance/Billing Policy Amendments

VI. Schedule 20/21/22/23 Updates

VII. NEPOOL Agreement/Participants Agreement Amendments

VIII. Regional Reports

IX. Membership Filings

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

XI. Misc. Regional Interest

XII. Misc: Administrative & Rulemaking Proceedings

XIII. FERC Enforcement Proceedings

XIV. Natural Gas Proceedings

XV. State Proceedings & Federal Legislative Proceedings

XVI. Federal Courts