NEPOOL
NEW ENGLAND POWER POOL
David T. Doot
Secretary

April 28, 2022

VIA ELECTRONIC MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of May 5, 2022 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 May meeting of the Participants Committee will be held ***in person*** **on Thursday, May 5, 2022, at 10:00 a.m. at the Seaport Boston Hotel, 1 Seaport Lane, Boston, MA in the Seaport Ballroom** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/. **Please note that, as indicated on the Final Agenda, the first agenda item will be held in confidential executive session, beginning at 10:00 a.m., for members and alternate members or their delegates only, to consider a confidential slate of candidates for election to the ISO Board, as recommended by the Joint Nominating Committee. For all other attendees, the general session is planned to begin at 10:30 a.m.**

For your information, the May 5 meeting, other than the meeting's executive session, will be recorded. NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, consumer advocates that are not members, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those participating in the meeting are required to identify themselves and their affiliation during the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.

For those who otherwise attend NEPOOL meetings but are unable to attend the May 5 meeting in person, virtual participation for the general session beginning at 10:30 a.m. will be available using the following dial-in information: **866-803-2146; Passcode: 7169224.** We encourage those participating virtually also log in to WebEx using this link and entering the event password **nepool.**

There are a limited number of rooms available at the Seaport Boston Hotel for the evening before the May 5 meeting at the rate of $289.00 per night, on a first-come, first-served basis through tomorrow, **Friday, April 29, 2022**. Please make your reservation here or contact the hotel directly (1-877-732-7678) and reference the "**New England Power Pool**" block of rooms.

Looking ahead, the 2022 Participants Committee Summer Meeting, will be held in person at The Samoset Resort, Rockport, ME, from June 21-23, 2022 (coffee & dessert on Monday evening, June 20). Detailed information regarding the Summer Meeting, including a link to the registration page and the hotel reservations block, will be circulated under separate cover tomorrow.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

Discussion on Item 1 will be held in executive session, during which participation will be limited exclusively to voting Members and Alternates, or their designates.

1. To consider a confidential slate of candidates for election to the ISO Board, as recommended by the Joint Nominating Committee. Background materials and a draft resolution are included with this supplemental notice for this meeting. Confidential information will be circulated to Members and Alternates under separate cover. Per direction of the Participants Committee and consistent with past practice, voting on the slate of ISO Board candidates will be conducted electronically by confidential, written ballot (a form of which is included with this supplemental notice).

The remainder of the meeting will be in general session, which is expected to begin at 10:30 a.m.:

2. To approve the draft minutes of the April 7, 2022 Participants Committee meeting. A copy of the draft minutes, marked to show the changes since the version circulated with the initial notice, is included with this supplemental notice.

3. There is **NO Consent Agenda** for this meeting.

3A. To consider and take action, as appropriate, on the following actions recommended by the Reliability Committee that, but for timing of the RC's action, would have been on the Consent Agenda:

    i. Revisions to OP-14 (addition of a reference to NX-12 and an exemption for DNE Dispatchable Generators and Continuous Storage Facilities).

    ii. Revisions to OP-18 (edits resulting from biennial review -- formatting and grammatical changes, updated references and terminology, and documentation of existing metering requirements for Alternative Technology Regulating Resources).

    iii. Revisions to PP5-6 (revisions clarifying treatment of facility re-dispatch under certain specific circumstances within the interconnection study and voltage response when interconnecting Distributed Energy Resources.

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

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

5. To receive a report from the ISO Chief Operating Officer. The May COO report will be circulated and posted in advance of the meeting.

[continued on next page]

FINAL AGENDA (cont.)

6. To consider and take action, as appropriate, on changes to the following proposed by Competitive Power Ventures to address Performance-Based Non-Commercial Capacity Financial Assurance requirements:

   a. Market Rule 1 §§ III.13.1.1.2.2.2, III.13.1.1.2.4 and III.13.3.2.2; and

   b. Financial Assurance Policy §§ VII.B and VII.D.

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

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

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

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

9. Administrative matters.

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

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.

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.

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Dave Doot and Pat Gerity, NEPOOL Counsel and Balloting Agent

DATE: April 28, 2022

RE: Vote on Recommended Slate of Candidates for ISO New England Board of Directors

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Participants will be asked at the May 5, 2022 Participants Committee (NPC) meeting to consider endorsing a two-person slate of candidates for the ISO Board recommended by the Joint Nominating Committee (JNC). The slate was identified in a confidential package circulated tonight under confidential cover to Members and Alternates only. A NEPOOL endorsement of the slate requires a 70% Vote of the NPC. If NEPOOL endorses the slate, it will then be presented to the ISO Board for final vote.

The process for selecting ISO Board members is set forth in the Participants Agreement. Under that Agreement, the JNC is convened to recommend a slate of candidates for NEPOOL's endorsement. The JNC is comprised of seven incumbent ISO Board members, the NPC Chair and Vice-Chairs (or their designees), and a representative of the New England Conference of Public Utilities Commissioners, who this year was Matthew Nelson, Massachusetts Department of Public Utilities Chairman. Mr. Brook Colangelo chaired the JNC. The confidential package circulated to Members and Alternates includes a transmittal memorandum from Mr. Colangelo that further describes the JNC process, the candidates' backgrounds and additional relevant information.

Per the Participants Agreement and prior direction from the NPC, discussion on this matter will be held in executive session, during which only representatives of NEPOOL Participants are to be participating. Each Participant's vote will be registered confidentially by written ballot, rather than through a roll call. You can vote on or before the end of the executive session next Thursday, by returning a completed ballot to us immediately following the end of the executive session discussion on this matter or electronically, either by completing the form of e-mail ballot either "in favor" or "not in favor" and e-mailing by reply e-mail to pmgerity@daypitney.com, or by completing the Word version of the form of ballot and e-mailing it to pmgerity@daypitney.com. For a completed ballot to be counted, we must receive it before or immediately following the end of the executive session on this matter or 10:30 a.m. on May 5, whichever is later. If more than one completed ballot is received from a Participant, we will count only the last ballot received. NEPOOL Counsel will announce the outcome vote either as "passed" or "failed" before the conclusion of the May 5 meeting, based on completed ballots received. ***Out of respect for the rights of the new ISO Board nominee, all Participant representatives are requested to keep the identity of that nominee in confidence until the ISO publicly announces the results of its Board election (following a NPC endorsement vote AND final election by the ISO Board).***

If the NPC does not endorse the slate, the Participants Agreement contemplates that Participants will provide feedback to the JNC for its consideration in recommending a second slate. In order to provide such feedback in that event, the NPC members who have not otherwise already volunteered their positions either to a NEPOOL Officer or during the discussions in executive session will be polled confidentially by a NEPOOL Officer.

The following form of resolution for NPC action on this matter is contained in the ballots to be used:

> RESOLVED, that the Participants Committee endorses the slate of candidates for the ISO Board that has been recommended by the Joint Nominating Committee and presented to the Participants Committee in executive session at this meeting.

NEPOOL
NEW ENGLAND POWER POOL
Participants Committee

May 5, 2022

FORM BALLOT ON
ISO BOARD OF DIRECTORS NOMINEES

Instructions

Each Participant is entitled to cast a confidential ballot either “in favor” or “not in favor” of the resolution to endorse the slate of candidates recommended by the Joint Nominating Committee, as identified in the confidential supplemental materials for the May 5, 2022 NEPOOL Participants Committee Meeting circulated to Committee voting members and alternates.

Ballots may be returned by e-mail to pmgerity@daypitney.com no later than 10:30 a.m., Thursday, May 5, 2022.

Ballot

The undersigned Participant through its duly authorized representative hereby votes as shown below for the election of the slate of candidates for the ISO Board of Directors as provided in the resolution as follows:

> RESOLVED, that the Participants Committee endorses the slate of candidates for the ISO Board that has been recommended by the Joint Nominating Committee and presented to the Participants Committee in executive session at this meeting.

☐ In favor ☐ Not in favor

Participant Information

Participant Name:

Sector:

By (Name):

Its*

* Voting Member / Alternate / Proxy / Duly Authorized Officer

Please indicate one (by using drop down field if completing electronically or by circling if completing a paper copy)

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Thursday, April 7, 2022, at the Seaport Hotel, One Seaport Lane, Boston, Massachusetts. A quorum, determined in accordance with the Second Restated NEPOOL Agreement, was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the meeting, either in person or by phone.

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

IN MEMORIAM – ANGIE O’CONNOR

Mr. Doot began the meeting with a tribute to Ms. Angie O’Connor, who he described as a force within the New England energy sector for nearly 25 years, and who had tragically passed away on March 23, 2022. He reflected on her contributions and impact as a representative for consumers, generators and, as the Chair of the Massachusetts Department of Public Utilities and NESCOE Manager, for the Commonwealth of Massachusetts and the New England region. He described how Ms. O’Connor touched the lives of many around the NEPOOL table and how she embodied the best of the collaborative process. He summarized the feelings of many of those around the table by noting that Ms. O’Connor would long be remembered and sorely missed.

JOINT NOMINATING COMMITTEE

Mr. Brook Colangelo, ISO Board Member, and Chair of the Joint Nominating Committee (JNC) and the ISO Board’s Nominating and Governance Committee, who was joined at the meeting by fellow Board members Ms. Cheryl LaFleur and Mr. Mark Vannoy, began by thanking Participant and state members of the JNC for their collegiality in identifying candidates for the slate of Directors to be elected in 2022. He reminded the Committee that Mr. Barney

Rush and Ms. Vickie VanZandt, who would each reach their term limits later that year, and Ms. LaFleur was eligible for re-election to a second term. In anticipation of those retirements, the Board was temporarily expanded by one Board member in 2021, with the expectation that only one seat vacated at the end of 2022 would be filled by a new member, thereby restoring the Board to its original number of members. At the JNC's first meeting in January for the 2022 cycle, the JNC agreed to seek candidates based on two main characteristics - leadership and diversity. The JNC worked with Russell Reynolds, identified four possible candidates and interviewed those candidates on March 24 and 25. From those interviews, the JNC had identified its preference for a candidate to fill the one seat that would open by Board member retirement. Information regarding that preference and the potential candidate had been shared confidentially with Sector members.

Turning to the candidacy for re-election of Ms. LaFleur, Mr. Colangelo summarized Ms. LaFleur's roles and accomplishments during her first Board term, including her service as current ISO Board Chair. He spoke highly of her leadership and her ability efficiently and effectively to draw out the views of all while maintaining progress in moving through important Board discussions and challenges. He highlighted her time commitment, dedication and continuous communications with the Board.

Following that summary, Mr. Colangelo introduced Ms. Cheryl LaFleur and invited her to offer her thoughts and comments. Ms. LaFleur provided an overview of her background and previous professional experience. She proceeded to describe her perspectives from her first term as a Board member and her views on the work facing the region ahead. She noted the challenges and opportunities that would come with the change in more than half the elected Board members in a span of three years and with the region's transition to a lower carbon future. She acknowledged the significance and value of the NEPOOL process, emphasizing the importance of effectively tackling challenges collectively, particularly in the face of the pressure and stress being imposed by the volume and significance of the markets and infrastructure efforts underway.

Following these remarks, the Chair invited questions from the members. In response to the subsequent questions, Ms. LaFleur highlighted the many challenges the region faces over the next few years and the need to work together to prioritize and focus on key issues. She indicated that discussions with Sectors were especially effective when the Sector focused its discussion on the two or three highest priority issues from that Sector's perspective. Ms. LaFleur then left the meeting.

Noting that there would be an opportunity at the end of the meeting to provide confidential feedback on Ms. LaFleur's proposed candidacy, Mr. Cavanaugh invited any last comments or questions. A representative for the New Hampshire Office of the Consumer Advocate (NH OCA) objected to the requirement that the identity of, and information concerning, new candidates for election to the Board be held in confidence until those candidates are elected by the ISO Board, noting the NH OCA view that such a limitation hinders selection of appropriate candidates. A member also voiced his continued objection to the requirement in the Participants Agreement that ~~that~~ NEPOOL vote on a nominated slate of candidates each year rather than on individual candidates.

Following discussion, Mr. Cavanaugh urged members to provide their JNC representatives their input on the candidacy of Ms. LaFleur and the new nominee conditionally identified by the JNC. He indicated that the JNC would consider feedback and following the ongoing background check of the potential new nominee, the JNC-recommended slate would be presented confidentially to the Committee for discussion in executive session and vote by ballot at its May 5 meeting.

APPROVAL OF MARCH 3, 2022 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the March 3, 2022 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of that meeting were unanimously approved as circulated.

CONSENT AGENDA

Mr. Cavanaugh referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved as circulated.

ISO CEO REPORT

In Mr. Gordon van Welie's absence, Mr. Cavanaugh referred the Committee to the summary of the ISO Board and Board Committee meetings that had occurred since the March 3 Participants Committee meeting and which had been circulated and posted in advance of the meeting. In response to a question about the ISO's plan to address ISO staffing vacancies, Ms. Maria Gulluni, ISO Vice President and General Counsel, noted the recent release of a comprehensive report about this topic. She reported that ~~recruitment~~ staff had been hired to assist with the recruitment process and that staff had been working with colleges and universities in support of internships and full-time job placement. She noted that the Legal Department was fully staffed and Market Developments had made significant hiring strides. There were no additional questions or comments.

ISO COO REPORT

Operations Highlights Report

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by referring the Committee to the April COO report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through March 30, 2022, unless otherwise noted. The report highlighted: (i) Energy Market value for March 2022 was $703 million, down $514 million from the updated February 2022 value and up $330 million from March 2021; (ii) March 2022 average natural gas prices were 54% lower than February average prices; (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for March ($66.67/MWh) were 39% lower than February averages; (iv) average March 2022 natural gas prices and Real-Time Hub LMPs over the period were both up 98% from March 2021 average prices; (v) average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 100.8% during March (up from the 99.3% reported for February), with the minimum value for the month of 94.3% on March 13; and (vi) Daily Net Commitment Period Compensation (NCPC) payments for March totaled $4.0 million, which was unchanged from February 2022 and up $1.8 million from March 2021. February NCPC payments, which were 0.6% of total Energy Market value, were comprised of $3.8 million in first contingency payments (down $9,000 from February 2022) and $202,000 in second contingency payments.

Discussing the status of transmission outages in the region, Dr. Chadalavada noted that line 329 (Frost Bridge to Southington) would be out from April 11 to April 30 and would restrict imports from New York to New England to 1,100 MW. The line 329 outage would overlap in time with the outage on line NY-2-AN (Alps to New Scotland) in New York.

Dr. Chadalavada discussed system operations on March 29, 2022, when the system experienced unexpectedly high morning prices. He reviewed slides summarizing system conditions and expectations going into the morning, forecast versus actual load and temperature, generator outages and reductions (roughly half were related to natural gas pipeline pressure issues), operator actions in response to the conditions, and the resulting LMPs and reserve pricing.

In response to questions on the March 29 summary, Dr. Chadalavada generally agreed that overall system posture would have been different had there been the possibility for co-optimized replacement, energy imbalance and/or generation contingency reserves scheduled Day-Ahead. He reminded the Committee of the challenges that arise because of differences in gas and electric market alignments, and how the ISO tries to account for those differences. He concurred with a member’s assessment that total energy prices would have been more in line with those experienced in the rest of the country had there been additional natural gas transmission capacity into New England. He provided additional information on the curtailments of gas-fired generators, noting the differences between the higher overnight dispatch amounts (for which additional gas nominations could not be made) and the Day-Ahead commitments. He explained that the steep morning ramp up and down was generally consistent with New England usage patterns (which had nearly, but not quite completely, returned to pre-pandemic patterns) and was not at that time of the day materially impacted by behind-the-meter solar photovoltaic resources~~PV~~. Finally, Dr. Chadalavada said that the extent to which the issues experienced on March 29 would have dissipated had some of the curtailed units been du~~e~~al-fuel and in a position to switch to oil was not perfectly clear. At a member’s request, he committed to explore and report back at the May meeting whether a distinction in Real-Time on-line reporting could be made between capacity from gas-only and dua~~e~~l-~~-~~fuel units.

Winter 2021-22 Operations Report

Dr. Chadalavada referred the Committee to the 2021-22 Winter Operations report, which had been circulated and posted in advance of the meeting. He highlighted the following: (i) the New England average winter temperature was 1.0°F above average, consistent with the National Oceanic and Atmospheric Administration's (NOAA's) seasonal outlook of above-average temperatures; (ii) overall energy demand (approximately 30 GWh) was similar to Winter 2020-21 and the most recent 5-year average, with actual peak load (19,623 MW) consistent with that forecasted (19,710 MW); (iii) there were no operational issues due to reductions in natural gas availability; (iv) a significant amount of fuel oil was utilized in January and early February (the ISO estimated that approximately 48% of fuel oil that was utilized throughout the winter had been replenished); (v) surplus generating capacity was available throughout the winter (there were no OP-4 (Capacity Deficiency) or OP-21 (Energy Alert or Energy Emergency) actions implemented during Winter 2021-22); and (vi) the ISO would continue to closely monitor global fuel markets, stored energy inventories, and weather forecasts in preparation for Winter 2022-23. To ensure preparedness, the ISO would work closely with transmission and distribution owners prior to Winter 2022-23 to conduct for the first time a tabletop exercise to evaluate existing operational processes and communication protocols that would be used during an energy emergency.

In response to a questions about oil use and replenishment, Dr. Chadalavada confirmed that replenishment occurred during the Winter, with 72% of the replacement No. 2 distillate fuel oil and 25% No. 6 light residual fuel oil. When asked about liquefied natural gas (LNG) sendout, Dr. Chadalavada confirmed it included the cumulative LNG injection expected plus the three additional cargos received in 2022.

Dr. Chadalavada then discussed the uncertainty of energy adequacy in the future and the challenges extreme weather changes would present. He referred to the project the ISO had undertaken with the Electric Power Research Institute (EPRI), encouraging Participant involvement. He was hopeful that the project, following Participant and State representative input, would provide a foundation for future courses of action. He confirmed that the ISO would not be doing an oil program, especially given the time frame and the use of the Mystic unit.

2022 ANNUAL WORK PLAN UPDATE

Next, Dr. Chadalavada referred the Committee to the 2022 Annual Work Plan update, which had been circulated and posted in advance of the meeting. He began by providing an update on the two market anchor projects -- Resource Capacity Accreditation (RCA) and Day-Ahead Ancillary Services. He reported that the RCA project would proceed as one initiative for FCA 19 rather than in two phases (for FCAs 18 and 19) as presented in the 2022 Annual Work Plan that was circulated last fall. The ISO expected to begin discussions on the RCA project in late-Q2/early-Q3, with plans for a detailed design to be defined by end of 2022. The ISO planned to file market rules reflecting a detailed design with the FERC by Q4 2023 for FCA 19.

Turning to the Day-Ahead Ancillary Services project, Dr. Chadalavada reported that the ISO was planning to outline major project components and timing with stakeholders in early Q2 2022. Discussions with stakeholders on design proposal would begin in Q4 and extend through 2023, with a FERC filing planned also by Q4 2023. He noted that, as previously indicated, the ISO planned~~s~~ to decouple the implementation timing from FCA 19 (the 2028-2029 Capacity Commitment Period), targeting implementation at the end of 2024 or the beginning of 2025.

Addressing the Pathways to the Future Grid efforts, he said that the ISO planned to issue the final report in April. Once that report was finalized, the ISO would seek consensus with the Participants and the States on a preferred pathway. He noted the particular importance of State input and participation in the assignment of roles and responsibilities given the overarching environmental and other objectives outside the scope of the ISO's mission.

Dr. Chadalavada then addressed the importance of priorities over the next 18 months. He noted that setting and sticking to priorities was critical to the ability to get all of the projects accomplished. He said that specific stakeholder requests had been collected, evaluated and the following projects included in the work plan: (i) return to service/retirement reforms; (ii) capacity resource performance; (iii) non-commercial financial assurance revisions; and (iv) the publication of public information from overlapping impact studies.

In response to questions and comments, Dr. Chadalavada added additional insight into the timing, sub-segments (concepts, details, impact analysis, and FERC filing) and opportunities for feedback and discussion during the RCA project. He acknowledged the importance and the complexity of the capacity resource performance issues. He confirmed that de-list bid price flexibility and the return to service/mothball efforts were not being linked and were on separate tracks. Dr. Chadalavada expressed confidence that the solar Do-Not-Exceed (DNE) ~~DNE~~ dispatch project would be implemented as scheduled in Q2 of 2023. He re-emphasized the importance of focusing priorities and the process for establishing or confirming those priorities.

LITIGATION REPORT

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

(i) The filing of and comments on the region's Order 2222 compliance filing;

(ii) The filing to eliminate the Minimum Offer Price Rule;

(iii) The FERC's denial of the waiver request by South Wrentham regarding closure of its availability window for participation in FCA 17;

(iv) The FERC's acceptance of the ISO's Exigent Circumstances filing, without change or condition;

(v) The filing of the FCA 16 auction results;

(vi) The complaint, filed by RENEW Northeast and the American Clean Power Association, urging the FERC to direct the establishment of new capacity requirements for certain types of resources and changes how they will be treated, with the ISO's response and replies due by April 14; and

(vii) The denial by the US Court of Appeals for the DC Circuit of LS Power's petition for review of the FERC's order accepting the ISO's implementation of Order 1000 exemptions for immediate need reliability projects.

COMMITTEE & OTHER REPORTS

Markets Committee (MC). Mr. William Fowler, the MC Vice-Chair, reported that the MC would meet virtually on April 12. Materials had been posted for that meeting and included a memo from Mr. Mark Karl regarding the Day-Ahead Ancillary Services project~~ESI ancillary services work~~. He noted that the meeting would include an overview of the stakeholder schedule, and he requested that members review the material prior to the meeting. He added that CPV's financial assurance proposal would also be discussed at that meeting.

Transmission Committee (TC). Mr. José Rotger, the TC Vice-Chair, reported that the next TC meeting was scheduled for April 14 and would include a discussion regarding allowing storage resource~~s~~ solutions to be selected for transmission and planning needs, Tariff redlines for the Order 881 compliance filing, which required owners to provide ambient air adjustment on transmission line ratings, and redlines to Schedules 22 and 23, to require all distribution projects to go through the state jurisdictional interconnection process. He urged members to respond to the Survey Monkey request regarding planned attendance for that in-person meeting.

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that the next regularly-scheduled RC meeting would take place in person on April 27 and would include a discussion of the FCA 16 results filling and the final determination of capacity zones for FCA 18.

Budget & Finance (B&F) Subcommittee. Mr. Thomas Kaslow, Subcommittee Chair, reported that the next B&F Subcommittee meeting was scheduled for April 21 and would include a discussion on the CPV financial assurance proposal.

NESCOE. Ms. Heather Hunt reported that the Pathways conversation began with the ISO Board's interest in carbon pricing and the study was requested to assist with the further assessment of the region's future needs. She expressed her appreciation for the sensitivity to the governance surrounding the topic.

ADMINISTRATIVE MATTERS

Looking ahead, Mr. Cavanaugh noted that the next Future Grid Pathways Study meeting was scheduled to take place on April 26 at the AC Hotel in Worcester, MA. The Participants Committee was scheduled to meet at the Seaport Hotel in Boston on May 5 for its monthly business.

Mr. Doot indicated that information about the Participants Committee Summer Meeting, which was scheduled for June 21-23 at the Samoset Resort in Rockport, Maine, would be released soon. He urged members to make their reservations early and encouraged members to bring their families given the long hiatus since the last in-person Summer Meeting.

FEEDBACK ON ISO BOARD MEMBER CANDIDATE (EXECUTIVE SESSION)

There being no other general business, the Committee went into executive session to afford Participants an opportunity to provide feedback confidentially on the one incumbent ISO Board Director whose term was scheduled to expire. Committee members provided that confidential feedback, and were encouraged to reach out to their Sector JNC representative with any remaining feedback. Prior to concluding the executive session, Mr. Doot noted the proposed schedule for consideration and action on the JNC-recommended slate.

There being no further business, the meeting adjourned at 1:00 p.m.

Respectfully submitted,

____
David Doot, Secretary

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN APRIL 7, 2022 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Melissa Birchard (tel)		
Advanced Energy Economy (AEE)	Associate Non-Voting	Caitlin Marquis (tel)		
Anbaric Development Partners LLC	Provisional Member		Theodore Paradise	
AR Large Renewable Gen. (RG) Group Member	AR-RG	Alex Worsley		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell		
AR Small Renew. Generation (RG) Group Member	AR-RG	Erik Abend (tel)		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
Associated Industries of Massachusetts (AIM)	End User			Mary Smith (tel)
AVANGRID: CMP/UI	Transmission	Alan Trotta	Jason Rauch	A. Novicki (tel)
Bath Iron Works Corporation	End User			Bill Short
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Borrego Solar Systems Inc.	AR-DG	Liz Delaney		
Boylston Municipal Light Department	Publicly Owned Entity		Brian Thomson	
BP Energy Company	Supplier			José Rotger (tel)
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Calpine Energy Services, LP	Supplier	Brett Kruse		Bill Fowler; John Flumerfelt (tel)
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Central Rivers Power	AR-RG		Dan Allegretti	
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
CleaResult Consulting, Inc.	AR-DG	Tamera Oldfield (tel)		
Clearway Power Marketing LLC	Supplier			Pete Fuller
Competitive Energy Services, LLC	Supplier		Eben Perkins (tel)	
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw (tel)		
Connecticut Office of Consumer Counsel	End User		Dave Thompson (tel)	Victor Owusu-Nantwi (tel)
Conservation Law Foundation (CLF)	End User	Phelps Turner (tel)		
Consolidated Edison Energy, Inc.	Supplier	Grant Flagler (tel)		
Constellation Energy Generation	Supplier	Steve Kirk (tel)	Bill Fowler	
CPV Towantic, LLC (CPV)	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger (tel)	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dominion Energy Generation Marketing	Generation	Michael Purdie		
DTE Energy Trading, Inc.	Supplier			José Rotger (tel)
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		Bill Fowler
Emera Energy Services	Supplier			Bill Fowler
Environmental Defense Fund	End User	Jolette Westbrook (tel)		
Eversource Energy	Transmission	James Daly (tel)	Dave Burnham	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger (tel)	Jeff Iafrati (tel)	
Garland Manufacturing Company	End User			Bill Short
Generation Group Member	Generation		Abby Krich	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Granite Shore Power Companies	Generation			Bob Stein
Great River Hydro	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned Entity		Brian Thomson	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN APRIL 7, 2022 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	Louis Guilbault (tel)	Bob Stein	
Hammond Lumber Company	End User			Bill Short
Harvard Dedicated Energy Limited	End User			Jason Frost
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Holyoke Gas & Electric Department	Publicly Owned Entity		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Ipswich Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths	Nancy Chafetz (tel)	
Jupiter Power	Provisional Member			Ron Carrier
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned Entity		Craig Kieny (tel)	
Long Island Lighting Company (LIPA)	Supplier		Bill Kilgoar (tel)	
Maine Power LLC	Supplier	Jeff Jones (tel)		
Maine Public Advocate’s Office	End User	Drew Landry (tel)		
Mansfield Municipal Electric Department	Publicly Owned Entity		Brian Thomson	
Maple Energy LLC	AR-LR			Doug Hurley
Marblehead Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Mass. Attorney General’s Office (MA AG)	End User	Tina Belew (tel)		
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Brian Thomson		
Mercuria Energy America, LLC	Supplier			José Rotger (tel)
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
National Grid	Transmission	Tim Brennan (tel)	Tim Martin	
Natural Resources Defense Council (NRDC)	End User	Bruce Ho (tel)		
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski		Brian Forshaw (tel)
New Hampshire Office of Consumer Advocate	End User		Jason Frost (tel)	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson		
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Power Marketing LLC	Supplier		Pete Fuller	
Nylon Corporation of America	End User			Bill Short
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Peabody Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PowerOptions, Inc.	End User			Jason Frost
Princeton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Brian Thomson	
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		

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PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN APRIL 7, 2022 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Brian Thomson	
South Hadley Electric Light Department	Publicly Owned Entity		Brian Thomson	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Brian Thomson	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Peter Fuller
Taunton Municipal Lighting Plant	Publicly Owned Entity	Devon Tremont (tel)	Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Tenaska Power Services Co.	Supplier		Eric Stallings (tel)	
The Energy Consortium	End User	Bob Espindola (tel)	Mary Smith (tel)	
Union of Concerned Scientists	End User		Francis Pullaro (tel)	
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny (tel)		
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corp. (VEIC)	AR-LR		Doug Hurley	
Versant Power	Transmission	Lisa Martin (tel)		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Vitol Inc.	Publicly Owned Entity	Joe Wadsworth (tel)		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Brian Thomson	
Walden Renewables Development LLC	Generation			Abby Krich
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	

MEMORANDUM

TO: NEPOOL Participants Committee

FROM: Eric Runge, NEPOOL Counsel

DATE: April 27, 2022

RE: Vote on Revisions to Operating Procedures 14 and 18 and Planning Procedure 5-6

At the May 5, 2022 Participants Committee meeting you will be asked to vote to support revisions to ISO-NE Operating Procedure 14 ("OP-14 Revisions"), Operating Procedure 18 ("OP-18 Revisions") and ISO-NE Planning Procedure 5-6 ("PP 5-6 Revisions"). The Reliability Committee unanimously recommended Participants Committee support for the OP-14 Revisions, the OP-18 Revisions and the PP 5-6 Revisions at its April 27, 2022 meeting. These Revisions, as well as the ISO's presentations on them, can be accessed as follows:

- OP-14 Revisions: https://www.iso-ne.com/static-assets/documents/2022/04/a06_2_op_14.zip
- OP-18 Revisions: https://www.iso-ne.com/static-assets/documents/2022/04/a06_1_op_18.zip
- PP 5-6 Revisions: https://www.iso-ne.com/static-assets/documents/2022/04/a08_1_pp5_6.zip

These items, as described in more detail below, would have been on the Participants Committee Consent Agenda but for the timing of the meetings:

(i) The ***OP-14 Revisions*** are in the nature of corrections as part of ISO-NE's periodic review of the procedure. They include adding a reference to reporting data using the NX-12 form and an exemption for certain types of generators to certain required actions in emergencies.

(ii) The ***OP-18 Revisions*** are in the nature of clean-up, corrections and changes as part of the biennial review of the document, and include changes to document existing telemetry requirements for Alternative Technology Regulating Resources.

(iii) The ***PP 5-6 Revisions*** include clarification of treatment of facility re-dispatch in interconnection studies. More specifically, the ISO proposes to allow re-dispatch of distribution-connected generation facilities, under N-1-1 conditions (after the first contingency, in preparation for the second contingency), under the following circumstances in the interconnection study: where the first and second contingencies are for facilities connected to less than 100 kV and where the potential performance violation is for a facility less than 100 kV, re-dispatch of non-market generation and/or Settlement Only Resources may also be assumed in the assessment; and the assessment must confirm that such re-dispatch is operable and does not introduce any other performance violations. Additionally, the ISO is proposing revisions to power factor and voltage response requirements for certain generating facilities. Specifically, the ISO is proposing: (i) that all generating facilities greater than 5 MW (regardless of interconnection process) will be required to be capable of a composite power delivery at their maximum rated power output (maximum MW) at both the power factor of 0.95 leading and 0.95 lagging; and (ii) for all generating facilities greater than 5 MW, the study will assume that the generating facility's responsiveness to changes in voltage is active and in-service, unless the study identifies that such responsiveness cannot be activated (e.g. due to the pre-existing voltage control strategy for a distribution feeder).

The following forms of resolution could be used for Participants Committee action on the Revisions, either in a single vote, absent objection, or individually:

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

NEPOOL PARTICIPANTS COMMITTEE | 5/5/22
Meeting Agenda item #5

NEPOOL Participants Committee Report

May 2022

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: March 2022 Energy Market value totaled $722M
  - April 2022 Energy market value was $525M, down $197M from March 2022 and up $279M from April 2021
    - April natural gas prices over the period were 4.8% lower than March average values
    - Average RT Hub Locational Marginal Prices ($59.51/MWh) over the period were 10% lower than March averages
      - DA Hub: $61.51/MWh
    - Average April 2022 natural gas prices and RT Hub LMPs over the period were up 170% and 129%, respectively, from April 2021 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 98.2% during April, down from 100.8% during March*
    - The minimum value for the month was 92.5% on Sunday, April 17th**

Data through April 27th, unless otherwise noted

Underlying natural gas data furnished by:

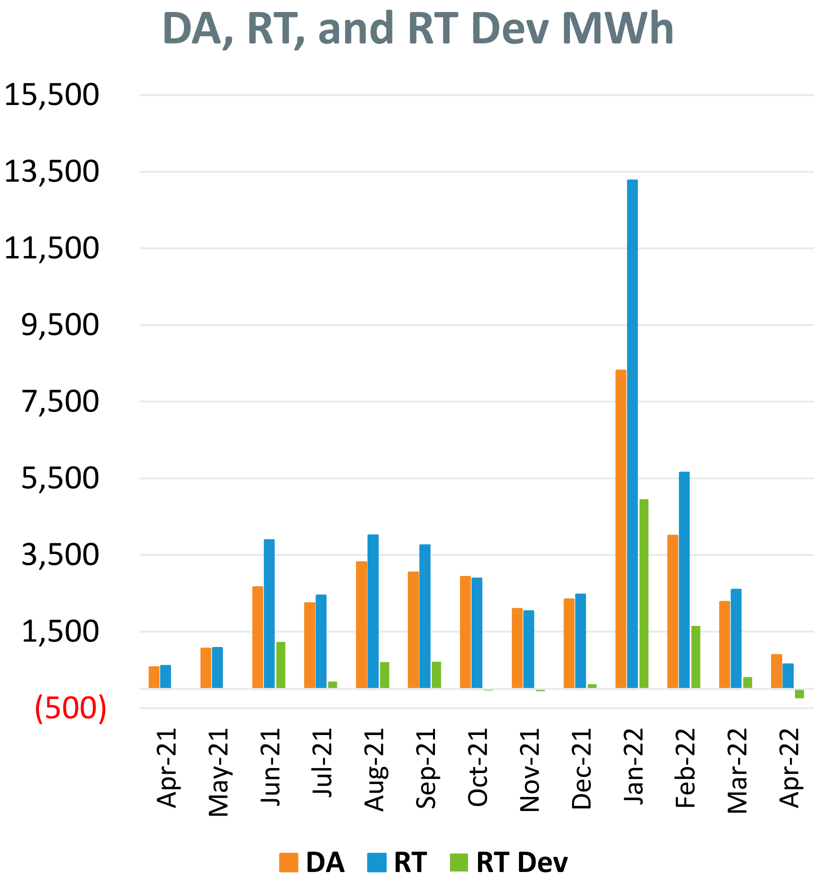
*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market
**Daily values shown on current slide 19

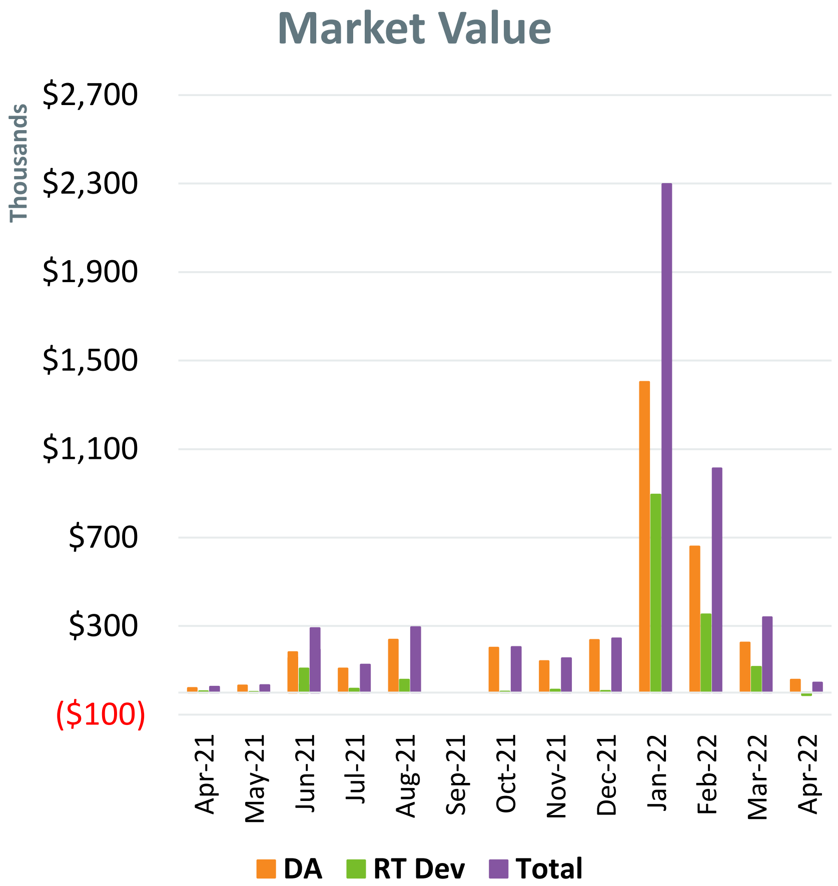
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - April NCPC payments totaled $1.9M over the period, down $2.2M from March and down $0.8M from April 2021
    - First Contingency payments totaled $1.9M, down $2M from March
      - $1.5M paid to internal resources, down $1.7M from March
        - » $493K charged to DALO, $0.488M to RT Deviations, $532K to RTLO*
      - $375K paid to resources at external locations, down $301K from March
        - » $84K charged to DALO at external locations, $291K to RT Deviations
    - Second Contingency, Voltage, and Distribution payments were all zero
  - NCPC payments over the period as percent of Energy Market value were 0.4%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $338K; Rapid Response Pricing (RRP) Opportunity Cost - $194K; Posturing - $0K; Generator Performance Auditing (GPA) - $0K**

Price Responsive Demand (PRD) Energy Market Activity by Month





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

Forward Capacity Market (FCM) Highlights

- CCP 13 (2022-2023)
  - Third and final annual reconfiguration auction (ARA3) was held on March 1-3, and results were posted on March 30
- CCP 14 (2023-2024)
  - Second annual reconfiguration auction (ARA2) will be held on August 1-3, and results will be posted no later than August 31
- CCP 15 (2024-2025)
  - First annual reconfiguration auction (ARA1) will be held on June 1-3, and results will be posted no later than July 5
- CCP 16 (2025-2026)
  - Auction results were filed with FERC on March 21 and the filing is pending
    - Comments are due May 5 and ISO requested an effective date of July 19

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 17 (2026-2027)
  - The qualification process has started and training has been provided
  - Topology certifications were shared at the January 19, 2022 RC Meeting
  - Capacity zone development discussions began at the November 17, 2021 PAC meeting
    - All subsequent reconfiguration auctions model the same zones as the FCA
  - The official FCA 17 schedule has been posted to the ISO website
    - The first activity listed on the FCA 17 schedule took place on April 13, 2022 (when the ISO notified Lead Market Participants of their Existing Capacity Resources' summer and winter Qualified Capacity values), and FCA 17 will commence on March 6, 2023

Highlights

- The final 2022 load forecast was published on April 29
- ISO finished the additional 2021 Economic Study scope requested at the February joint MC/RC meeting, presented the results at the April PAC, and plans to release the draft report in June
- Economic Planning for the Clean Energy Transition Pilot Study
  - New effort to review all assumptions in economic planning and perform a test study consistent with the proposed changes to the Tariff
- Qualified Transmission Project Sponsor (QTPS)
  - 25 companies have achieved QTPS status

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (1.5°F) Max: 73°F, Min: 35°F Precipitation: 2.32" – Below Normal Normal: 3.63"	Hartford	Temperature: Above Normal (0.4°F) Max: 78°F, Min: 30°F Precipitation: 5.22" - Above Normal Normal: 3.88"

Peak Load:	14,242 MW	April 7, 2022	20:00 (ending)

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

Procedure	Declared	Cancelled	Note
None for March 2022			

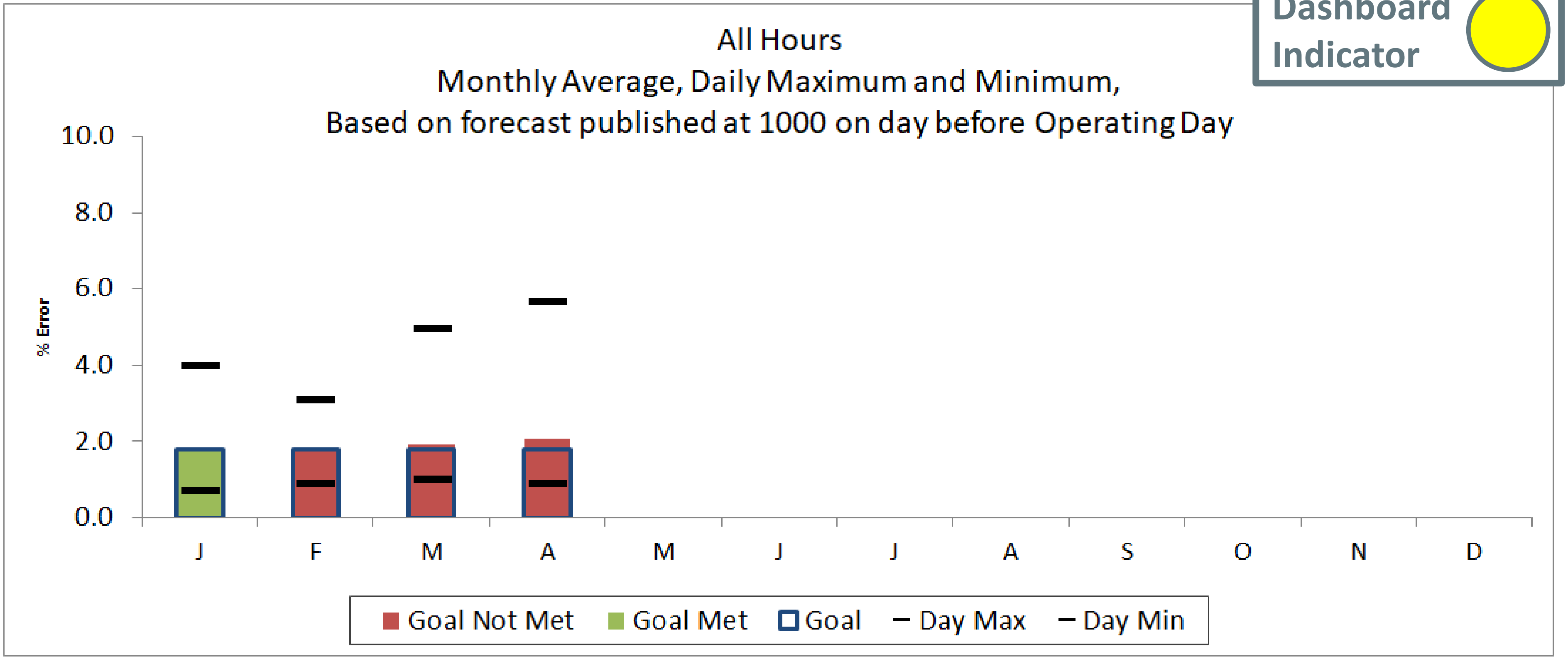
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
4/5/2022	NYISO	1,290
4/6/2022	PJM	1,042
4/13/2022	PJM	800
4/30/2022	IESO	850

2022 System Operations - Load Forecast Accuracy

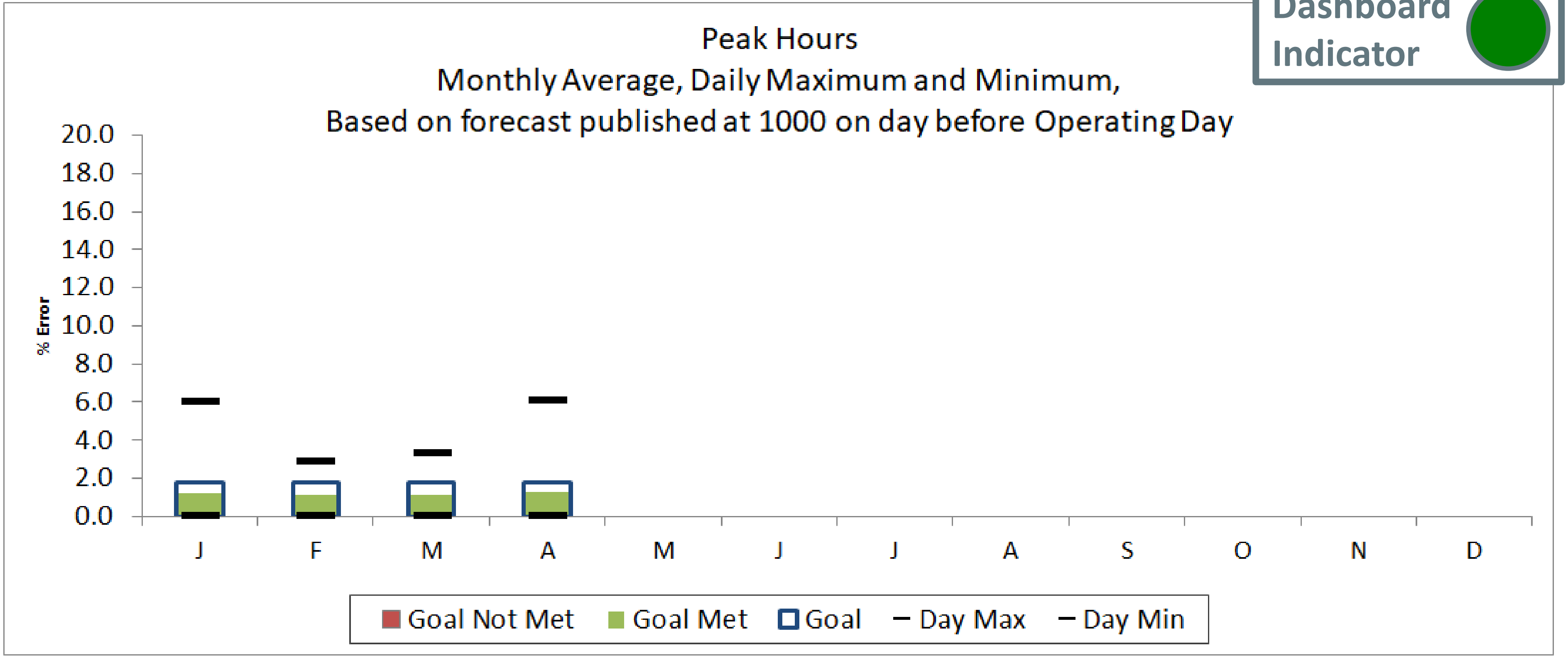
Dashboard Indicator ●



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	3.97	3.07	4.92	5.66									5.66
Day Min	0.69	0.87	0.97	0.85									0.69
MAPE	1.79	1.81	1.93	2.05									1.90
Goal	1.80	1.80	1.80	1.80									

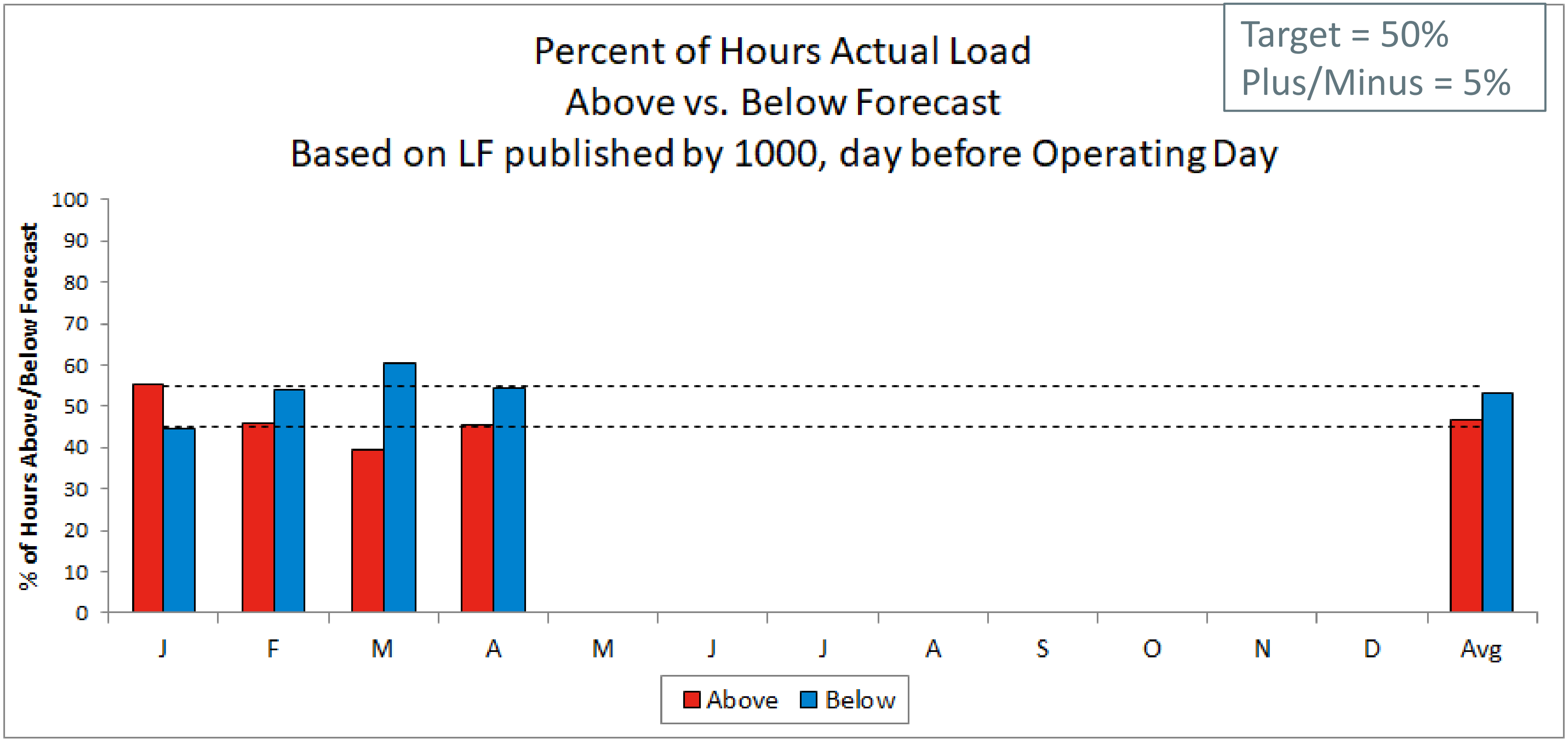
2022 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator ●



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	6.01	2.85	3.32	6.08									6.08
Day Min	0.02	0.03	0.04	0.00									0.00
MAPE	1.25	1.11	1.13	1.29									1.20
Goal	1.80	1.80	1.80	1.80									

2022 System Operations - Load Forecast Accuracy cont.

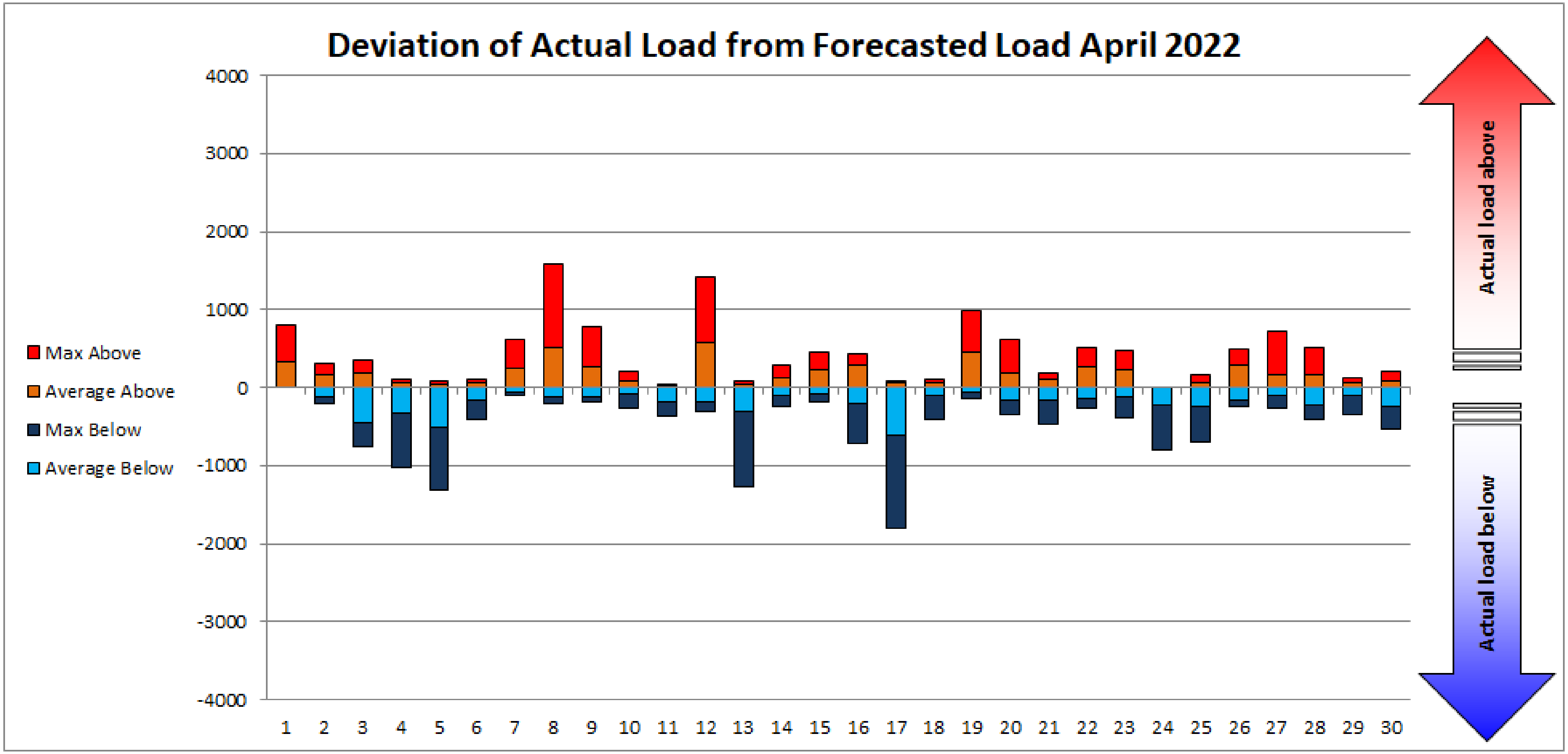


Target = 50%
Plus/Minus = 5%

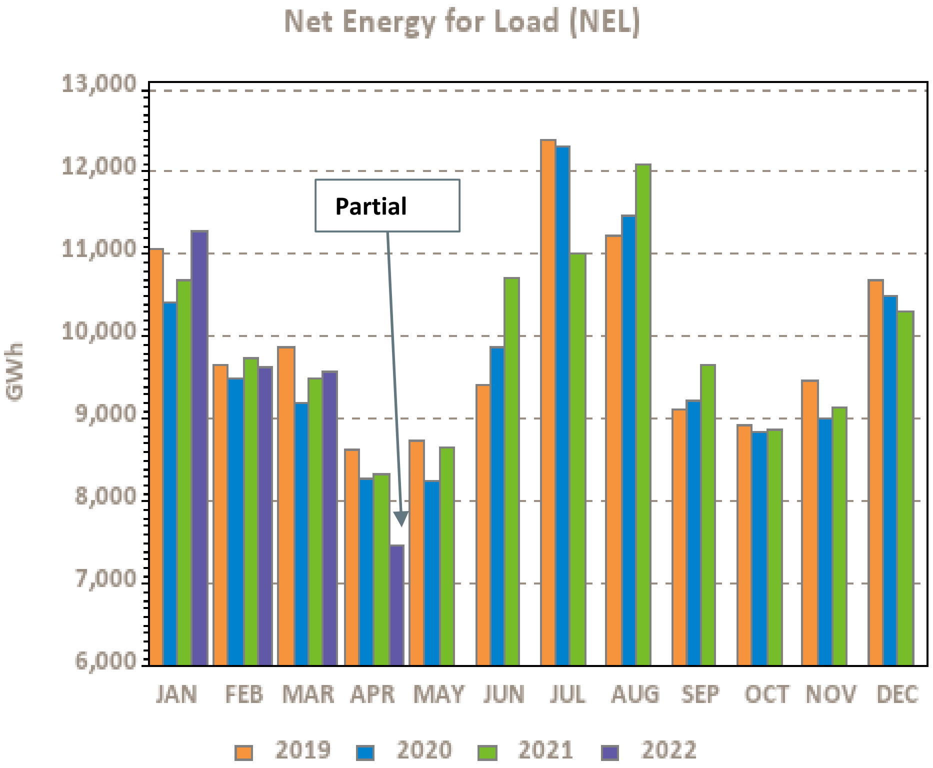
Percent of Hours Actual Load
Above vs. Below Forecast
Based on LF published by 1000, day before Operating Day

	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	55.2	46	39.7	45.6									47
Below %	44.8	54	60.3	54.4									53
Avg Above	219.5	245.7	175.9	180									246
Avg Below	-223.1	-207.6	-240.0	-191.5									-240
Avg All	22	6	-78	-18									-18

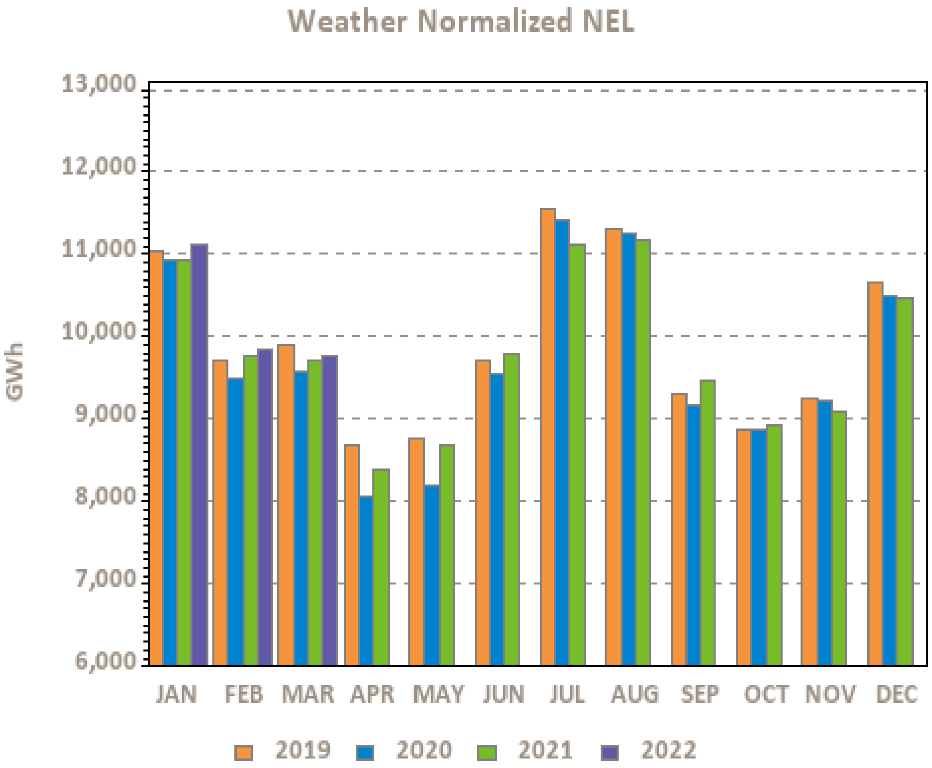
2022 System Operations - Load Forecast Accuracy cont.



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



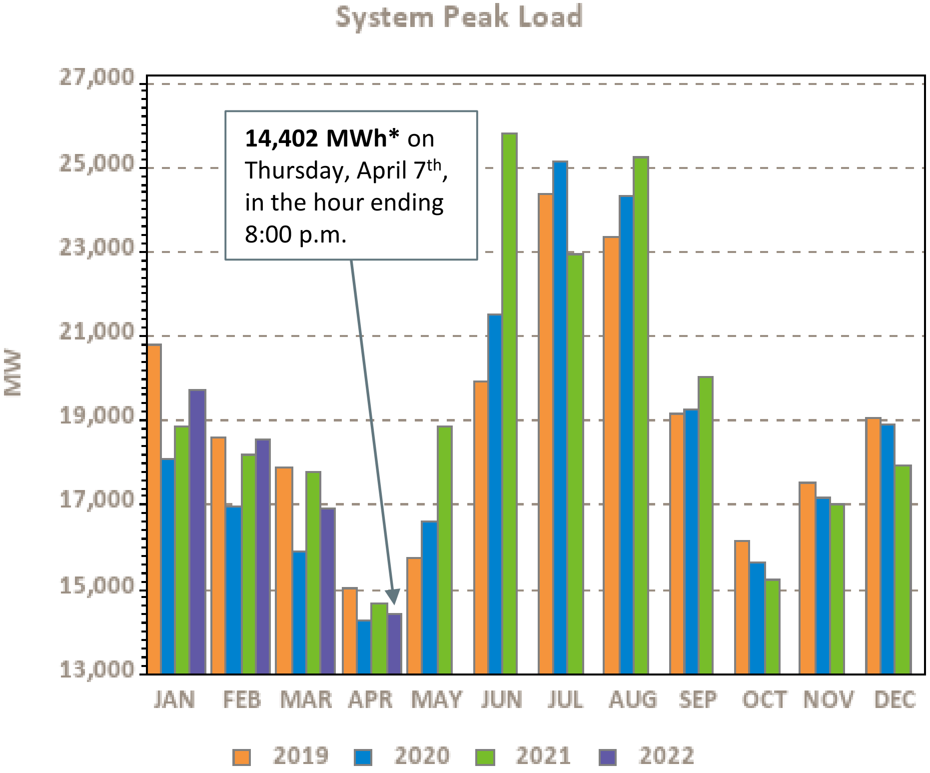
Ann Tot (TWh): 119.2 116.9 118.7 38.0



Ann Tot (TWh): 118.8 116.3 117.5 30.7

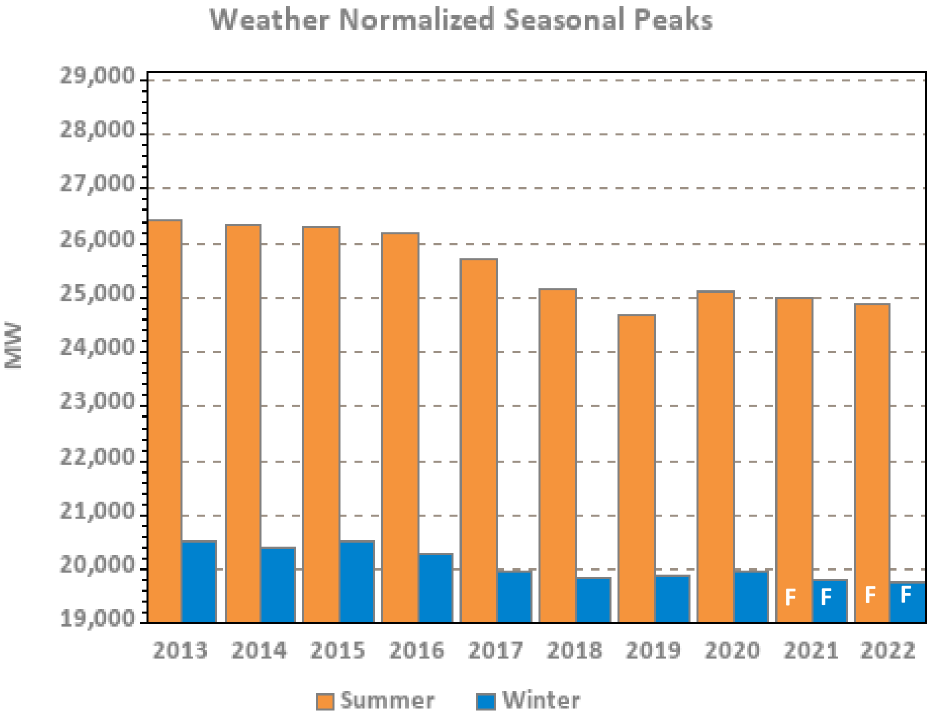
NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather normalized NEL is typically reported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

Monthly Peak Loads and Weather Normalized Seasonal Peak History



14,402 MWh* on Thursday, April 7th, in the hour ending 8:00 p.m.

***Revenue quality metered value**

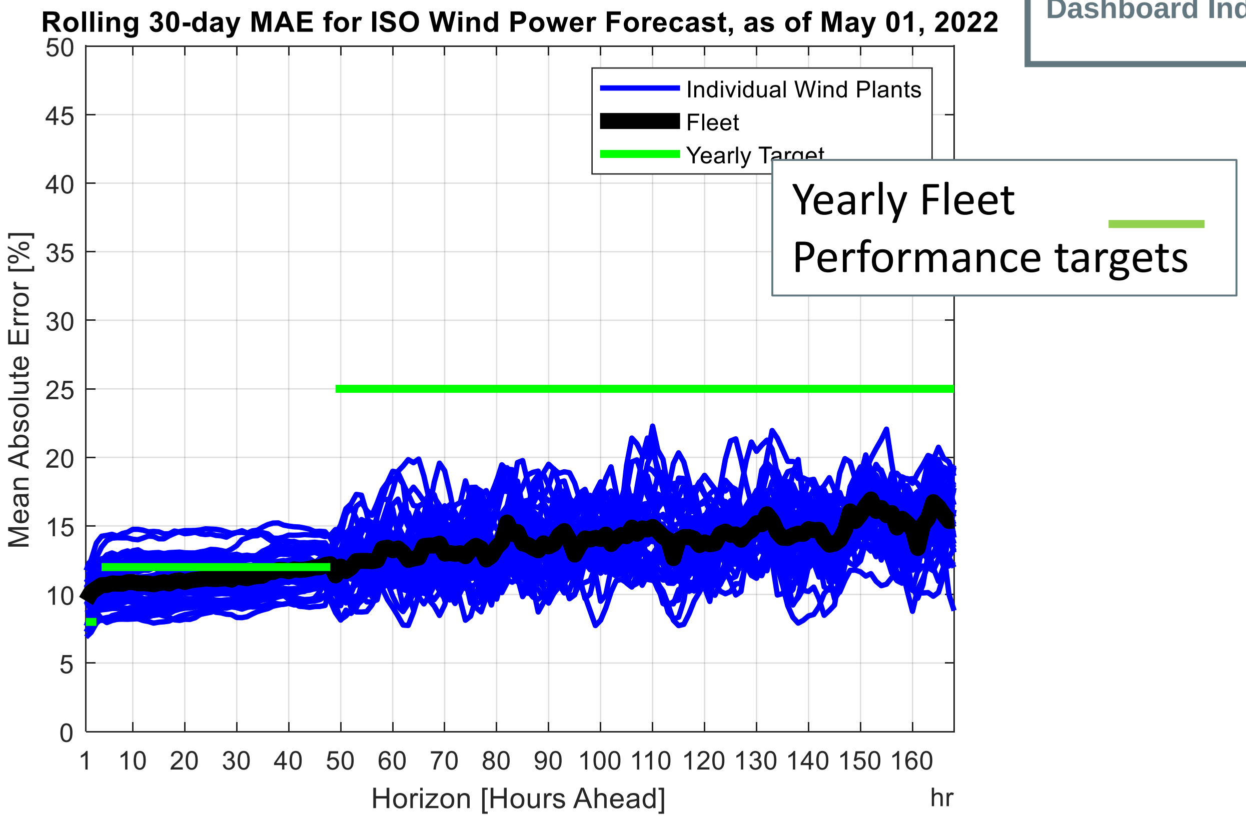


Winter beginning in year displayed

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

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

Dashboard Indicator ●

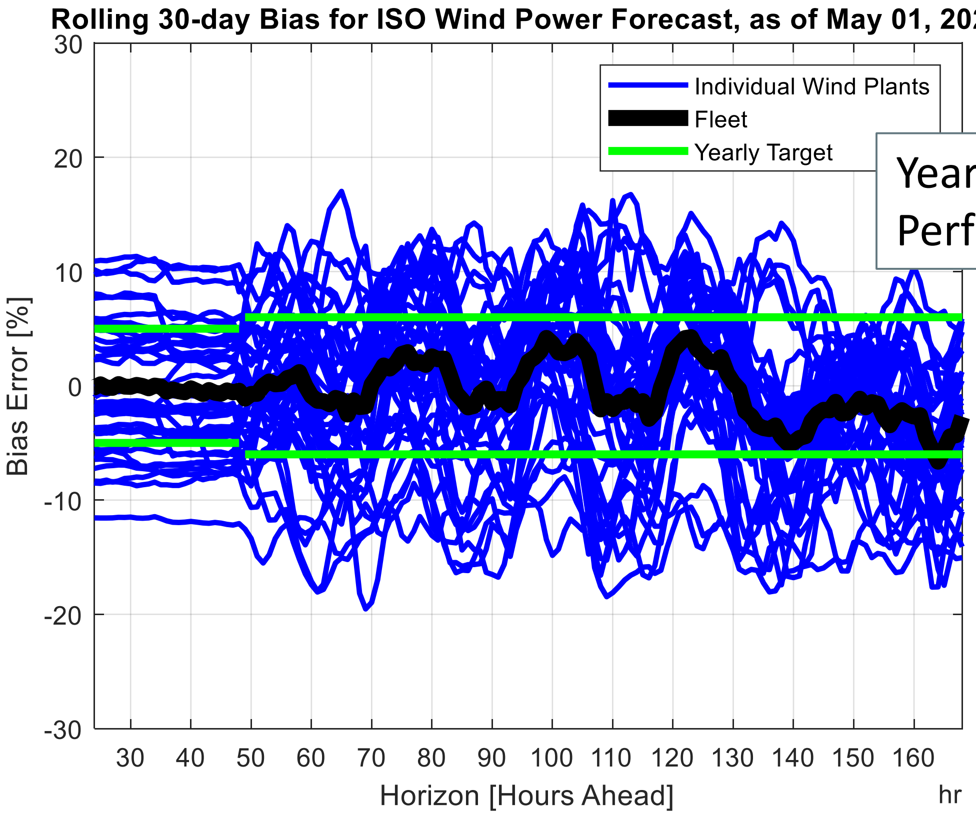


Yearly Fleet Performance targets

Ideally, MAE and Bias would be both equal to zero. As is typical, MAE increases with the forecast horizon. MAE and Bias for the fleet of wind power resources are less due to offsetting errors. Across all time frames, the ISO-NE/DNV forecast is very good compared to industry standards, and monthly MAE (with the exception of hour 1 look ahead) is within the yearly performance targets.

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

Dashboard Indicator ●

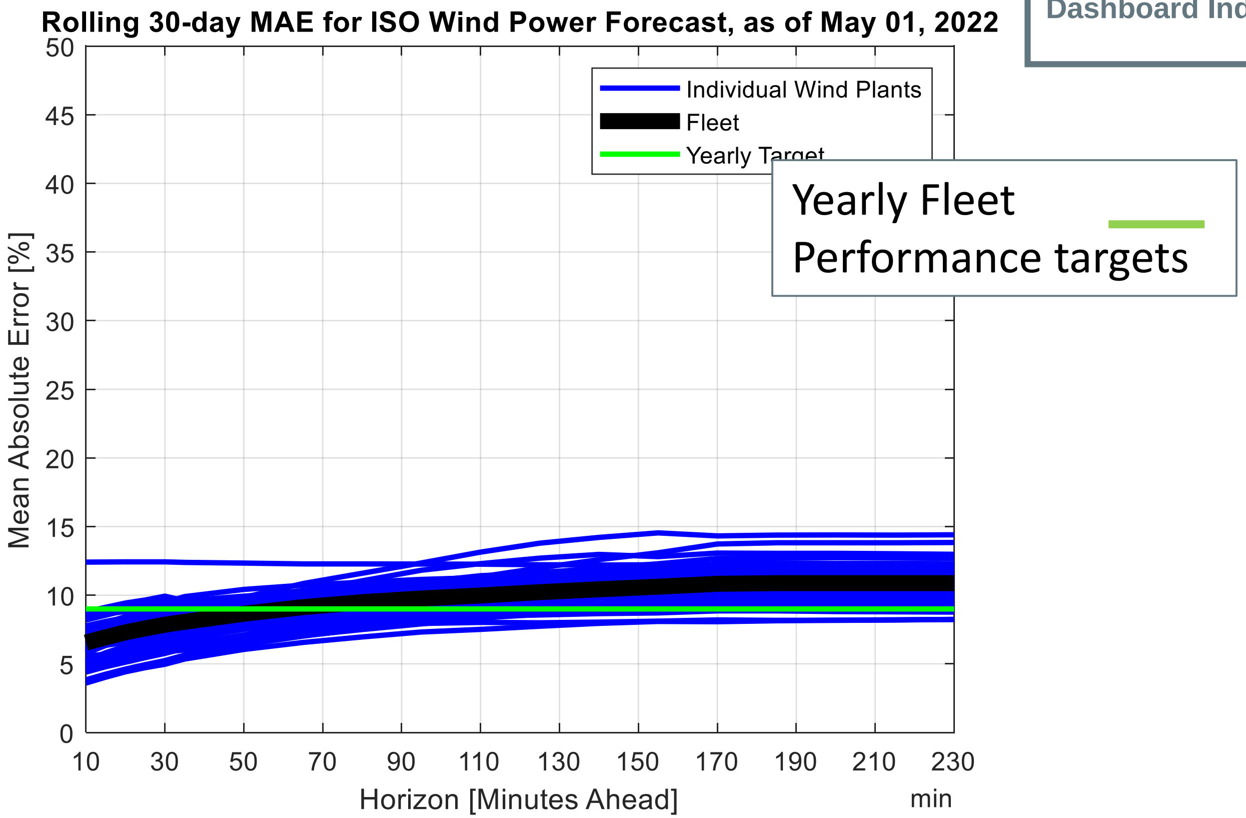


Yearly Fleet Performance targets

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

Wind Power Forecast Error Statistics: Short Term Forecast MAE

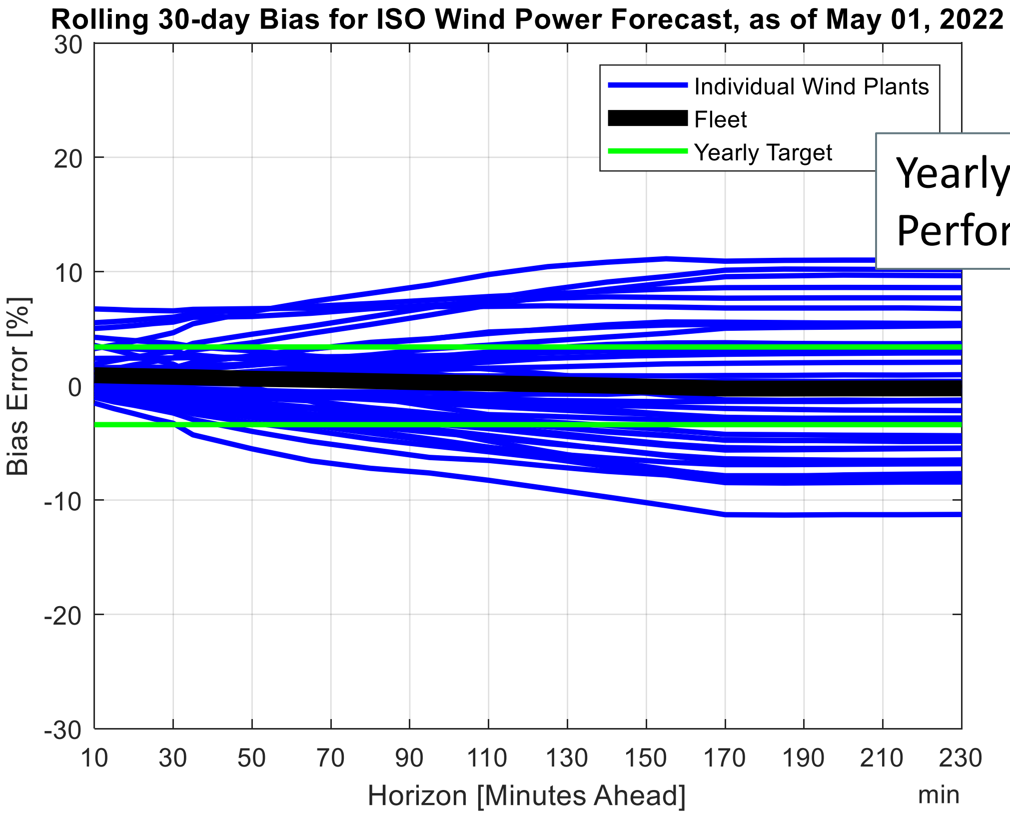
Dashboard Indicator ●



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 up to 90 minutes look-ahead monthly MAE is within the yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator ●

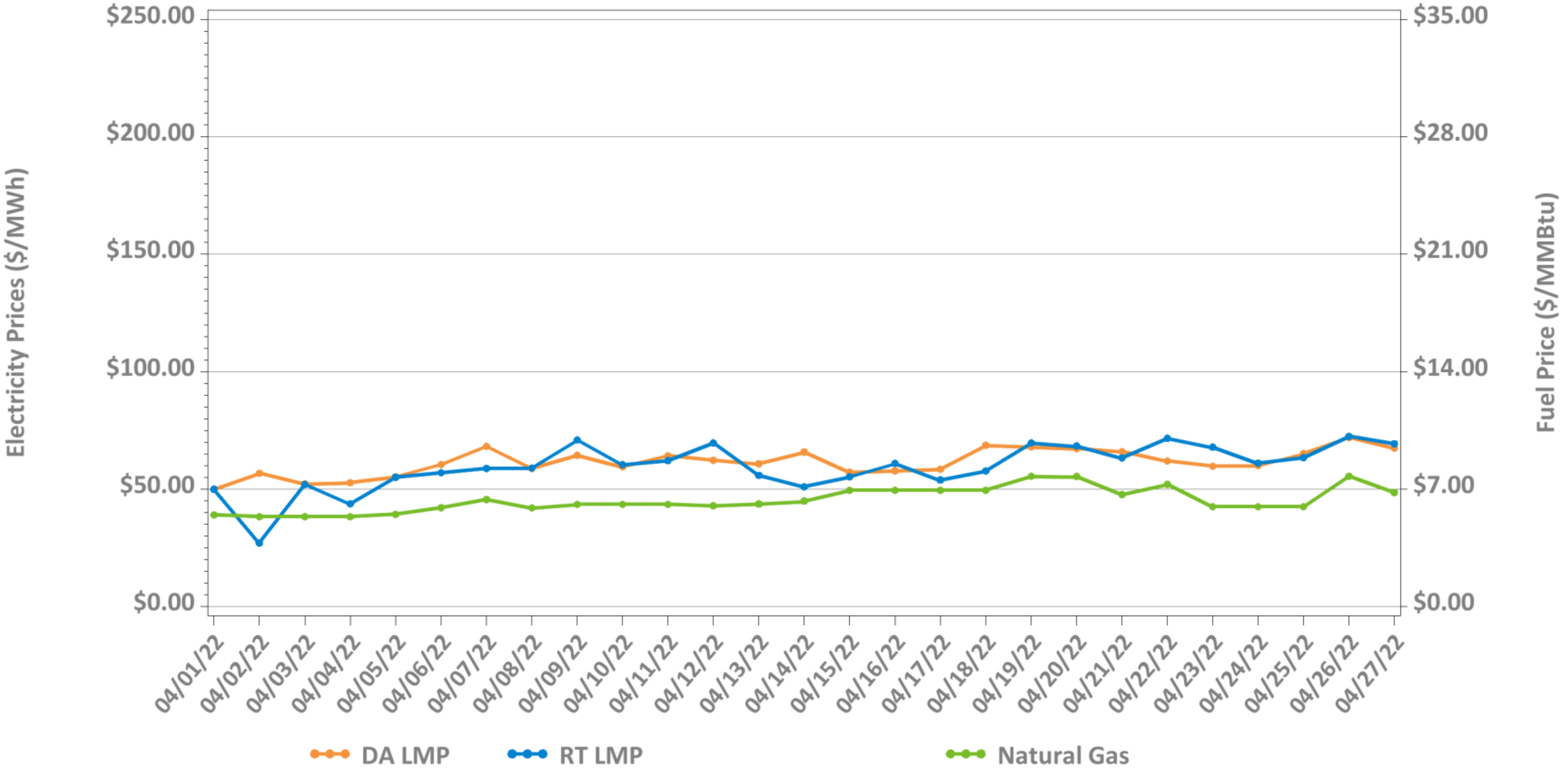


Yearly Fleet Performance targets

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

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: April 1-27, 2022

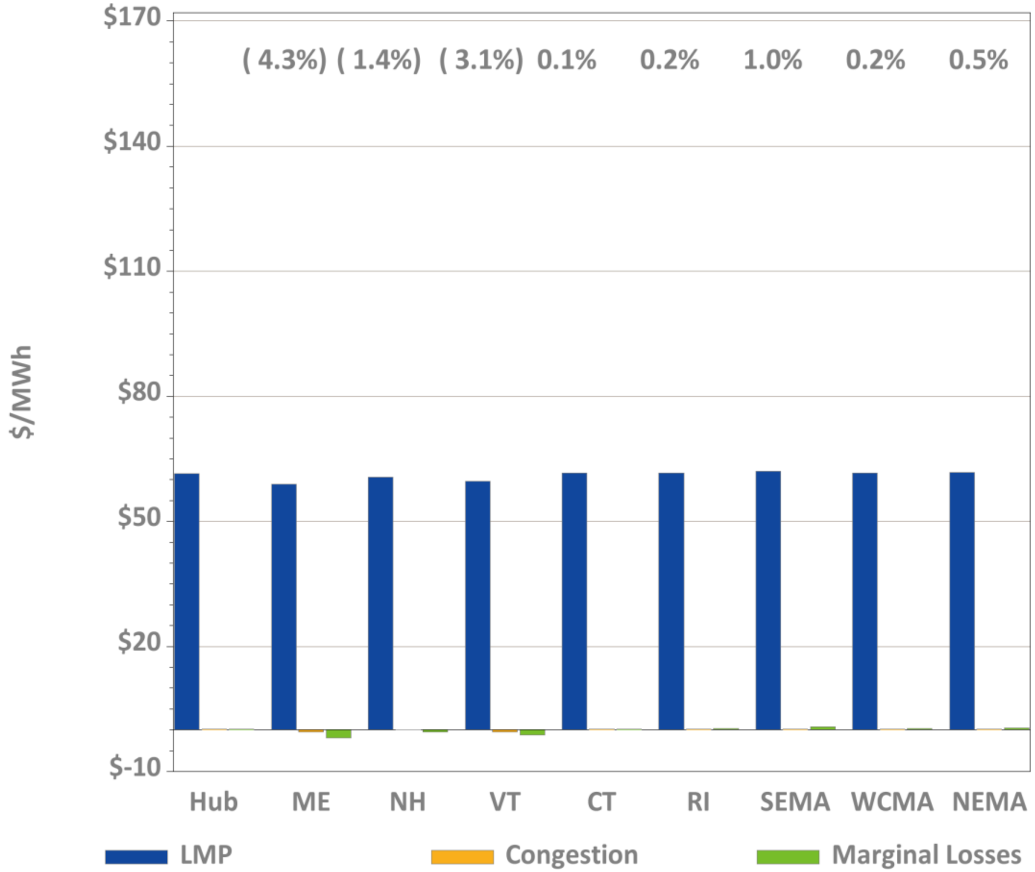


Underlying natural gas data furnished by:

ICE Global markets in clear view

Average price difference over this period (DA-RT): $2.00
Average price difference over this period ABS(DA-RT): $5.11
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 9%
Gas price is average of Massachusetts delivery points

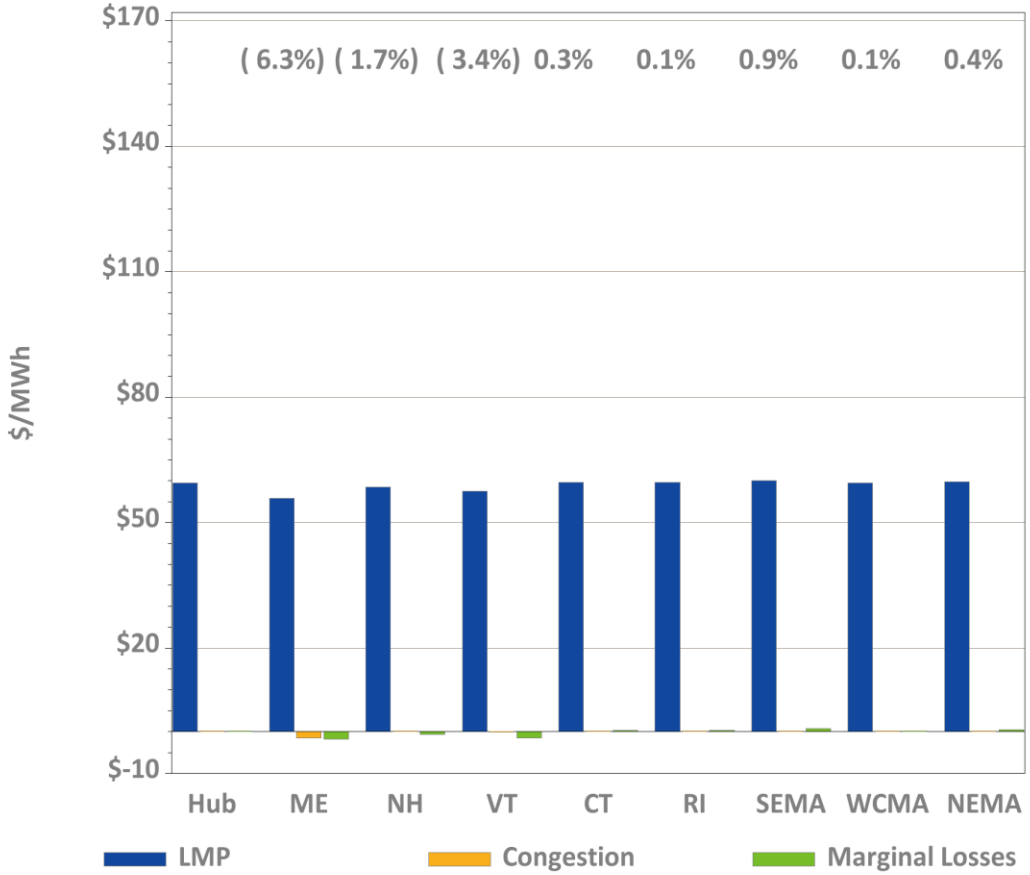
DA LMPs Average by Zone & Hub, April 2022



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

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

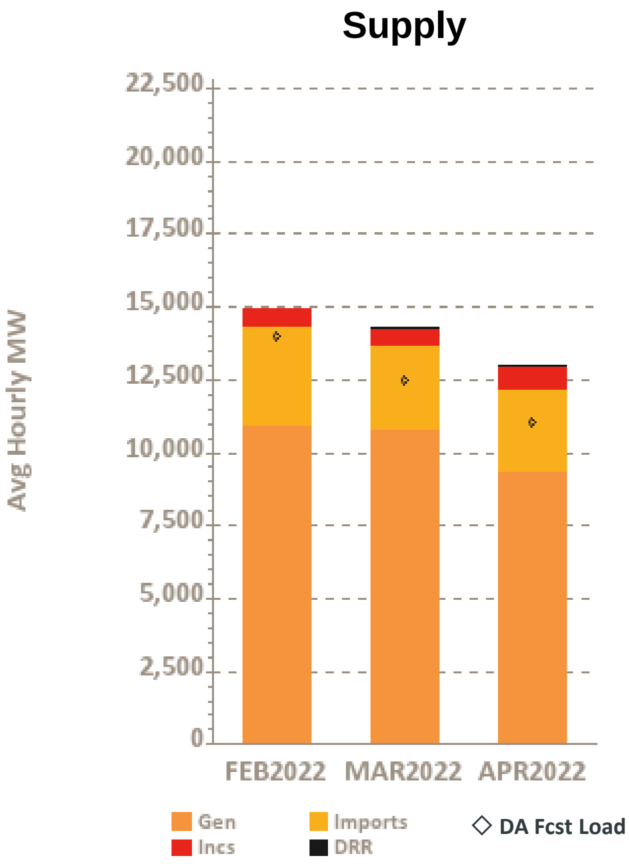
RT LMPs Average by Zone & Hub, April 2022

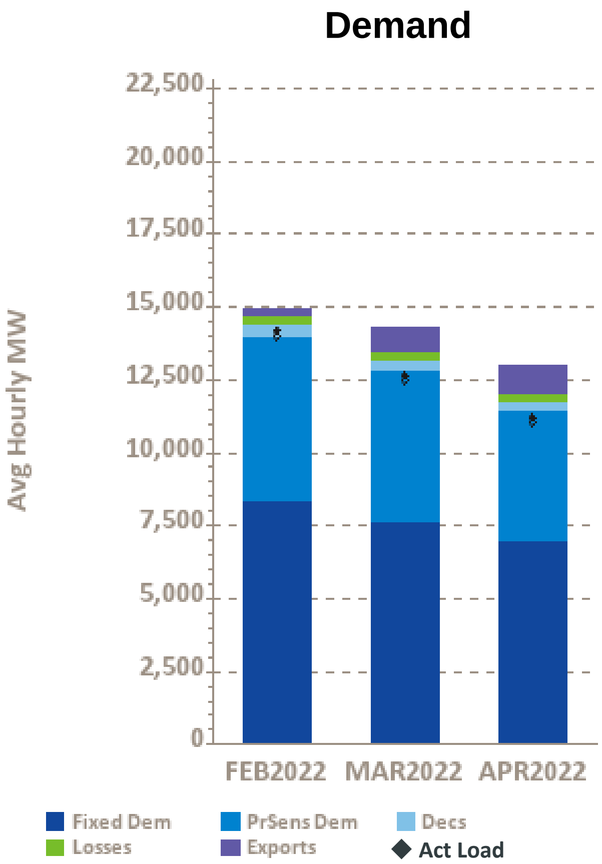


Definitions

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

Components of Cleared DA Supply and Demand – Last Three Months

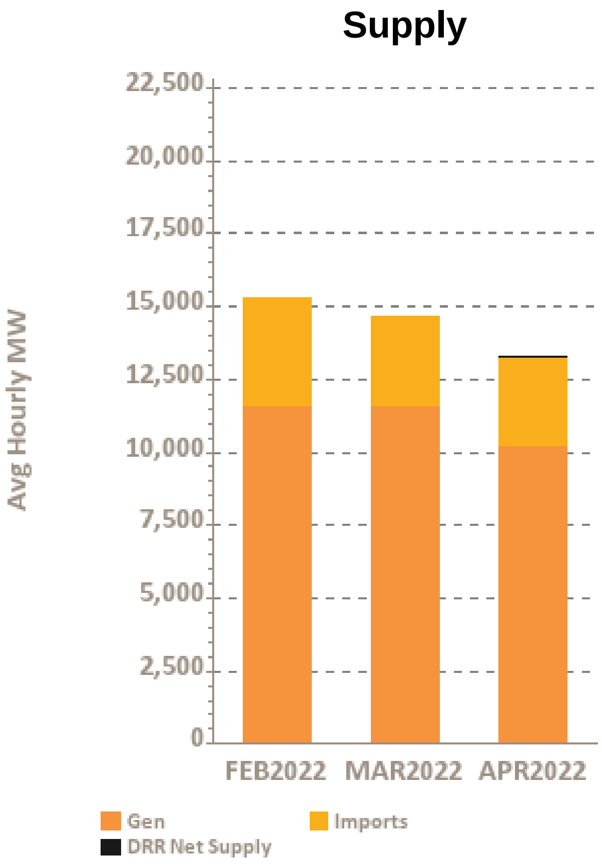


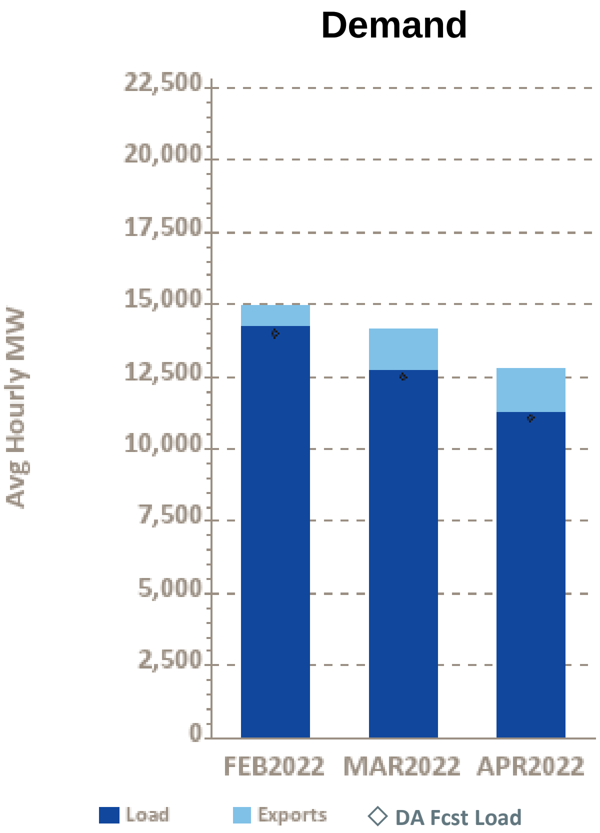


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

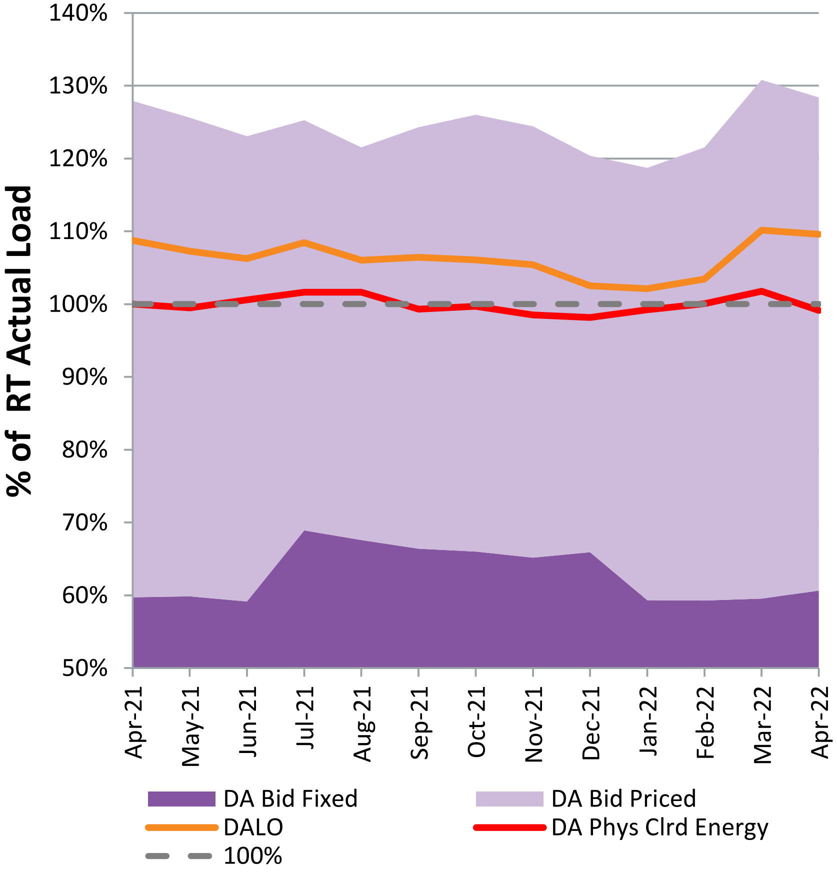
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

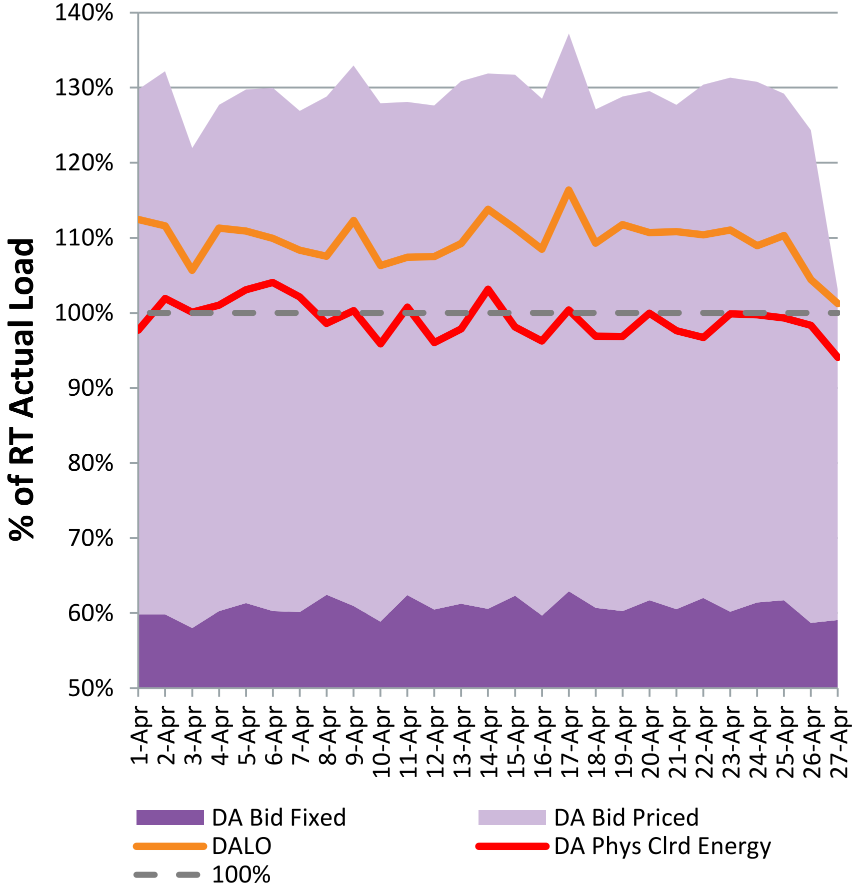
Components of RT Supply and Demand – Last Three Months





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

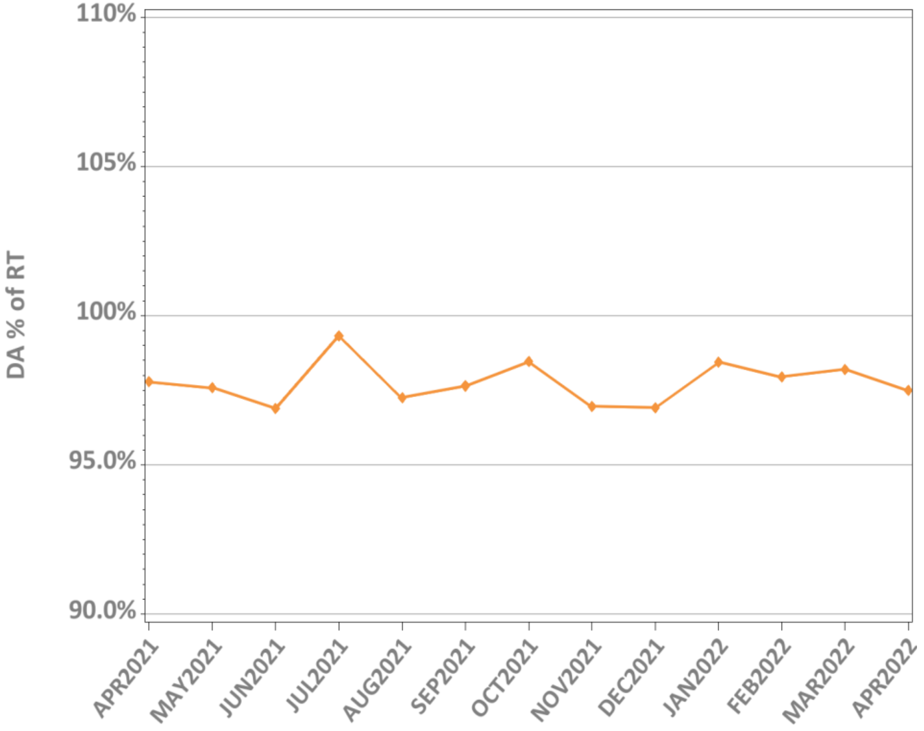




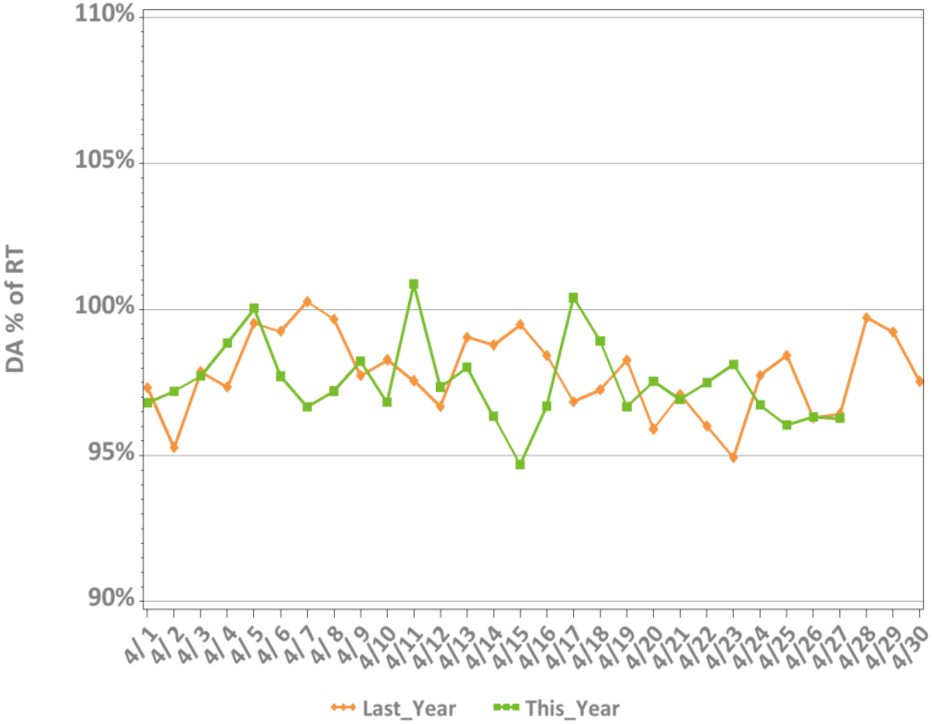
Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

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

Monthly, Last 13 Months

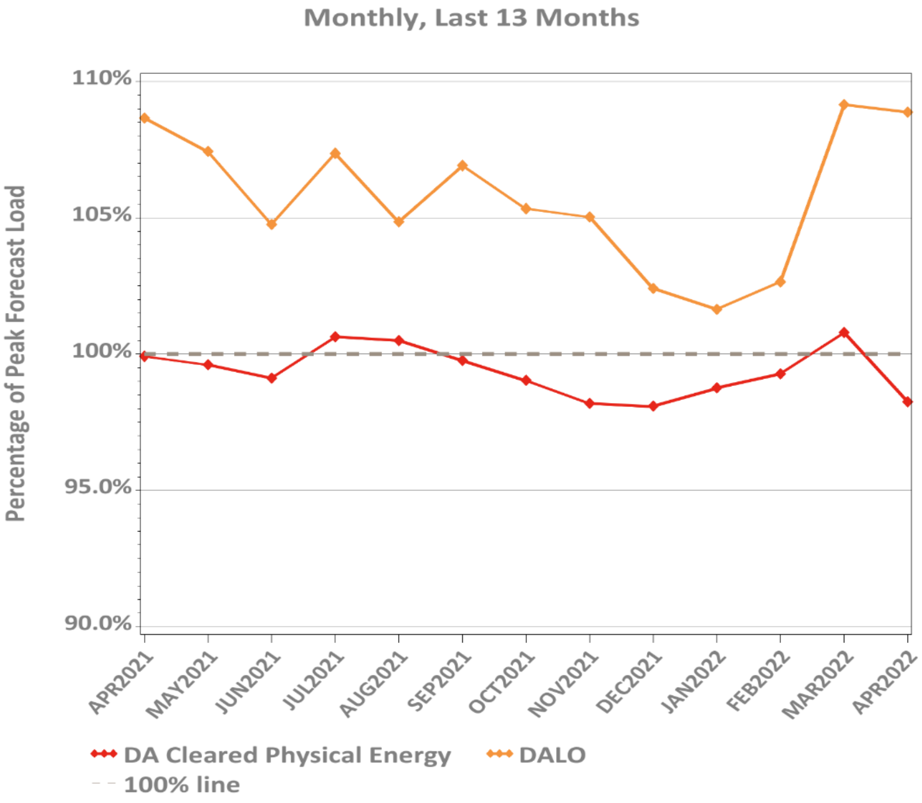


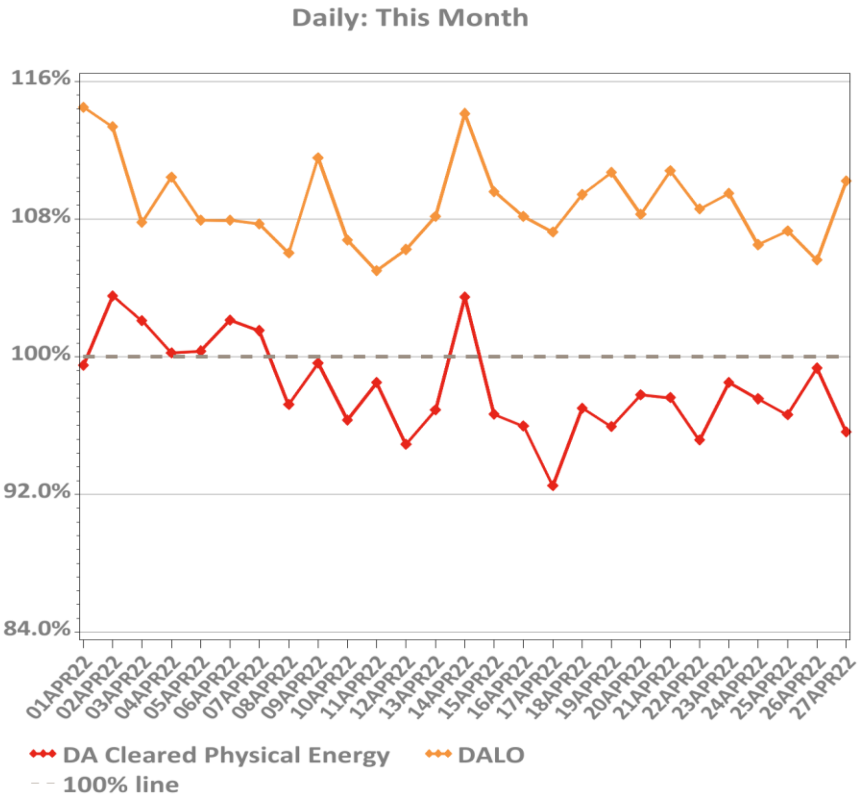
Daily, This Year vs. Last Year



*Hourly average values

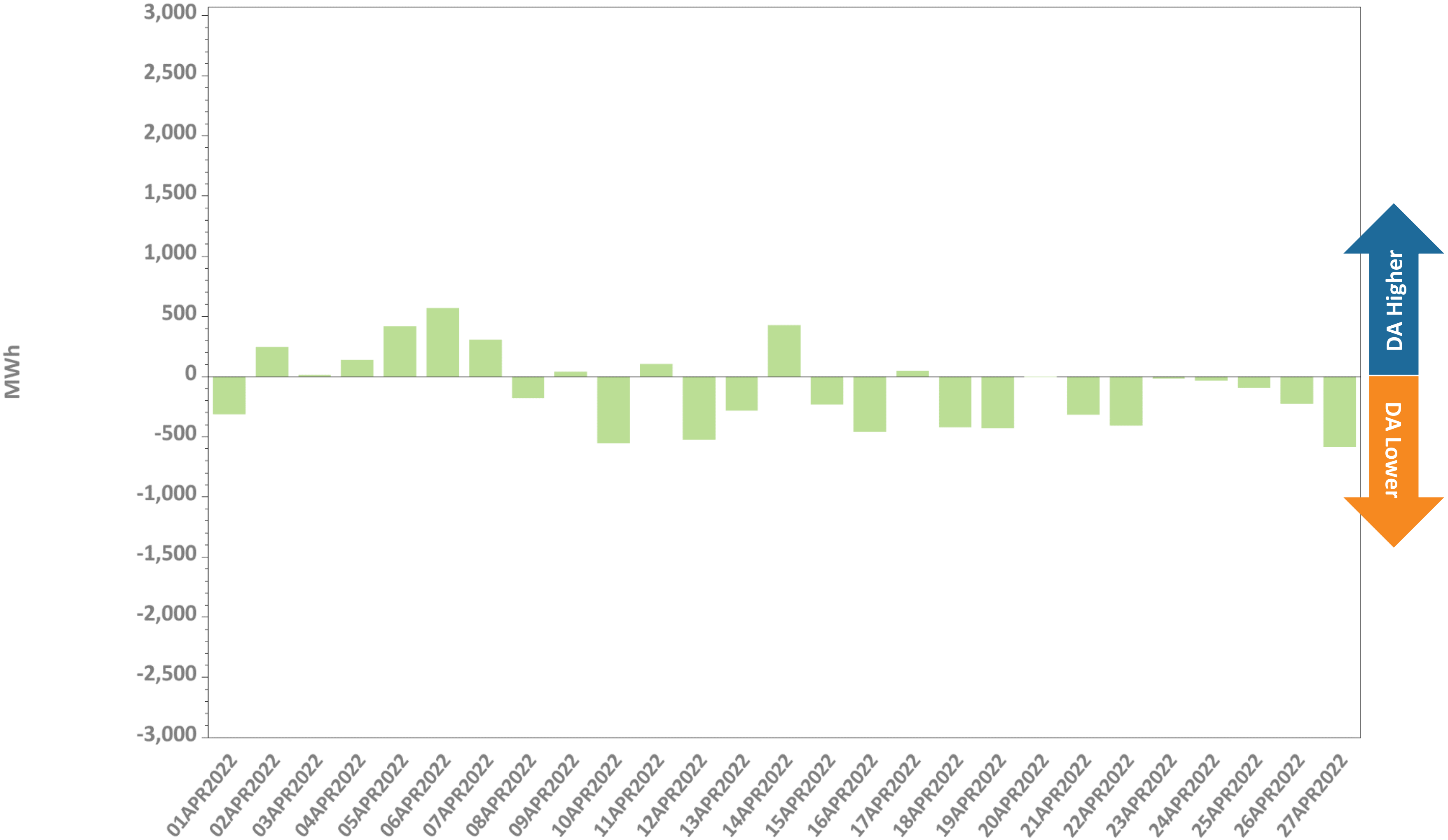
DA Volumes as % of Forecast in Peak Hour





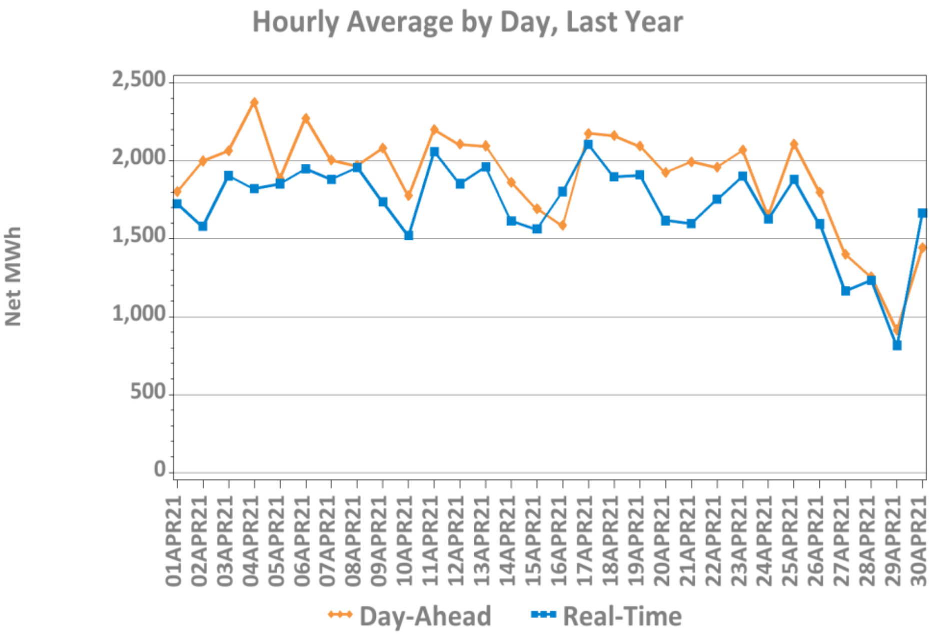
Note: There were no system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during the month.

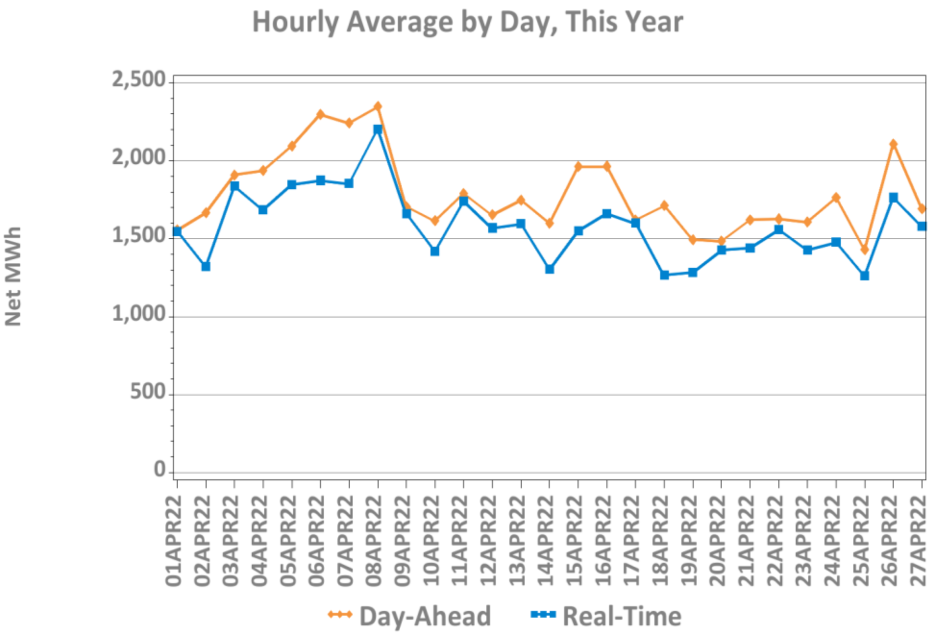
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



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

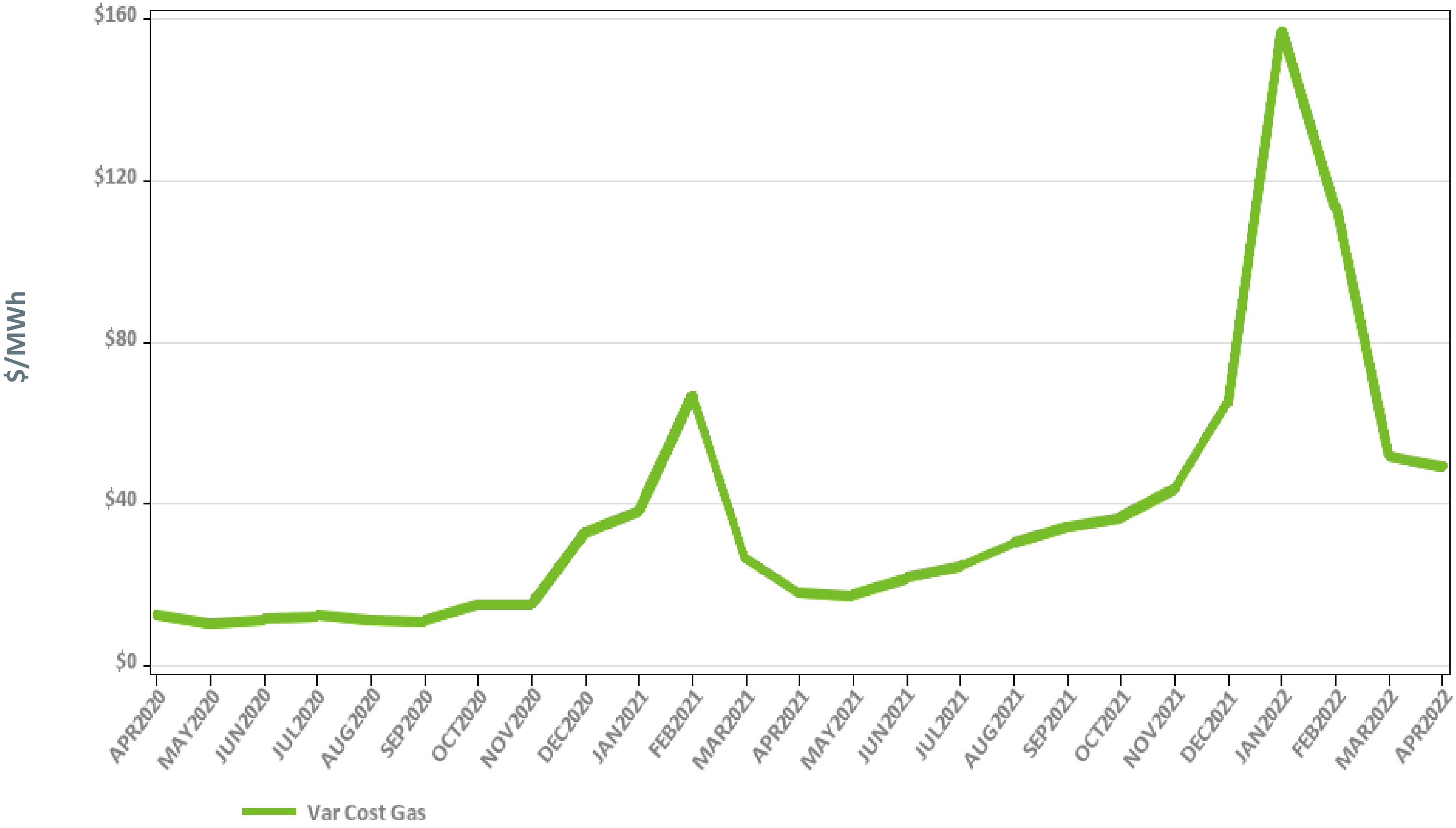
DA vs. RT Net Interchange April 2021 vs. April 2022





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

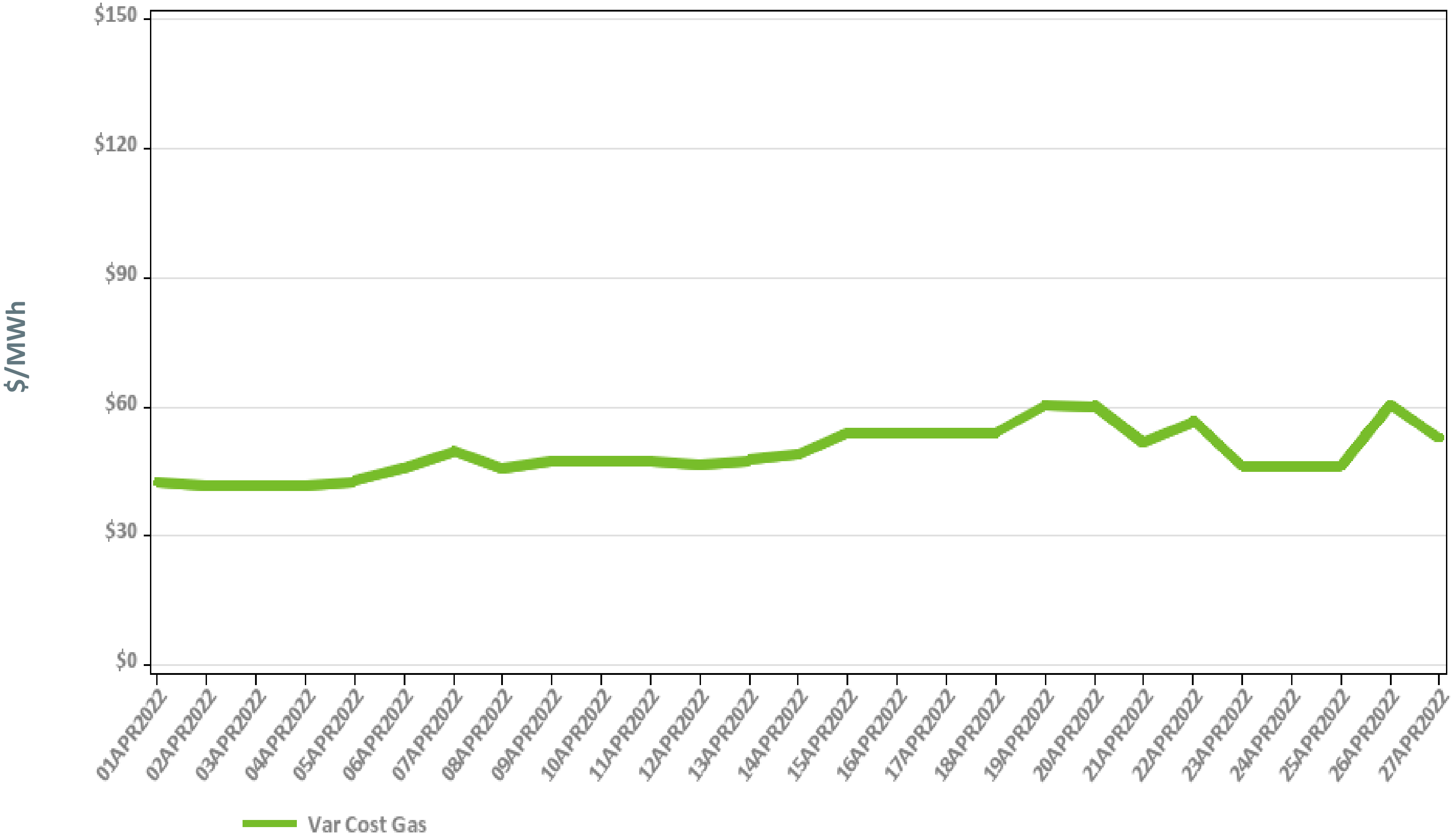
Variable Production Cost of Natural Gas: Monthly



Underlying natural gas data furnished by:

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

Variable Production Cost of Natural Gas: Daily

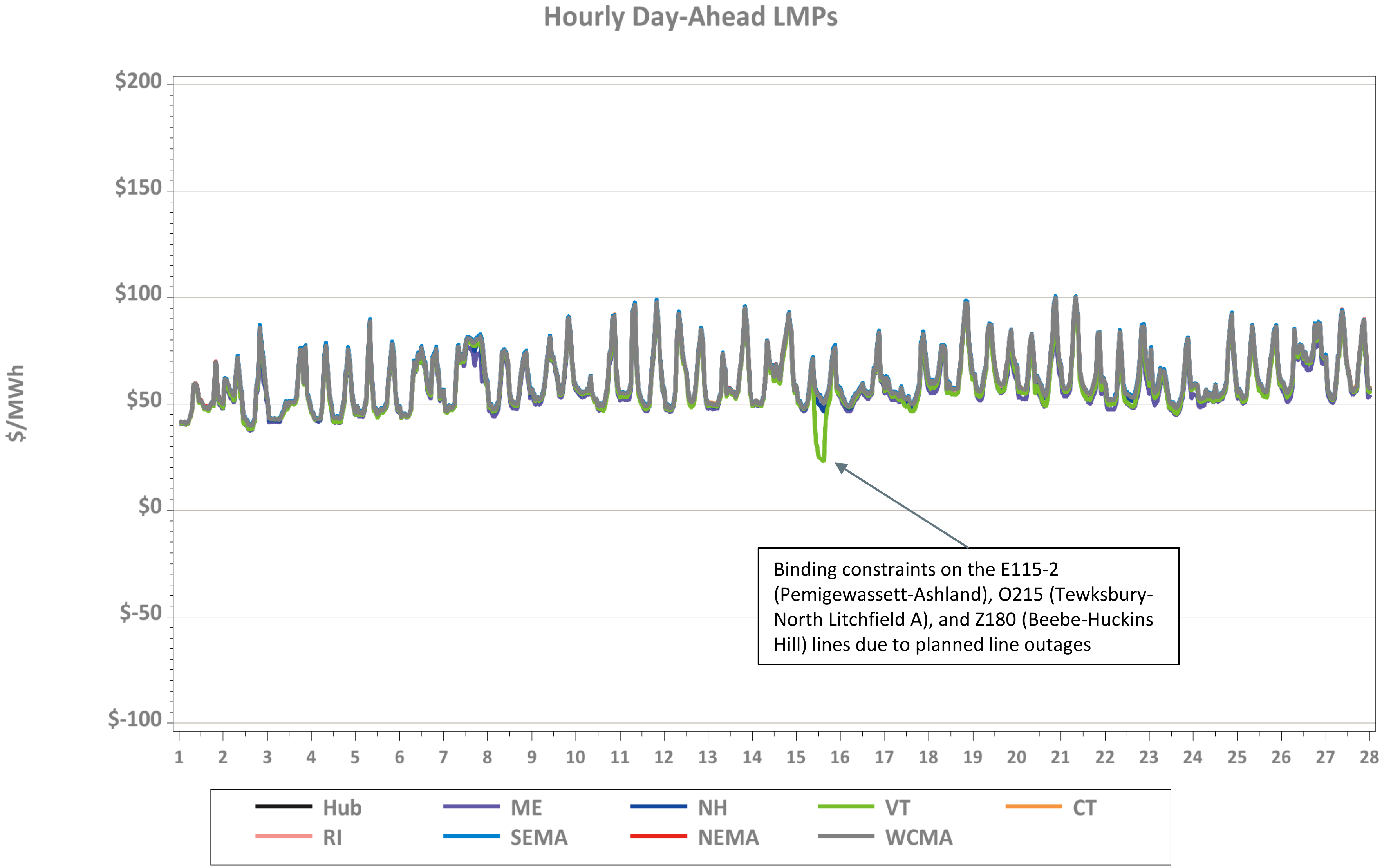


Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Underlying natural gas data furnished by:

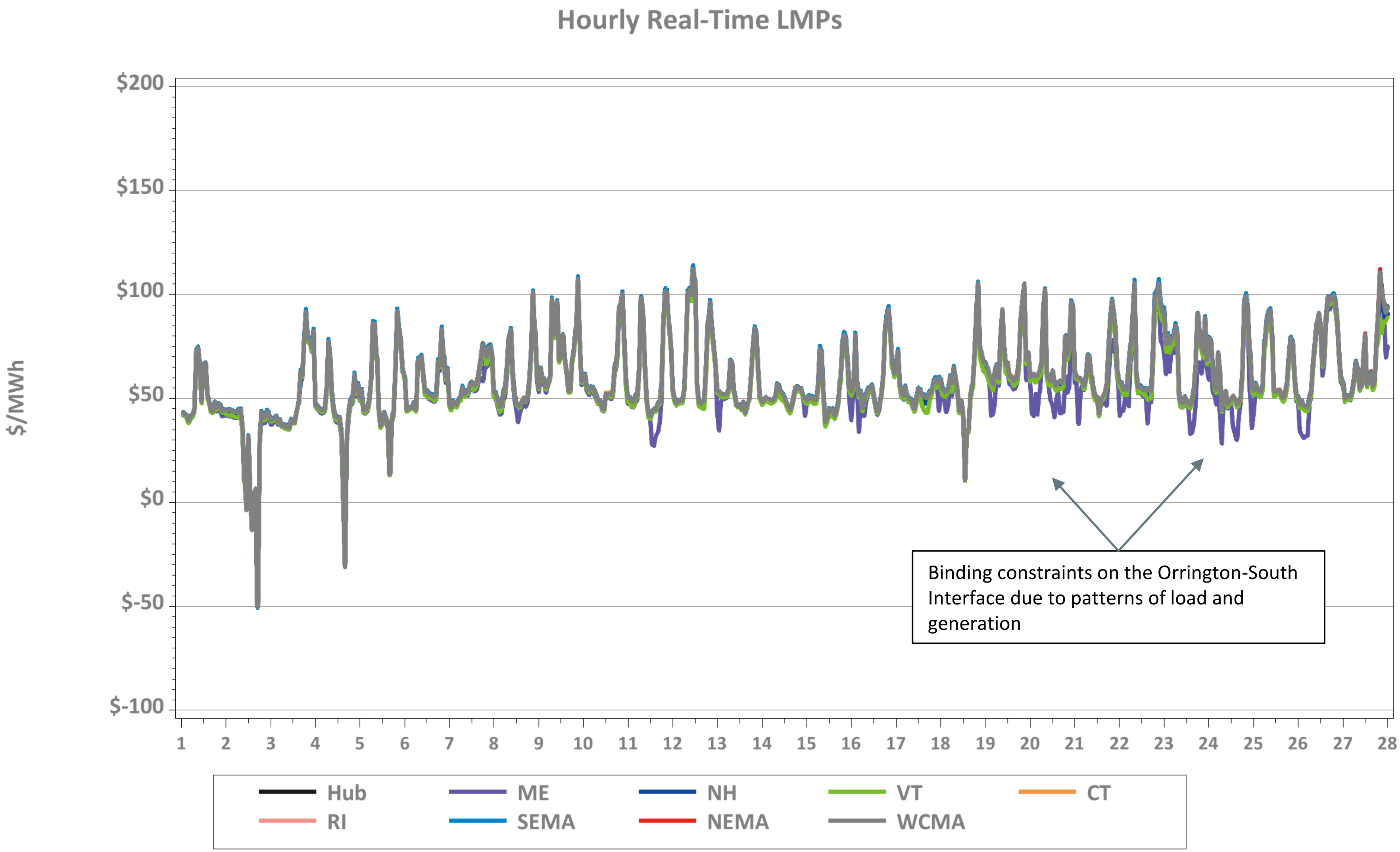
ICE Global markets in clear view

Hourly DA LMPs, April 1-27, 2022



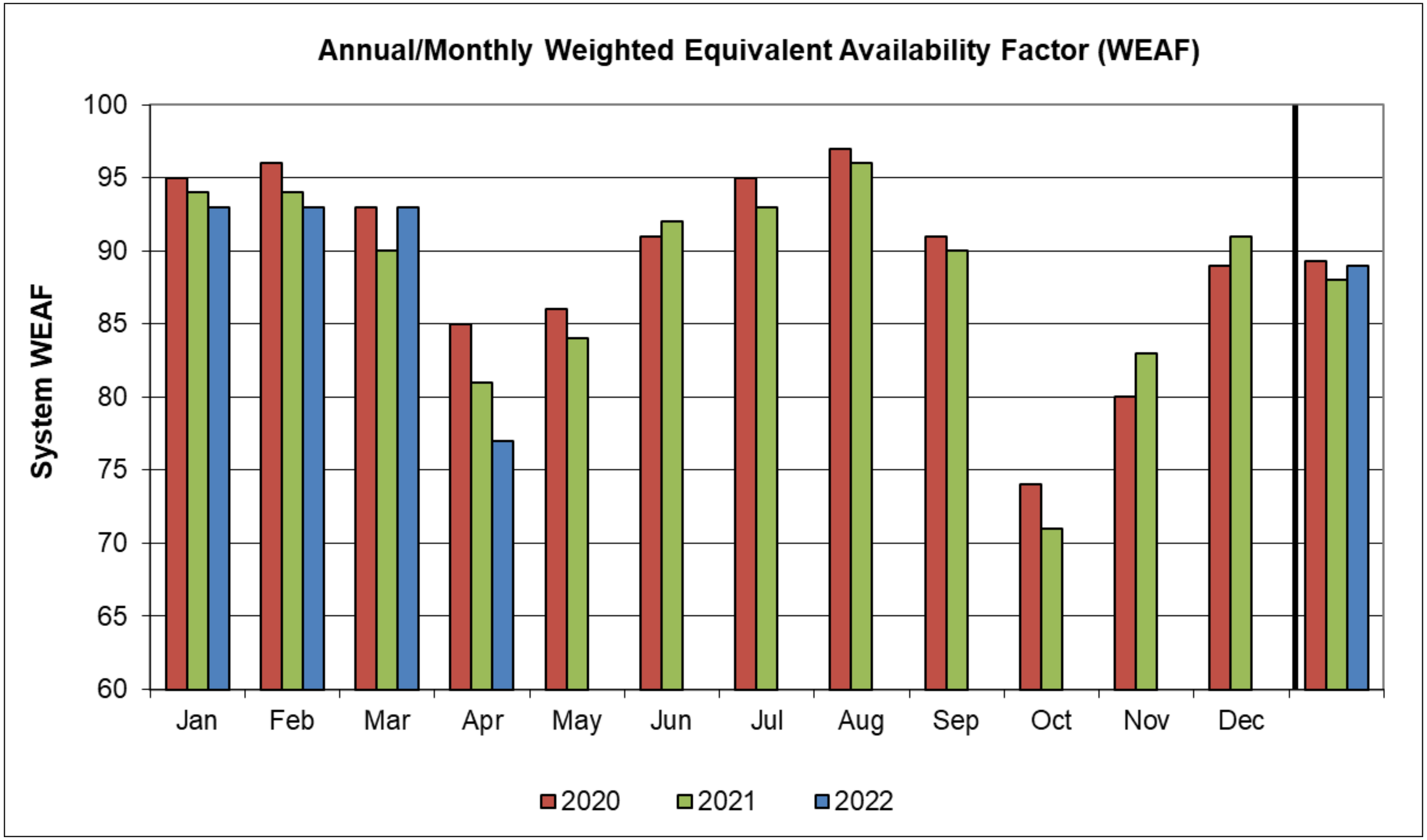
Binding constraints on the E115-2 (Pemigewassett-Ashland), O215 (Tewksbury-North Litchfield A), and Z180 (Beebe-Huckins Hill) lines due to planned line outages

Hourly RT LMPs, April 1-27, 2022



Binding constraints on the Orrington-South Interface due to patterns of load and generation

System Unit Availability



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

Data as of 4/29/2022

BACK-UP DETAIL

DEMAND RESPONSE

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

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	79.4	214.3	0.0	293.7
NH	42.6	168.3	0.0	210.9
VT	38.4	132.2	0.0	170.6
CT	139.4	131.7	646.6	917.8
RI	37.7	327.7	0.0	365.4
SEMA	43.5	529.2	0.0	572.7
WCMA	89.2	537.4	39.6	666.2
NEMA	61.1	898.0	0.0	959.1
Total	**531.4**	**2,938.8**	**686.2**	**4,156.4**

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

NEW GENERATION

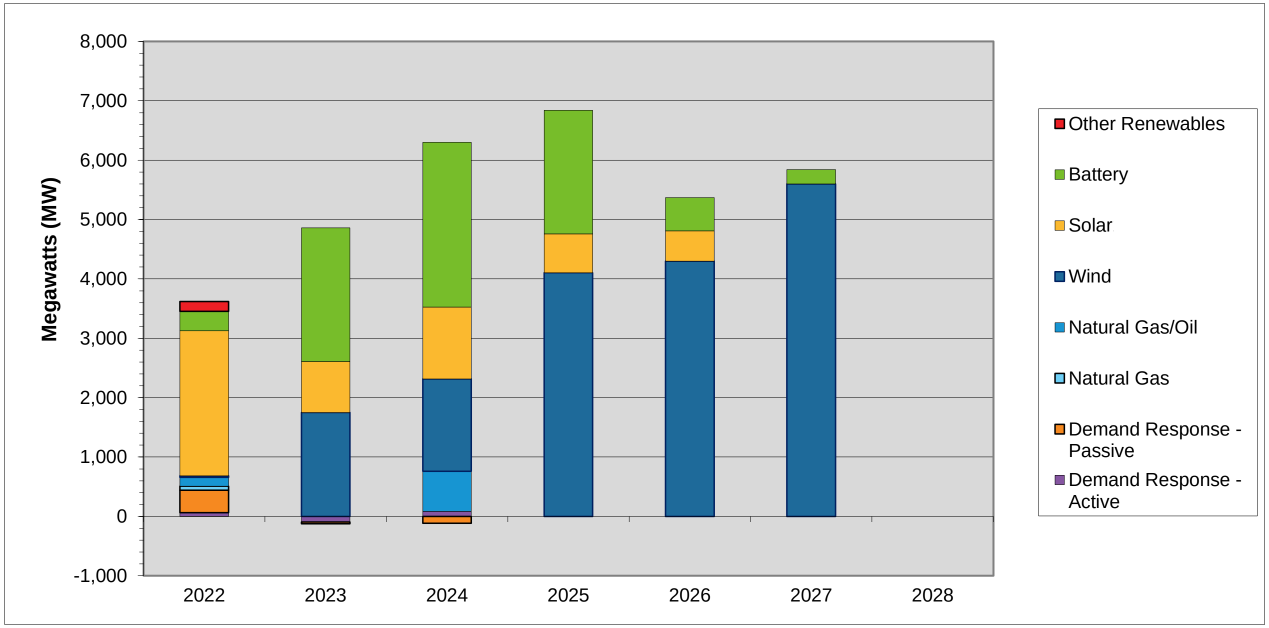
New Generation Update

Based on Queue as of 04/29/22

- Six projects totaling 604 MW were added to the interconnection queue since the last update
  - They consist of five battery projects and one solar project, with in-service dates of 2022 through 2026
- Two projects were withdrawn and none went commercial
- In total, 333 generation projects are currently being tracked by the ISO, totaling approximately 33,504 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2022	2023	2024	2025	2026	2027	2028	Total MW	% of Total[1]
Other Renewables	166	0	0	0	0	0	0	166	0.5
Battery	325	2,253	2,776	2,082	559	242	0	8,237	25.3
Solar[2]	2,443	855	1,213	654	512	0	0	5,677	17.4
Wind	24	1,752	1,556	4,105	4,298	5,599	0	17,334	53.2
Natural Gas/Oil[3]	151	0	672	0	0	0	0	823	2.5
Natural Gas	67	0	0	0	0	0	0	67	0.2
Demand Response - Passive	380	-28	-114	0	0	0	0	238	0.7
Demand Response - Active	62	-94	86	0	0	0	0	54	0.2
Totals	3,618	4,738	6,189	6,841	5,369	5,841	0	32,596	100.0

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

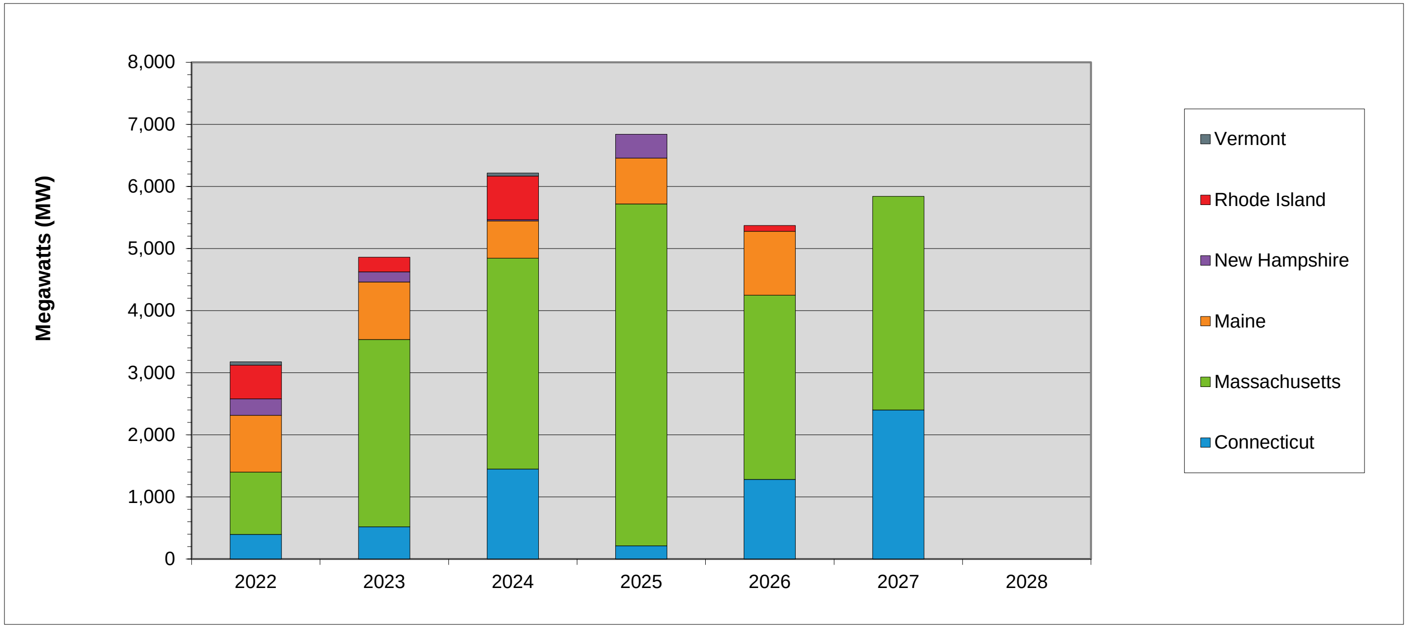
[2] This category includes both solar-only, and co-located solar and battery projects

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

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

Actual and Projected Annual Generator Capacity Additions

By State



	2022	2023	2024	2025	2026	2027	2028	Total MW	% of Total[1]
Vermont	55	0	50	0	0	0	0	105	0.3
Rhode Island	540	236	704	0	91	0	0	1,571	4.9
New Hampshire	266	164	20	385	0	0	0	835	2.6
Maine	917	927	597	737	1,029	0	0	4,207	13.0
Massachusetts	1,001	3,013	3,397	5,509	2,966	3,441	0	19,327	59.8
Connecticut	397	520	1,449	210	1,283	2,400	0	6,259	19.4
Totals	**3,176**	**4,860**	**6,217**	**6,841**	**5,369**	**5,841**	**0**	**32,304**	**100.0**

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

New Generation Projection

By Fuel Type

	Total		**Green**		**Yellow**	
Unit Type	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	54	8,237	0	0	54	8,237
Fuel Cell	2	30	0	0	2	30
Hydro	3	99	2	71	1	28
Natural Gas	7	67	0	0	7	67
Natural Gas/Oil	5	823	1	62	4	761
Nuclear	1	37	0	0	1	37
Solar	231	5,677	26	302	205	5,375
Wind	30	18,534	1	20	29	18,514
Total	333	33,504	30	455	303	33,049

- 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	7	804	0	0	7	804
Peaker	290	14,059	28	430	262	13,629
Wind Turbine	30	18,534	1	20	29	18,514
Total	333	33,504	30	455	303	33,049

- 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

	Total		**Baseload**		**Intermediate**		**Peaker**		**Wind Turbine**	
Unit Type	**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	54	8,237	0	0	0	0	54	8,237	0	0
Fuel Cell	2	30	2	30	0	0	0	0	0	0
Hydro	3	99	2	33	0	0	1	66	0	0
Natural Gas	7	67	1	7	3	43	3	17	0	0
Natural Gas/Oil	5	823	0	0	4	761	1	62	0	0
Nuclear	1	37	1	37	0	0	0	0	0	0
Solar	231	5,677	0	0	0	0	231	5,677	0	0
Wind	30	18,534	0	0	0	0	0	0	30	18,534
Total	333	33,504	6	107	7	804	290	14,059	30	18,534

- 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 13

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

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

ARA – Annual Reconfiguration Auction
CSO – Capacity Supply Obligation
FCA – Forward Capacity Auction
ICR – Installed Capacity Requirement

Capacity Supply Obligation FCA 14

Resource Type	**Resource Type**	**FCA**	**ARA 1**		**ARA 2**		**ARA 3**	
		CSO	**CSO**	**Change**	**CSO**	**Change**	**CSO**	**Change**
		MW	**MW**	**MW**	**MW**	**MW**	**MW**	**MW**
Demand	*Active Demand*	592.043	688.07	96.027				
	Passive Demand	3,327.071	3,327.932	0.861				
Demand Total		**3,919.114**	**4,016.002**	**96.888**				
Generator	*Non-Intermittent*	27,816.902	28,275.143	458.241				
	Intermittent	1,160.916	1,128.446	-32.47				
Generator Total		**28,977.818**	**29,403.589**	**425.771**				
Import Total		**1,058.72**	**1,058.72**	**0**				
Grand Total*		**33,955.652**	**34,478.311**	**522.661**				
Net ICR (NICR)		**32,490**	**32,980**	**490**				

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 15

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	677.673						
	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.

Capacity Supply Obligation FCA 16

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	765.35						
	Passive Demand	2,557.256						
Demand Total		**3,322.606**						
Generator	*Non-Intermittent*	26,805.003						
	Intermittent	1,178.933						
Generator Total		**27,983.936**						
Import Total		**1,503.842**						
Grand Total*		**32,810.384**						
Net ICR (NICR)		**31,645**						

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

Note: A resource’s CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2020 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Active/Passive Demand Response

CSO Totals by Commitment Period

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

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

What are Daily NCPC Payments?

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

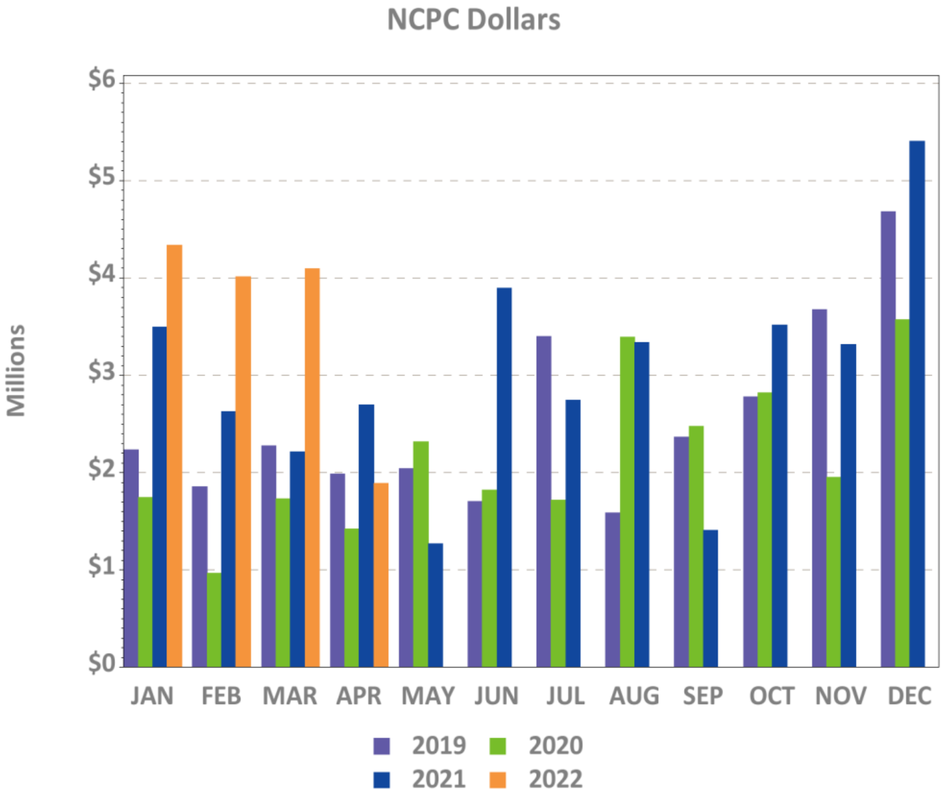
Definitions

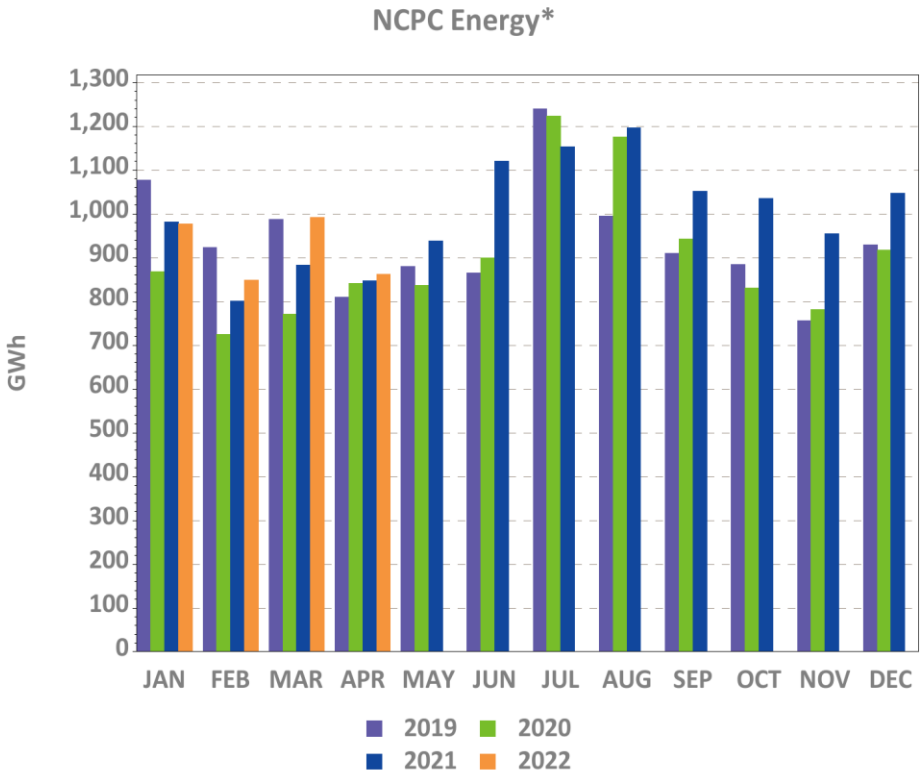
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

Charge Allocation Key

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

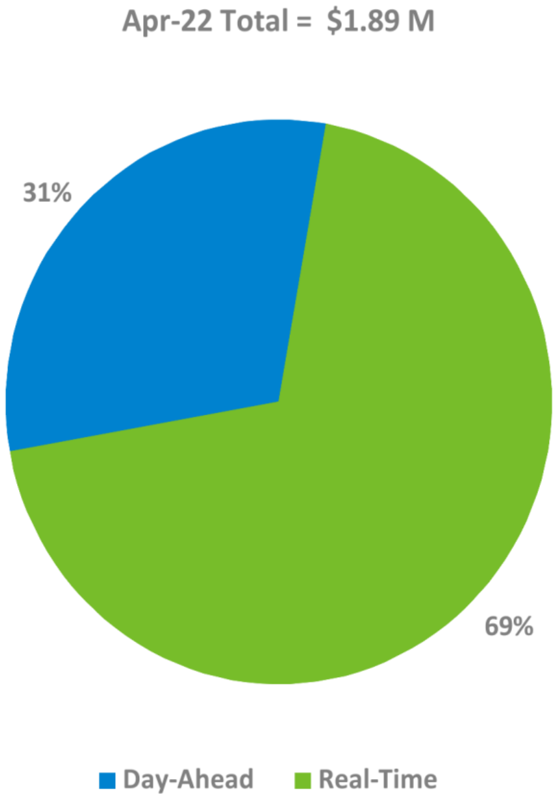
Year-Over-Year Total NCPC Dollars and Energy

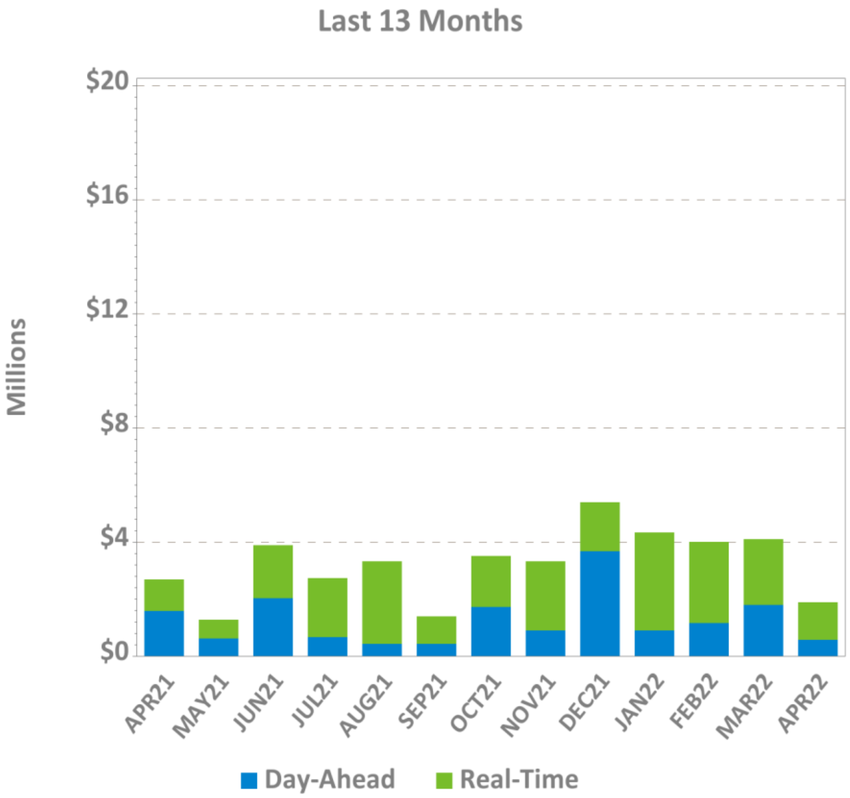




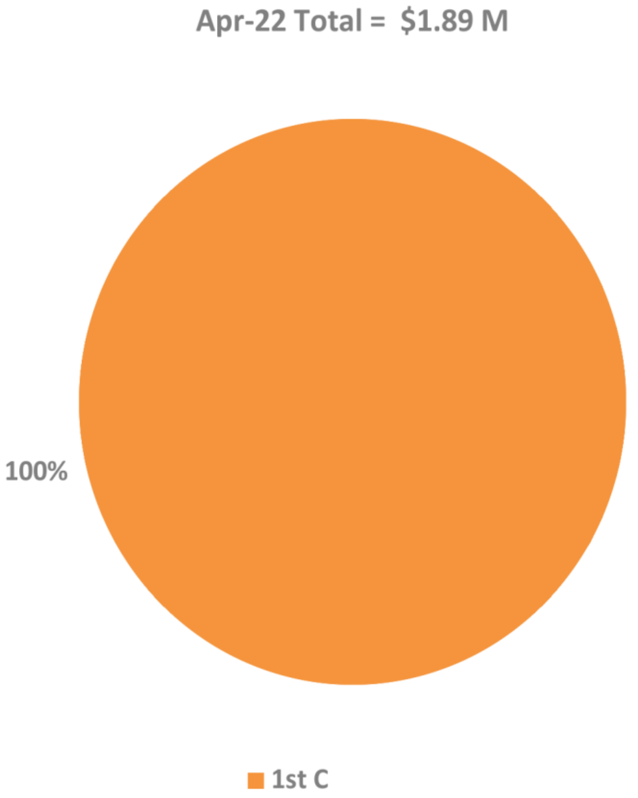
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

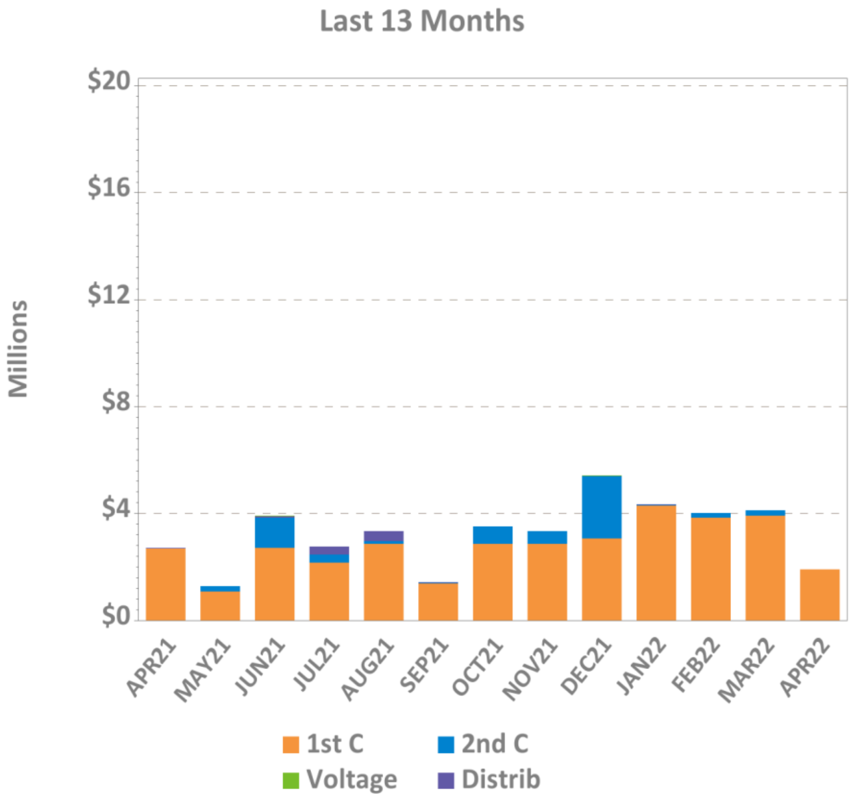
DA and RT NCPC Charges





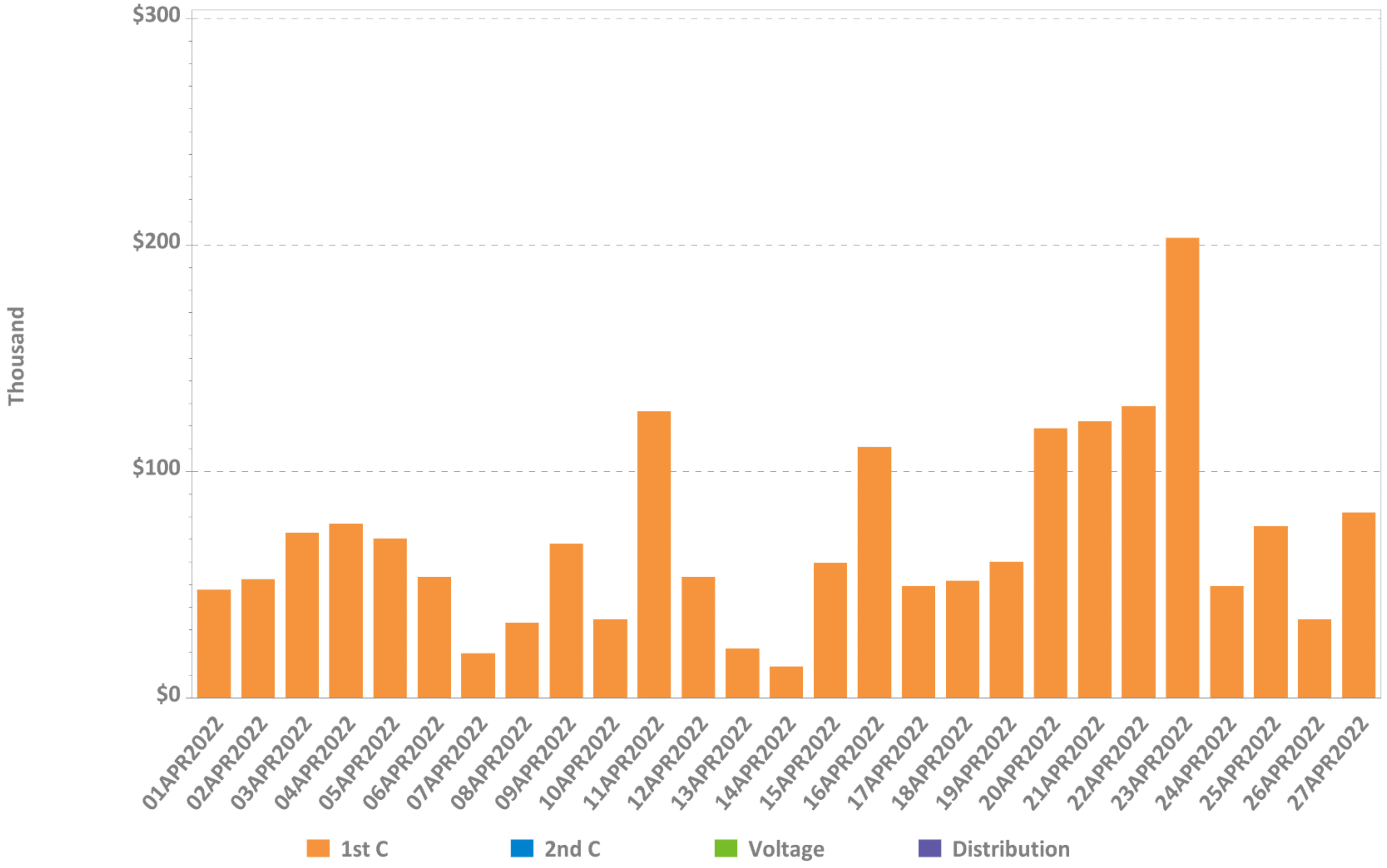
NCPC Charges by Type



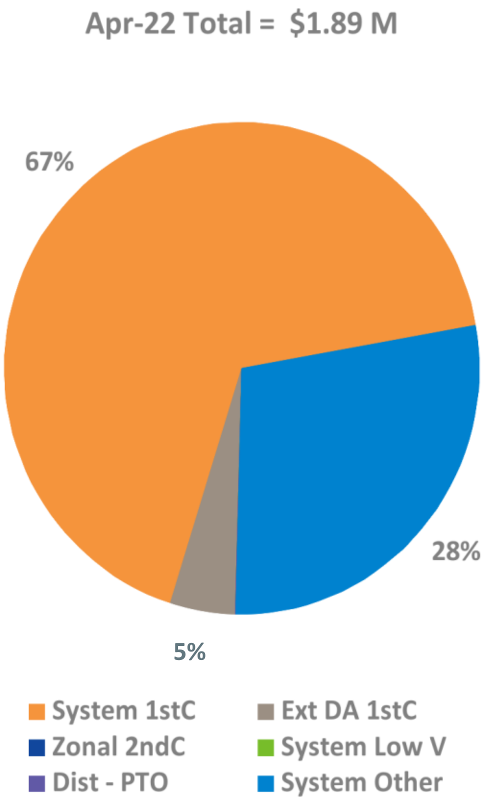


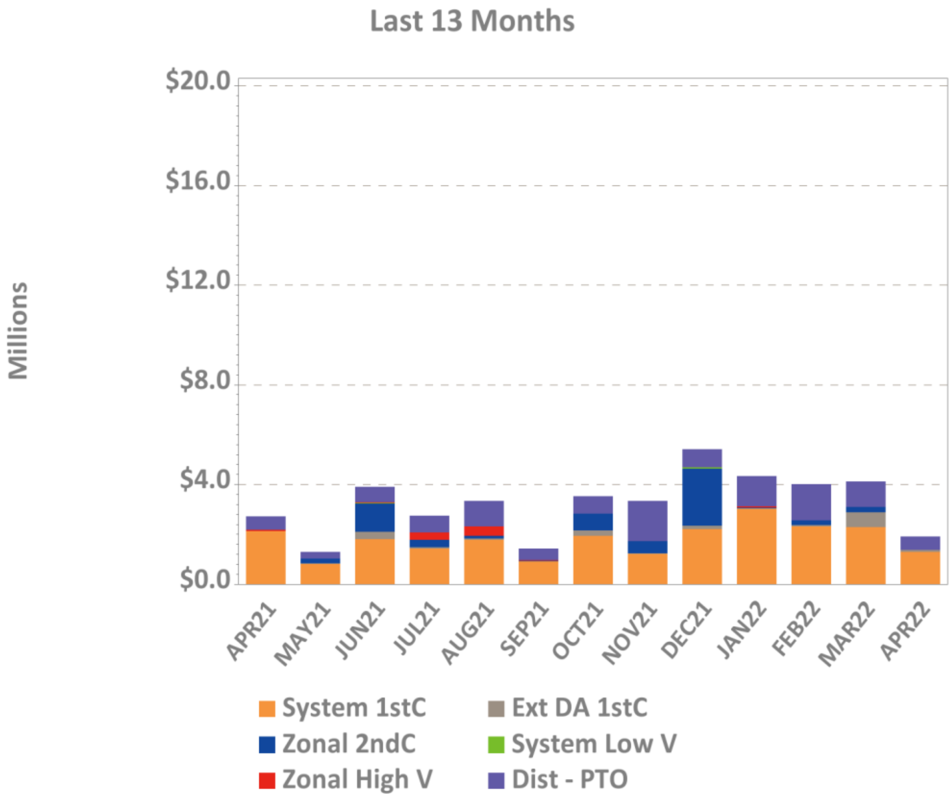
1^{st} C – First Contingency
2^{nd} C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



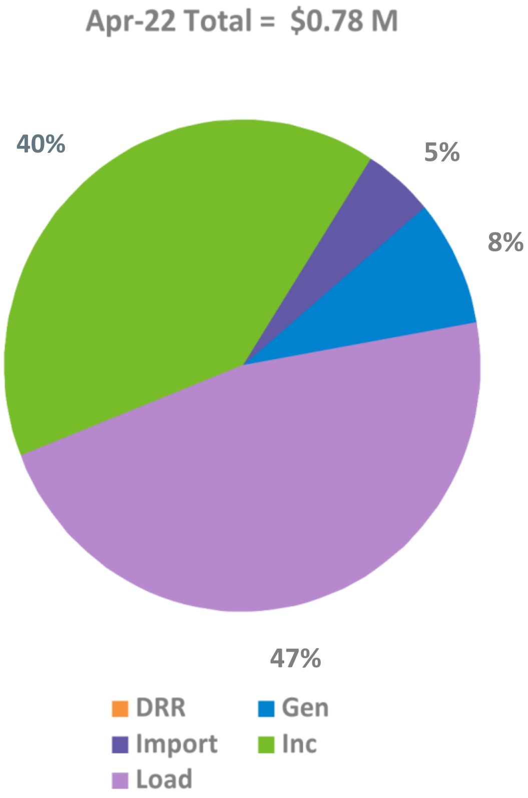
NCPC Charges by Allocation

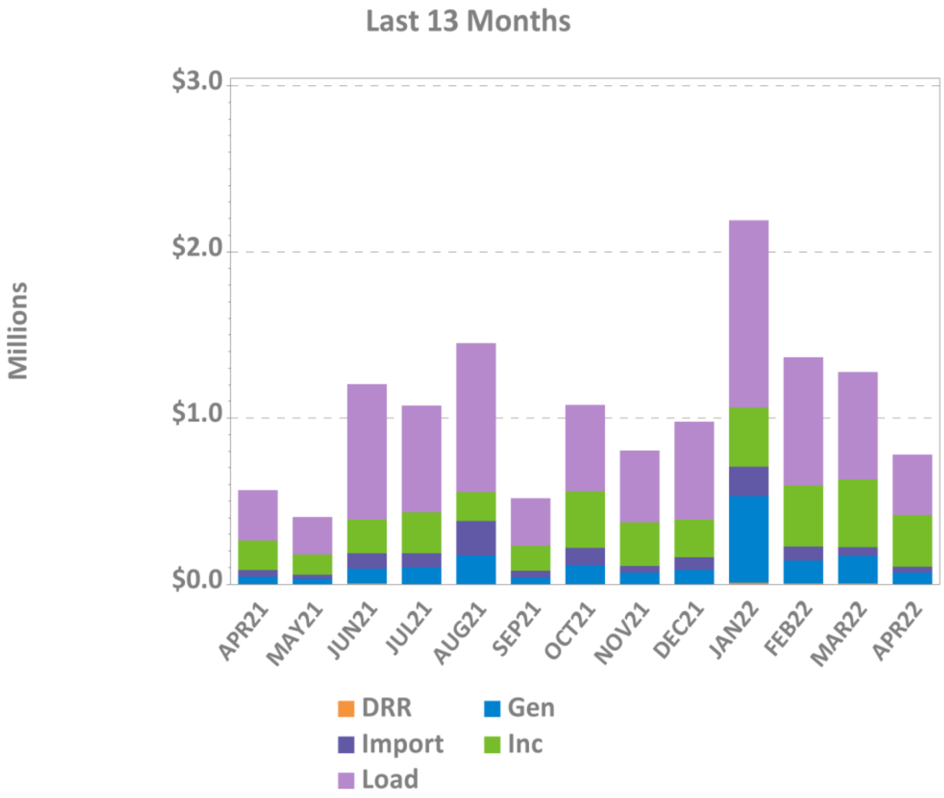




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

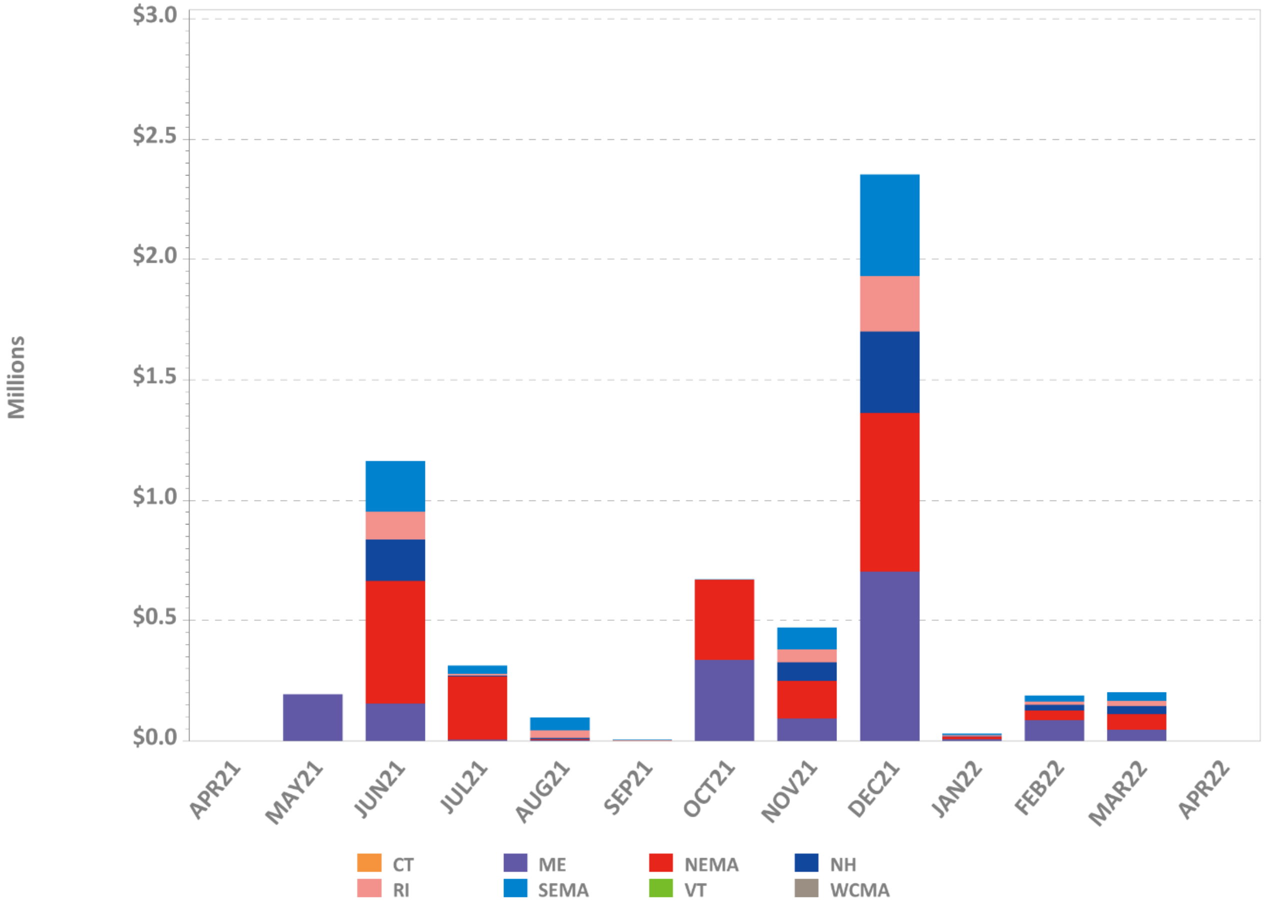
RT First Contingency Charges by Deviation Type





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

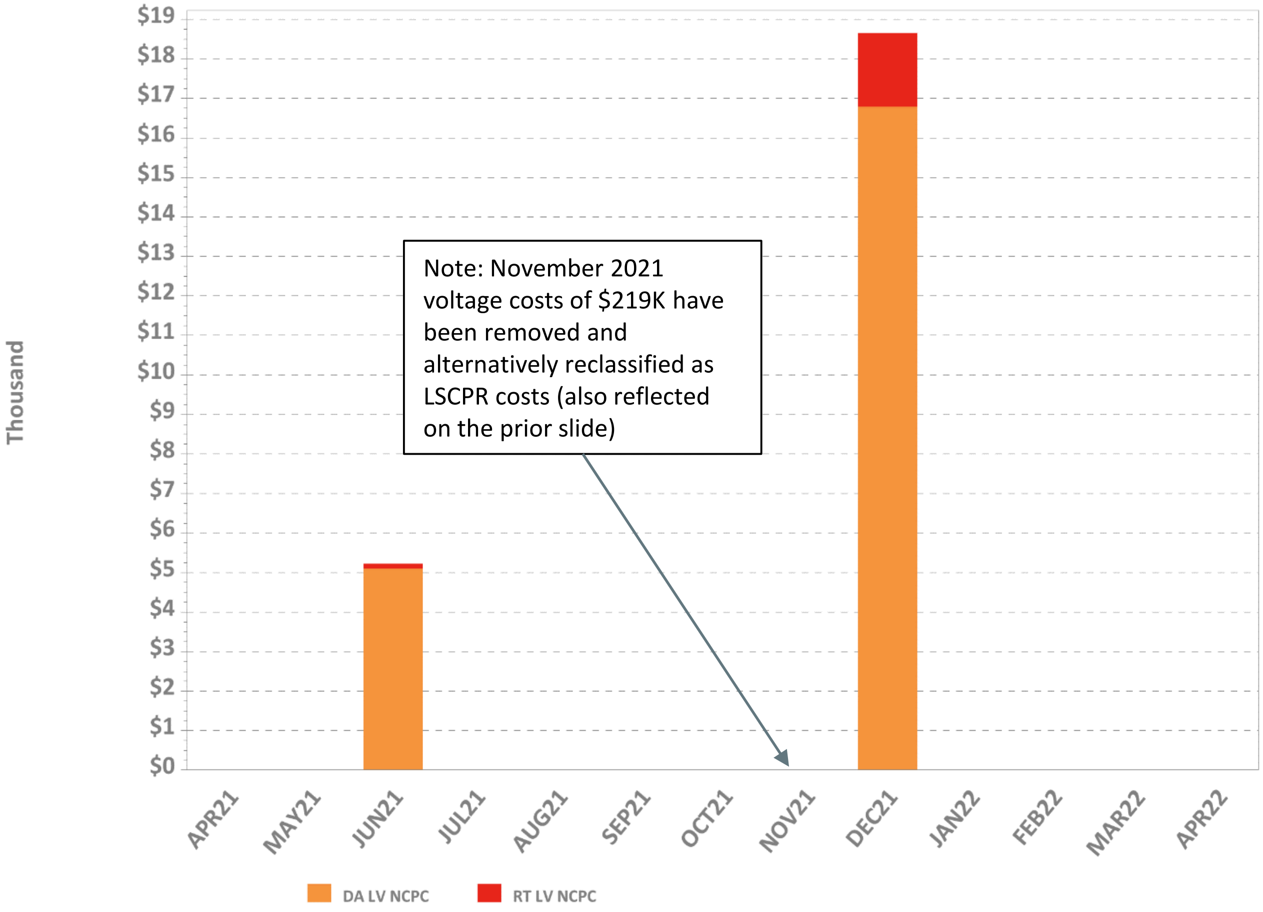
LSCPR Charges by Reliability Region



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

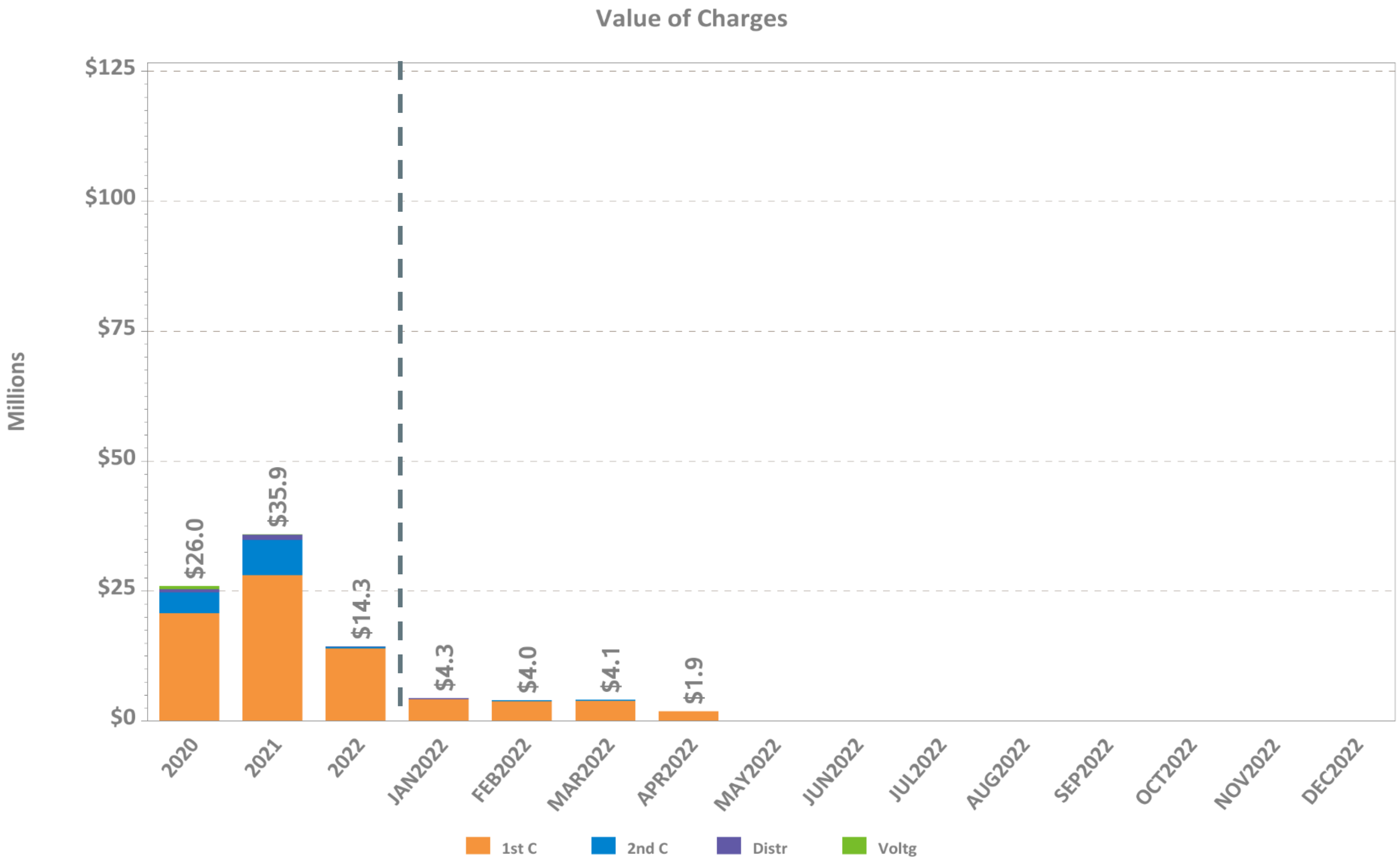
SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region

NCPC Charges for Voltage Support and High Voltage Control

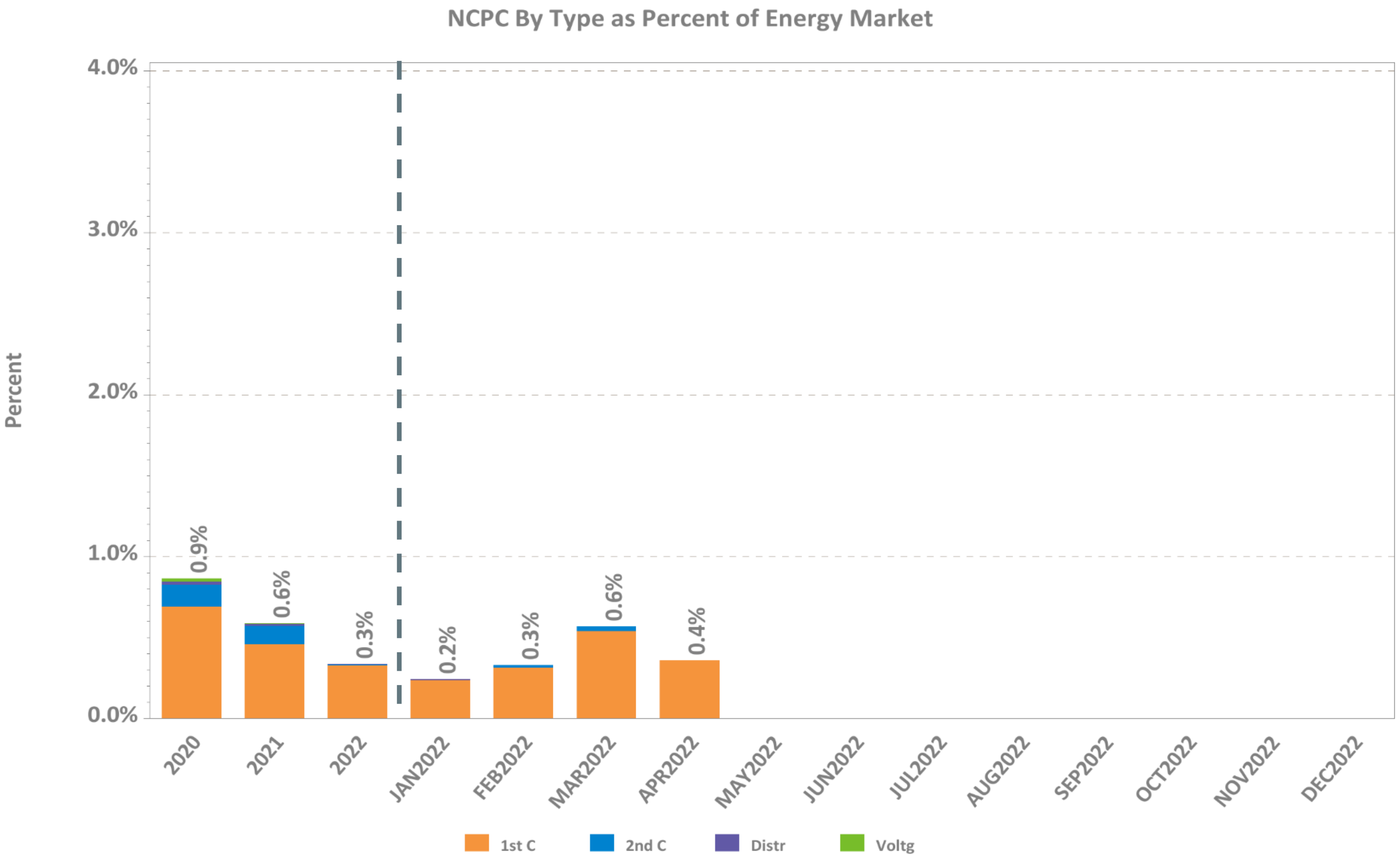


Note: November 2021 voltage costs of $219K have been removed and alternatively reclassified as LSCPR costs (also reflected on the prior slide)

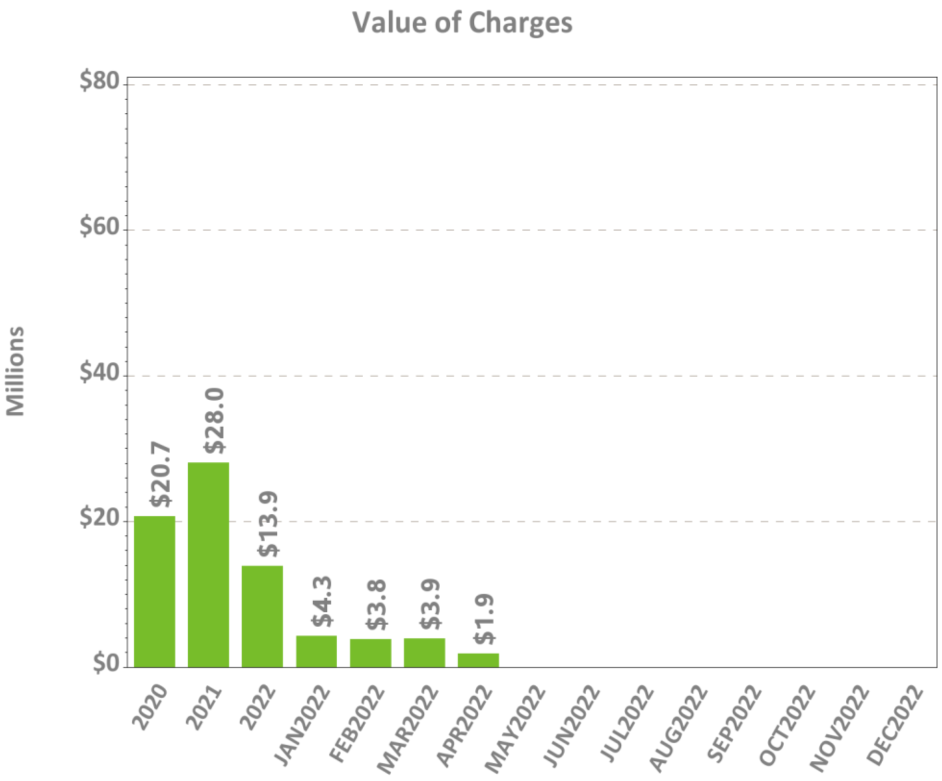
NCPC Charges by Type

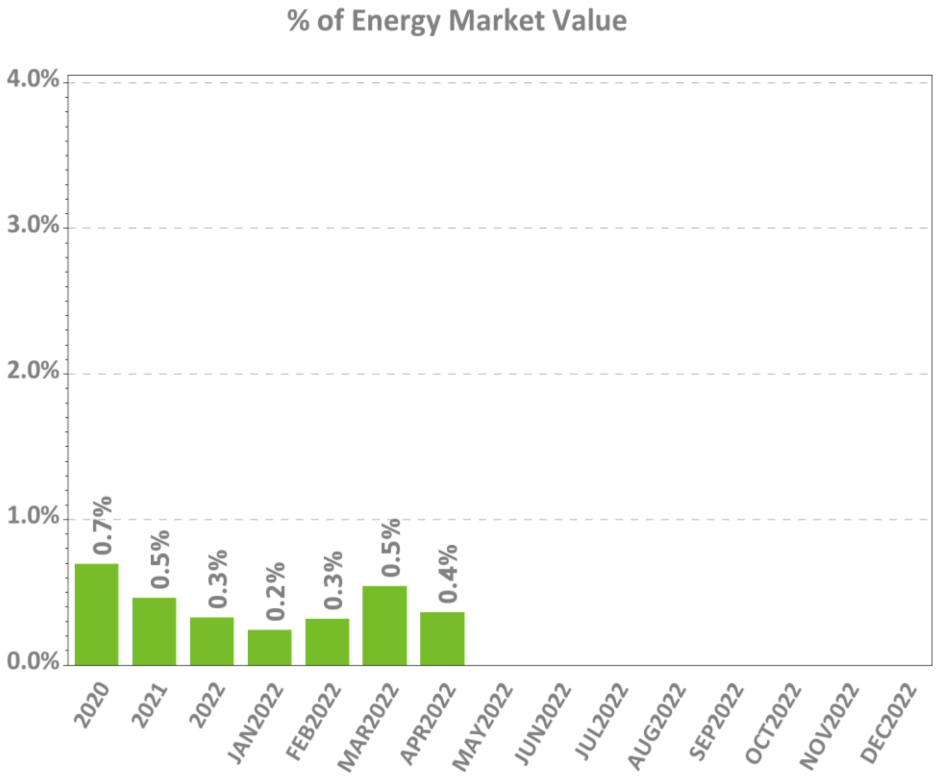


NCPC Charges as Percent of Energy Market



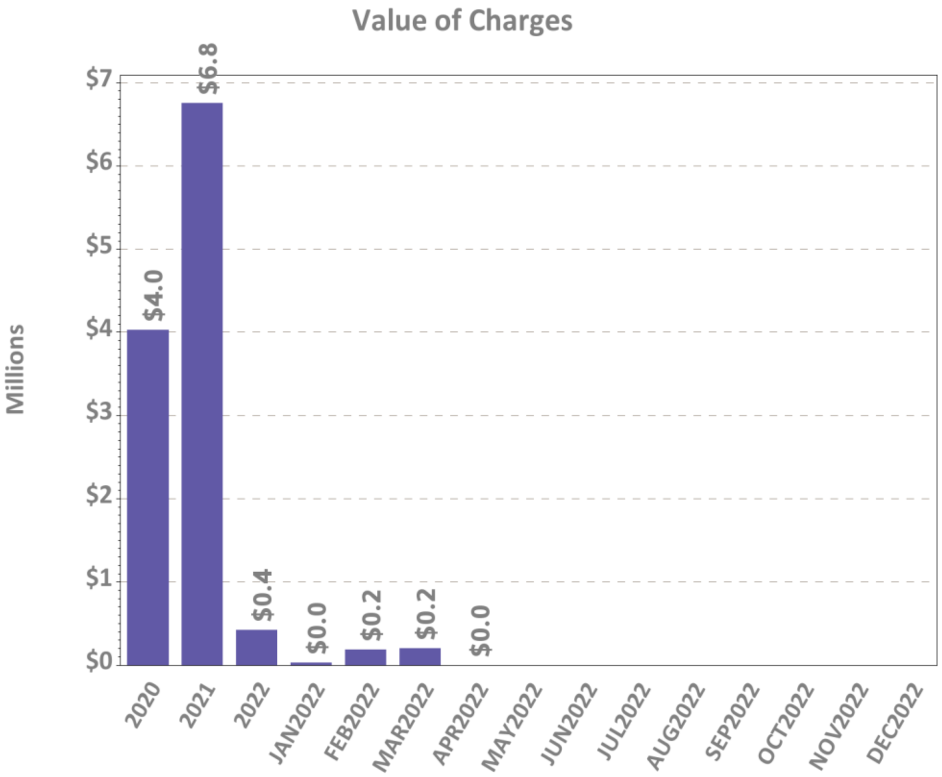
First Contingency NCPC Charges

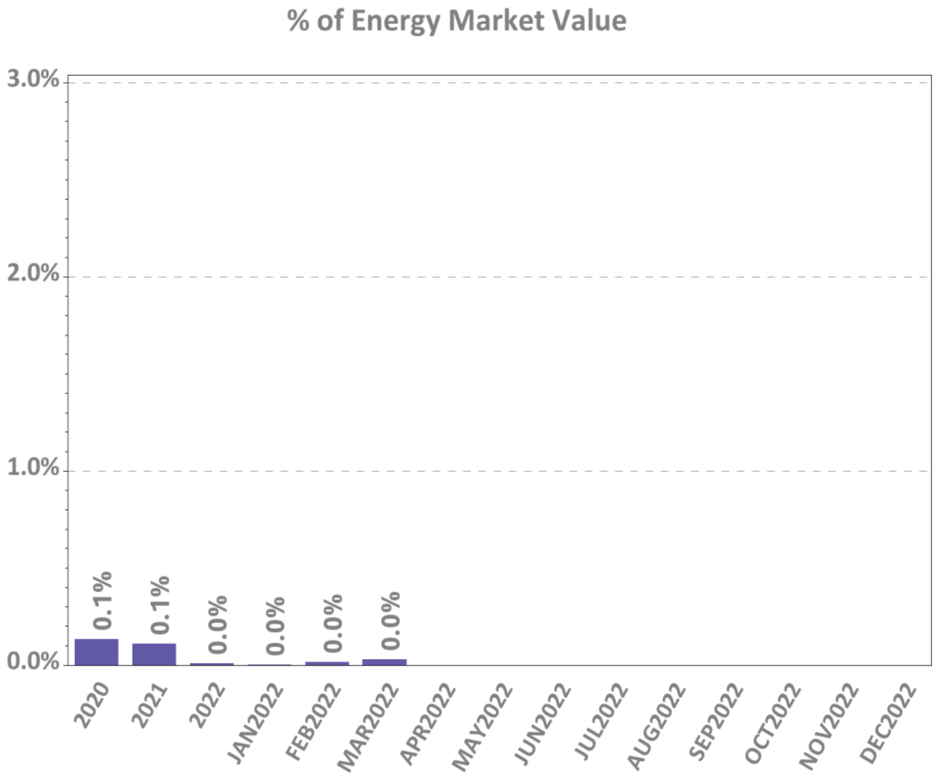




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

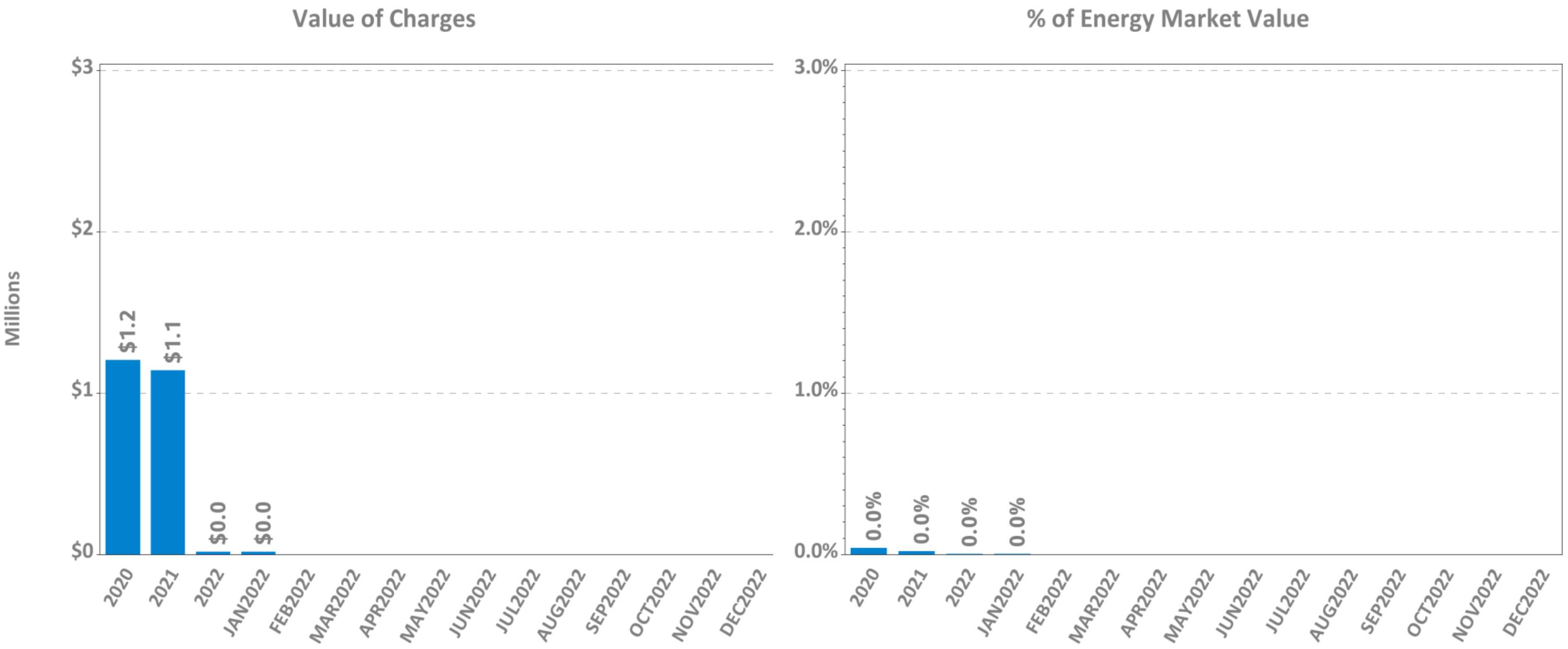
Second Contingency NCPC Charges





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

Voltage and Distribution NCPC Charges



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

DA vs. RT Pricing

The following slides outline:

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

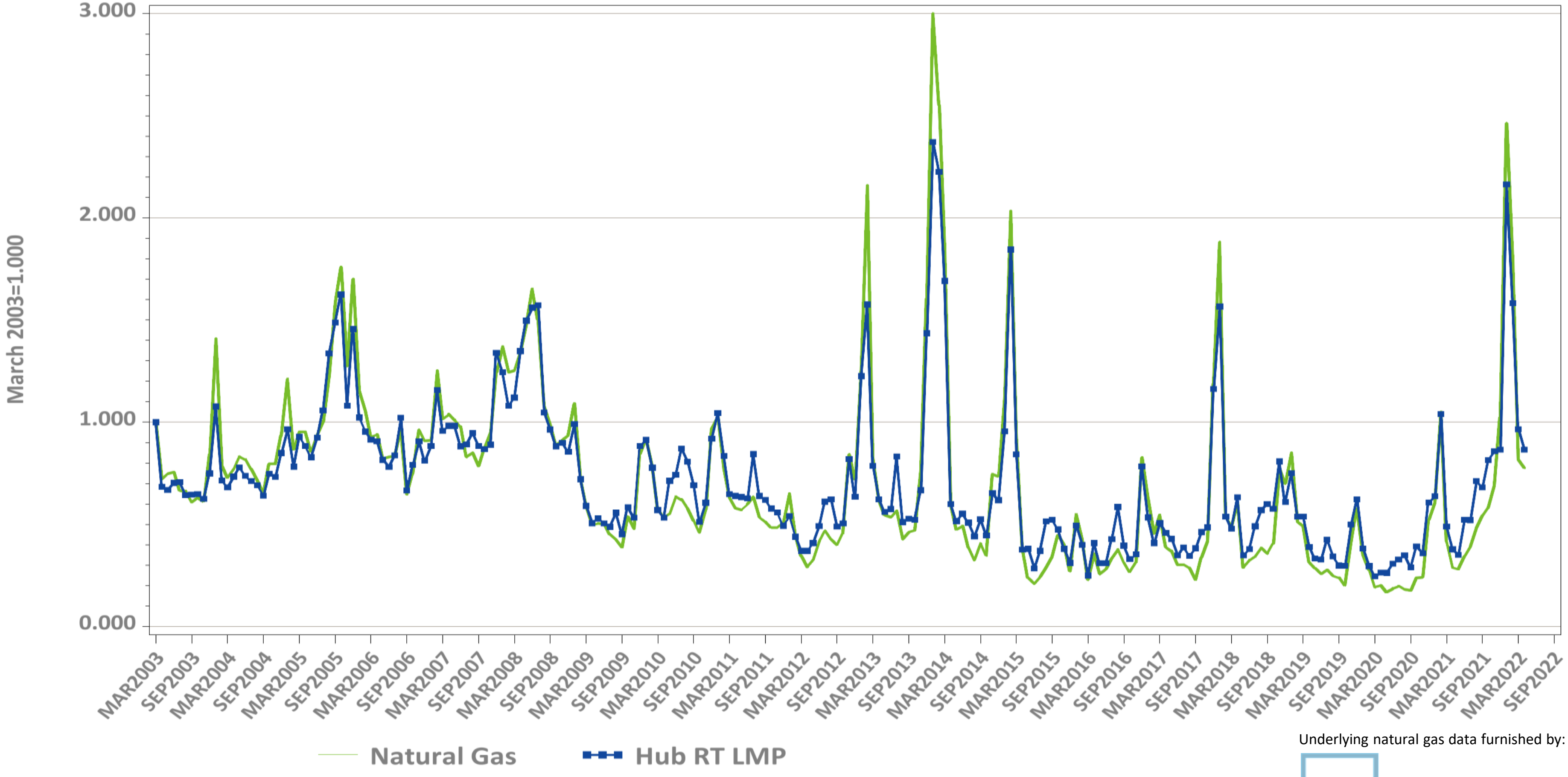
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2020	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$23.62	$22.59	$23.27	$23.50	$22.76	$23.27	$23.57	$23.30	$23.32
Real-Time	$23.62	$22.91	$23.23	$23.54	$22.90	$23.29	$23.56	$23.37	$23.38
RT Delta %	0.0%	1.4%	-0.2%	0.2%	0.6%	0.1%	-0.1%	0.3%	0.3%
Year 2021	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$46.54	$44.60	$45.52	$46.27	$45.05	$45.88	$46.38	$45.91	$45.92
Real-Time	$45.25	$43.97	$44.28	$45.10	$44.15	$44.61	$45.09	$44.85	$44.84
RT Delta %	-2.8%	-1.4%	-2.7%	-2.5%	-2.0%	-2.8%	-2.8%	-2.3%	-2.3%

April-21	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$26.28	$25.80	$25.26	$26.00	$25.35	$26.14	$26.34	$26.15	$26.14
Real-Time	$26.17	$25.71	$25.19	$25.90	$25.21	$25.97	$26.19	$25.99	$25.99
RT Delta %	-0.4%	-0.3%	-0.3%	-0.4%	-0.5%	-0.6%	-0.6%	-0.6%	-0.6%
April-22	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$61.80	$61.59	$58.89	$60.67	$59.57	$61.64	$62.10	$61.63	$61.51
Real-Time	$59.75	$59.66	$55.77	$58.50	$57.47	$59.57	$60.02	$59.54	$59.51
RT Delta %	-3.3%	-3.1%	-5.3%	-3.6%	-3.5%	-3.4%	-3.4%	-3.4%	-3.2%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	135.1%	138.7%	133.2%	133.3%	135.0%	135.8%	135.8%	135.7%	135.3%
Yr over Yr RT	128.3%	132.0%	121.4%	125.9%	127.9%	129.4%	129.2%	129.1%	129.0%

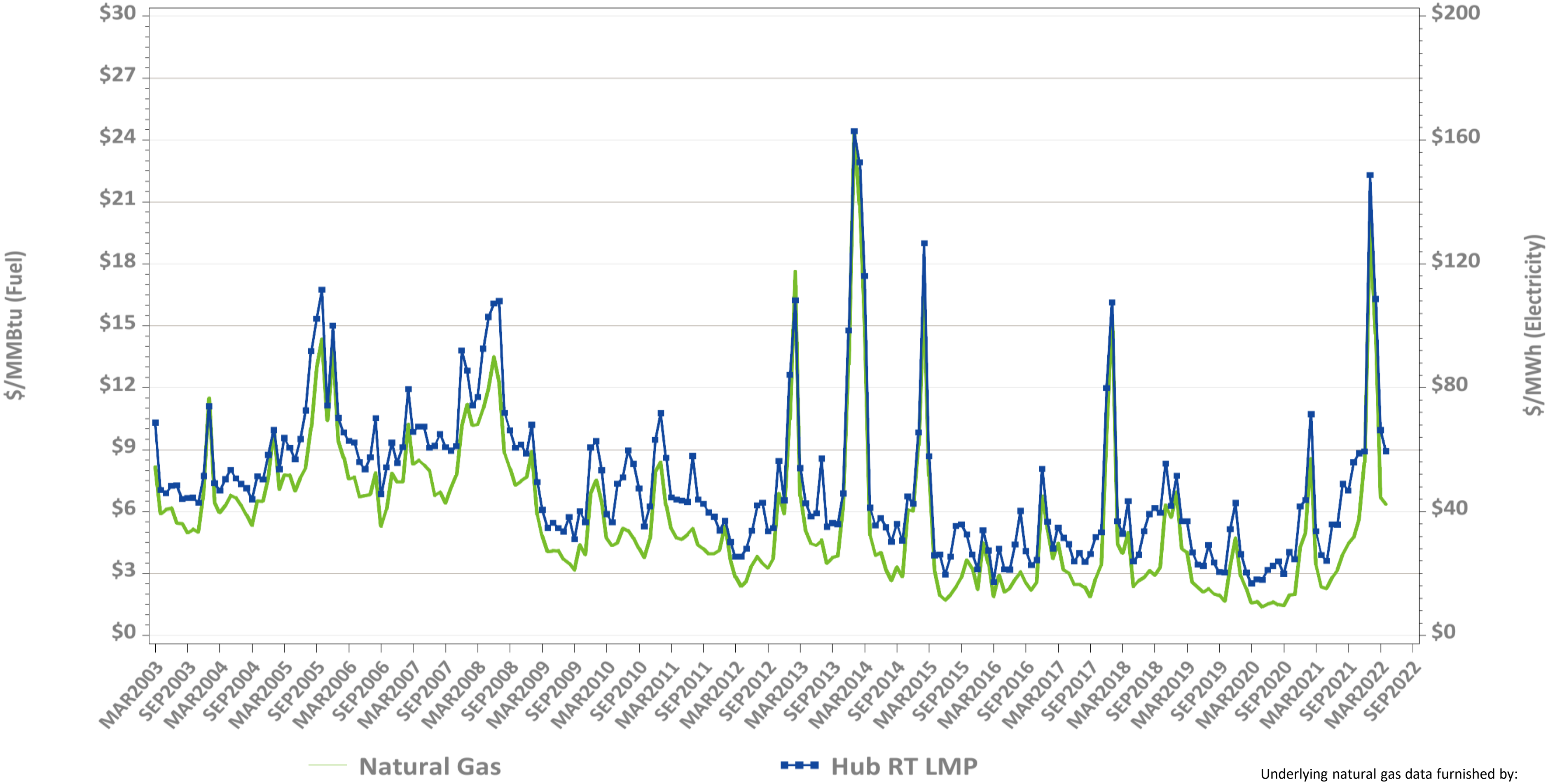
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ice Global markets in clear view

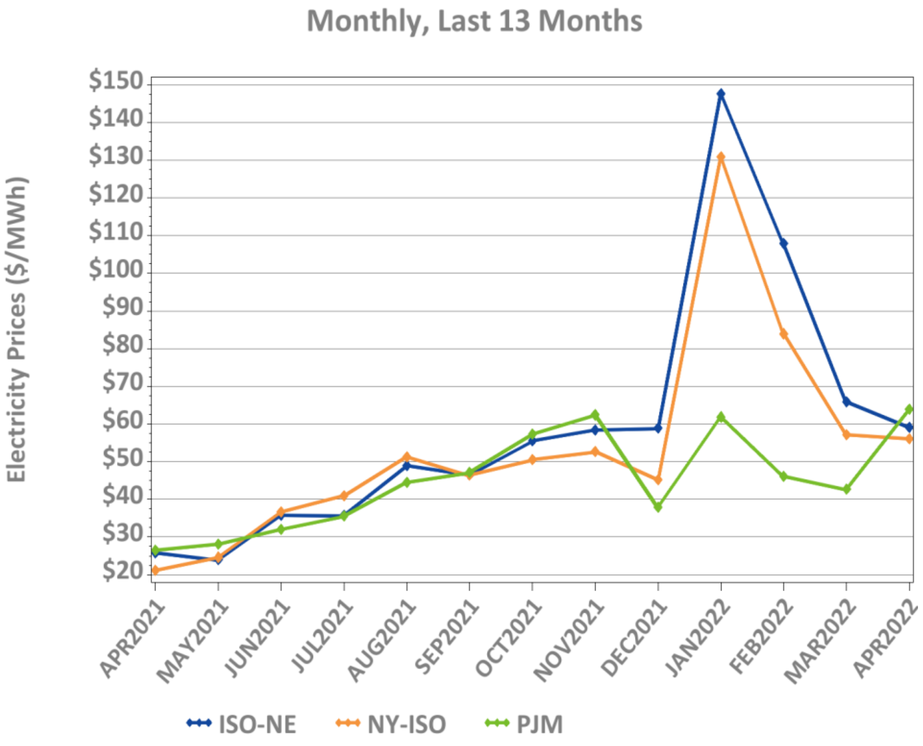
Monthly Average Fuel Price and RT Hub LMP



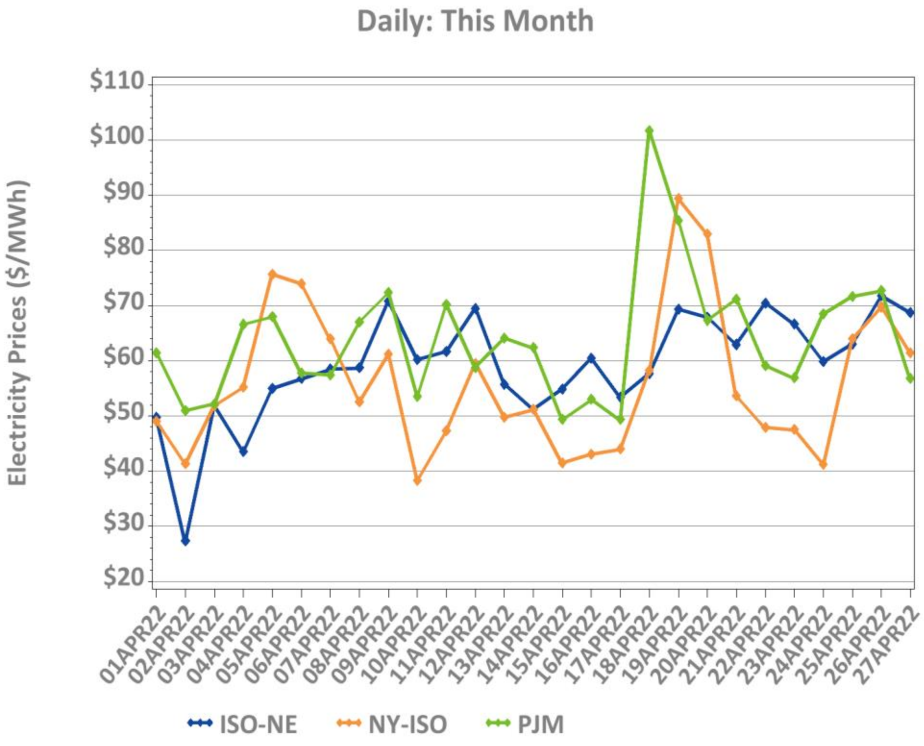
Underlying natural gas data furnished by:

ICE Global markets in clear view

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

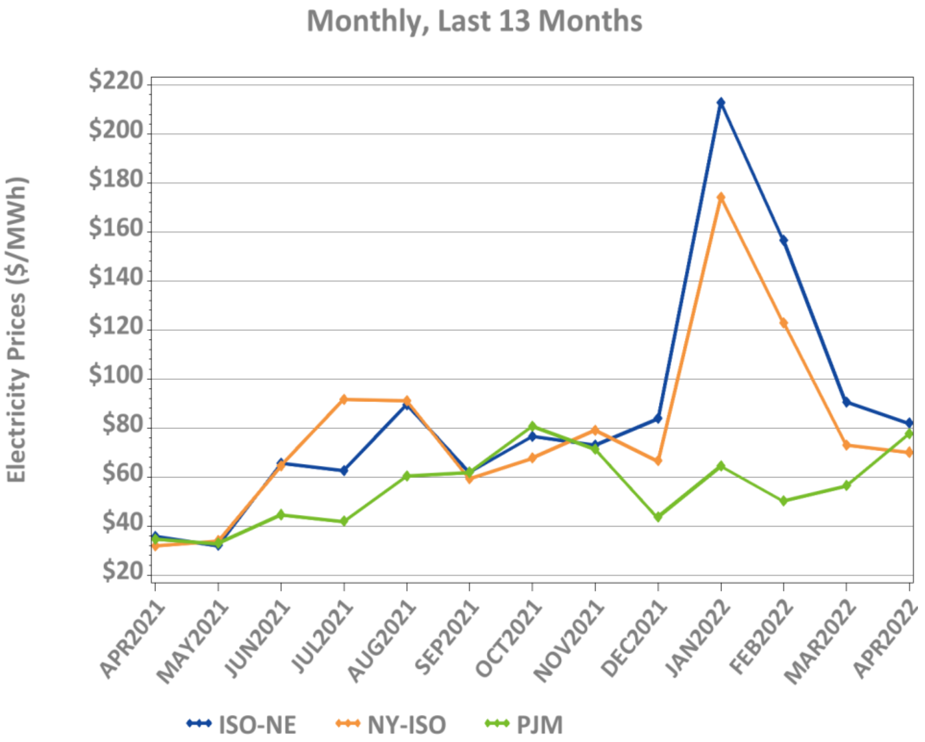

Monthly, Last 13 Months

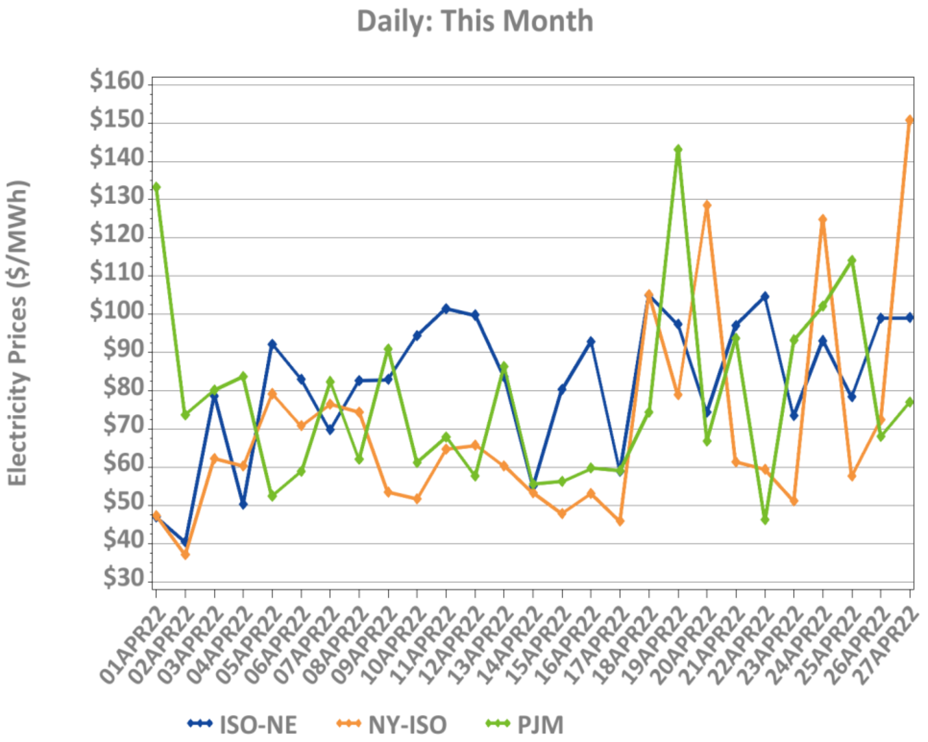
*Note: Hourly average prices are shown.


Daily: This Month

*Note: Hourly average prices are shown.

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


Monthly, Last 13 Months


Daily: This Month

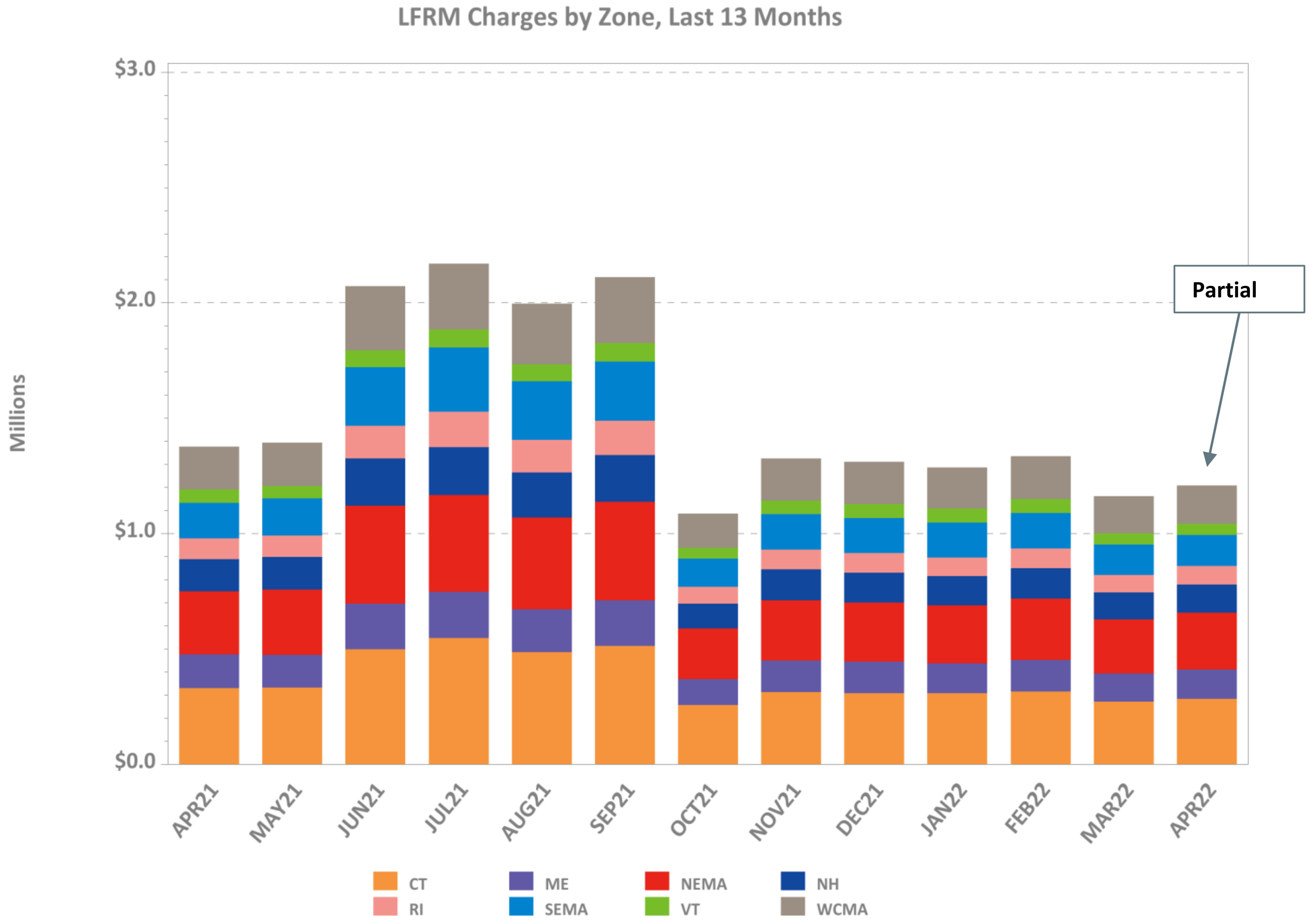
*Forecasted New England daily peak hours reflected

Reserve Market Results – April 2022

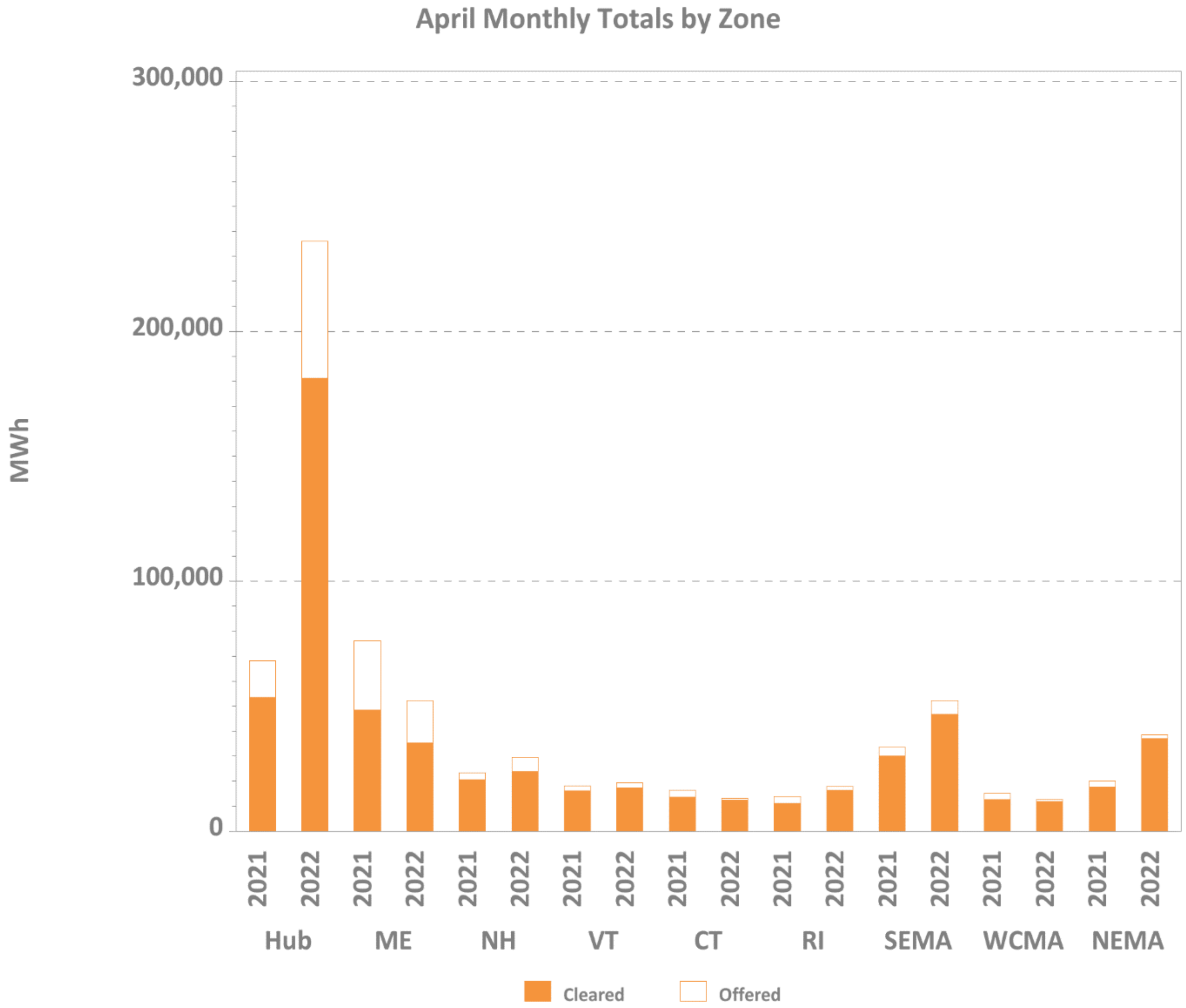
- Maximum potential Forward Reserve Market payments of $1.1M were reduced by credit reductions of $19K, failure-to-reserve penalties of $28K and no failure-to-activate penalties, resulting in a net payout of $1.1M or 96% of maximum
  - Rest of System: $0.79M/0.84M (95%)
  - Southwest Connecticut: $0.03M/0.03M (99%)
  - Connecticut: $0.27M/0.27M (100%)
  - NEMA: $3.8/4.0K (95%)
- $602K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of $602K in Real-Time Reserve payments
  - Rest of System: 202 hours, $408K
  - Southwest Connecticut: 202 hours, $88K
  - Connecticut: 202 hours, $64K
  - NEMA: 202 hours, $42K

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

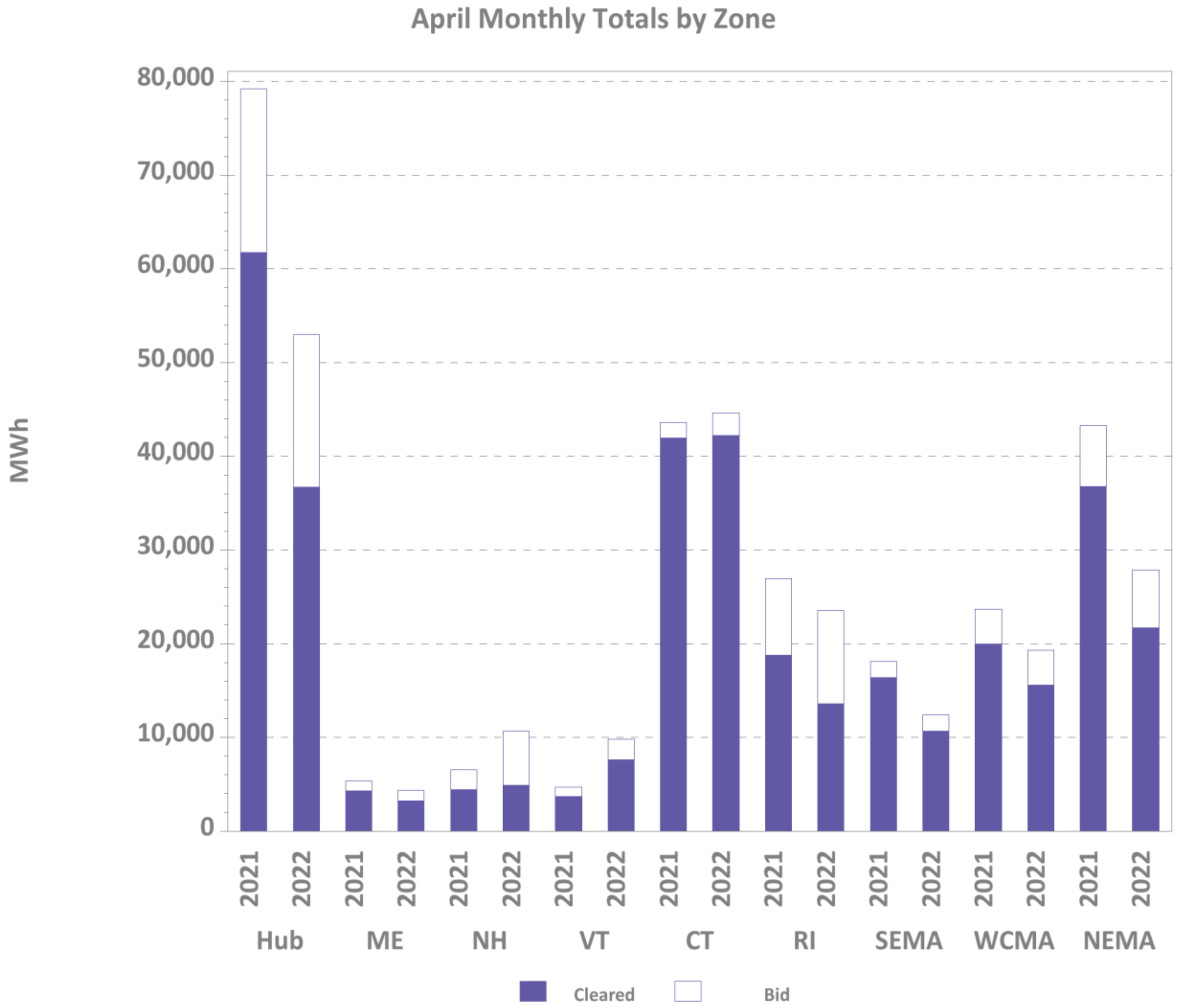
LFRM Charges to Load by Load Zone ($)



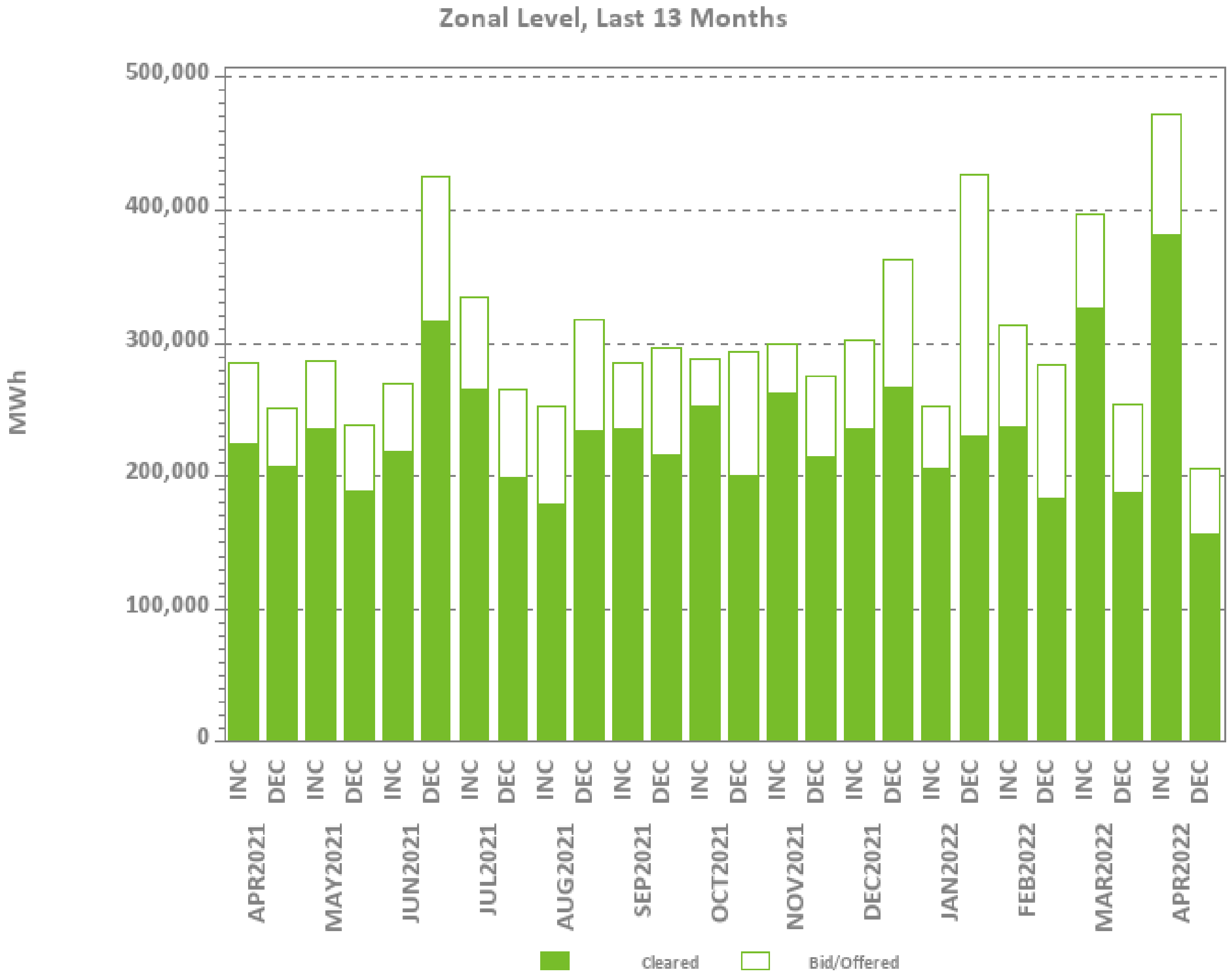
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

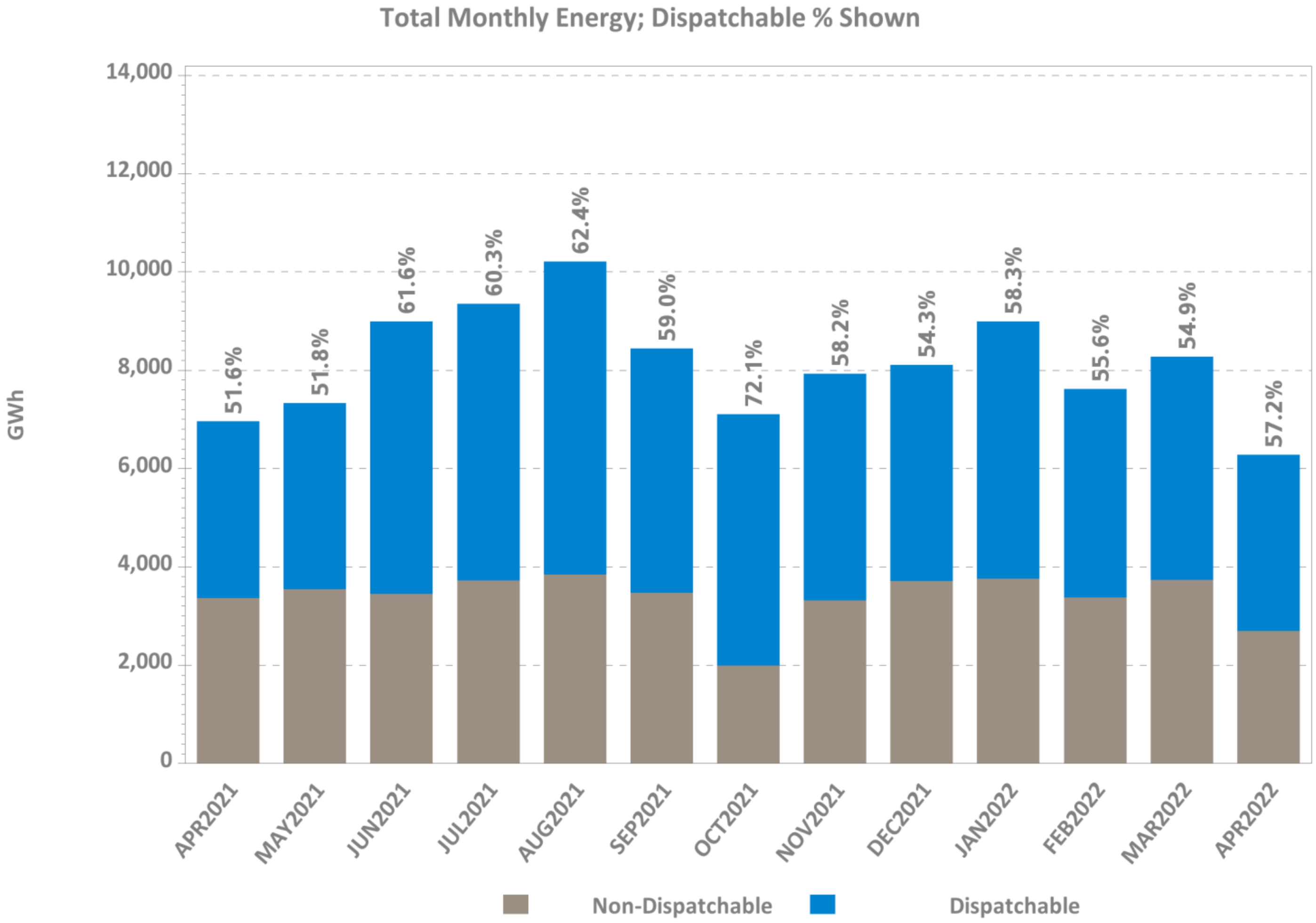


Total Increment Offers and Decrement Bids



Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



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

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- May 18 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - Transmission Line Refurbishment - K21, K32, and K50 Lines - VELCO
    - 345 kV Breaker Replacements - Eversource
    - NERC Alert II - CMP
  - Annual Update on New England Natural Gas Developments - Northeast Gas Association
  - Final 2022 Load Forecast: Regional Energy and Peak Demand Forecasts
  - Revised Max Generator Output for Peak Load Steady-State Analyses
  - Transmission Planning for the Clean Energy Transition: Updates on DER Modeling Assumptions

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

Transmission Planning for the Clean Energy Transition (TPCET)

- On 9/24/20 the ISO initiated discussions with the PAC about proposed refinements to transmission planning study assumptions that better reflect long-term trends, such as increased amounts of distributed-energy resources (primarily solar PV), offshore wind generation, and battery energy storage
- A follow-up presentation at the 11/19/20 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
- The final TPCET Pilot Study Report was posted to the PAC website on 1/14/22
- A status update on ongoing transient stability modeling and performance criteria work was given at the 4/28/22 PAC meeting

2050 Transmission Study

- A meeting with the states was held on 10/15/21 to review the draft study scope
- The draft study scope was discussed with the PAC on 11/17/21
- Written stakeholder comments were due on 12/2/21
- ISO worked with NESCOE to address the comments and finalized the scope on 12/22/21
- ISO provided initial results at the 3/16/22 PAC meeting
- Sensitivity results, as well as a high-level approach to solutions development, were discussed at the 4/28/22 PAC meeting

Economic Studies

- 2020 Economic Study Request
  - Study proponent is National Grid
  - Study simulations are complete and results have been presented to PAC
  - Draft report is expected in Q2
- 2021 Economic Study Request
  - Also known as Future Grid Reliability Study – Phase 1 (FGRS)
  - Study proponent is NEPOOL
  - Additional scope discussed at the February 16 joint MC/RC meeting and presented at the April PAC meeting
  - Draft report expected in June
- Economic Planning for the Clean Energy Transition Pilot Study
  - New effort to review all assumptions in economic planning and perform a test study consistent with the proposed changes to the Tariff

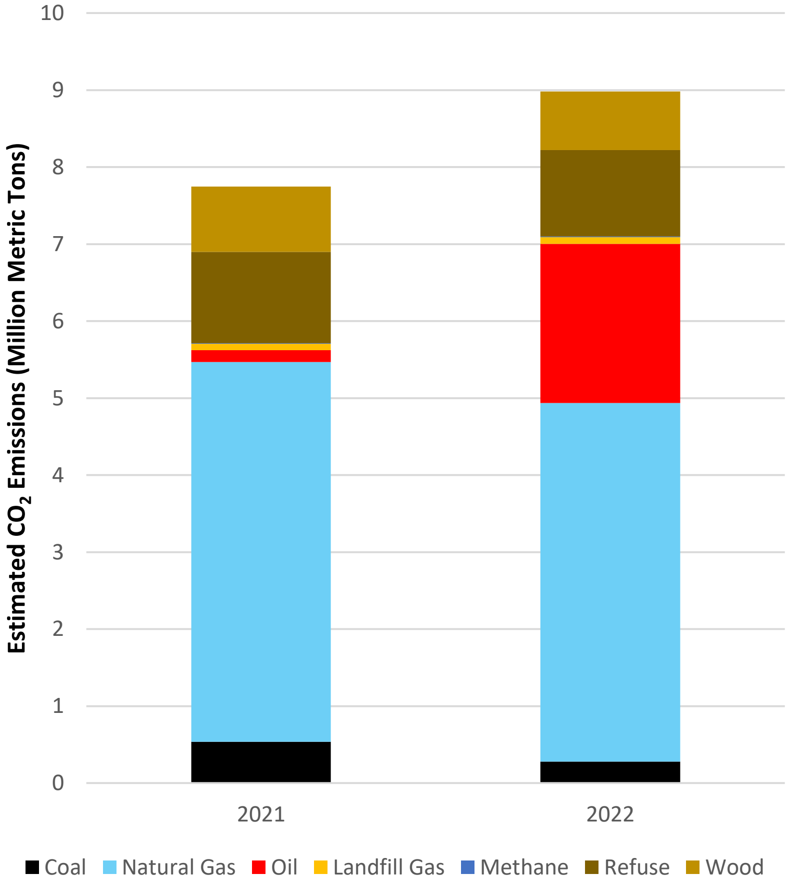
Future Grid Reliability Study (FGRS)

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

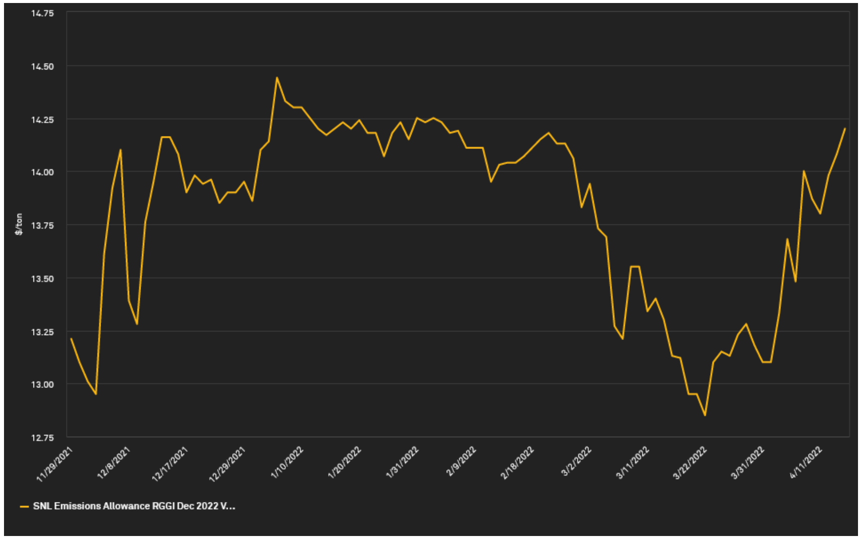
New England Power System Carbon Emissions

CO_2 emissions Up 16% year to year, reflects January oil-fired generation spike

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



RGGI Allowance Prices Volatile, Affected by Factors Outside New England



- 4/15/22: RGGI allowance spot price - $14.20 per allowance
- 3/9/22 55th RGGI auction cleared at $13.50
  - 97 million allowances will be auctioned in 2022
  - 192 million allowances already in circulation
- Coal-fired retirements in PJM RGGI states during 2022 projected to lower future demand for allowances

RGGI – Regional Greenhouse Gas Initiative

Massachusetts CO_2 Generator Emissions Cap

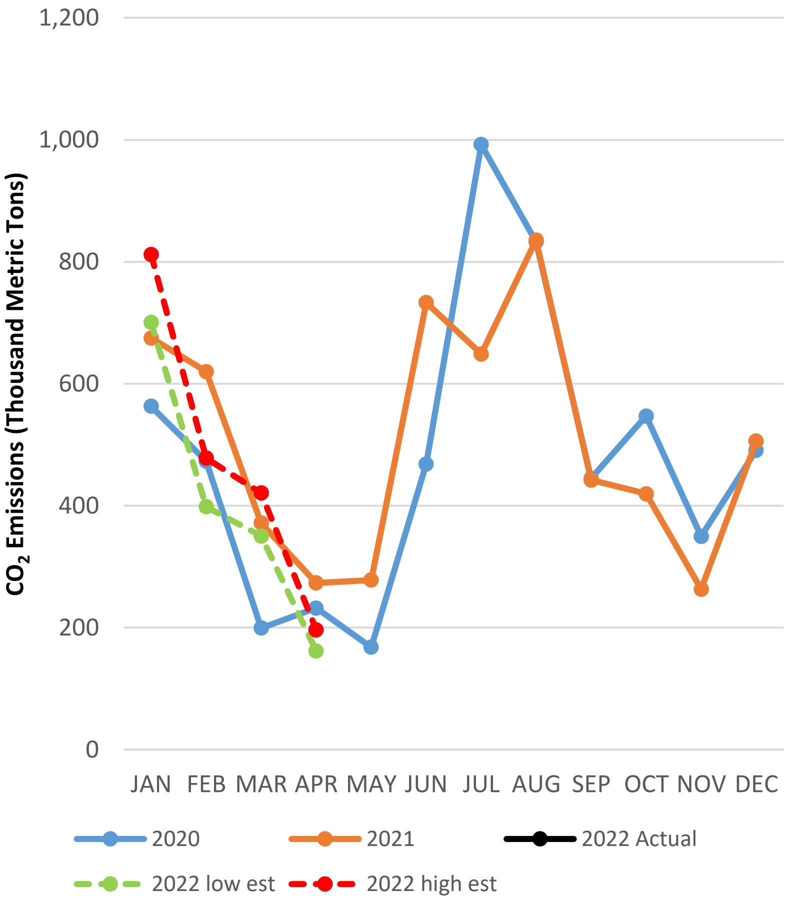
Uptick in 2022 Estimated Emissions Under CO_2 Cap

- 4/13/22: 2022 estimated GWSA CO_2 emissions range between 1.6 and 1.9 MMT
  - 20% to 24% of the 8.06 MMT 2022 cap
- 3/16/22 GWSA auction cleared at $0.50, the auction minimum reserve price; all 1.61 million 2022 vintage allowances sold
  - 2022 RGGI allowance spot price at $14.58 per metric ton
- 12/15/21 GWSA auction cleared at $9.75 per metric ton of CO_2 for 2022 vintage GWSA allowances
- IMM estimated compliance costs by fuel type (based on average GWSA emission/heat rates):
  - No. 2 fuel oil - $8.54/MWh
  - No. 6 fuel oil - $8.29/MWh
  - Natural gas - $2.39/MWh

GWSA – Global Warming Solutions Act
MMT – Million Metric Tons

Sources: ISO-NE (estimated emissions); EPA (actual emissions)

2019-2022 Estimated Monthly Emissions (Thousand Metric tons)



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 4/19/2022

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1213, 1220, 1365	Install new 345 kV line from Scobie to Tewksbury	Dec-17	4
1527, 1528	Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Apr-17	4
1212, 1549	Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
1549	Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
1260	Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
1550	Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-19	4
1551, 1552	Install new 345 kV cable from Woburn to Wakefield Junction, install two new 160 MVAR variable shunt reactors and associated work at Wakefield Junction and Woburn*	May-23	3*
1329	Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	4
1327	Reconductor W-23W 69 kV line from Woodside to Northboro Road	Jun-19	4

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

Greater Boston Projects, cont.

Status as of 4/19/2022

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1330	Separate X-24 and E-157W DCT	Dec-18	4
1363	Separate Q-169 and F-158N DCT	Dec-15	4
1637, 1640	Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
1516	Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-20	4
965	Install third 115 kV line from West Walpole to Holbrook	Sep-20	4
1558	Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
1199	Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-17	4
1335	Install a new 115 kV line from Sudbury to Hudson	Dec-23	2

Greater Boston Projects, cont.

Status as of 4/19/2022

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1336	Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-19	4
1553	Install a 345 kV breaker in series with breaker 104 at Woburn	Jun-17	4
1337	Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	4
1339	Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
1521	Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	4
1522	Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	4
1352	Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	May-19	4
1353	Install a 115 kV breaker on the East bus at K Street	Jun-16	4
1354, 1738	Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	Jul-21	4
1355	Split 110-522 and 240-510 DCT from Baker Street to Needham for a portion of the way and install a 115 kV cable for the rest of the way	Mar-21	4

Greater Boston Projects, cont.

Status as of 4/19/2022

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1356	Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	Dec-22	3
1357	Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station.	May-19	4
1518	Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	4
1519	Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 4/19/2022

Plan Benefit: Addresses long-term system needs in the Greater Boston area and improves system reliability

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1520	Upgrade North Cambridge to mitigate 115 kV 5 and 10 stuck breaker contingencies	Dec-17	4
1643	Install a 200 MVAR STATCOM at Coopers Mills	Nov-18	4
1341, 1645	Install a 115 kV 36.7 MVAR capacitor bank at Hartwell	May-17	4
1646	Install a 345 kV 160 MVAR shunt reactor at K Street	Dec-19	4
1647	Install a 115 kV breaker in series with the 5 breaker at Framingham	Mar-17	4
1554	Install a 115 kV breaker in series with the 29 breaker at K Street	Apr-17	4

SEMA/RI Reliability Projects

Status as of 4/19/2022

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1714	Construct a new 115 kV GIS switching station (Grand Army) which includes remote terminal station work at Brayton Point and Somerset substations, and the looping in of the E-183E, F-184, X3, and W4 lines	Oct-20	4
1742	Conduct remote terminal station work at the Wampanoag and Pawtucket substations for the new Grand Army GIS switching station	Oct-20	4
1715	Install upgrades at Brayton Point substation which include a new 115 kV breaker, new 345/115 kV transformer, and upgrades to E183E, F184 station equipment	Oct-20	4
1716	Increase clearances on E-183E & F-184 lines between Brayton Point and Grand Army substations	Nov-19	4
1717	Separate the X3/W4 DCT and reconductor the X3 and W4 lines between Somerset and Grand Army substations; reconfigure Y2 and Z1 lines	Nov-19	4

SEMA/RI Reliability Projects, cont.

Status as of 4/19/2022

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Mar-22	4
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	May-25	2
1721	Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor	Dec-23	3
1722	Extend the Line 114 from the Dartmouth town line (Eversource-National Grid border) to Bell Rock substation	Dec-24	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 4/19/2022

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1725	Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	Dec-23	1
1726	Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	4
1727	Retire the Barnstable SPS	Nov-21	4
1728	Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Dec-22	2
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Dec-22	2
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-24	2

SEMA/RI Reliability Projects, cont.

Status as of 4/19/2022

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1731	Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	4
1732	Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Dec-25	3
1733	Separate the 325/344 DCT lines from West Medway to West Walpole substations	Cancelled**	N/A
1734	Reconductor and upgrade the 112 Line from the Tremont substation to the Industrial Tap	Jun-18	4
1736	Reconductor the 108 line from Bourne substation to Horse Pond Tap*	Oct-18	4
1737	Replace disconnect switches on 323 line at West Medway substation and replace 8 line structures	Aug-20	4

* Does not include the reconductoring work over the Cape Cod canal

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

SEMA/RI Reliability Projects, cont.

Status as of 4/19/2022

Project Benefit: Addresses system needs in the Southeast Massachusetts/Rhode Island area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1741	Rebuild the Middleborough Gas and Electric portion of the E1 line from Bridgewater to Middleborough	Apr-19	4
1782	Reconductor the J16S line	Jun-22	3
1724	Replace the Kent County 345/115 kV transformer	Mar-22	4
1789	West Medway 345 kV circuit breaker upgrades	Apr-21	4
1790	Medway 115 kV circuit breaker replacements	Nov-20	4

Eastern CT Reliability Projects

Status as of 4/19/2022

Project Benefit: Addresses system needs in the Eastern Connecticut area

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

Eastern CT Reliability Projects, cont.

Status as of 4/19/2022

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1855	Re-terminate the 100 Line at Montville station and associated work. Energize the 100 Line at 115 kV	Dec-23	2
1856	Rebuild 400-1 Line section to allow operation at 115 kV (Tunnel to Ledyard Jct.)	Dec-22	2
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	2
1858	Rebuild 400-2 Line section to allow operation at 115 kV (Ledyard Jct. to Border Bus with CMEEC)	Dec-22	3
1859	Rebuild the 400-3 Line Section to allow operation at 115 kV (Gales Ferry to Ledyard Jct.)	Dec-22	2
1860	Install a 25.2 MVAR 115 kV capacitor and one capacitor breaker at Killingly	Dec-21	4

Eastern CT Reliability Projects, cont.

Status as of 4/19/2022

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1861	Install one 345 kV series breaker with the Montville 1T	Nov-21	4
1862	Install a 50 MVAR synchronous condenser with two 115 kV breakers at Shunock	Dec-24	3
1863	Install a 1% series reactor with bypass switch at Mystic, CT on the 1465 Line	Dec-22	3
1864	Convert the 400-2 Line Section to 115 kV (Border Bus to Buddington), convert Buddington to 115 kV	Dec-23	3

Boston Area Optimized Solution Projects

Status as of 4/19/2022

Project Benefit: Addresses system needs in the Boston area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1874	Install two 11.9 ohm series reactors at North Cambridge Station on Lines 346 and 365	Dec-21	4
1875	Install a direct transfer trip (DTT) scheme between Ward Hill and West Amesbury Substations for Line 394	Apr-22	4
1876	Install one +/- 167 MVAR STATCOM at Tewksbury 345 kV Substation	Oct-23	3

New Hampshire Solution Projects

Status as of 4/19/2022

Project Benefit: Addresses system needs in the New Hampshire area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1878	Install a +50/-25 MVAR synchronous condenser at N. Keene 115 kV Substation with a 115 kV breaker	Aug-23	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	Oct-23	1

Upper Maine Solution Projects

Status as of 4/19/2022

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1882	Rebuild 21.7 miles of the existing 115 kV line Section 80 Highland – Coopers Mills 115 kV line	Dec-27	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	Jun-24	1

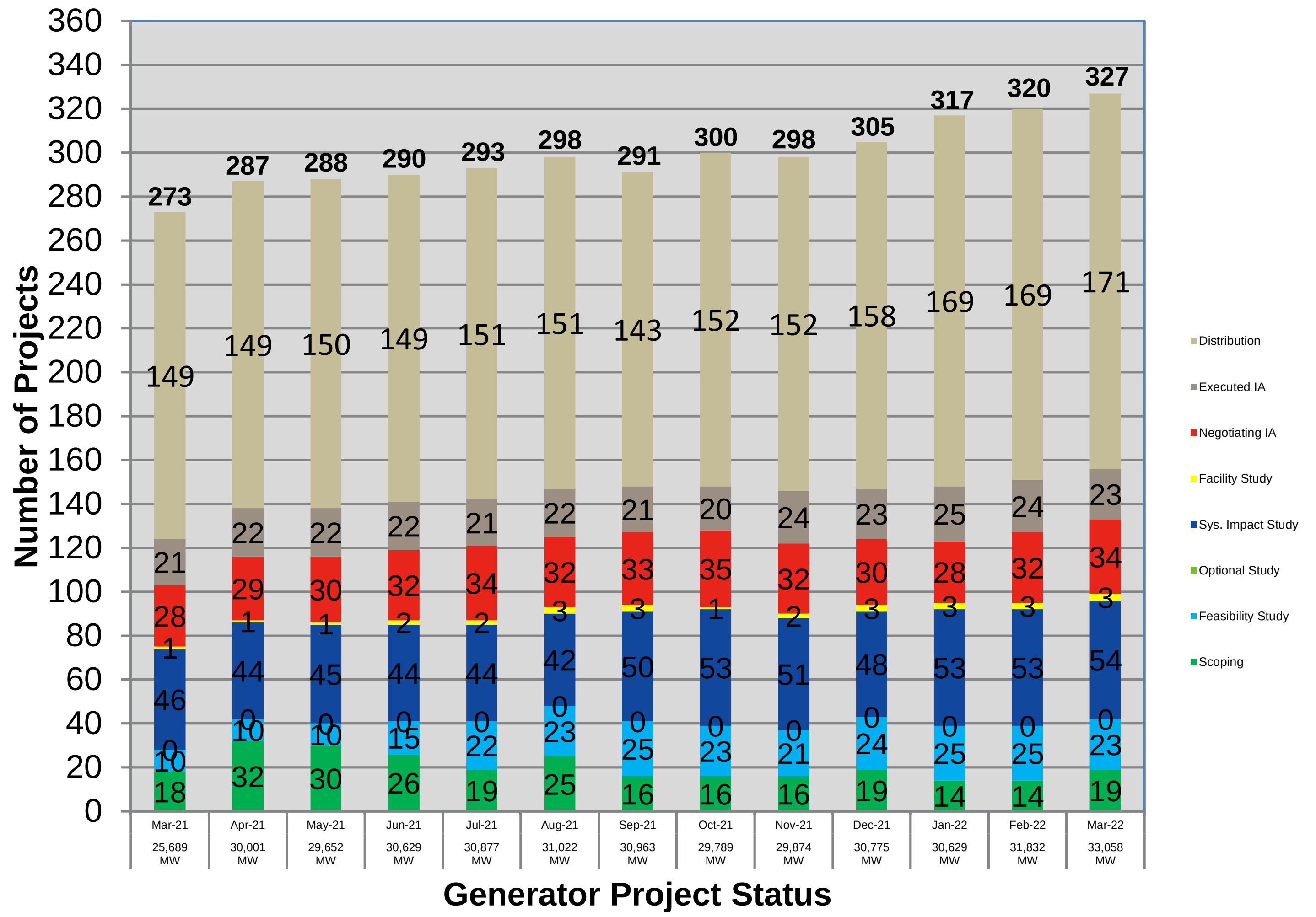
Upper Maine Solution Projects, cont.

Status as of 4/19/2022

Project Benefit: Addresses system needs in the Upper Maine area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1887	Install 25 MVAR reactor at Boggy Brook 115 kV substation	Jun-24	1
1888	Install 10 MVAR reactor at Keene Road 115 kV substation	Jun-24	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

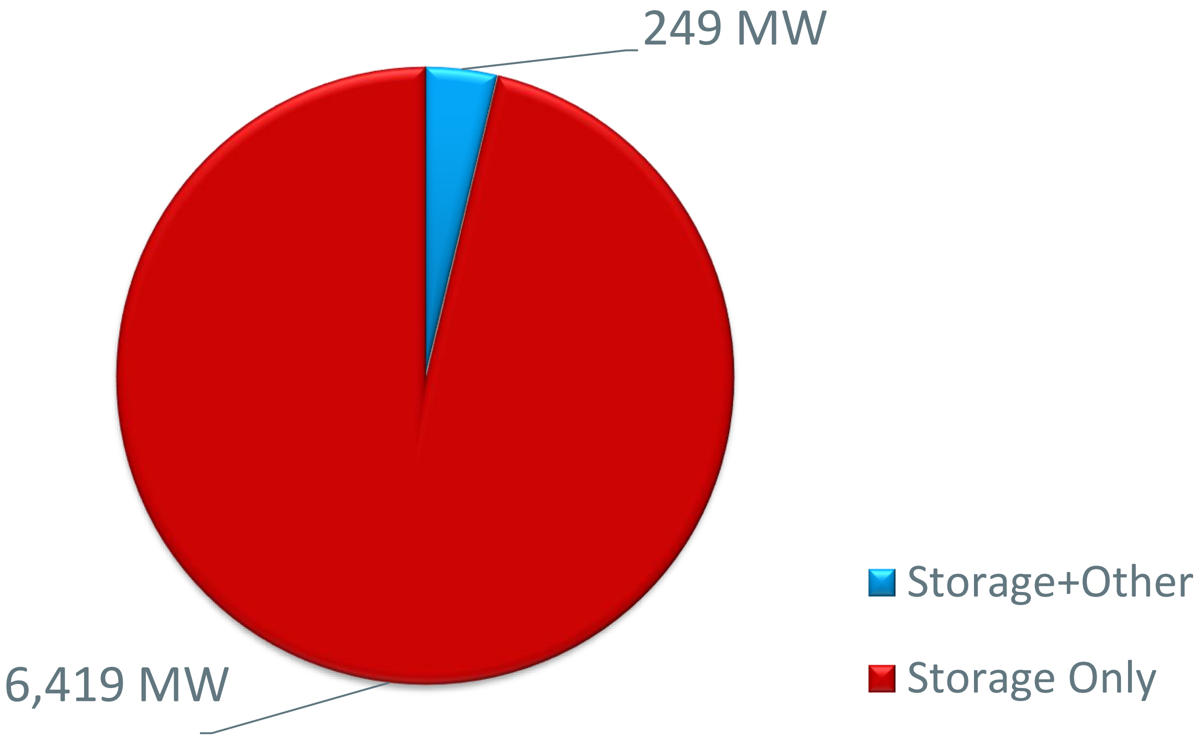
Status of Tariff Studies as of April 1, 2022



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

What is in the Queue (as of April 1, 2022)

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



OPERABLE CAPACITY ANALYSIS

Spring 2022 Analysis

Spring 2022 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2022[2] CSO (MW)	May - 2022[2] SCC (MW)
Operable Capacity MW [1]	29,574	32,049
Active Demand Capacity Resource (+) [5]	492	420
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,087	1,087
Non Commercial Capacity (+)	19	19
Non Gas-fired Planned Outage MW (-)	5,229	6,192
Gas Generator Outages MW (-)	1,016	1,097
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	21,527	22,886
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,011	19,011
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,316	21,316
Operable Capacity Margin	211	1,570

[1] Operable Capacity is based on data as of **April 25, 2022** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **April 25, 2022.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 14, 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.

Spring 2022 Operable Capacity Analysis

90/10 Load Forecast	**May - 2022[2] CSO (MW)**	**May - 2022[2] SCC (MW)**
Operable Capacity MW [1]	29,574	32,049
Active Demand Capacity Resource (+) [5]	492	420
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,087	1,087
Non Commercial Capacity (+)	19	19
Non Gas-fired Planned Outage MW (-)	5,229	6,192
Gas Generator Outages MW (-)	1,016	1,097
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	21,527	22,886
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,379	20,379
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,684	22,684
Operable Capacity Margin	-1,157	202

[1] Operable Capacity is based on data as of **April 25, 2022** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **April 25, 2022.**

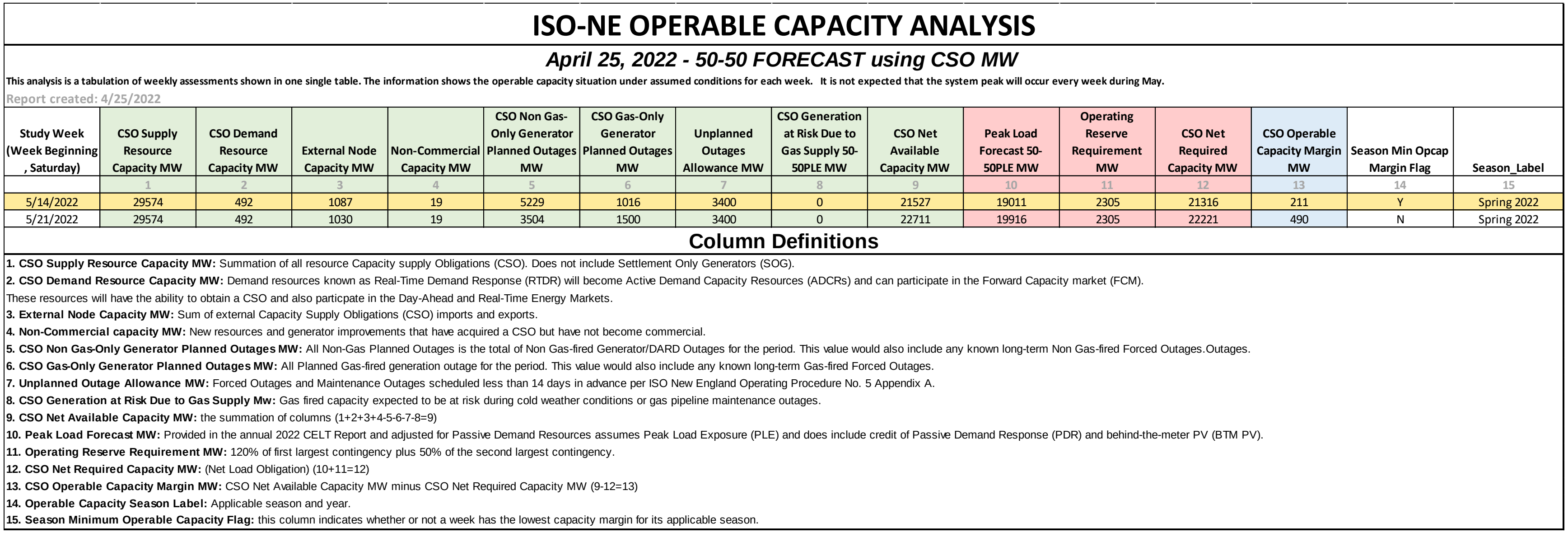
[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 14, 2022.**

[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.

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



ISO-NE OPERABLE CAPACITY ANALYSIS

April 25, 2022 - 50-50 FORECAST using CSO MW

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

Report created: 4/25/2022

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
5/14/2022	29574	492	1087	19	5229	1016	3400	0	21527	19011	2305	21316	211	Y	Spring 2022
5/21/2022	29574	492	1030	19	3504	1500	3400	0	22711	19916	2305	22221	490	N	Spring 2022

Column Definitions

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

2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM). These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.

3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.

4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.

5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.

6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.

7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.

8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.

9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)

10. Peak Load Forecast MW: Provided in the annual 2022 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).

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

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

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

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

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

Spring 2022 Operable Capacity Analysis

90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

April 25, 2022 - 90/10 FORECAST using CSO MW

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

Report created: 4/25/2022

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
5/14/2022	29574	492	1087	19	5229	1016	3400	0	21527	20379	2305	22684	-1157	Y	Spring 2022
5/21/2022	29574	492	1030	19	3504	1500	3400	0	22711	21339	2305	23644	-933	N	Spring 2022

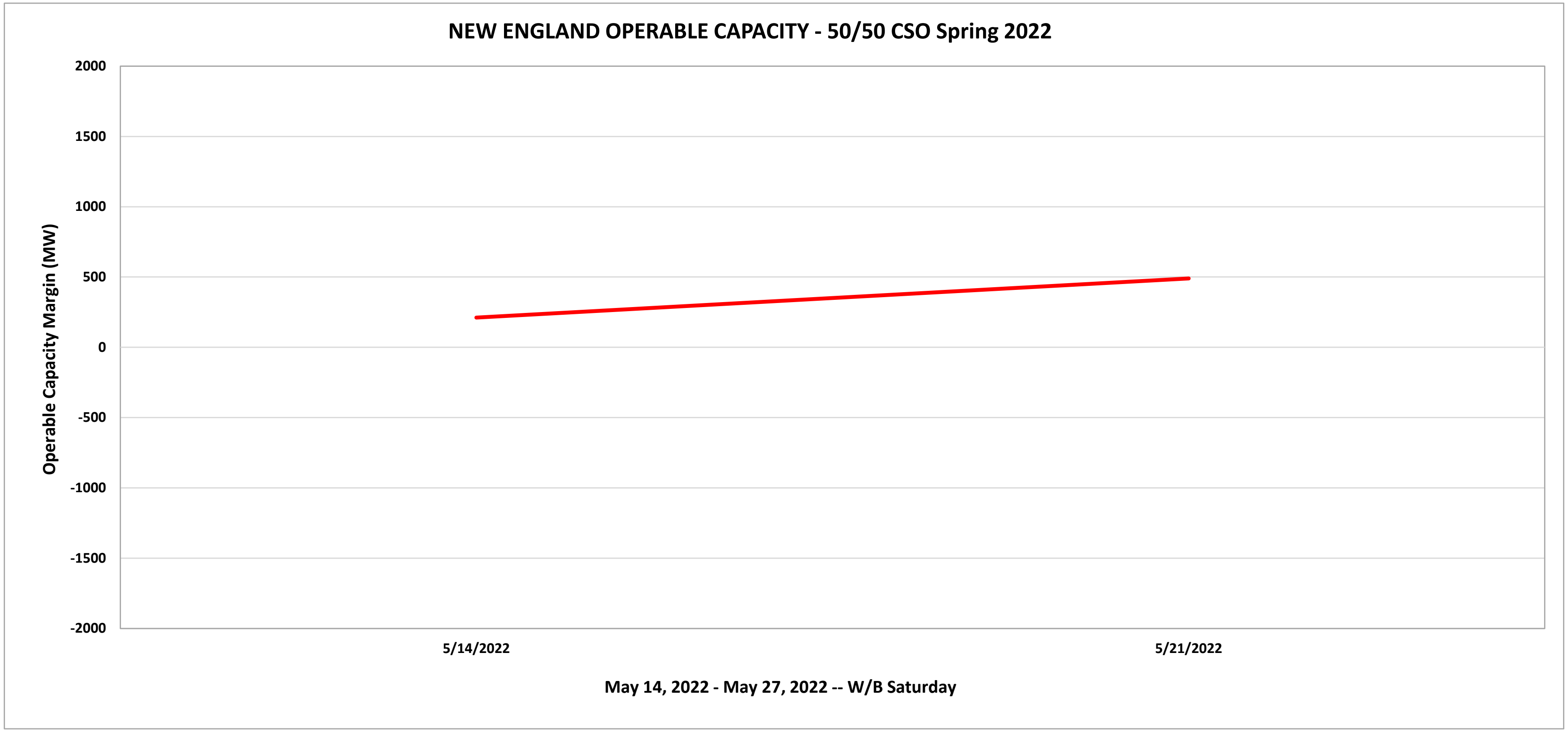
Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM). These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2022 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

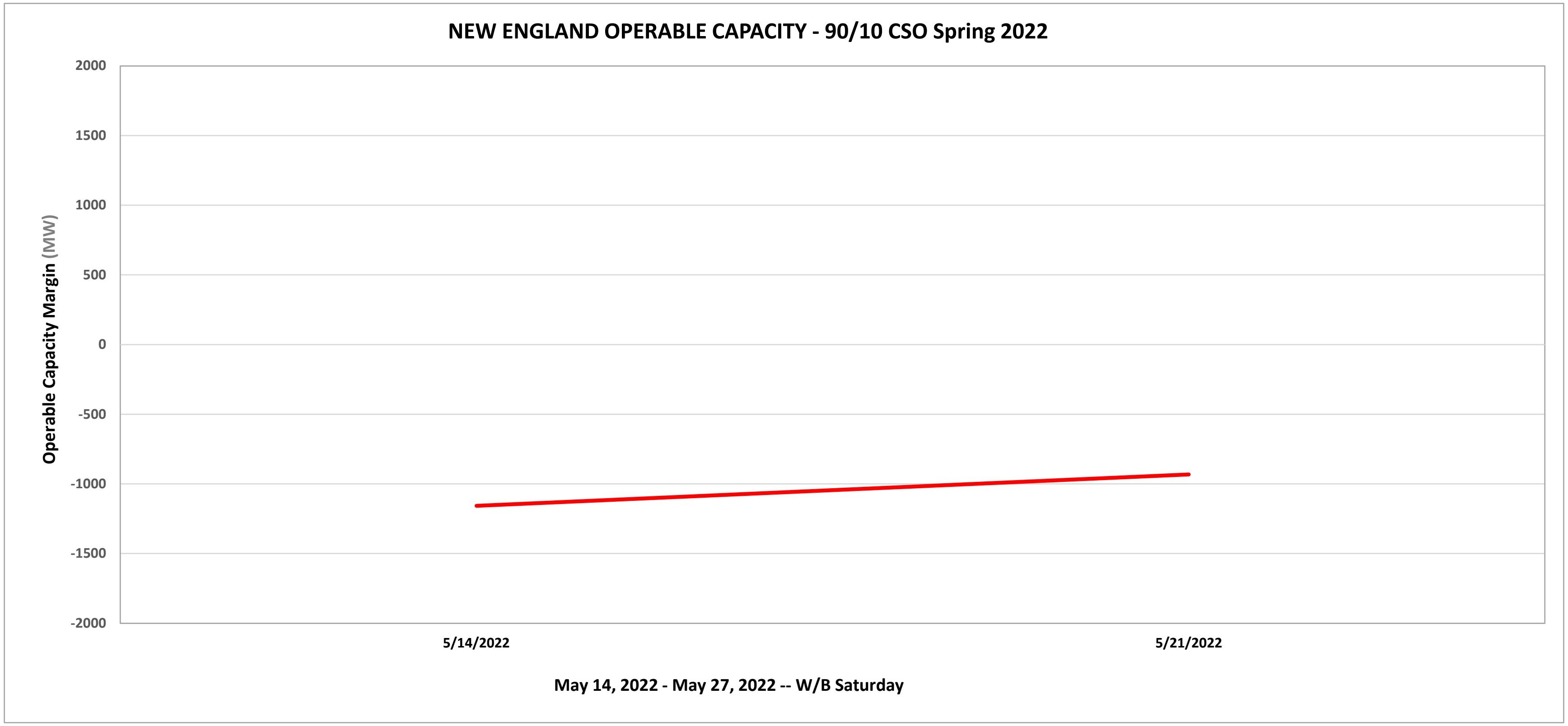
Spring 2022 Operable Capacity Analysis

50/50 Forecast (Reference)



Spring 2022 Operable Capacity Analysis

90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Summer 2022 Analysis

Summer 2022 Operable Capacity Analysis

50/50 Load Forecast (Reference)	September - 2022[2] CSO (MW)	September - 2022[2] SCC (MW)
Operable Capacity MW [1]	27,848	29,537
Active Demand Capacity Resource (+) [5]	559	483
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,115	1,115
Non Commercial Capacity (+)	152	152
Non Gas-fired Planned Outage MW (-)	806	1,103
Gas Generator Outages MW (-)	272	275
Allowance for Unplanned Outages (-) [4]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	26,496	27,809
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	24,686	24,686
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	26,991	26,991
Operable Capacity Margin	-495	818

[1] Operable Capacity is based on data as of **April 25, 2022** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **April 25, 2022.**

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

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

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

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

Summer 2022 Operable Capacity Analysis

90/10 Load Forecast	**September - 2022[2] CSO (MW)**	**September - 2022[2] SCC (MW)**
Operable Capacity MW [1]	27,848	29,537
Active Demand Capacity Resource (+) [5]	559	483
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,115	1,115
Non Commercial Capacity (+)	152	152
Non Gas-fired Planned Outage MW (-)	806	1,103
Gas Generator Outages MW (-)	272	275
Allowance for Unplanned Outages (-) [4]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	26,496	27,809
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	26,416	26,416
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	28,721	28,721
Operable Capacity Margin	-2,225	-912

[1] Operable Capacity is based on data as of **April 25, 2022** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **April 25, 2022.**

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

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

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

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

Summer 2022 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

April 25, 2022 - 50-50 FORECAST using CSO MW

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

Report created: 4/25/2022

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
5/28/2022	27848	559	1115	152	71	192	2800	0	26611	24686	2305	26991	-380	N	Summer 2022
6/4/2022	27848	559	1115	152	128	192	2800	0	26554	24686	2305	26991	-437	N	Summer 2022
6/11/2022	27848	559	1115	152	98	192	2800	0	26584	24686	2305	26991	-407	N	Summer 2022
6/18/2022	27848	559	1115	152	78	192	2800	0	26604	24686	2305	26991	-387	N	Summer 2022
6/25/2022	27848	559	1115	152	78	192	2800	0	26604	24686	2305	26991	-387	N	Summer 2022
7/2/2022	27848	559	1115	152	78	0	2100	0	27496	24686	2305	26991	505	N	Summer 2022
7/9/2022	27848	559	1115	152	150	28	2100	0	27396	24686	2305	26991	405	N	Summer 2022
7/16/2022	27848	559	1115	152	130	0	2100	0	27444	24686	2305	26991	453	N	Summer 2022
7/23/2022	27848	559	1115	152	89	0	2100	0	27485	24686	2305	26991	494	N	Summer 2022
7/30/2022	27848	559	1115	152	68	0	2100	0	27506	24686	2305	26991	515	N	Summer 2022
8/6/2022	27848	559	1115	152	78	0	2100	0	27496	24686	2305	26991	505	N	Summer 2022
8/13/2022	27848	559	1115	152	105	0	2100	0	27469	24686	2305	26991	478	N	Summer 2022
8/20/2022	27848	559	1115	152	105	0	2100	0	27469	24686	2305	26991	478	N	Summer 2022
8/27/2022	27848	559	1115	152	19	0	2100	0	27555	24686	2305	26991	564	N	Summer 2022
9/3/2022	27848	559	1115	152	39	0	2100	0	27535	24686	2305	26991	544	N	Summer 2022
9/10/2022	27848	559	1115	152	806	272	2100	0	26496	24686	2305	26991	-495	Y	Summer 2022

Column Definitions

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

2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).

These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.

3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.

4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.

5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.

6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.

7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.

8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.

9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)

10. Peak Load Forecast MW: Provided in the annual 2022 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).

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

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

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

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

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

Summer 2022 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

April 25, 2022 - 90/10 FORECAST using CSO MW

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

Report created: 4/25/2022

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
5/28/2022	27848	559	1115	152	71	192	2800	0	26611	26416	2305	28721	-2110	N	Summer 2022
6/4/2022	27848	559	1115	152	128	192	2800	0	26554	26416	2305	28721	-2167	N	Summer 2022
6/11/2022	27848	559	1115	152	98	192	2800	0	26584	26416	2305	28721	-2137	N	Summer 2022
6/18/2022	27848	559	1115	152	78	192	2800	0	26604	26416	2305	28721	-2117	N	Summer 2022
6/25/2022	27848	559	1115	152	78	192	2800	0	26604	26416	2305	28721	-2117	N	Summer 2022
7/2/2022	27848	559	1115	152	78	0	2100	0	27496	26416	2305	28721	-1225	N	Summer 2022
7/9/2022	27848	559	1115	152	150	28	2100	0	27396	26416	2305	28721	-1325	N	Summer 2022
7/16/2022	27848	559	1115	152	130	0	2100	0	27444	26416	2305	28721	-1277	N	Summer 2022
7/23/2022	27848	559	1115	152	89	0	2100	0	27485	26416	2305	28721	-1236	N	Summer 2022
7/30/2022	27848	559	1115	152	68	0	2100	0	27506	26416	2305	28721	-1215	N	Summer 2022
8/6/2022	27848	559	1115	152	78	0	2100	0	27496	26416	2305	28721	-1225	N	Summer 2022
8/13/2022	27848	559	1115	152	105	0	2100	0	27469	26416	2305	28721	-1252	N	Summer 2022
8/20/2022	27848	559	1115	152	105	0	2100	0	27469	26416	2305	28721	-1252	N	Summer 2022
8/27/2022	27848	559	1115	152	19	0	2100	0	27555	26416	2305	28721	-1166	N	Summer 2022
9/3/2022	27848	559	1115	152	39	0	2100	0	27535	26416	2305	28721	-1186	N	Summer 2022
9/10/2022	27848	559	1115	152	806	272	2100	0	26496	26416	2305	28721	-2225	Y	Summer 2022

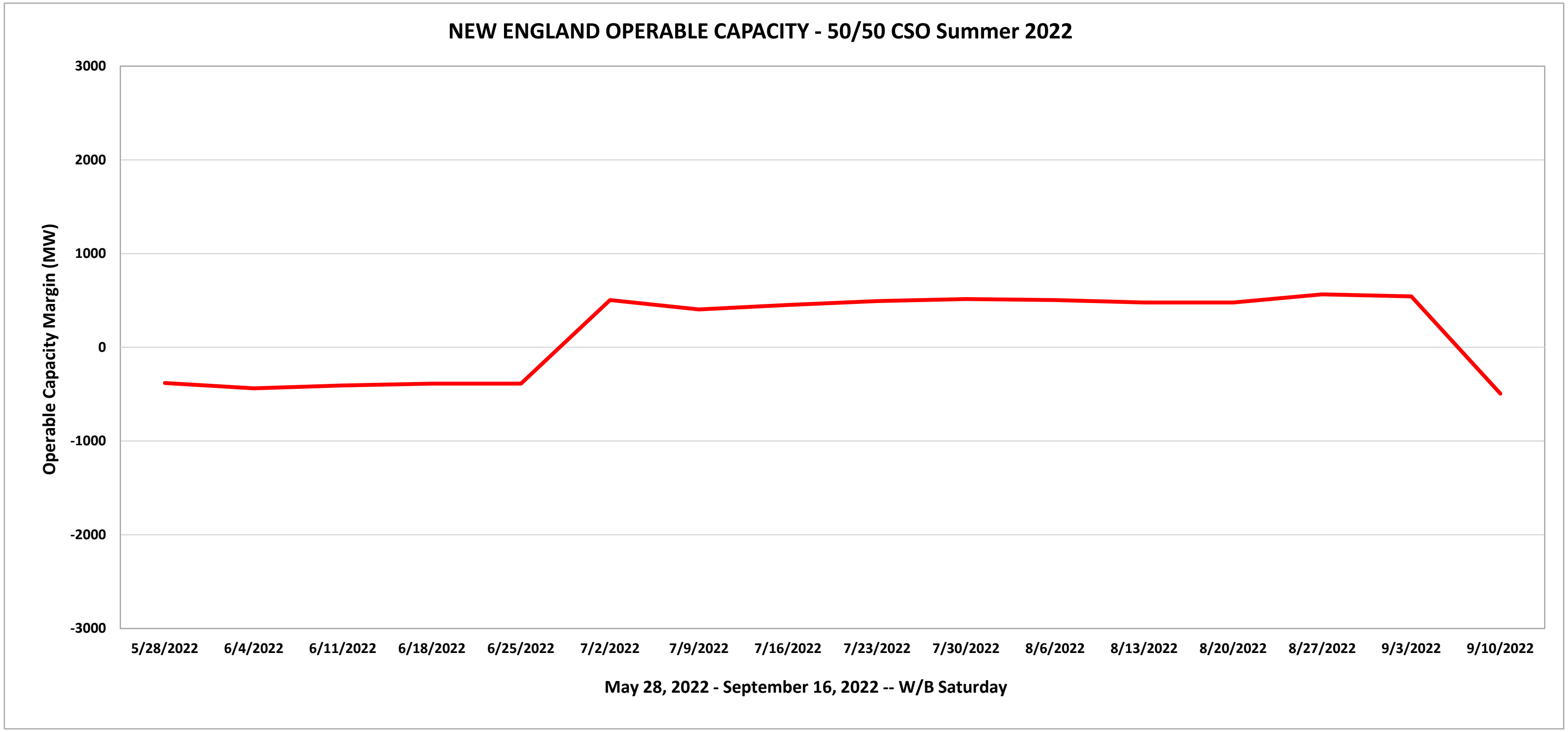
Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2022 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

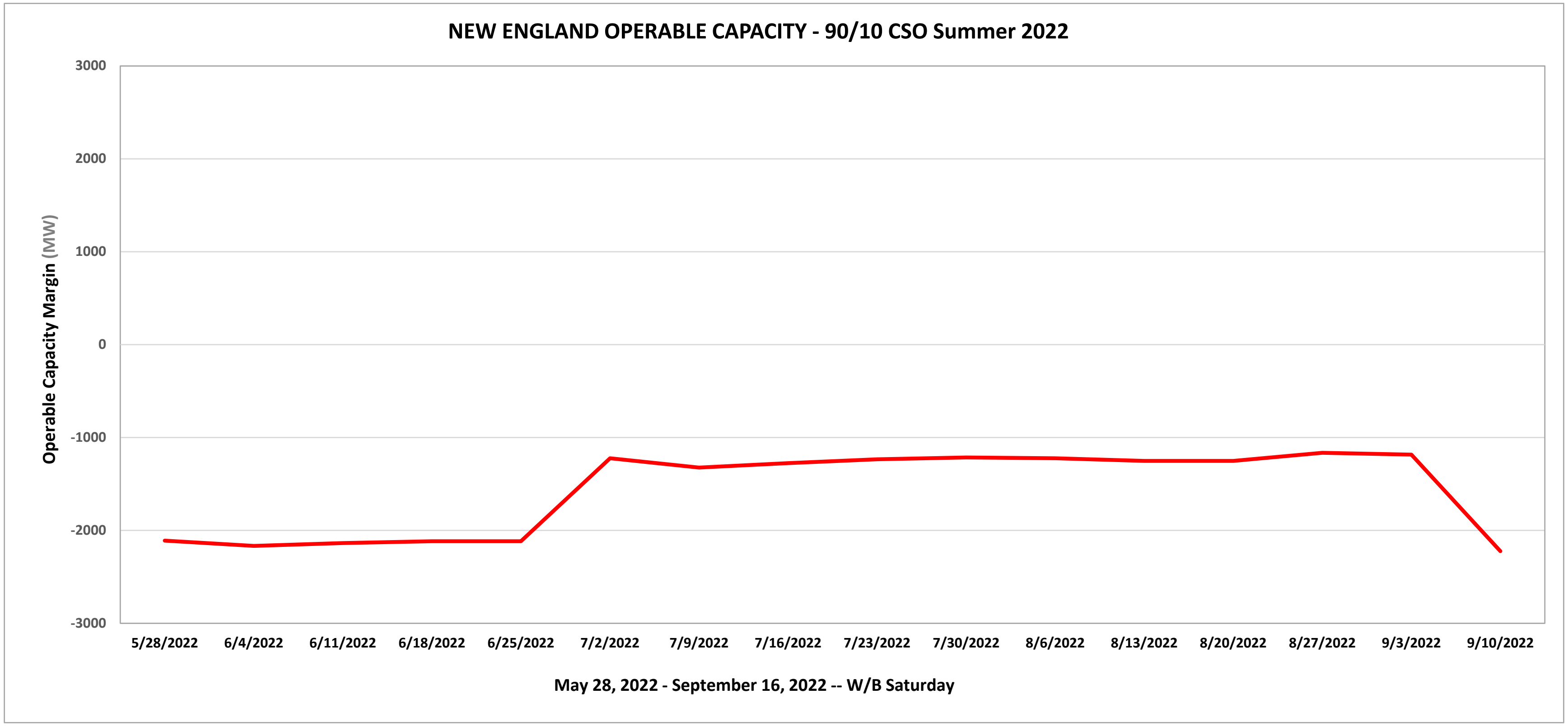
***Highlighted week is based on the week determined by the 50/50 Load Forecast Reference week**

Summer 2022 Operable Capacity Analysis

50/50 Forecast (Reference)



Summer 2022 Operable Capacity Analysis
90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4: Appendix A

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

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

Possible Relief Under OP4: Appendix A

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

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

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval and Rosendo Garza, NEPOOL Counsel

DATE: April 28, 2022

RE: Competitive Power Ventures' Proposal to Reform Financial Assurance Construct for Non-Commercial Capacity Resources

At the May 5, 2022 Participants Committee[1] meeting, you will be asked to consider the matter that was postponed during the February 3 meeting relating to revisions to Market Rule 1 and the ISO-NE Financial Assurance Policy (FAP), as proposed by Competitive Power Ventures (CPV), to change the financial assurance requirements for non-commercial capacity resources in the Forward Capacity Market (FCM), which is referred to as the "CPV Proposal." Recall that CPV agreed to postpone consideration of its proposal to allow the Markets Committee and the Budget & Finance Subcommittee to discuss changes in response to concerns expressed shortly before the February 3 meeting. In that time, CPV and other stakeholders collaborated with respect to those concerns.

This memorandum provides a high-level summary, including updates, of the CPV Proposal and the stakeholder processes to vet the proposal to date. Included with this memorandum are the following CPV-sponsored materials:

- Attachment A1: Proposed Market Rule 1 Tariff sheets
- Attachment A2: Proposed FAP Tariff sheets
- Attachment B1: PowerPoint presentation provided at the April 12, 2022 Markets Committee meeting
- Attachment B2: PowerPoint presentation provided at the April 21, 2022 Budget & Finance Subcommittee meeting

BACKGROUND AND THE REVISED CPV PROPOSAL

As CPV explained at the Markets Committee and Budget & Finance Subcommittee, CPV's proposal intends to differentiate the amount of financial assurance required from projects meeting all of their milestone commitments, projects that are delayed in their development, and projects that have failed. To implement the proposed reforms to the financial assurance construct for non-commercial capacity resources in the FCM, CPV has proposed a package of Tariff revisions, with a majority of the changes in the FAP, and a corresponding set of changes in

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[1] Capitalized terms used but not defined in this memorandum are intended to have the same meaning given to such terms in the Second Restated New England Power Pool Agreement, the Participants Agreement, or the ISO New England Inc. Transmission, Markets and Services Tariff.

Market Rule 1. CPV seeks for this proposal to be implemented in time for the seventeenth Forward Capacity Auction (FCA).

Proposed Market Rule 1 Revisions

The proposed Market Rule 1 revisions would modify the Critical Path Schedule (CPS) milestone for a non-commercial resource. Specifically, the project financing closing milestone is revised, and the CPV Proposal adds a new "notice to proceed" milestone to the CPS (*see* changes to Tariff Section III.13.1.1.2.2.2). Relatedly, the CPV Proposal includes new language in Market Rule 1 concerning the documentation requirements for the project financing closing and the notice to proceed milestones.

CPV provides Tariff sheets reflecting its proposed Market Rule 1 revisions in Attachment A1 and provides additional information explanation for those revisions in Attachment B1.

Proposed FAP Revisions

Under the current rules, the financial assurance requirement from a non-commercial resource with a Capacity Supply Obligation (CSO) increases by a factor of one before the first and second FCAs after the auction in which that CSO was awarded. The CPV Proposal would add an additional increment of financial assurance prior to the third FCA after the auction in which that CSO was awarded for projects that have not exceeded 20 percent of budgeted spending on construction activities. For Demand Capacity Resources less than 5 MW, the additional increment would be required if the project has not achieved its first target date percentage obligation of its demand reduction value.

Since the March 3 meeting, CPV added a cap on the financial assurance required for resources that miss a milestone, which is based on the annual Capacity Base Payments expected to be received by the resource. In addition, the financial assurance requirement for a project that fails to achieve Commercial Operation by the start of the relevant Capacity Commitment Period will also be based on the expected annual Capacity Base Payments. These proposed changes since March 3 reduce from the previously proposed incremental financial assurance requirements amounts that would be required from delayed solar resources, which only receive Capacity Base Payments in four months of each year.

The CPV Proposal also includes two new categories of financial assurance:

(i) "NCC Milestone FA" would establish a new financial assurance requirement for a non-commercial project that fails to meet its project financing and notice to proceed milestones (as described in the ***Proposed Market Rule 1 Revisions***) and will not achieve its commercial operation date by the start of the Capacity Commitment Period to which its Capacity Supply Obligation relates;[2] and

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[2] The revised CPV Proposal includes a NCC FA Milestone Cap based on the expected capacity revenues, as reflected in Attachment A2 and explained in Attachment B2.

(ii) "NCC Delay FA" would add additional financial assurance requirements for a non-commercial project that fails to achieve its commercial operation date by the start of the Capacity Commitment Period to which its Capacity Supply Obligation relates.

Neither the NCC Milestone FA nor the NCC Delay FA would be applied to Demand Capacity Resources or to New Capacity Resources not subject to Schedules 22 or 25 of Section II the Transmission, Markets and Services Tariff.

CPV has provided Tariff language reflecting its proposed FAP revisions in Attachment A2 and has provided additional explanation for those revisions in Attachment B2.

STAKEHOLDER PROCESS TO DATE

Through the Participant Processes, including additional meetings since the February 3 postponement, the Markets Committee reviewed and offered input to portions of the CPV Proposal, while the Budget & Finance Subcommittee reviewed the FAP changes. Additional information is provided herein regarding the outcome of the deliberations.

Markets Committee Review (Agenda Item 6.a)

The Markets Committee discussed and reviewed the CPV Proposal at multiple meetings, most recently at the April 12 meeting when CPV presented the changes to its proposal. During the Markets Committee discussion, the ISO explained that, although it was in general agreement that incentives for non-commercial capacity resources is a matter that is worthy of further evaluation, the ISO was unable to "devote further resources" that would be necessary to examine fully the potential implications and impacts of the CPV Proposal, including whether adjustments to financial assurance is the best way to address the matter.[3] Thus, the ISO's position remains unchanged, namely, that it is unable to support the CPV Proposal at this time.

At its April 12, 2022, the Markets Committee meeting, the Committee considered a motion to recommend Participants Committee support for the Market Rule 1 changes in the CPV Proposal. That motion, which required a 60% Vote or greater to pass, failed with a 55.47% Vote in favor in which an entire Sector abstained.[4]

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[3] Memorandum from ISO-NE to the NEPOOL Markets Committee and NEPOOL Budget & Finance Subcommittee, subject: Concerns with Competitive Power Ventures' Proposed Financial Assurance Modifications, at 1 (Jan. 7, 2022), https://www.iso-ne.com/static-assets/documents/2022/01/a07_mc_2022_01_11-12_cpv_non-commercial_financial_assurance_improvements_iso_memo.pdf. To review CPV's response, see Memorandum from Joel Gordon to NEPOOL Markets Committee and NEPOOL Budget & Finance Subcommittee, subject: ISO Memo "Concerns with Competitive Power Ventures' Proposed Financial Assurance Modifications" dated January 7, 2022 (Jan. 10, 2022), https://www.iso-ne.com/static-assets/documents/2022/01/a07_mc_2022_01_11-12_cpv_non-commercial_financial_assurance_improvements_response_memo.docx.

[4] Previously, the Markets Committee vote on the CPV Proposal was 40.24% Vote in favor. In any event, the individual Sector votes at the April 12 Markets Committee were as follows: Generation –

Budget & Finance Subcommittee Review (Agenda Item 6.b)

The Budget & Finance Subcommittee considered CPV's proposed changes to the FAP at its meetings on August 26, October 12, November 29, January 26, February 10, March 22, and April 21. The Budget & Finance Subcommittee is a non-voting subcommittee. The Participants attending these various meetings expressed a range of views on the CPV Proposal. At its most recent teleconference meeting on April 21, many members in attendance were supportive of the CPV Proposal. None of the April 21 meeting attendees expressed concerns with CPV's proposal, but some indicated they needed substantive input from the ISO before they would take a position. A copy of the FAP changes, which require a 66.67% Vote to be supported by the Participants Committee, are included as Attachment A2.

Participants Committee Review

A 60% Vote is required for the Participants Committee to approve CPV's proposed Market Rule 1 modifications, while the proposed FAP revisions require a 66.67% Vote. Accordingly, the following forms of resolutions may be used for Participants Committee action, voted either individually or in a single, combined vote:

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

16.7% in favor, 0% opposed, 0 abstentions; Transmission – 0% in favor, 16.70% opposed, 1 abstention; Supplier – 16.7% in favor, 0% opposed, 6 abstentions; Publicly Owned Entity – 0% in favor, 0% opposed, 49 abstentions; Alternative Resources – 16.5% in favor, 0% opposed, 4 abstentions; and End User – 5.57% in favor, 11.13% opposed, 1 abstention. Because the entire Publicly Owned Entity Sector abstained, no portion of the Adjusted Sector Voting Share was reallocated to other Sectors or included in either the totals "in favor" or "opposed" to the motion.

CPV's Proposed Market Rule 1 Revisions

III.13. Forward Capacity Market.

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III.13.1.1.2.2.2. Critical Path Schedule.

In the New Capacity Qualification Package, the Project Sponsor must provide a critical path schedule for the project with sufficient detail to allow the ISO to evaluate the feasibility of the project being built and the feasibility that the project will meet the requirement that the project achieve all its critical path schedule milestones no later than the start of the relevant Capacity Commitment Period. The critical path schedule shall include, at a minimum, the dates on which the following milestones have or are expected to occur:

(a) **Major Permits**. In the New Capacity Qualification Package, the Project Sponsor must list all major permits required for the project, and for each major permit, the Project Sponsor must list the agency requiring the permit, the date on which application for the permit is expected to be made, and the expected date of approval. Major permits shall include, but are not limited to: (i) all federal and state permits; and (ii) local, regional, and town permits. The permitting and installation process associated with any major ancillary infrastructure (such as new gas pipelines, new water supply systems, or large storage tanks) should be included in this portion of the New Capacity Qualification Package.

(b) **Project Financing Closing**. In the New Capacity Qualification Package, the Project Sponsor shall provide (i) the total estimated project budget; (ii) the estimated dollar amount of third party~~required~~ project financing; (iii) the estimated dollar amount of the project budget to be self-funded by the Project Sponsor; (iv) the estimated cost of construction activities for purposes of determining the requirement in section (d) below; (~~ii~~v) the expected sources of the~~at~~ financing, including debt and equity; and (vi~~ii~~) the expected deadline for the closing date(s) for the project financing (i.e., the date on which the amount of the financing available to the project is at least equal to the stated dollar amount of the total project budget). The Project Sponsor will demonstrate its financial capability to obtain the third party financing and/or self-funding noted here as part of the New Capacity Qualification Package.

(b.1) **Notice to Proceed**. In the New Capacity Qualification Package, the Project Sponsor shall provide the date by which it will direct its contractor(s) to install the major components described in clause (c) below.

(c) **Major Equipment Orders**. In the New Capacity Qualification Package, the Project Sponsor must provide a list of all of the major components necessary for the project, and the date or dates on which all major components necessary for the project have been or are expected to be ordered. Although the specific technology will determine the list of major components to be included, the list shall include, to the extent applicable: (i) electric generators which may include equipment such as fuel cells or solar photovoltaic equipment; (ii) turbines; (iii) step-up transformers; (iv) relay panels (v) distributed control systems; and (vi) any other single piece of equipment or system such as a cooling water system, steam generation, steam handling system, water treatment system, fuel handling system or emissions control system that is not included as a sub-component of other equipment listed in this Section III.13.1.1.2.2.2(c) and that accounts for more than five percent of the total project cost. For an Import Capacity Resource associated with an Elective Transmission Upgrade that has not yet achieved Commercial Operation as defined in Schedule 25 of Section II of the Transmission, Markets and Services Tariff, major components shall also include, to the extent applicable, transmission facilities and associated substation equipment.

(d) **Substantial Site Construction**. In the New Capacity Qualification Package, the Project Sponsor must provide the approximate date on which the amount of money expended on construction activities occurring on the project site is expected to exceed 20 percent of construction financing costs.

(e) **Major Equipment Delivery**. In the New Capacity Qualification Package, the Project Sponsor must provide the dates on which the major equipment described in subsection (d) above has been or is scheduled to be delivered to the project site.

(f) **Major Equipment Testing**. In the New Capacity Qualification Package, the Project Sponsor must provide the date or dates on which each piece of major equipment described in subsection (c) above is scheduled to undergo testing, including major systems testing, as appropriate for the specific technology to establish its suitability to allow, in conjunction with other major equipment, subsequent operation of the project in accordance with the design capacity of the resource and in accordance with Good Utility Practice. The test(s) shall include those conducted at the point at which the operation of the major equipment will be determined to be in compliance with the requirements of the engineering or purchase specifications.

(g) **Commissioning**. In the New Capacity Qualification Package, the Project Sponsor must provide the date on which the project is expected to have demonstrated the level of performance specified in the New Capacity Show of Interest Form and in the New Capacity Qualification Package.

(h) **Commercial Operation**. In the New Capacity Qualification Package, the Project Sponsor must provide the date by which the project is expected to achieve Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) and/or the date by which the Project Sponsor expects to be ready to demonstrate to the ISO that the Demand Capacity Resource described in the New Demand Capacity Resource Qualification Package has achieved its full demand reduction value. This date must be no later than the start of the Capacity Commitment Period associated with the Forward Capacity Auction.

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III.13.1.1.2.4 Evaluation of New Capacity Qualification Package

The ISO shall review a New Generating Capacity Resource's New Capacity Qualification Package consistent with the dates set forth in Section III.13.1.10, and shall determine whether the package is complete and whether, based on the information provided, the New Generating Capacity Resource is accepted for participation in the Forward Capacity Auction. In making these determinations, the ISO may consider, but is not limited to considering, the following:

(a) whether the New Capacity Qualification Package contains all of the elements required by this Section III.13.1.1.2;

(b) whether the critical path schedule includes all necessary elements and is sufficiently developed;

(c) whether the milestones in the critical path schedule are reasonable and likely to be met and the financial capability of the Project Sponsor has been sufficiently demonstrated;

(d) whether, in the case of a resource previously counted as a capacity resource, the requirements for treatment as a New Generating Capacity Resource are satisfied; and

(e) whether, in the case of an Intermittent Power Resource, sufficient data for confirming the resource's claimed summer and winter Qualified Capacity is provided, and whether the data provided reasonably supports the claimed summer and winter Qualified Capacity.

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III.13.3.2.2. Documentation of Milestones Achieved.

(a) For all new resources except for Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW (discussed in Section III.13.3.2.2(b)), for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Project Sponsor must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Major Permits**. For each major permit described in the critical path schedule, the Project Sponsor shall provide documentation showing that the permit was applied for and obtained as described in the critical path schedule. For permit applications, this documentation could include a dated copy of the permit application or cover letter requesting the permit. For approved permits, this documentation could include a dated copy of the approved permit or letter granting the permit from the permitting authority.

(ii) **Project Financing Closing**. The Project Sponsor shall provide documentation showing that the sources of financing identified in the critical path schedule have committed to provide the amount of financing described in the critical path schedule. This documentation ~~could~~ should include copies of commitment letters from the sources of financing as well as certification by an officer of the Project Sponsor that all loan and financing arrangements have been executed and all conditions precedent to the initial funding for the project are complete and funds for the financing and construction of the project are available to the Project Sponsor. For Project Sponsors who are self-funding their projects, this milestone will be satisfied by a certification by an officer of the Project Sponsor that all internal approvals have been obtained for such self-funding.

(ii.a) **Notice to Proceed**. The Project Sponsor shall provide documentation and certification attesting to providing notice to its contractor(s) to install the major components described in Section III.13.1.1.2.2.2(c) above.

(iii) **Major Equipment Orders**. For each major component described in the critical path schedule, the Project Sponsor shall provide documentation showing that the equipment was ordered as described in the critical path schedule. This documentation should include a copy of a dated confirmation of the order from the manufacturer or supplier. This documentation should confirm scheduled delivery dates consistent with milestone Section III.13.3.2.2(a)(vi).

(iv) **Substantial Site Construction.** The Project Sponsor shall provide documentation showing that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of the construction financing costs.

(v) **Major Equipment Delivery**. For each major component described in the critical path schedule, the Project Sponsor shall provide documentation showing that the equipment was delivered to the project site and received as preliminarily acceptable as described in the critical path schedule. This documentation should include a copy of a dated confirmation of delivery to the project site.

(vi) **Major Equipment Testing.** For each major component described in the critical path schedule, the Project Sponsor shall provide documentation showing that the component was tested, including major systems testing as appropriate for the specific technology as described in the critical path schedule, and that the test results demonstrate the equipment's suitability to allow, in conjunction with other major components, subsequent operation of the project in accordance with the amount of capacity obligated from the resource in the Capacity Commitment Period in accordance with Good Utility Practice. This documentation could include a dated copy of the satisfactory test results.

(vii) **Commissioning**. The Project Sponsor shall provide documentation showing that the resource has demonstrated a level of performance equal to or greater than the amount of capacity obligated from the resource in the Capacity Commitment Period. This documentation should include a copy of a dated letter of confirmation from the applicable manufacturer, contractor, or installer.

(viii) **Commercial Operation.** The Project Sponsor is not required to provide documentation of Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) to the ISO as part of the ISO's critical path schedule monitoring. The ISO shall confirm that the resource has achieved Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff) as described in the critical path schedule through the resource's compliance with the other relevant requirements of the Transmission, Markets and Services Tariff and the ISO New England System Rules.

(ix) **Transmission Upgrades**. If during the qualification process it was determined that transmission upgrades (including any upgrades identified in a re-study pursuant to Section 3.2.1.3 of Schedule 22, Section 1.7.1.3 of Schedule 23, or Section 3.2.1.3 of Schedule 25 of Section II of the Transmission, Markets and Services Tariff) are needed for the new resource to complete its interconnection, then the Project Sponsor shall provide documentation showing that the transmission upgrades have been completed.

(b) For Demand Capacity Resources installed at multiple facilities and Demand Capacity Resources from a single facility with a demand reduction value of less than 5 MW, for each critical path schedule milestone achieved since the submission of the previous critical path schedule report, the Project Sponsor must include in the critical path schedule report documentation demonstrating that the milestone has been achieved by the date indicated and as otherwise described in the critical path schedule, as follows:

(i) **Substantial Project Completion**. The Project Sponsor shall provide documentation showing the total offered demand reduction value achieved as of target dates which are: (a) the cumulative percentage of total demand reduction value achieved on target date 1 occurring five weeks prior to the first Forward Capacity Auction after the Forward Capacity Auction in which the Demand Capacity Resource supplier's capacity award was made; (b) the cumulative percentage of total demand reduction value achieved on target date 2 occurring five weeks prior to the second Forward Capacity Auction after the Forward Capacity Auction in which the Demand Capacity Resource supplier's capacity award was made; and (c) target date 3 which is the date the resource is expected to be ready to demonstrate to the ISO that the Demand Capacity Resource described in the Project Sponsor's New Demand Capacity Resource Qualification Package has achieved its full demand reduction value, which must be on or before the first day of the relevant Capacity Commitment Period and by which date 100 percent of the total demand reduction value must be complete.

(ii) **Additional Requirements**. For each customer and each prospective customer the Project Sponsor shall provide: name, location, MW amount, and description of stage of negotiation. If the customer's Asset has been registered with the ISO, then the Project Sponsor shall also provide the Asset identification number.

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CPV's Proposed FAP Revisions

EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

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EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

Overview

The procedures and requirements set forth in this ISO New England Financial Assurance Policy shall govern all Applicants, all Market Participants and all Non-Market Participant Transmission Customers. Capitalized terms used in the ISO New England Financial Assurance Policy shall have the meaning specified in Section I.

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VII. ADDITIONAL PROVISIONS FOR FORWARD CAPACITY MARKETS

Any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in the Forward Capacity Market that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy (each a "Designated FCM Participant"), is required to provide additional financial assurance meeting the requirements of Section X below in the amounts described in this Section VII (such amounts being referred to in the ISO New England Financial Assurance Policy as the "FCM Financial Assurance Requirements"). If the Lead Market Participant for a Resource changes, then the new Lead Market Participant for the Resource shall become the Designated FCM Participant.

A. FCM Delivery Financial Assurance

A Designated FCM Participant must include, for the Capacity Supply Obligation of each resource in its portfolio other than the Capacity Supply Obligation associated with any Energy Efficiency measures, FCM Delivery Financial Assurance in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy. If a Designated FCM Participant's FCM Delivery Financial Assurance is negative, it will be used to reduce the Designated FCM Participant's Financial Assurance Obligations (excluding FTR Financial Assurance Requirements), but not to less than zero. FCM Delivery Financial Assurance is calculated according to the following formula:

$$\text{FCM Delivery Financial Assurance} = [\text{DFAMW} \times \text{PE} \times \max[(\text{ABR} - \text{CWAP}), 0.1] \times \text{SF} \times \text{DF}] - \text{MCC}$$

Where:

MCC (monthly capacity charge) equals Monthly Capacity Payments incurred in previous months, but not yet billed. The MCC is estimated from the first day of the current delivery month until it is replaced by the actual settled MCC value when settlement is complete.

DFAMW (delivery financial assurance MW) equals the sum of the Capacity Supply Obligations of each resource in the Designated FCM Participant's portfolio for the month, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. If the calculated DFAMW is less than zero, then the DFAMW will be set equal to zero.

PE (potential exposure) is a monthly value calculated for the Designated FCM Participant's portfolio as the difference between the Capacity Supply Obligation weighted average Forward Capacity Auction Starting Price and the Capacity Supply Obligation weighted average capacity price for the portfolio, excluding the Capacity Supply Obligation of any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1. The Forward Capacity Auction Starting Price shall correspond to that used in the Forward Capacity Auction corresponding to the instant Capacity Commitment Period and the capacity prices shall correspond to those used in the calculation of the Capacity Base Payment for each Capacity Supply Obligation in the delivery month.

In the case of a resource subject to a multi-year Capacity Commitment Period election made in a Forward Capacity Auction prior to the ninth Forward Capacity Auction as described in Sections III.13.1.1.2.2.4 and III.13.1.4.1.1.2.7 of Market Rule 1, the Forward Capacity Auction Starting Price shall be replaced with the applicable Capacity Clearing Price (indexed for inflation) in the above calculation until the multi-year election period expires.

ABR (average balancing ratio) is the duration-weighted average of all of the system-wide Capacity Balancing Ratios calculated for each system-wide Capacity Scarcity Condition occurring in the relevant group of months in the three Capacity Commitment Periods immediately preceding the instant Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary ABR for June through September shall equal 0.90; the temporary ABR for December through February shall equal 0.70; and the temporary ABR for all other months shall equal 0.60. As actual data becomes available for each relevant group of months, calculated values for the relevant group of months will replace the temporary ABR values after the end of each group of months each year until all three years reflect actual data.

CWAP (capacity weighted average performance) is the capacity weighted average performance of the Designated FCM Participant's portfolio. For each resource in the Designated FCM Participant's portfolio, excluding any resource that has reached the annual stop-loss as described in Section III.13.7.3.2 of Market Rule 1, and excluding from the remaining resources the resource having the largest Capacity Supply Obligation in the month, the resource's Capacity Supply Obligation shall be multiplied by the average performance of the resource. The CWAP shall be the sum of all such values, divided by the Designated FCM Participant's DFAMW. If the DFAMW is zero, then the CWAP is set equal to one.

The average performance of a resource is the Actual Capacity Provided during Capacity Scarcity Conditions divided by the product of the resource's Capacity Supply Obligation and the equivalent hours of Capacity Scarcity Conditions in the relevant group of months in the three Capacity Commitment Periods immediately preceding the instant Capacity Commitment Period. Three separate groups of months shall be used for this purpose: June through September, December through February, and all other months. Until data exists to calculate this number, the temporary average performance for gas-fired steam generating resources, combined-cycle combustion turbines and simple-cycle combustion turbines shall equal 0.90; the temporary average performance for coal-fired steam generating resources shall equal 0.85; the temporary average performance for oil-fired steam generating resources shall equal 0.65; the temporary average performance for all other resources shall equal 1.00. As actual data for each resource becomes available for each relevant group of months, calculated values for the relevant group of months will replace the temporary average performance values after the end of each group of months each year until all three years reflect actual data. The applicable temporary average performance value will be used for new and existing resources until actual performance data is available.

SF (scaling factor) is a month-specific multiplier, as follows:

June	2.000;
December and July	1.732;
January and August	1.414;
All other months	1.000.

DF(discount factor) is a multiplier that for the three Capacity Commitment Periods beginning June 1, 2018 and ending May 31, 2021, DF shall equal 0.75; and thereafter, DF shall equal 1.00.

B. Non-Commercial Capacity

Notwithstanding any provision of this Section VII to the contrary, a Designated FCM Participant offering Non-Commercial Capacity for a Resource that elected existing Resource treatment for the Capacity Commitment Period beginning June 1, 2010 will not be subject to the provisions of this Section VII.B with respect to that Resource (other than financial assurance obligations relating to transfers of Capacity Supply Obligations).

1. FCM Deposit

A Designated FCM Participant offering Non-Commercial Capacity into any upcoming Forward Capacity Auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) on the fifth (5th) Business Day after its qualification for such auction under Market Rule 1, an amount equal to $2/kW times the Non-Commercial Capacity qualified for such Forward Capacity Auction by such Designated FCM Participant (the “FCM Deposit”).

2. Non-Commercial Capacity in Forward Capacity Auctions

a. Non-Commercial Capacity Participating in a Forward Capacity Auction Up To and Including the Eighth Forward Capacity Auction

For Non-Commercial Capacity participating in a Forward Capacity Auction up to and including the eighth Forward Capacity Auction, a Designated FCM Participant that had its supply offer of Non-Commercial Capacity accepted in a Forward Capacity Auction must include in the calculation of its Financial Assurance Requirement under the ISO New England Financial Assurance Policy the following amounts at the following times:

(i) beginning at 8 a.m. (Eastern Time) on the fifth (5th) Business Day following announcement of the awarded supply offers in that Forward Capacity Auction, an amount equal to $5.737(on a $/kW-month basis) multiplied by the number of kW of capacity awarded to that Designated FCM Participant in that Forward Capacity Auction (such amount being referred to herein as the "Non-Commercial Capacity FA Amount");

(ii) beginning at 8 a.m. (Eastern Time) on the tenth (10th) Business Day prior to the next annual Forward Capacity Auction after the Forward Capacity Auction in which such supply offer was awarded, an additional amount required to make the total amount included in the calculation of the Financial Assurance Requirement with respect to that Non-Commercial Capacity equal to two (2) times the Non-Commercial Capacity FA Amount; and

(iii) beginning at 8 a.m. (Eastern Time) on the tenth (10th) Business Day prior to the second annual Forward Capacity Auction after the Forward Capacity Auction in which such supply offer was accepted, an additional amount required to make the total amount included in the calculation of the Financial Assurance Requirement with respect to that Non-Commercial Capacity equal to three (3) times the Non-Commercial Capacity FA Amount.

b. Non-Commercial Capacity Participating in the Ninth Forward Capacity Auction and All Forward Capacity Auctions Thereafter

A Designated FCM Participant offering Non-Commercial Capacity into the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction an amount equal to the difference between the Net CONE associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded (adjusted as described in Section III.13.2.4) times the Non-Commercial Capacity qualified for such Forward Capacity Auction and the FCM Deposit.

Upon completion of the Forward Capacity Auction, the Non-Commercial Capacity Financial Assurance Amount shall be recalculated according to the following formula:

Non-Commercial Capacity Financial Assurance Amount = (NCC x NCCFCA$ x Multiplier) + NCC Trading FA + NCC Milestone FA + NCC Delay

Where:
NCC = the Capacity Supply Obligation awarded in the Forward Capacity Auction minus any Commercial Capacity

For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the thirteenth Forward Capacity Auction, NCCFCA$ = the Capacity Clearing Price from the first run of the auction-clearing process of the Forward Capacity Auction in which the Capacity Supply Obligation was awarded. For Capacity Supply Obligations acquired in the fourteenth through sixteenth Forward Capacity Auctions ~~and all Forward Capacity Auctions thereafter~~, NCCFCA$ = the lesser of Net CONE associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded (adjusted as described in Section III.13.2.4). For Capacity Supply Obligations acquired in the seventeenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCCFCA$ = the lesser of Net CONE associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded (adjusted as described in Section III.13.2.4) or one-third of the expected portion of the Capacity Base Payments calculated pursuant Section III.13.7.1.1(a) and (d) for the applicable Resource for the initial Capacity Commitment Period in which the Capacity Supply Obligation was awarded.

Multiplier = one at the completion of the Forward Capacity Auction in which the Capacity Supply Obligation was awarded; two beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the next Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded; ~~and~~ three beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the second

Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded; four beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the third Forward Capacity Auction in which the Capacity Supply Obligation was awarded, provided that the increase in the Multiplier from three to four will occur if and only if either (x) the Project Sponsor has not demonstrated pursuant to Section III.13.3.2.2 that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of the construction financing costs or, (y) for a Demand Capacity Resource installed at multiple facilities or a Demand Capacity Resource from a single facility with a demand reduction value of less than 5 MW, such Demand Capacity Resource has not achieved its first target date percentage obligation of its demand reduction value pursuant to Section III.13.1.4.1.1.2 prior to such time; and for resources not subject to Schedules 22 and 25 of Section II of the Transmission, Markets and Services Tariff the Multiplier shall be increased by one at 8 a.m. (Eastern Time) on the tenth Business Day prior to each subsequent Forward Capacity Auction in which the Capacity Supply Obligation was awarded, provided that the increase in the Multiplier will occur if and only if either (x) the Project Sponsor has not demonstrated pursuant to Section III.13.3.2.2 that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of the construction financing costs or, (y) for a Demand Capacity Resource installed at multiple facilities or a Demand Capacity Resource from a single facility with a demand reduction value of less than 5 MW, such Demand Capacity Resource has not achieved its first target date percentage obligation of its demand reduction value pursuant to Section III.13.1.4.1.1.2 prior to such time.

Where this multiplier was increased above three, it shall be reduced back to three on the first day of the calendar month that is at least 30 days following the date on which such Project Sponsor has demonstrated pursuant to Section III.13.3.2.2(iv) that it has achieved substantial site construction or achieved the first target date percentage obligation of its demand reduction value pursuant to Section III.13.1.4.1.1.2.

For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the sixteenth Forward Capacity Auction, NCC Milestone FA = zero. For Capacity Supply Obligations acquired in the seventeenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCC Milestone FA shall lesser of (i) NCC x

NCCFCA$ (each as defined above) x Milestone FA Multiplier or (ii) the NCC Milestone FA Cap.

Milestone FA Multiplier = one beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the next Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded if and only if (1) the Project Sponsor has not demonstrated pursuant to Section III.13.3.2.2 that the applicable Resource has both (x) achieved its project financing closing as described in Section III.13.3.2.2.ii and (y) achieved notice to proceed as described in Section III.13.3.2.2.ii.a and (2) Commercial Operation (as defined in Schedule 22 or 25 of Section II of the Transmission, Markets and Services Tariff) will not be achieved by the start of the associated Capacity Commitment Period;

three beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the second Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded if and only if (1) the Project Sponsor has not demonstrated pursuant to Section III.13.3.2.2 that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of construction financing costs and (2) Commercial Operation (as defined in Schedule 22 or 25 of Section II of the Transmission, Markets and Services Tariff) will not be achieved by the start of the associated Capacity Commitment Period;

six beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the third Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded if and only if (1) the Project Sponsor has not demonstrated pursuant to Section III.13.3.2.2 that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of construction financing costs and (2) Commercial Operation (as defined in Schedule 22 or 25 of Section II of the Transmission, Markets and Services Tariff) will not be achieved by the start of the associated Capacity Commitment Period; and in all other instances, zero.

“NCC FA Milestone Cap” equals one-sixth (1/6) of the expected portion of the Capacity Base Payments calculated pursuant to Section III.13.7.1.1(a) and (d) for the applicable Resource for the initial Capacity Commitment Period in which the Capacity Supply Obligation was awarded beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the next Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded; one-half (1/2) of the portion of the expected Capacity Base Payments calculated pursuant to Section III.13.7.1.1(a) and (d) for the applicable Resource for the initial Capacity Commitment Period in which the Capacity Supply Obligation was awarded beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the second Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded; and the Capacity Base Payments calculated pursuant to Section III.13.7.1.1(a) and (d) for the applicable Resource for the initial Capacity Commitment Period in which the Capacity Supply Obligation was awarded beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the third Forward Capacity Auction after the Forward Capacity Auction in which the Capacity Supply Obligation was awarded.

Notwithstanding the foregoing, NCC Milestone FA shall equal zero (a) for all Demand Capacity Resources and all New Capacity Resources not subject to Schedules 25 or 25 of Section II of the Transmission, Markets and Services Tariff and (b) beginning at 8 a.m. (Eastern Time) on the first day of the calendar month that is at least 30 days following the date upon which the applicable Project Sponsor has demonstrated pursuant to Section III.13.3.2.2 that the amount of money expended on construction activities occurring on the project site has exceeded 20 percent of construction financing costs.

For purposes of determining whether a New Capacity Resource has achieved any of the milestones described in this section by the date set forth in its approved critical path schedule, adjustments to that schedule that have been approved by the ISO pursuant to Section III.13.3.3 will be taken into account, so long as the schedule date for the New Capacity Resource's Commercial Operation (as defined in Schedule 22 or 25 of Section II of the Transmission, Markets and Services Tariff) does not extend beyond the start of the Capacity Commitment Period associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded.

In the case of Non-Commercial Capacity acquiring a Capacity Supply Obligation in the seventeenth Forward Capacity Auction or any Forward Capacity Auction thereafter that fails to achieve Commercial Operation (as defined in Schedule 22 or 25 of Section II of the Transmission, Markets and Services Tariff) ~~become commercial~~ by the commencement of the Capacity Commitment Period associated with the Forward Capacity Auction in which it was awarded a Capacity Supply Obligation, NCC Delay FA shall equal the expected portion of the Capacity Base Payments calculated pursuant to Section III.13.7.1.1(a) and (d) for the applicable Resource that would have received from the start of the Capacity Commitment Period associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded, as reduced by the amount of any NCC Delay FA that is drawn down by the ISO as provided herein. For all other Non-Commercial Capacity (including without limitation Non-Commercial Capacity acquiring Capacity Supply Obligations in Forward Capacity Auctions up to an including the sixteenth Forward Capacity Auction), NCC Delay shall equal zero.

Delay FA shall be due for the first three months of the Capacity Commitment Period ~~the Non-Commercial Capacity Financial Assurance Amount shall be recalculated as follows: beginning~~ at 8 a.m. (Eastern Time) on the first Business Day of the ~~second~~ fourth month of the Capacity Commitment Period associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded~~,~~ and every three months thereafter ~~the Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance Amount shall be four. The Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance shall increase by one every six months thereafter shall increase by one every six months thereafter~~ until the Non-Commercial Capacity achieves Commercial Operation (as defined in Schedule 22 or 25 of Section II of the Transmission, Markets and Services Tariff) ~~becomes commercial~~ or the Capacity Supply Obligation is terminated.

Notwithstanding the foregoing, NCC Delay FA shall equal zero (a) for all Demand Capacity Resources and all New Capacity Resources not subject to Schedules 22 or 25 of Section II of the Transmission, Markets and Services Tariff and (b) beginning at 8 a.m. (Eastern Time) on the first day of the calendar month that is at least 30 days following the date upon which the applicable Project Sponsor has achieved Commercial

Operation (as defined in Schedule 22 or 25 of Section II of the Transmission, Markets and Services Tariff).

For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the twelfth Forward Capacity Auction, NCC Trading FA = zero. For Capacity Supply Obligations acquired in the thirteenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCC Trading FA shall be zero until the start of the applicable Capacity Commitment Period, at which time NCC Trading FA = the total amount of NCC that has been shed (whether before or after the start of the Capacity Commitment Period) in any reconfiguration auctions or Capacity Supply Obligation Bilaterals or that is subject to a failure to cover charge pursuant to Section III.13.3.4(b) (but this total amount shall not be greater than NCC) multiplied by the difference (but not less than zero) between: (i) the weighted average price at which the Capacity Supply Obligation was acquired in the Forward Capacity Auction (adjusted, where appropriate, in accordance with the Handy-Whitman Index of Public Utility Construction Costs); and (ii) the weighted average price or failure to cover charge rate at which the Capacity Supply Obligation was shed or assessed, as applicable (except that for monthly Capacity Supply Obligation Bilaterals, the applicable monthly reconfiguration auction clearing price will be used instead of the Capacity Supply Obligation Bilateral price).

c. Non-Commercial Capacity Deferral

Where the Commission approves a request to defer a Capacity Supply Obligation filed pursuant to Section III.13.3.7 of Market Rule 1, the Designated FCM Participant must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, beginning at 8 a.m. (Eastern Time) 30 days after Commission approval of the request to defer, an amount equal to the amount that would apply to a resource that has not achieved commercial operation one year after the start of a Capacity Commitment Period in which it has a Capacity Supply Obligation, as calculated pursuant to Section VII.B.2.a or Section VII.B.2.b, as applicable.

3. Return of Non-Commercial Capacity Financial Assurance

Non-Commercial Capacity cleared in a Forward Capacity Auction up to and including the eighth Forward Capacity Auction that is declared commercial and has had its capacity rating verified by the ISO or otherwise becomes a Resource meeting the definition of Commercial Capacity, or that is declared commercial and had a part of its capacity rating verified by the ISO and the applicable Designated FCM Participant indicates no additional portions of that Resource will become commercial, that portion of the Resource shall no longer be considered Non-Commercial Capacity under the ISO New England Financial Assurance Policy and will instead become subject to the provisions of the ISO New England Financial Assurance Policy relating to Commercial Capacity; provided that in either such case, the Designated FCM Participant will need to include in the calculation of its Financial Assurance Requirement an amount attributable to any remaining Non-Commercial Capacity.

Once Non-Commercial Capacity associated with a Capacity Supply Obligation awarded in the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter becomes commercial, the Non-Commercial Capacity Financial Assurance Amount for any remaining Non-Commercial Capacity shall be recalculated according to the process outlined above for Non-Commercial Capacity participating in the ninth Forward Capacity Auction and all Forward Capacity Auctions thereafter.

4. Credit Test Percentage Consequences for Provisional Members

If a Provisional Member is required to provide additional financial assurance under the ISO New England Financial Assurance Policy solely in connection with (A) a supply offer of Non-Commercial Capacity into any Forward Capacity Auction and (B) its obligation to pay Participant Expenses as a Provisional Member, and that Provisional Member is maintaining the amount of additional financial assurance required under the ISO New England Financial Assurance Policy, then the provisions of Section III.B of the ISO New England Financial Assurance Policy relating to the consequences of that Market Participant's Market Credit Test Percentage equaling 80 percent (80%) or 90 percent (90%) shall not apply to that Provisional Member.

C. FCM Capacity Charge Requirements

The FCM Capacity Charge Requirements shall be calculated for the current month and all previously unbilled months. The FCM Capacity Charge Requirements shall be the product of the Estimated Capacity Load Obligation times the FCM Charge Rate for the applicable Capacity Zone. For purposes of this calculation, the FCM Charge Rate for Capacity Commitment Periods beginning prior to June 1, 2022 for a Capacity Zone will be calculated using the same methodology described in Section III.13.7.5 of Market Rule 1 for deriving the Net Regional Clearing Price, with the exception that the FCM Charge Rate will include the balance of the CTR fund after the value of specifically allocated CTRs has been paid, as described in Section III.13.7.5.3.1 of Market Rule 1. For purposes of this calculation, the FCM Charge Rate for Capacity Commitment Periods beginning on or after to June 1, 2022 for a Capacity Zone will be calculated as the sum of the charge and adjustment rates specified in Section III.13.7.5.1.1 of Market Rule 1.

D. Loss of Capacity and Forfeiture of Non-Commercial Capacity Financial Assurance

If a Designated FCM Participant that has acquired Capacity Supply Obligations associated with Non-Commercial Capacity is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy and does not cure such default within the appropriate cure period, or if a Designated FCM Participant is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy during the period between the day that is three Business Days before the FCM Deposit is required and the first day of the Forward Capacity Auction and does not cure such default within the appropriate cure period, then: (i) beginning with the first Business Day following the end of such cure period that Designated FCM Participant will be assessed a default charge of one percent (1%) of its total Non-Commercial Capacity Financial Assurance Amount at that time for each Business Day that elapses until it cures its default; and (ii) if such default is not cured by 5:00 p.m. (Eastern Time) on the sooner of (x) the fifth Business Day following the end of such cure period or (y) the second Business Day prior to the start of the next scheduled Forward Capacity Auction or annual reconfiguration auction or annual Capacity Supply Obligation Bilateral submission (such period being referred to herein as the “Non-Commercial Capacity Cure Period”), then, in addition to the other actions described in this Section VII, (A) all Capacity Supply Obligations associated with Non-Commercial Capacity that were awarded to the defaulting Designated FCM Participant in previous Forward Capacity Auctions and reconfiguration auctions and that the defaulting Designated FCM Participant acquired by entering into Capacity Supply Obligation Bilaterals shall be terminated; (B) the defaulting

Designated FCM Participant shall be precluded from acquiring any Capacity Supply Obligation that would be associated with Non-Commercial Capacity for which the defaulting Designated FCM Participant has submitted an FCM Deposit; (C) the ISO will (1) draw down the entire amount of the FCM Deposit and the Non-Commercial Capacity Financial Assurance Amount associated with the terminated Capacity Supply Obligations and (2) issue an Invoice to the Designated FCM Participant if there is a shortfall resulting from that Designated FCM Participant's failure to maintain adequate financial assurance hereunder or if the Designated FCM Participant used a Market Credit Limit to meet its FCM Financial Assurance Requirements; and (D) the default charges described in clause (i) above shall not be assessed to that Designated FCM Participant. All default charges collected under clause (i) above will be deposited in the Late Payment Account in accordance with the ISO New England Billing Policy.

If a Designated FCM Participant's Capacity Supply Obligation is terminated under Market Rule 1, the ISO will draw down the entire Non-Commercial Capacity Financial Assurance Amount provided by such Designated FCM Participant with respect to such terminated Capacity Supply Obligation. If the Designated FCM Participant has not provided enough financial assurance to cover the amount due (or that would have been due but for the Designated FCM Participant's positive Market Credit Limit) with respect to such Non-Commercial Capacity Financial Assurance Amount, then the ISO will issue an Invoice to the Designated FCM Participant for the amount due.

In addition, the ISO will draw down the additional financial assurance provided by a Designated FCM Participant under the calculation of NCC Delay FA three months following the date upon which that financial assurance is due if the applicable Resource fails to achieve Commercial Operation (as defined in Schedule 22 or 25 of Section II of the Transmission, Markets and Services Tariff) by such date. In each case, such financial assurance will be allocated as provided in Section III.13.1.9.2.3.

E. Composite FCM Transactions

For separate resources that seek to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide that capacity (collectively, a "Composite FCM Transaction"), each Designated FCM Participant participating in that Composite FCM Transaction will be responsible for providing the financial assurance required as follows:

1. the FCM Financial Assurance Requirements for each Designated FCM Participant shall be determined solely with respect to the capacity being provided, or sought to be provided, by that Designated FCM Participant;

2. [reserved];

3. if the Composite FCM Transaction involves one or more Resources seeking to provide or providing Non-Commercial Capacity, the Non-Commercial Capacity Financial Assurance Amount under Section VII.B for each Designated FCM Participant with respect to that Composite FCM Transaction will be calculated based on the commercial status of the Non-Commercial Capacity cleared through the Forward Capacity Auction;

4. any Non-Commercial Capacity Financial Assurance Amount provided under Section VII.B by each Designated FCM Participant with respect to each Resource providing Non-Commercial Capacity in the Composite FCM Transaction will be recalculated according to Section VII.B.3 as the corresponding Resource becomes commercial; and

5. in the event that the Capacity Supply Obligation is terminated, Section VII.D shall apply only to the Non-Commercial Capacity of the Designated FCM Participant participating in the Composite FCM Transaction that has failed to satisfy its obligations, and any Invoice issued thereunder will be issued only to that Designated FCM Participant.

6. the FCM Delivery Financial Assurance calculated under Section VII.A for each Designated FCM Participant contributing resources to a Composite FCM Transaction shall be based on the Capacity Supply Obligation that is provided by that Designated FCM Participant in the current month of the Capacity Commitment Period, provided that the FCM charges incurred in previous months, but not yet paid, shall increase the FCM Financial Assurance Requirements only of the Designated FCM Participant that incurred the charges.

F. Transfer of Capacity Supply Obligations

1. Transfer of Capacity Supply Obligations in Reconfiguration Auctions

A Designated FCM Participant that seeks to transfer its Capacity Supply Obligation in a reconfiguration auction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of bidding in that reconfiguration auction, the amounts described in subsections (a) and (b) below.

(a) For the 12 month period beginning with the current month, the sum of that Designated FCM Participant's net monthly FCM charges for each month in which the net FCM revenue results in a charge. For purposes of this subsection (a), months in this period in which that Designated FCM Participant's net FCM revenue results in a credit are disregarded (i.e., the net credits from such months are not used to reduce the amount described in this subsection (a)). The amount described in this subsection (a), if any, will increase the Designated FCM Participant's FCM Financial Assurance Requirements.

(b) For the period including each month that is after the period described in subsection (a) above and that is included in a Capacity Commitment Period for which a Forward Capacity Auction has been conducted, the sum of that Designated FCM Participant's net monthly FCM charges for each month in which the net FCM revenue results in a charge. For this period, the sum of such charges may be offset by net credits from months in which the net FCM revenue results in a credit, but in no case will the amount described in this subsection (b) be less than zero. The amount described in this subsection (b), if any, will increase the Designated FCM Participant's FCM Financial Assurance Requirements.

For purposes of these calculations, the net FCM revenue for a month shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations, demand bids and Annual Reconfiguration Transactions in the Forward Capacity Market, exclusive of any accrued Capacity Performance Payments on positions currently or previously held. Upon the completion of each reconfiguration auction, the amount to be included in the calculation of any FCM Financial Assurance Requirements of that Designated FCM Participant shall be adjusted to reflect the cleared quantities at the zonal clearing price for all activity in that reconfiguration auction and accepted Annual Reconfiguration Transactions.

2. **Transfer of Capacity Supply Obligations in Capacity Supply Obligation Bilaterals** A Designated FCM Participant that seeks to transfer its Capacity Supply Obligation in a Capacity Supply Obligation Bilateral must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of the period for submission of that Capacity Supply Obligation Bilateral, amounts calculated as described in Section VII.F.1 above, as applicable. If a Designated FCM Participant fails to provide the required additional financial assurance for its Capacity Supply Obligation Bilaterals, all of those transactions will be rejected. If the Designated FCM Participant's request to transfer a Capacity Supply Obligation in a Capacity Supply Obligation Bilateral is not accepted, it will no longer include amounts related to that Capacity Supply Obligation in the calculation of its FCM Financial Assurance Requirements.

3. **Financial Assurance for Annual Reconfiguration Transactions**
A Designated FCM Participant that submits an Annual Reconfiguration Transaction must include in the calculation of its FCM Financial Assurance Requirements under the ISO New England Financial Assurance Policy, prior to the close of the period for submission of that Annual Reconfiguration Transaction, amounts calculated as described in Section VII.F.1 above, as applicable. If a Designated FCM Participant fails to provide the required additional financial assurance for its Annual Reconfiguration Transactions, all of those transactions will be rejected. If a transaction is rejected, the Designated FCM Participant is no longer required to include amounts related to that transaction in the calculation of its FCM Financial Assurance Requirements.

4. Substitution Auctions

A Designated FCM Participant that participates in a substitution auction must include the following charges and credits in its FCM Financial Assurance Requirements.

a. For any supply offer with at least one price-quantity pair priced less than zero must include in the calculation of its FCM Financial Assurance Requirements, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction, amounts calculated as described in Section VII.F.1 above. For purposes of these calculations, the maximum charge that would result from clearing any price-quantity pairs priced less than zero for each month of the Capacity Commitment Period associated with the Forward Capacity Auction shall be included in the amount calculated as described in Section VII.F.1(b) above, the net FCM revenue for all other months in the defined periods shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations in the Forward Capacity Market, and any accrued Capacity Performance Payments on positions currently or previously held are excluded.

b. A Designated FCM Participant (i) that submits a demand bid into a substitution auction for a resource that is subject to a multi-year rate pursuant to Section III.13.1.3.5.4 or Section III.13.1.1.2.2.4, (ii) for which the maximum charge that would result from clearing the capacity subject to the multi-year rate election would exceed the revenue the Designated FCM Participant will receive for the relevant Capacity Commitment Period under its multi-year rate election for the resource, (iii) must include in the calculation of its FCM Financial Assurance Requirements, beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction, amounts calculated as described in Section VII.F.1 above. For purposes of these calculations, the maximum charge that would result from clearing the capacity subject to the multi-year rate election shall be included in the amount calculated as described in Section VII.F.1(b) above, the net FCM revenue for all other months in the defined periods shall be determined by accounting for all charges and credits related to the purchase or sale of Capacity Supply Obligations in the Forward Capacity Market, and any accrued Capacity Performance Payments on positions currently or previously held are excluded.

c. If a Designated FCM Participant is in default under the ISO New England Financial Assurance Policy or the ISO New England Billing Policy beginning at 8 a.m. (Eastern Time) on the tenth Business Day prior to the Forward Capacity Auction and does not cure such default by the earlier of (i) the end of the appropriate cure period and (ii) 5 p.m. (Eastern Time) on the second Business Day prior to the start of the Forward Capacity Auction, then the defaulting Designated FCM Participant shall be precluded from submitting a supply offer or demand bid that is subject to this Section VII.F.4.

d. Upon the completion of the substitution auction, the amount to be included in the calculation of the FCM Financial Assurance Requirements for a Designated FCM Participant as described in Section VII.F.1 above shall be adjusted to reflect all charges and credits related to the purchase or sale of Capacity Supply Obligations in the substitution auction.

Competitive
Power Ventures

Performance Based Non-Commercial Financial Assurance

April 12, 2022
NEPOOL Markets Committee

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Process, Schedule and Status

- We would still like to have these changes in place for FCA 17.
  - Target is to have a FERC filing end of May in order to have a decision by the New Capacity Qualification Package Submission window which closes on July 27, 2022.

- Seeking MC action for recommendation to the Participants Committee.
  - MR1 changes were voted down at the February 8 Markets Committee
    - Since then, the proposal has been modified to address several concerns raised by stakeholders:
      - Reverts cost allocation of forfeited FA to maintain the existing status quo (MR1).
      - Adds more clarity to existing Critical Path Milestone Schedule (MR1).
      - Rationalizes the FA to expected capacity revenues (FAP):
        - This addresses concerns with Solar resource which clear only 4 month of the year.

- Four components now down to three:
  1. Adds an increment of FA prior to the third and all subsequent FCAs for resources not achieving Substantial Site Construction. (B&F)
  2. Require additional "Milestone FA" during the critical path schedule tracking. (B&F)
  3. Changes intervals of post-COD FA ("Delay FA") to every three months and adds forfeiture provision. (B&F)
  ~~4. Allocate forfeited Milestone and Delay FA all buyers and sellers in the FCM~~. (MC Vote)

Other Improvements to the Proposal

- The Market Rule 1 Changes are about clarity – there are no substantive changes in the design:
    - Designed to make it easier to understand the projects during qualification.
    - Designed to make it easier to evaluate performance against the critical path schedule:
- Changes in the Critical Path Schedule section:
    - Clarification and more specificity of Project Finance Closing III.13.1.1.2.2.2(b).
        - Adds "estimated cost of construction component to allow future tracking of "Substantial Site Construction" milestone.
    - Addition of Notice to Proceed concept in the critical path milestone (which has been implicit) III.13.1.1.2.2.2(bi).
- Changes in Documentation of Milestones Achieved:
    - Adds certification and documentation for achievement of the above Milestones.

With better definition comes easier determination of the achievement of those milestones.

- Changes in how the increments of FA are calculated – fixing the solar problem.

The Need for Performance-Based Financial Assurance -REVIEW

- There is no performance-based FA for non-commercial capacity across the range of performance contrary to good market design.
  - The current FA design makes no distinction between a project meeting all its milestone commitments, a delayed project, and a totally failed project.
    - The only performance-based FA is *after* the resource has failed to meet its initial COD, yet even this provision does not consider the status of the project (i.e.: has it even started construction?).

- Lack of performance-based consequences undermine incentives for balanced decision-making for sponsors of highly unlikely projects.
  - In the recent NE example, the project sponsor had little financial incentive to withdraw a failed project:
    - There is no additional posting requirement prior to the third subsequent FCA.
    - There is no incremental financial consequence for missing *any* or *every* single milestone.
    - The opportunity to recover previously posted FA may incent resources to wait for ISO-NE to make a termination decision, and then to challenge that decision.

- The qualification process and the financial assurance requirements are not working together to ensure that cleared projects are “real” or “timely.”
  - The only real tool in the ISO toolbox is a sledgehammer - termination.

Impacts from Current Design Shortfall - REVIEW

- Failed non-commercial capacity participating in capacity auctions financially impact all other capacity sellers in the auction with no recourse by those impacted.
  - A resource that has not achieved COD by its FCA required commitment date will have posted just three months of FA but would have participated in <u>four</u> FCAs (see FCA16 issues currently pending).
  - Financial impacts to other CSO holders is through lower clearing prices in each auction and higher performance risk during the delivery period.
    - Most recent NE example estimated to have a market impact of $380 million over three auctions: $0.31 kw-month average.#

- Projects that are not ripe for participation can displace other shovel-ready projects.

- Existing FA requirements are not balanced with either the project cost, or potential market impact for projects failing to meeting their commitments.
  - Most recent NE example using current FA rules:
    - Total FA prior to committed COD: $14.1 million*
    - Total Market impact: $380 million.
    - Total Project Cost: $621MM @

Proposed Performance Based FA Enhancements - REVIEW

Current FA includes:

- FA that is collected prior to the primary FCA and then prior to the first and second subsequent auctions (aka: “Base FA” for ease of reference)
- Trading FA: FA that is collected in the delivery period as any positive trading revenue from cover transactions.

This proposal establishes two new categories of FA to incorporate a performance-based design– changes that impact only those resources failing to perform consistent with their FCA commitments:

- Milestone FA: New FA requirements for projects that fail to meet two critical delivery obligations – Financing/Start of Construction, and 20% construction completed.
- Delay FA: Increased posting of FA and potential forfeiture for projects that fail to deliver physically by their commitment date.
  - And… adds additional increments of “Base FA” prior each subsequent FA for significantly delayed projects.

Determination of FA Amounts – For "Base FA"

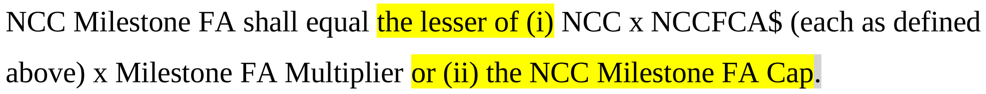
- Proposal now attempts to rationalize how the increments of FA are calculated:
  - Earlier proposal used Net CONE as the "increment" of FA.
    - This created a significant disconnect between FA requirements verses revenues expected in the capacity market, especially for solar resources as noted in the March 1 RENEW memo to the NPC.
      - Solar only clears the four summer months.

- Proposal now seeks to set the "Base FA" increment (NCCFCA$) to the lesser of
  a) Net CONE; or,
  b) One third of the expected capacity revenue* coming out of the auction.
    - Using the "lesser of" better ties the FA to the expected capacity revenues from the auction.
    - Using 1/3rd of the total annual capacity revenue *fixes the solar issue* and provides balance for resources clearing all twelve months in the event of very low clears.
      - FCA 15 Net CONE: $8.71 1/3 Annual Revenue: $10.44
      - FCA 16 Net CONE: $7.47 1/3 Annual Revenue: $10.36

- Uses the Definition of Capacity Base Payment but limited to two of the four components only.
    - Determined monthly using clearing price and MW quantity cleared in the primary auction or substitution auction.

Determination of FA Increments for Milestone FA

- Milestone FA builds upon the NCCFCA$ construct used for the Base FA requirement but adds a new “lesser-of” component – the “NCC FA Milestone Cap”.



NCC Milestone FA shall equal the lesser of (i) NCC x NCCFCA$ (each as defined above) x Milestone FA Multiplier or (ii) the NCC Milestone FA Cap.

- The NCC FA Milestone Cap is the based upon expected capacity revenues consistent with the Base FA methodology but establishes a cap in each of the milestones as follows:
  - For missing the first milestone: one-sixth (1/6) of the expected annual capacity revenues.
  - For missing the second milestone: one-half (1/2) of the expected annual capacity revenues.
  - For missing the third milestone: one year of the expected annual capacity revenues.
    - These are total requirements at each step, not cumulative.
- Upon achievement of the milestone, the FA is returned to the project.

Milestone FA Proposal:

Adds a financial consequence for projects failing to advance in a timely fashion consistent with their schedule:

- Prior to the First Subsequent FCA:
  - Resources that have not achieved Project Finance Closing and Notice to Proceed* according to their approved milestone schedule would be required to post an additional one increment of FA prior to the first subsequent auction, subject to the NCC FA Milestone Cap (two months cap of revenues).

- Prior to the Second Subsequent FCA:
  - Resources that have not achieved Substantial Site Construction according to their approved milestone schedule would be required to post an incremental two increments of FA prior to the second subsequent FCA, subject to the NCC FA Milestone Cap (six months cap of revenues).

- Prior to the Third Subsequent FCA:
  - Resources that have *still* not achieved Substantial Site Construction according to their approved milestone schedule would be required to post an incremental three increments of FA prior to the third subsequent FCA, subject to the NCC FA Milestone Cap. (1 year cap on revenues).

In determining the trigger on Milestone FA, changes to the milestone schedule approved by the ISO will be considered, so long as the scheduled date for the resource's COD (per Schedule 22 or 25 of Section II of the Tariff) does not extend beyond the start of the Capacity Commitment Period associated with the Forward Capacity Auction in which the CSO was awarded.

- Again, Milestone FA is only required for resources that fail to advance consistent with their critical path schedule *and* will miss their guaranteed COD.

Delay FA Product

- Proposal is to replace current post COD FA with one increment of FA for every three months of delayed COD.
  - Current FA requirement is one month of FA for every six months of delay.

- COD in this construct is pursuant to Schedule 22 & 25 – is the project commercial and available to the system:
  - It recognizes some resources will be unable to demonstrate their FCM COD capability due to FCA test procedures.

- Delay FA is collected three months after-the-fact and is forfeited if the project has not declared COD by the end of the subsequent three months – effectively a six-month grace period.

- Revised calculation of Delay FA is the expected capacity revenue that would have been earned over the period for which the resource was late (with a six month grace period).
  - This address the solar issue of only clearing 4 summer months.
  - It creates a late delivery penalty equal to the amount of revenue otherwise expected from the market.

THANK YOU!

Financial Assurance Policy Tariff Changes:

Please refer to Budget and Finance Subcommittee posting for most current version of the FAP.

Includes yellow highlighted changes from the last B&F meeting.

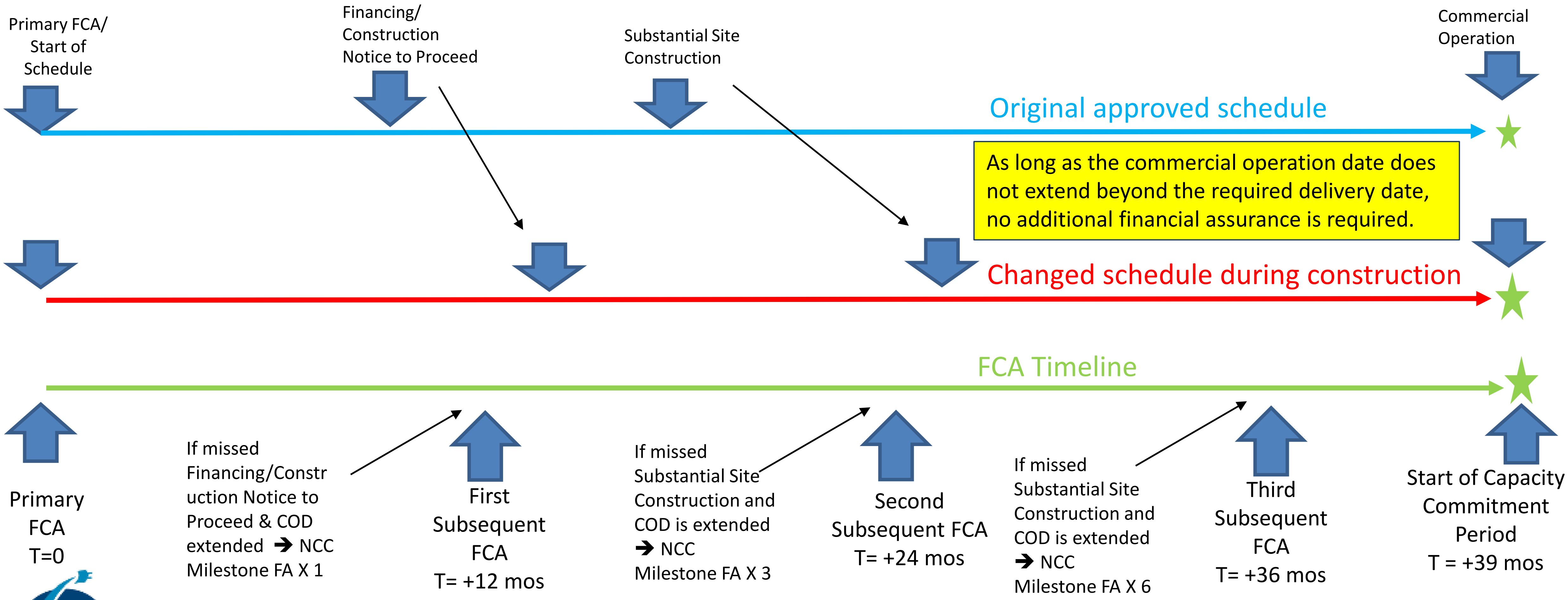
Additional Slides

Changes to the Milestone Schedule/ Mechanics

Approved Critical Path Milestone Schedule

- This is established at qualification and is subject to change consistent with current rules. The current rules allow all milestones to be pushed out without any financial consequence.

Performance-based FA proposal allows for all milestones to be adjusted without increased FA as long as the Commercial Operation date remains on or before the start of the Capacity Commitment Period associated with the CSO.



Primary FCA/ Start of Schedule

Financing/ Construction Notice to Proceed

Substantial Site Construction

Commercial Operation

Original approved schedule

As long as the commercial operation date does not extend beyond the required delivery date, no additional financial assurance is required.

Changed schedule during construction

FCA Timeline

Primary FCA T=0

If missed Financing/Construction Notice to Proceed & COD extended ➔ NCC Milestone FA X 1

First Subsequent FCA T= +12 mos

If missed Substantial Site Construction and COD is extended ➔ NCC Milestone FA X 3

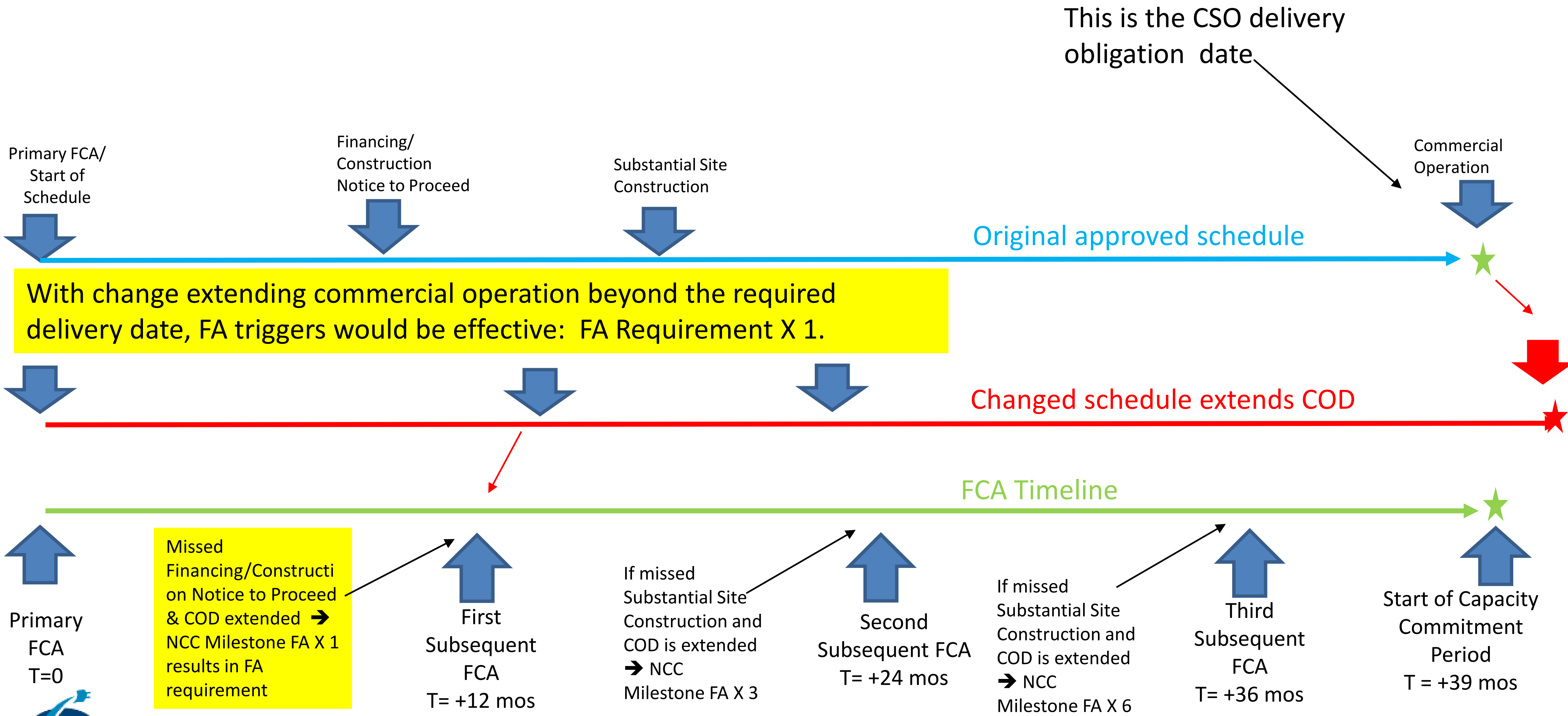
Second Subsequent FCA T= +24 mos

If missed Substantial Site Construction and COD is extended ➔ NCC Milestone FA X 6

Third Subsequent FCA T= +36 mos

Start of Capacity Commitment Period T = +39 mos

Milestone Requirement/ Example



This is the CSO delivery obligation date

Primary FCA/ Start of Schedule

Financing/ Construction Notice to Proceed

Substantial Site Construction

Commercial Operation

Original approved schedule

With change extending commercial operation beyond the required delivery date, FA triggers would be effective: FA Requirement X 1.

Changed schedule extends COD

FCA Timeline

Primary FCA T=0

Missed Financing/Construction Notice to Proceed & COD extended ➔ NCC Milestone FA X 1 results in FA requirement

First Subsequent FCA T= +12 mos

If missed Substantial Site Construction and COD is extended ➔ NCC Milestone FA X 3

Second Subsequent FCA T= +24 mos

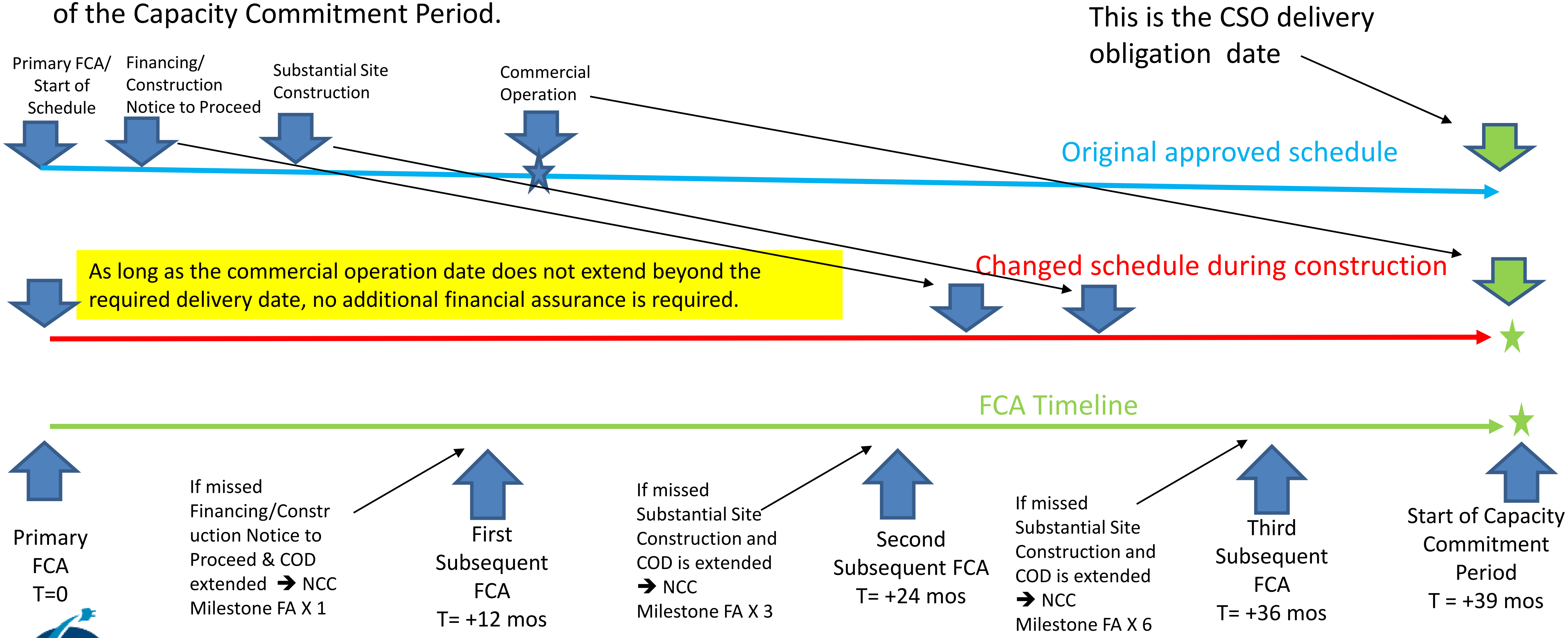
If missed Substantial Site Construction and COD is extended ➔ NCC Milestone FA X 6

Third Subsequent FCA T= +36 mos

Start of Capacity Commitment Period T = +39 mos

Short Duration Project Example

Some projects with short construction schedules submit milestone schedules with early CODs, however the capacity market obligation is for COD by the start of the Capacity Commitment Period.



This is the CSO delivery obligation date

Primary FCA/ Start of Schedule

Financing/ Construction Notice to Proceed

Substantial Site Construction

Commercial Operation

Original approved schedule

Changed schedule during construction

As long as the commercial operation date does not extend beyond the required delivery date, no additional financial assurance is required.

FCA Timeline

Primary FCA T=0

If missed Financing/Construction Notice to Proceed & COD extended ➔ NCC Milestone FA X 1

First Subsequent FCA T= +12 mos

If missed Substantial Site Construction and COD is extended ➔ NCC Milestone FA X 3

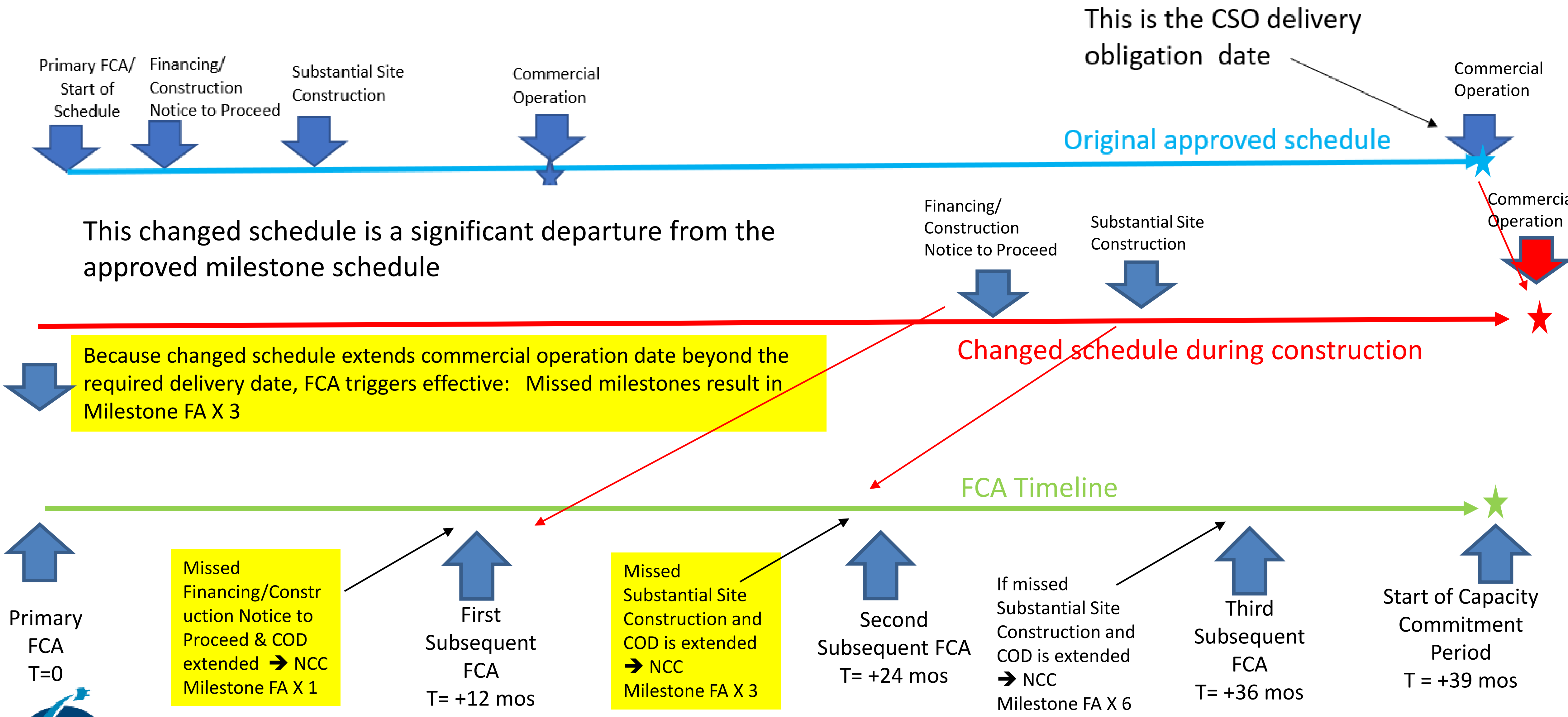
Second Subsequent FCA T= +24 mos

If missed Substantial Site Construction and COD is extended ➔ NCC Milestone FA X 6

Third Subsequent FCA T= +36 mos

Start of Capacity Commitment Period T = +39 mos

Short Duration Project Milestone FA Required - Example



This is the CSO delivery obligation date

Primary FCA/ Start of Schedule

Financing/ Construction Notice to Proceed

Substantial Site Construction

Commercial Operation

Commercial Operation

Original approved schedule

This changed schedule is a significant departure from the approved milestone schedule

Financing/ Construction Notice to Proceed

Substantial Site Construction

Commercia Operation

Changed schedule during construction

Because changed schedule extends commercial operation date beyond the required delivery date, FCA triggers effective: Missed milestones result in Milestone FA X 3

FCA Timeline

Primary FCA T=0

Missed Financing/Construction Notice to Proceed & COD extended ➔ NCC Milestone FA X 1

First Subsequent FCA T= +12 mos

Missed Substantial Site Construction and COD is extended ➔ NCC Milestone FA X 3

Second Subsequent FCA T= +24 mos

If missed Substantial Site Construction and COD is extended ➔ NCC Milestone FA X 6

Third Subsequent FCA T= +36 mos

Start of Capacity Commitment Period T = +39 mos

Current Milestone Schedule

- The current Critical Path Milestone Schedule process requires all non-commercial capacity to provide a schedule for major milestones as part of its qualification.

> III.13.1.1.2.2.2. Critical Path Schedule. In the New Capacity Qualification Package, the Project Sponsor must provide a critical path schedule for the project *with sufficient detail to allow the ISO to evaluate the feasibility of the project being built and the feasibility that the project will meet the requirement that the project achieve all its critical path schedule milestones* no later than the start of the relevant Capacity Commitment Period.

- A critical path schedule report is due on a quarterly basis from the Project Sponsor.
  - Each report must update the original schedule, note changes to milestones and project scope. (III. 13.2.2.1)
  - Achievement of milestones must include documentation in support.
    - Failure to provide *the report* can result in termination.

- Failure to meet the original milestone, and changes to the schedule, may result in a monthly reporting requirement (III.13.3.3).
  - Covering obligations for late delivery is optional…
    - Although choosing not to cover will result in failure to cover charge, but only *after* the start of the delivery period (III.13.3.4.(b)).
    - Failure to provide *the monthly reports* can result in termination.

- There are no financial consequences of failing to achieve milestones until after the delivery date has been passed.

Previous Presentations:

Budget and Finance Committee – August 26, 2021

NEPOOL Markets Committee – September 13-14, 2021

Budget and Finance Committee – October 12, 2021

NEPOOL Markets Committee – November 9-10, 2021

NEPOOL Budget and Finance Committee – November 29, 2021

Tariff Language:

NEPOOL Markets Committee – December 9, 2021

NEPOOL Markets Committee – January 12, 2022

NEPOOL Budget and Finance Committee – January 26, 2022

jgordon@cpv.com
603-673-6654

Competitive
Power Ventures

Performance Based Non-Commercial Financial Assurance

April 21, 202
NEPOOL Budget & Finance Subcommittee

SILVER SPRING | BRAINTREE

Process, Schedule and Status

- We would still like to have these changes in place for FCA 17.
  - FERC filing end of May in time for the New Capacity Qualification Package Submission window by July 27, 2022.
- MR1 changes were voted down at the April 12th Markets Committee with over 55% in favor.
  - The MR 1 portion of the proposal had been modified to address several concerns raised by stakeholders:
    - Reverts cost allocation of forfeited FA to maintain the existing status quo (MR1).
    - Adds more clarity to existing Critical Path Milestone Schedule (MR1).
- Seeking a recommendation of the B&F for the NPC on this revised proposal:
  - Changes in yellow in the FAP designed to better rationalize the FA to expected capacity revenues:
    - This addresses concerns with Solar resource which clear only 4 month of the year.
- Four components now down to three:

1. Adds an increment of FA prior to the third and all subsequent FCAs for resources not achieving Substantial Site Construction.
2. Require additional "Milestone FA" during the critical path schedule tracking.
3. Changes intervals of post-COD FA ("Delay FA") to every three months and adds forfeiture provision.
4. ~~Allocate forfeited Milestone and Delay FA all buyers and sellers in the FCM~~.

MR1 Proposal (At the MC)

- The Market Rule 1 Changes are about clarity – there are no substantive changes in the design:
  - Designed to make it easier to understand the projects during qualification.
  - Designed to make it easier to evaluate performance against the critical path schedule:

- Changes in the Critical Path Schedule section:
  - Clarification and more specificity of Project Finance Closing III.13.1.1.2.2.2(b).
    - Adds "estimated cost of construction component to allow future tracking of "Substantial Site Construction" milestone.
  - Addition of Notice to Proceed concept in the critical path milestone (which has been implicit) III.13.1.1.2.2.2(bi).

- Changes in Documentation of Milestones Achieved:
  - Adds certification and documentation for achievement of the above Milestones.

With better definition comes easier determination of the achievement of those milestones.

The Need for Performance-Based Financial Assurance - Recap

- There is no performance-based FA for non-commercial capacity across the range of performance contrary to good market design.
  - The current FA design makes no distinction between a project meeting all its milestone commitments, a delayed project, and a totally failed project.
    - The only performance-based FA is *after* the resource has failed to meet its initial COD, yet even this provision does not consider the status of the project (i.e.: has it even started construction?).

- Lack of performance-based consequences undermine incentives for balanced decision-making for sponsors of highly unlikely projects.
  - In the recent NE example, the project sponsor had little financial incentive to withdraw a failed project:
    - There is no additional posting requirement prior to the third subsequent FCA.
    - There is no incremental financial consequence for missing *any* or *every* single milestone.
    - The opportunity to recover previously posted FA may incent resources to wait for ISO-NE to make a termination decision, and then to challenge that decision.
      - Litigation was extremely disruptive to the market participants, but lower cost than posting at risk FA.
- The qualification process and the financial assurance requirements are not working together to ensure that cleared projects are “real” or “timely.”
  - The only real tool in the ISO toolbox is a sledgehammer - termination.

Impacts from Current Design Shortfall - Recap

- Failed non-commercial capacity participating in capacity auctions financially impact all other capacity sellers in the auction.
  - A resource that has not achieved COD by its FCA required commitment date will have posted just three increments of FA but would have participated in four FCAs (see FCA16 issues currently pending).
  - Financial impacts to other CSO holders is through lower clearing prices in each auction and higher performance risk during the delivery period.
    - Most recent NE example estimated to have a market impact of $380 million over three auctions: $0.31 kw-month average.#

- Projects that are not ripe for participation can displace other shovel-ready projects.

- Existing FA requirements are not balanced with either the project cost, or potential market impact for projects failing to meet their commitments.
  - Most recent NE example using current FA rules:
    - Total FA prior to committed COD: $14.1 million*
    - Total Market impact: $380 million.
    - Total Project Cost: $621MM @

Proposed Performance Based FA Enhancements - Recap

Current FA includes:

- FA that is collected prior to the primary FCA and then prior to the first and second subsequent auctions (aka: “Base FA” for ease of reference); followed by every six months post COD.
- Trading FA: FA that is collected in the delivery period as any positive trading revenue from cover transactions.

This proposal establishes two new categories of FA to incorporate a performance-based design– *changes that impact only those resources failing to perform* consistent with their FCA commitments:

- Milestone FA: FA requirements for projects that fail to meet two critical delivery obligations – Financing/Start of Construction, and 20% construction completed.

- Delay FA: Increased posting of FA and potential forfeiture for projects that fail to deliver physically by their commitment date.

  - And… adds additional increments of “Base FA” prior each subsequent FA for significantly delayed projects.

Determination of FA Amounts – For "Base FA"

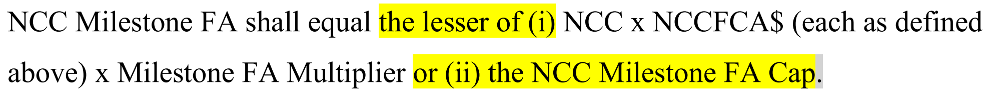
- Proposal now attempts to rationalize how the increments of FA are calculated:
  - Earlier proposal followed the current policy using Net CONE as the "increment" of FA.
    - This created a significant disconnect between FA requirements verses revenues expected in the capacity market, especially for solar resources as noted in the March 1 RENEW memo to the NPC.
      - Solar only clears the four summer months thus required to post 3X of year-round resources when compared to expected revenues.

- Current proposal now seeks to set the "Base FA" increment (NCCFCA$) to the lesser of
  a) Net CONE; or,
  b) One third of the expected capacity revenue* coming out of the auction.
    - Using the "lesser of" better ties the FA to the expected capacity revenues from the auction.
    - Using 1/3rd of the total annual capacity revenue *fixes the solar issue* and provides balance for resources clearing all twelve months in the event of very low clears.
      - FCA 15 Net CONE: $8.71 v. 1/3 Annual Revenue: $10.44 v. Solar FA Requirement: $3.48
      - FCA 16 Net CONE: $7.47 v. 1/3 Annual Revenue: $10.36 v. Solar FA Requirement: $3.45

- Uses the Definition of Capacity Base Payment but limited to two of the four components only:.
    - Determined monthly using clearing price and MW quantity cleared in the *primary auction* or *substitution auction.*

Determination of FA Increments for Milestone FA

- Milestone FA builds upon the NCCFCA$ construct used for the Base FA requirement but adds a new “lesser-of” component – the “NCC FA Milestone Cap”.



NCC Milestone FA shall equal the lesser of (i) NCC x NCCFCA$ (each as defined above) x Milestone FA Multiplier or (ii) the NCC Milestone FA Cap.

- The NCC FA Milestone Cap is the based upon expected capacity revenues consistent with the Base FA methodology above, but also establishes a cap for each milestone as follows:
  - For missing the first milestone: one-sixth (1/6) of the expected annual capacity revenues.
  - For missing the second milestone: one-half (1/2) of the expected annual capacity revenues.
  - For missing the third milestone: one year of the expected annual capacity revenues.
    - These are total requirements at each step, not cumulative.
- Upon achievement of the milestones, the FA is returned to the project.

Milestone FA Proposal:

Adds a financial consequence for projects failing to advance in a timely fashion consistent with their schedule:

- Prior to the First Subsequent FCA:
  - Resources that have not achieved Project Finance Closing and Notice to Proceed* according to their approved milestone schedule would be required to post _an additional one_ increment of FA prior to the first subsequent auction, subject to the NCC FA Milestone Cap (two months cap of revenues).
- Prior to the Second Subsequent FCA:
  - Resources that have not achieved Substantial Site Construction according to their approved milestone schedule would be required to post _an incremental two_ increments of FA prior to the second subsequent FCA, subject to the NCC FA Milestone Cap (Total Milestone FA Cap: six months cap of revenues).
- Prior to the Third Subsequent FCA:
  - Resources that have *still* not achieved Substantial Site Construction according to their approved milestone schedule would be required to post _an incremental three_ increments of FA prior to the third subsequent FCA, subject to the NCC FA Milestone Cap. (Total Milestone FA cap: 1 year of expected revenues).

In determining the trigger on Milestone FA, changes to the milestone schedule approved by the ISO will be considered, so long as the scheduled date for the resource’s COD (per Schedule 22 or 25 of Section II of the Tariff) does not extend beyond the start of the Capacity Commitment Period associated with the Forward Capacity Auction in which the CSO was awarded.

Milestone FA is only required for resources that fail to advance consistent with their critical path schedule _and_ will miss their guaranteed COD.

Delay FA Product

- Proposal is to replace current post COD FA with one increment of FA for every three months of delayed COD.
    - Current FA requirement is one month of FA for every six months of delay.

- COD in this construct is pursuant to Schedule 22 & 25 – is the project commercial and available to the system:
    - It recognizes some resources will be unable to demonstrate their FCM COD capability due to FCA test procedures.

- Delay FA is collected three months after-the-fact and is forfeited if the project has not declared COD by the end of the subsequent three months – effectively a six-month grace period.

- Revised calculation of Delay FA is the expected capacity revenue that would have been earned over the period for which the resource was late (with a six month grace period).
    - This address the solar issue of only clearing 4 summer months.
    - It creates a late delivery penalty equal to the amount of revenue otherwise expected from the market.

THANK YOU!

Financial Assurance Policy Tariff Changes:

Includes yellow highlighted changes from the last B&F meeting.

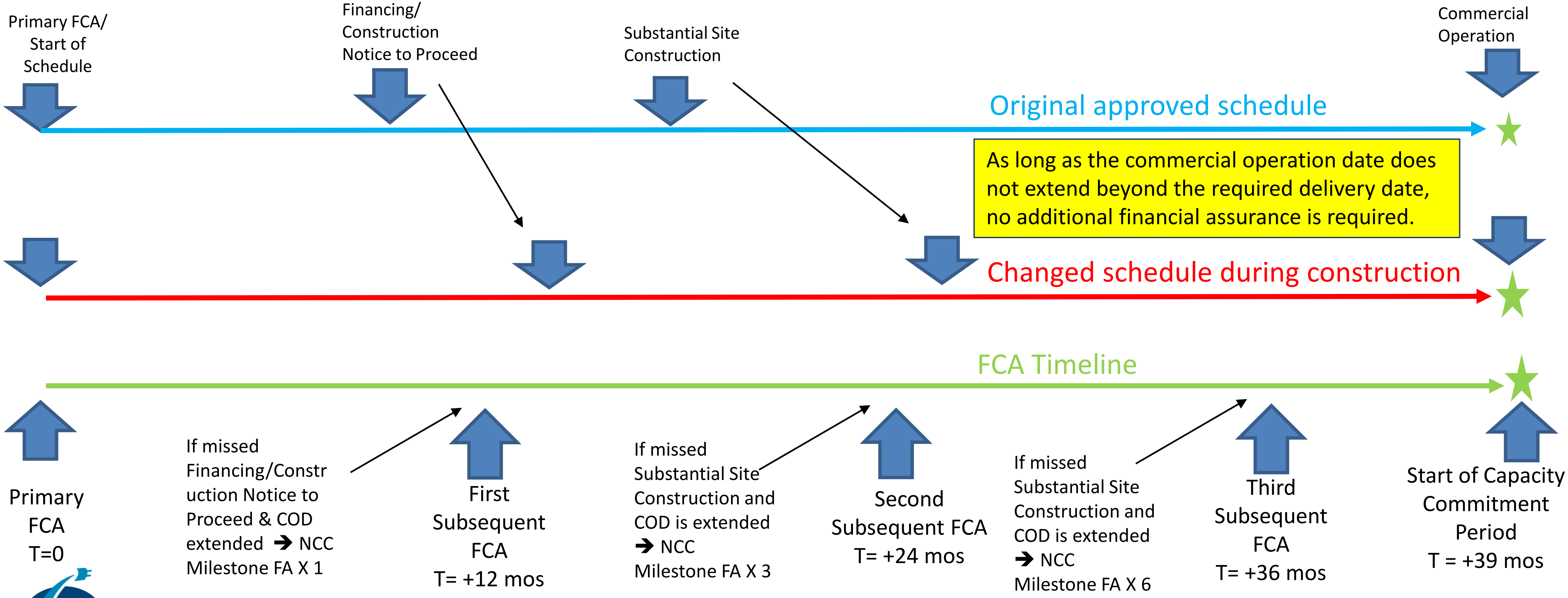
Additional Slides

Changes to the Milestone Schedule/ Mechanics

Approved Critical Path Milestone Schedule

- This is established at qualification and is subject to change consistent with current rules. The current rules allow all milestones to be pushed out without any financial consequence.

Performance-based FA proposal allows for all milestones to be adjusted without increased FA as long as the Commercial Operation date remains on or before the start of the Capacity Commitment Period associated with the CSO.



Primary FCA/ Start of Schedule

Financing/ Construction Notice to Proceed

Substantial Site Construction

Commercial Operation

Original approved schedule

As long as the commercial operation date does not extend beyond the required delivery date, no additional financial assurance is required.

Changed schedule during construction

FCA Timeline

Primary FCA T=0

If missed Financing/Construction Notice to Proceed & COD extended ➔ NCC Milestone FA X 1

First Subsequent FCA T= +12 mos

If missed Substantial Site Construction and COD is extended ➔ NCC Milestone FA X 3

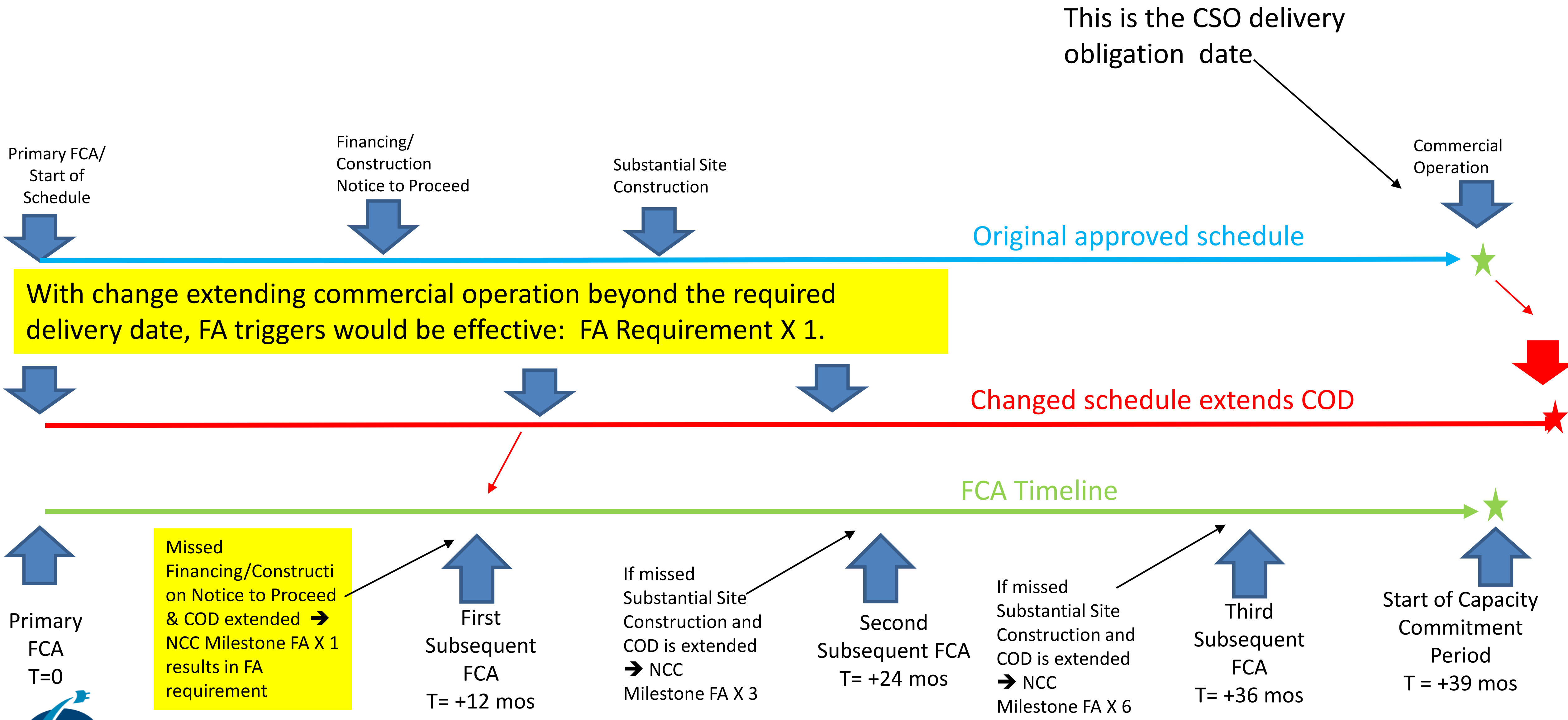
Second Subsequent FCA T= +24 mos

If missed Substantial Site Construction and COD is extended ➔ NCC Milestone FA X 6

Third Subsequent FCA T= +36 mos

Start of Capacity Commitment Period T = +39 mos

Milestone Requirement/ Example



This is the CSO delivery obligation date

Primary FCA/ Start of Schedule

Financing/ Construction Notice to Proceed

Substantial Site Construction

Commercial Operation

Original approved schedule

With change extending commercial operation beyond the required delivery date, FA triggers would be effective: FA Requirement X 1.

Changed schedule extends COD

FCA Timeline

Primary FCA T=0

Missed Financing/Construction Notice to Proceed & COD extended ➔ NCC Milestone FA X 1 results in FA requirement

First Subsequent FCA T= +12 mos

If missed Substantial Site Construction and COD is extended ➔ NCC Milestone FA X 3

Second Subsequent FCA T= +24 mos

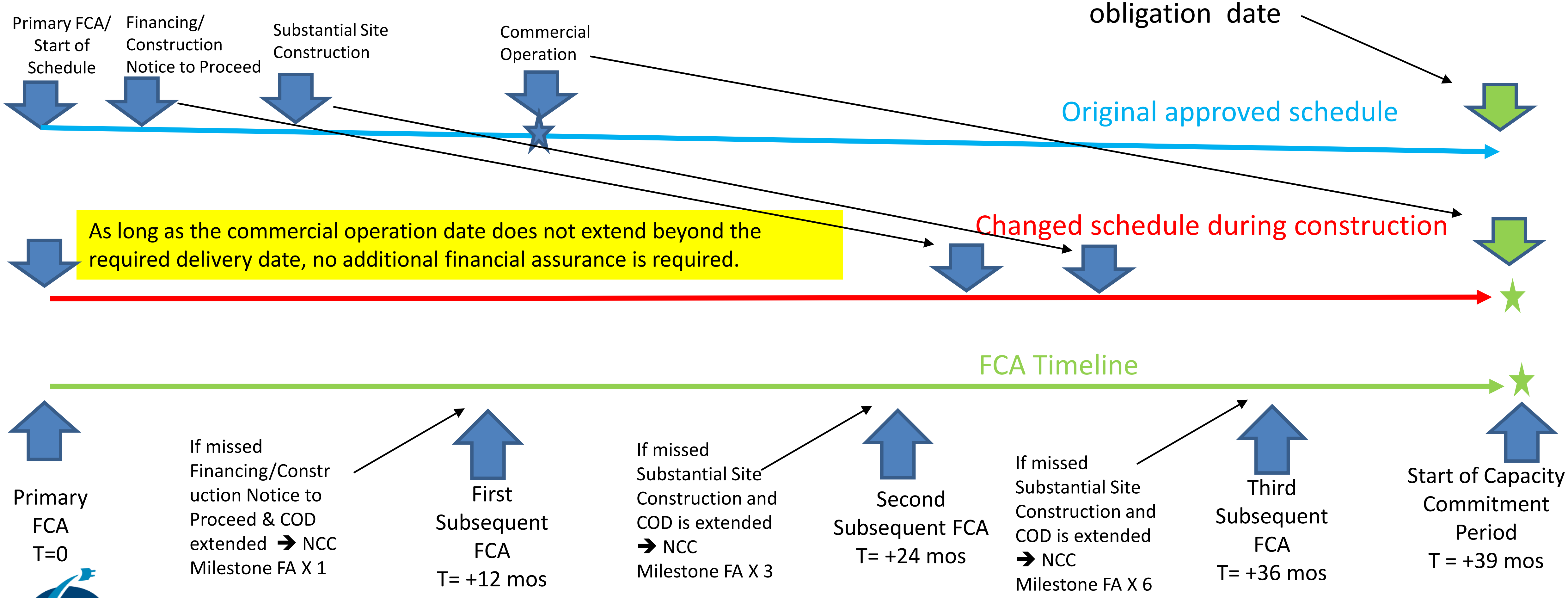
If missed Substantial Site Construction and COD is extended ➔ NCC Milestone FA X 6

Third Subsequent FCA T= +36 mos

Start of Capacity Commitment Period T = +39 mos

Short Duration Project Example

Some projects with short construction schedules submit milestone schedules with early CODs, however the capacity market obligation is for COD by the start of the Capacity Commitment Period.



This is the CSO delivery obligation date

Primary FCA/ Start of Schedule

Financing/ Construction Notice to Proceed

Substantial Site Construction

Commercial Operation

Original approved schedule

Changed schedule during construction

As long as the commercial operation date does not extend beyond the required delivery date, no additional financial assurance is required.

FCA Timeline

Primary FCA T=0

If missed Financing/Construction Notice to Proceed & COD extended ➔ NCC Milestone FA X 1

First Subsequent FCA T= +12 mos

If missed Substantial Site Construction and COD is extended ➔ NCC Milestone FA X 3

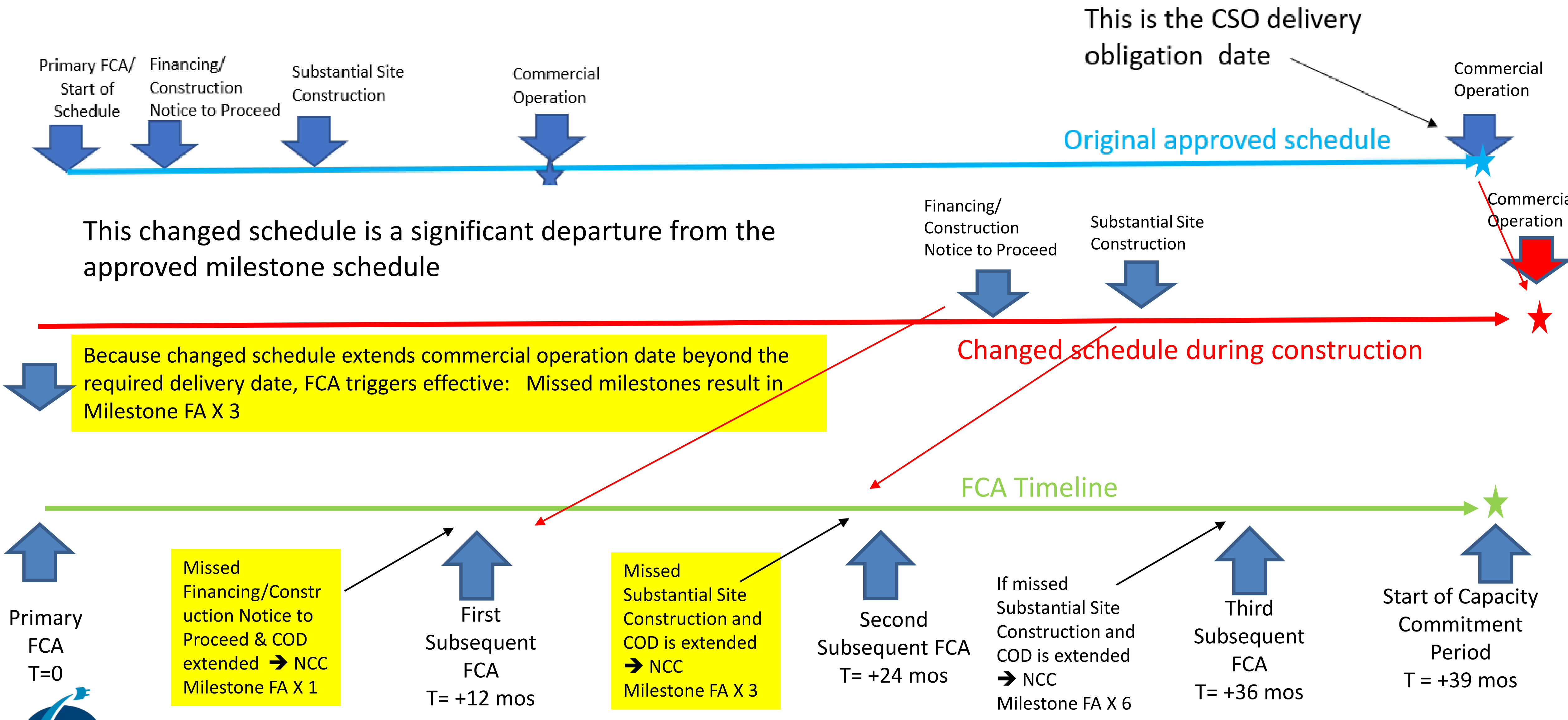
Second Subsequent FCA T= +24 mos

If missed Substantial Site Construction and COD is extended ➔ NCC Milestone FA X 6

Third Subsequent FCA T= +36 mos

Start of Capacity Commitment Period T = +39 mos

Short Duration Project Milestone FA Required - Example



This is the CSO delivery obligation date

Primary FCA/ Start of Schedule

Financing/ Construction Notice to Proceed

Substantial Site Construction

Commercial Operation

Commercial Operation

Original approved schedule

This changed schedule is a significant departure from the approved milestone schedule

Financing/ Construction Notice to Proceed

Substantial Site Construction

Commercia Operation

Changed schedule during construction

Because changed schedule extends commercial operation date beyond the required delivery date, FCA triggers effective: Missed milestones result in Milestone FA X 3

FCA Timeline

Primary FCA T=0

Missed Financing/Construction Notice to Proceed & COD extended ➔ NCC Milestone FA X 1

First Subsequent FCA T= +12 mos

Missed Substantial Site Construction and COD is extended ➔ NCC Milestone FA X 3

Second Subsequent FCA T= +24 mos

If missed Substantial Site Construction and COD is extended ➔ NCC Milestone FA X 6

Third Subsequent FCA T= +36 mos

Start of Capacity Commitment Period T = +39 mos

Current Milestone Schedule

- The current Critical Path Milestone Schedule process requires all non-commercial capacity to provide a schedule for major milestones as part of its qualification.

> III.13.1.1.2.2.2. Critical Path Schedule. In the New Capacity Qualification Package, the Project Sponsor must provide a critical path schedule for the project *with sufficient detail to allow the ISO to evaluate the feasibility of the project being built and the feasibility that the project will meet the requirement that the project achieve all its critical path schedule milestones* no later than the start of the relevant Capacity Commitment Period.

- A critical path schedule report is due on a quarterly basis from the Project Sponsor.
  - Each report must update the original schedule, note changes to milestones and project scope. (III. 13.2.2.1)
  - Achievement of milestones must include documentation in support.
    - Failure to provide *the report* can result in termination.

- Failure to meet the original milestone, and changes to the schedule, may result in a monthly reporting requirement (III.13.3.3).
  - Covering obligations for late delivery is optional…
    - Although choosing not to cover will result in failure to cover charge, but only *after* the start of the delivery period (III.13.3.4.(b)).
    - Failure to provide *the monthly reports* can result in termination.

- There are no financial consequences of failing to achieve milestones until after the delivery date has been passed.

Previous Presentations:

Budget and Finance Committee – August 26, 2021

NEPOOL Markets Committee – September 13-14, 2021

Budget and Finance Committee – October 12, 2021

NEPOOL Markets Committee – November 9-10, 2021

NEPOOL Budget and Finance Committee – November 29, 2021
https://www.iso-ne.com/static-assets/documents/2021/11/7b2_competitive_power_ventures_noncommercial_fa_improvements_ii.pdf
Tariff Language: https://www.iso-ne.com/static-assets/documents/2021/11/7b2_proposed_fa_tariff_language_enhanced_fa_noncommercial_capacity_exhibit_1a_redline_pages_only.pdf

NEPOOL Markets Committee – December 9, 2021

NEPOOL Markets Committee – January 12, 2022
https://www.iso-ne.com/static-assets/documents/2022/01/a07_mc_2022_01_11-12_cpv_non-commercial_financial_assurance_improvements_presentation.pptx
https://www.iso-ne.com/static-assets/documents/2022/01/a07_mc_2022_01_11-12_cpv_non-commercial_financial_assurance_improvements_iso_memo.pdf
https://www.iso-ne.com/static-assets/documents/2022/01/a07_mc_2022_01_11-12_cpv_non-commercial_financial_assurance_improvements_response_memo.docx

NEPOOL Budget and Finance Committee – January 26, 2022
https://www.iso-ne.com/static-assets/documents/2022/01/2a_performace_based_noncommericcal_fa_cpv_presentation.pdf
https://www.iso-ne.com/static-assets/documents/2022/01/7b2_participant_proposed_fa_policy_chg_tariff_lang_perf_based_fa_noncommercial_cap_exhibit1a_redline_fulldoc_revised_01052022.pdf

NEPOOL Markets Committee – Feb 8, 2022

NEPOOL Budget & Finance Committee – Feb 10, 2022

NEPOOL Budget & Finance Committee – March 29, 2022

NEPOOL Markets Committee – April 12, 2022

jgordon@cpv.com
603-673-6654

RENEW Northeast

To: NEPOOL Participants Committee Members and Alternates

From: Francis Pullaro, Executive Director, RENEW Northeast

Date: May 3, 2022

Subject: RENEW co-sponsorship of CPV's Performance Based Financial Assurance for Non-Commercial Capacity proposal

After working with CPV on refining its initial proposal for Performance Based Financial Assurance for Non-Commercial Capacity, RENEW finds the revised proposal now before the Participants Committee for its May 5 meeting meets the design principles from RENEW's March 1, 2022, memo and strikes a good balance between creating incentives to encourage market entry only when projects are sufficiently confident of success while not creating a barrier to entry for any size or type of new resource.[1]

A gap exists in the current market incentives that encourages new resources to participate in the market prematurely. It is one of the root causes of the reliability concern ISO identified for supporting the two year delay to its MOPR reforms.[2] This gap is best addressed by creating the right incentives to guide and discipline market entry for all resource types in all future auctions as this proposal does, rather than attempting to address it by delaying the entry of a narrow set of new resources for a two year time period.[3] This is a key reason why, now that the proposal has

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[1] The positions herein represent the views of RENEW and not necessarily those of any particular member of RENEW.

[2] In ISO-NE's January 26, 2022 memo to the Participants Committee meeting ISO highlighted that "*development delays in major new resources replacing [existing resources] can create 'gaps' in the region's resource adequacy in the capacity commitment period.*" (page 3) While ISO-NE was speaking specifically to state sponsored resources, development delays are a risk faced by all non-commercial resources that enter the FCM.

[3] Excerpt from the April 21, 2022 Protest of Clean Energy and Consumer Advocates in Docket ER22-1528 at page 67 (footnotes omitted, emphasis added):

"e. *More Effective And Less Discriminatory Solutions Exist To Target The Commercial-Operation Delay Problem*

"If there is a resource adequacy problem in the next five years (which ISO-NE has not described with any level of precision), then the remedy lies not in the "square peg" tool of delaying MOPR reform, but in changes to its qualification rules and other forward market design features to address risks of delayed entry of new projects.

"Most fundamentally, ISO-NE could shorten the forward period of its auction to ensure that resources that obtain supply obligations are much closer to commercial operation. This forward period made sense when ISO-NE also offered a five- or seven-year rate lock on the price in the first auction in which a resource cleared. Under those circumstances—developers were more likely to make decisions about whether to build based on whether they cleared the auction; without the price lock, developers rely more on their own long-term forecasts of market revenues, which do not depend on clearing in a specific auction prior to beginning construction.

"**More modest steps that would incent resources to enter the market only when ready are also available and already under discussion in New England. For example, stakeholders have been developing a** been revised, RENEW has decided to cosponsor the proposal and would encourage all market participants and ISO-NE to support it.

The March 1 memo expressed strong concern regarding Competitive Power Venture's proposal to modify the rules regarding Non-Commercial Capacity Financial Assurance. The memo was intended to:

1) Outline why RENEW believed it was important to address the market incentive gap that CPV's proposal was intended to address;
2) Provide the design principles RENEW believed were important for an effective solution;
3) Explain in detail why the CPV proposal at the time fell short of these design principles; and
4) Offer to work with ISO/stakeholders on developing a proposal that met these design principles.

Following publication of the March 1 memo, CPV withdrew its motion for a vote at the March 3 Participants Committee and committed to working with RENEW to address the issues outlined in the memo.

There is still time to implement the proposal for FCA 17. The first change to the Financial Assurance requirements will occur after FCA 17 has been conducted in March 2023. Ideally, any rule changes for an FCA cycle would occur prior to the qualification process beginning. However, provided the FERC filing has been made prior to the New Capacity Sponsor Withdrawal Deadline on December 7, 2022, market participants will be aware of the impending change prior to making a binding decision. Given the benefits of the proposal, this is a reasonable outcome.

This memo (and the attached spreadsheet with detailed numerical examples) explains how the revised proposal meets the design principles laid out in the March 1 memo and contains several practical examples how the proposal would work for a variety of different technologies and development scenarios.

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proposal to modify the Non-Commercial Capacity Financial Assurance rules in order to provide a stronger incentive for resources not to enter an FCA prematurely. Broader changes to the qualification rules to make them more strenuous would also help to reduce the risk of projects obtaining a capacity supply obligation that will not ultimately be able to deliver in time. ISO-NE could also eliminate the three-year capacity time out rule, which provides another incentive for resources to prematurely enter the FCA in order to avoid losing their place in the interconnection queue.

"**Notably, any or all of these measures would address potential commercial operation delays that ISO-NE acknowledges can affect all resource types, rather than ISO-NE's unduly discriminatory MOPR Delay Proposal, which bluntly targets only state policy resources—in particular offshore wind—and effectively assumes that these resources will be delayed rather than creating market rules and assurances to reduce or eliminate potential delays.**"

Meeting RENEW's 10 Design Criteria

1. As with the CPV proposal, we believe there should be *some* amount of increase in the FA requirement prior to every single FCA that a non-commercial resource participates in. This is currently missing prior to the fourth FCA in which a resource clears.

   Update: All resources would now be required to post some additional FA prior to participating in each FCA after the one in which they initially clear.

2. The level of FA required should be a careful balance between what is needed to incent the desired behavior without creating an overly punitive barrier to entry for any resource type.

   Update: The level of FA has been calibrated to provide this balance. Base FA increments are capped at one third of annual FCA revenues, Milestone FA is capped at one year of FCA revenue, and Delay FA is set to the amount of actual FCA revenue earned during the resource's delay.

3. High financial barriers to entry disproportionately affect smaller developers without large balance sheets, while large incumbents are likely unphased by any monetary barrier. The level of FA required should be considered carefully so as not to unintentionally decrease market competition.

   Update: Because the FA cap amounts have been tied to actual FCA revenues, they adjust automatically in the case of resources that receive different CSOs in the summer and winter so as not to prove excessive for those resources (e.g., solar). Resources not subject to the LGIP or ETUIP remain exempt from Milestone and Delay FA, but are subject to an additional Base FA increment for each subsequent FCA in which they clear. This reduces the FA burden for small resources, while continuing to provide an incentive to discipline their market participation.

4. Any charges for delayed commercial operation should be called as such and should be put into Market Rule 1, just as the failure to cover charge is. The Financial Assurance Policy is not the right place in the Tariff to put such a charge.

   Update: This is the only one of RENEW's design principles that this proposal does not meet. After further consideration we determined this may have been preferable but was not necessary. The end result is the same, regardless of where in the Tariff these rules are located.

5. Any charges for delayed commercial operation should consider the interaction with and cumulative effect of this new charge along with the existing failure to cover charge, Trading Financial Assurance, and the two-year grace period for reaching commercial operation. Consideration should also be given to whether the existing policy of paying FCA revenues to non-commercial capacity provides the proper incentives, and whether changes to this policy would obviate the need for some of these other charges or FA requirements.

   Update: Consideration was given to these aspects of the market design when developing the revised proposal. This consideration led to the redesign of the

Delay FA, tying it to actual revenues paid to non-commercial capacity prior to COD.

6. The duration and nature of the grace period should be evaluated to consider the timeline required for the resource termination process to be completed prior to the FCA occurring.
   <u>Update</u>: Based on the timing of the FA increments, we believe that this proposal provides the proper incentives for non-commercial resources to withdraw voluntarily prior to participating in additional FCAs. No further change was determined to be required for this design principle.

7. Treatment of projects that proceed on-schedule, projects that are delayed but successful, and projects that are never built should be differentiated, with decreased requirements for the former and increased requirements for the latter.
   <u>Update</u>: This proposal now meets this principle.

8. FA requirements should decrease as a project proceeds through its critical path schedule, as CPV has attempted to do by tying some of its new FA amounts to milestones such as Substantial Site Construction. However, care should be given to ensure that the milestones selected are appropriate for and can be monitored and achieved by all resource types.
   <u>Update</u>: The proposal uses milestones appropriate to each resource type and as such is able to provide an ongoing incentive for every resource type until it reaches commercial operation.

9. Any increase in Financial Assurance over today's requirements should, except in the case of demand resources, be tied to Commercial Operation as defined in Schedules 22, 23, and 25, not to FCM Commercial Operation. This is the case in the CPV proposal.
   <u>Update</u>: The revised proposal meets this design principle, just as the prior CPV proposal did.

10. Reconsideration should be given to whether the existing Non-Commercial Capacity FA amounts should be tied to FCM Commercial Operation or Commercial Operation as defined in Schedules 22, 23, and 25 (or, alternatively, the FCM Commercial Operation audit for intermittent generators should be revised such that it is purely a test of the generator's capabilities and not an attempt to audit the weather forecast).
    <u>Update</u>: The first three increments of Base FA (required prior to participating in the first three FCAs) remain tied to FCM Commercial Operation as they are today. All other FA is tied to earlier milestones a new resource would achieve (e.g., Substantial Site Construction or Commercial Operation as defined in Schedule 22).

Numerical Examples of the Revised Proposal

A spreadsheet with a variety of detailed numerical examples for different resource types facing different levels of delay has been posted with the meeting materials. A summary of these examples is shown below.

	Onshore Wind in NNE			Large Battery in RoP			Small Battery in RoP	Big PV in NNE			Small PV in NNE	OSW in SENE	
Summer/Winter CSO (kW)	1/2			1/1			1/1	1/0			1/0	1/2	
	On Time	7 mo Late	22 mo late	On Time	7 mo Late	22 mo late	22 mo late	On Time	7 mo Late	22 mo late	22 mo late	On Time	22 mo late
FCA 15 Revenue	$ 49.54	$ 49.54	$ 49.54	$ 31.33	$ 31.33	$ 31.33	$ 31.33	$ 9.91	$ 9.91	$ 9.91	$ 9.91	$ 79.60	$ 79.60
FCA 16 Revenue	$ 50.62	$ 50.62	$ 50.62	$ 31.09	$ 31.09	$ 31.09	$ 31.09	$ 10.12	$ 10.12	$ 10.12	$ 10.12	$ 52.78	$ 52.78
Total FCA Revenue 15+16	$ 100.16	$ 100.16	$ 100.16	$ 62.42	$ 62.42	$ 62.42	$ 62.42	$ 20.03	$ 20.03	$ 20.03	$ 20.03	$ 132.38	$ 132.38
Peak FA (Current Rules)	$ 26.12	$ 43.54	$ 60.95	$ 26.12	$ 34.83	$ 60.95	$ 60.95	$ 26.12	$ 34.83	$ 60.95	$ 60.95	$ 26.12	$ 60.95
Peak FA (Proposed Rules)	$ 26.12	$ 84.37	$ 99.23	$ 26.12	$ 66.16	$ 73.99	$ 43.54	$ 9.91	$ 23.12	$ 30.55	$ 16.51	$ 26.12	$ 99.01
Peak FA Proposed/Peak FA Current	100%	194%	163%	100%	190%	121%	71%	38%	66%	50%	27%	100%	162%
Takeaways:													
1) Except for PV, projects that are on time have no increase in their maximum FA requirements compared with the current rules, projects that are delayed have increased FA requirements													
2) PV FA requirements are reduced compared to current requirements (because they only earn capacity revenue in 4 months of the year), though delayed projects have higher obligation than on-time projects													
3) <20 MW generators, DERs, and Demand Resources that are significantly delayed have reduced FA requirements compared to current rules													
Amount of Forfeited FA for Successful Project	$ -	$ 7.43	$ 69.79	$ -	$ 7.83	$ 46.88	$ -	$ -	$ 7.43	$ 20.03	$ -	$ -	$ 100.71
2 yr FCA Revenue minus amount forfeited	$ 100.16	$ 92.73	$ 30.37	$ 62.42	$ 54.59	$ 15.55	$ 62.42	$ 20.03	$ 12.60	$ -	$ 20.03	$ 132.38	$ 31.67
Takeaways:													
3) Projects that are ultimately successful still forfeit a portion of their FA if they are more than 6 months late reaching COD, but this forfeited FA never exceeds the FCA revenue paid to the resource during its delay													
Peak FA posted for project with 100 MW summer CSO (current)	$2,612,100	$4,353,500	$6,094,900	$2,612,100	$3,482,800	$6,094,900	$6,094,900	$2,612,100	$3,482,800	$6,094,900	$6,094,900	$2,612,100	$6,094,900
Peak FA posted for project with 100 MW summer CSO (proposed)	$2,612,100	$8,436,800	$9,923,000	$2,612,100	$6,616,000	$7,399,300	$4,353,500	$990,800	$2,311,867	$3,054,967	$1,651,333	$2,612,100	$9,901,000

Overview of CPV Non-Commercial Capacity Financial Assurance Proposal

This overview of the CPV non-commercial capacity financial assurance proposal was prepared by Abby Krich and Alex Worsley of Boreas Renewables for RENEW Northeast. We are sharing it in the hopes that it may help explain this complex proposal to Participants Committee members.

The overview is broken into four sections:

1. Base FA,
2. Milestone FA,
3. Delay FA, and
4. Market Rule 1 Changes

Terminology used in this overview

FCA = Forward Capacity Auction
FCA1 = FCA in which the resource clears as new capacity
FCA2 = First FCA in which the resource participates as existing
CCP = Capacity Commitment Period
Net CONE = Net Cost of New Entry (FCA 16 Net CONE was $7.468)
CSO = Capacity Supply Obligation
COD = Commercial Operation Date
FCM COD Audit = simple for non-intermittent resources, often difficult/impossible for intermittent generators to complete with full success
FCA revenue = revenue resource would expect to earn based on clearing in FCA (does not include revenue or charges from pay for performance, reconfiguration auctions, or bilaterals)
SSC = Substantial Site Construction (20% of construction budget spent)
Schedule 22 = Large Generator Interconnection Procedures (for generators > 20 MW)
Schedule 25 = Elective Transmission Upgrade Interconnection Procedures
CPS = Critical Path Schedule

	Timing	Current Rules			Proposed Rules		
		Incremental FA Obligation	**Cumulative FA Obligation**	**Notes**	**Incremental FA Obligation**	**Cumulative FA Obligation**	**Notes**
“ Base” FA	Upon Qualification	$2	$2	• /kW of summer qualified capacity • Returned if capacity doesn’t clear or else after successful FCM COD audit	$2	$2	• /kW of summer qualified capacity • Returned if capacity doesn’t clear or else after successful FCM COD audit
	Prior to 1st FCA	Net CONE - $2	Net CONE	• /kW of summer qualified capacity • Returned if capacity doesn’t clear or else after successful FCM COD audit	Net CONE - $2	Net CONE	• /kW of summer qualified capacity • Returned if capacity doesn’t clear or else after successful FCM COD audit • FCA 16 Net CONE (Cost of New Entry) = $7.468
	After 1st FCA		Net CONE	• /kW of summer CSO • Adjustment based on cleared quantity	MIN(Net CONE, annual FCA revenue/3) – Net CONE	MIN(Net CONE, annual FCA revenue/3)	• /kW of summer CSO • Adjustment based on cleared quantity and clearing price • Incremental FA ≤ $0
	Prior to 2nd FCA	Net CONE	2 * Net CONE	• /kW of summer CSO • Returned after successful FCM COD audit	MIN(Net CONE, annual FCA revenue/3)	2 * MIN(Net CONE, annual FCA revenue/3)	• /kW of summer CSO • Returned after successful FCM COD audit
	Prior to 3rd FCA		3 * Net CONE			3 * MIN(Net CONE, annual FCA revenue/3)	
	Prior to 4th FCA	$0	3 * Net CONE			4 * MIN(Net CONE, annual FCA revenue/3)	• /kW of summer CSO • Only required if SSC not yet achieved • Returned after SSC achieved
	Prior to 5th FCA		3 * Net CONE			5 * MIN(Net CONE, annual FCA revenue/3)	• /kW of summer CSO • Only required if SSC not yet achieved AND resource not subject to Schedule 22 or 25 • Returned after SSC achieved
	Prior to 6th FCA		3 * Net CONE			6 * MIN(Net CONE, annual FCA revenue/3)	

	Etc.		Etc.			Etc.	

General Notes

- 4th FCA occurs <4 months prior to start of Capacity Commitment Period associated with 1st FCA, when resource committed to deliver
- All FA forfeited if resource is terminated or withdraws after clearing in FCA

Base FA Proposal Notes

- Base FA applies to all resources, regardless of which FCA they first cleared in

Pros for New Resource Developers:

* Increments are capped at 1/3 annual FCA revenue. Particularly helpful for PV, also helps limit risk if Net Cone > 4*FCA Clearing Price

* Base FA increments 4+ are returned after SSC achieved, removes risk related to pieces of FCM COD beyond the project's control such as the FCM COD Audit for intermittent generators in particular or timing of transmission upgrades related to overlapping impact test

* Base FA increments 5+ for resources not subject to Schedule 22 or 25 is less than Delay FA required under current rules, and returned after SSC achieved

Cons for New Resource Developers:

* Projects that haven't achieved SSC by the 4th FCA have to post additional FA that isn't currently required

	Timing	Current Rules			Proposed Rules		
		Incremental FA Obligation	Cumulative FA Obligation	Notes	Incremental FA Obligation	Cumulative FA Obligation	Notes
“ Milestone” FA	Prior to 1st FCA	n/a			n/a	n/a	
	Prior to 2nd FCA				MIN(1*MIN(Net CONE, annual FCA revenue/3), annual FCA revenue/6)	MIN(1*MIN(Net CONE, annual FCA revenue/3), annual FCA revenue/6)	• /kW of summer CSO • Only required if ○ Resource hasn’t achieved project financing <u>and</u> given notice to proceed to contractors AND ○ Resource’s CPS has been delayed such that COD is after the start of its CCP • Returned after SSC achieved
	Prior to 3rd FCA				MIN(3*MIN(Net CONE, annual FCA revenue/3),annual FCA revenue/2) - MIN(1*MIN(Net CONE, annual FCA revenue/3), annual FCA revenue/6)	MIN(3*MIN(Net CONE, annual FCA revenue/3), annual FCA revenue/2)	• /kW of summer CSO • Only required if ○ Resource hasn’t achieved SSC AND ○ Resource’s CPS has been delayed such that COD is after the start of its CCP • Returned after SSC
	Prior to 4th FCA				MIN(6*MIN(Net CONE, annual FCA revenue/3), annual FCA revenue) - MIN(3*MIN(Net CONE, annual FCA revenue/3), annual FCA revenue/2)	MIN(6*MIN(Net CONE, annual FCA revenue/3), annual FCA revenue)	

<u>Milestone FA Proposal Notes</u>

- Milestone FA applies only for resources that first clear in FCA 17 or after
- Resources not subject to Schedule 22 or 25 (i.e., generators 20 MW or less, generators interconnecting under state jurisdiction, or demand capacity resources) are <u>exempt</u> from Milestone FA

<u>Pros for New Resource Developers:</u>
* Milestone FA only required for delayed projects
* Returned once SSC is achieved, removes risk related to pieces of FCM COD beyond the project’s control such as the FCM COD Audit for intermittent generators in particular or timing of transmission upgrades related to overlapping impact test
* Milestone FA never exceeds annual FCA revenue
<u>Cons for New Resource Developers:</u>
* Projects that are delayed have to post additional FA that isn’t currently required in order to continue clearing in further FCAs

	Current Rules				**Proposed Rules**			
	Timing	**Incremental FA Obligation**	**Cumulative FA Obligation**	**Notes**	**Timing**	**Incremental FA Obligation**	**Cumulative FA Obligation**	**Notes**
“Delay” FA	1 mo after start of CCP	Net CONE	Net CONE	• /kW of summer CSO that has not yet achieved successful FCM COD audit • Returned after successful FCM COD audit	3 mo after start of CCP (i.e., Sept 1)	FCA revenue from prior 3 months	FCA1 Revenue Jun - Aug	• Returned upon COD OR • Forfeited if COD not achieved within 3 months of providing each increment of FA (first FA forfeiture occurs 7 mo after start of CCP in amount equal to FCA revenue from first 3 mo of CCP)
	7 mo after start of CCP		2 * Net CONE		6 mo after start of CCP		FCA1 Revenue Sept – Nov (FCA1 Revenue Jun – Aug Forfeited)	
	13 mo after start of CCP		3 * Net CONE		9 mo after start of CCP		FCA1 Revenue Dec – Feb (FCA1 Revenue Sept – Nov Forfeited)	
	19 mo after start of CCP		4 * Net CONE		12 mo after start of CCP		FCA1 Revenue Mar – May (FCA1 Revenue Dec – Feb Forfeited)	
	Etc., every 6 mo		5 * Net CONE		15 mo after start of CCP		FCA2 Revenue Jun – Aug (FCA1 Revenue Mar – May Forfeited)	
			Etc.		18 mo after start of CCP		FCA2 Revenue Sept – Nov (FCA2 Revenue Jun – Aug Forfeited)	
					21 mo after start of CCP		FCA2 Revenue Jun – Aug (FCA2 Revenue Sept – Nov Forfeited)	
					Etc., every 3 mo		Etc.	

General Notes

- Once resource clears in FCA, ISO pays resource its FCA revenue regardless of whether or not resource has achieved COD or completed successful FCM COD audit
- If resource has not completed successful FCM COD audit prior to its CCP, it must pay for replacement capacity at market price
- ISO may terminate resource (or portion of resource) if it is not expected to achieve successful FCM COD audit within 2 yrs of start of CCP; all FA forfeited upon termination

Delay FA Proposal Notes

- Delay FA applies only for resources that first clear in FCA 17 or after
- Resources not subject to Schedule 22 or 25 (i.e., generators 20 MW or less, generators interconnecting under state jurisdiction, or demand capacity resources) are exempt from Delay FA (they instead provide additional increments of Base FA)

Pros for New Resource Developers:

* First Delay FA increment occurs 3 mo after start of CCP compared with 1 mo under current rules

* Delay FA is limited to FCA revenue already paid out to the delayed resource (can be significantly less than current FA amount for solar PV or when FCA clearing prices are low, as they have been)

* Returned upon COD, no risk related to FCM COD audit for intermittent generators or transmission upgrades related to overlapping impact test

Cons for New Resource Developers:

* A portion of the delay FA is forfeited for projects that are delayed reaching COD by at least 6 months (under current rules, FA is returned for projects that achieve COD and have a successful FCM COD audit within 2 years of their initial delivery date, the “free 2-year option”)

Market Rule 1 Changes

Modification to Critical Path Schedule Milestones in Qualification Package

- **Project Financing Closing** - modified to provide added detail about project budget and expected source of funds, demonstration of financial capability to obtain such funding
- **Notice to Proceed** – new milestone added for date when contractor(s) will be directed to install the project's major equipment

Modification to ISO evaluation of Critical Path Schedule

- Makes explicit that ISO must consider whether the project sponsor has sufficiently demonstrated its financial capability

Documentation of Milestones Achieved

- **Project Financing Closing** - modified to include certification by officer of project sponsor that funds for the financing and construction of the project are available to the project sponsor; in the case of self-funding, officer certification that all internal approvals have been obtained for the self-funding.
- **Notice to Proceed** – adds the new milestone

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EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of May 3, 2022

The following activity, as more fully described in the attached litigation report, has occurred since the report dated April 5, 2022 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

I. Complaints/Section 206 Proceedings

1	RENEW/ACPA Resource Capacity Accreditation & Operating Reserve Designation Complaint (EL22-42)	Apr -14	CPV Towantic, Excelerate, CT PURA, MPUC, NYU Institute for Policy Integrity intervene
		Apr 14	ISO-NE responds to Complaint; protests and comments filed by: NEPOOL, AEE, Calpine, EDF, FirstLight, LS Power, NEPGA, NESCOE, Public Interest Orgs, Vistra/LSP Power, State Parties, EPSA, National Hydropower Assoc., SEIA
		Apr 29	RNEW/ACPA answer ISO-NE and NEPOOL motions to dismiss and other protests and adverse comments filed on Apr 14

II. Rate, ICR, FCA, Cost Recovery Filings

7	FCA16 Results Filing (ER22-1417)	Apr 6–May 3	Over 100 individuals and the No Coal No Gas Campaign submit comments
		Apr 13	National Grid intervenes
8	Constellation Post-Spin Updates to Mystic COS Agreement (ER22-1192)	Apr 8	Mystic answers CT PURA, ENECOS, MA AG protests
		May 2	FERC accepts and suspends in part Mystic's filing, eff. Jun 1, 2022, subject to refund, and establishes a paper hearing on what capital structure and cost of debt should be used in the Agreement, with the hearing to be held in abeyance pending the outcome of settlement judge procedures
8	CSC Request for Regulatory Asset Recovery of Previously-Incurred CIP IROL Costs (ER21-2334)	Apr 27	FERC rejects rehearing request of *CSC CIP-IROL Costs Allegheny Order*
9	Mystic 8/9 COS Agreement First CapEx Info Filing (ER18-1639)	Apr 28	FERC issues order granting in part, and denying in part, ENECOS' and NESCOE's formal challenges to the First Cap Ex Info. Filing, subject to refund, and establishing hearing and settlement judge procedures

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

10	MOPR Elimination Filing (ER22-1528)	Apr 6-25	Over 150 individuals submit comments/protests
		Apr 21	Comments and protests were submitted by: NEPOOL; ISO-NE EMM; ISO-NE IMM; AEE; Calpine/Cogentrix/Vistra; Clean Energy & Consumer Advocates; Great River Hydro; MA AG/MOPA; NESCOE; NEPGA; Shell; CT DEEP; MA Exec. Office of Energy and Environ. Affairs; ACRE; Berkshire Environ. Action Team; E2; EPSA; Nat'l Caucus of Envir. Legislators; and SEIA
11	New England's *Order 2222* Compliance Filing (ER22-983)	Apr 6-19	Centrica, MPUC intervene out-of-time
		Apr 19	National Grid/Avangrid/Eversource answer comments and protests
		Apr 20	ISO-NE answers comments and protests
		Apr 28	4 New England US Senators file comments

IV. OATT Amendments / TOAs / Coordination Agreements

No Activity to Report

V. Financial Assurance/Billing Policy Amendments

	12	FCM Billing Acceleration and RBA Changes (ER22-1167)	Apr 28	FERC accepts changes, eff. May 1, 2022 (RBA Changes) and Jun 1, 2022 (FCM Acceleration Changes, FCM Cost Allocation Changes, Clean-Up Changes)

VI. Schedule 20/21/22/23 Changes

	13	Schedule 21-VP: Schedule 21 Name Update (ER22-1115)	Apr 25	FERC accepts re-named Schedule 21-VP, eff. Jan 1, 2022
	13	Schedule 21-NEP: 2nd Revised Narragansett LSA (ER22-707)	Apr 18	FERC issues a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration" of Green Development's request for reh'g of the *2nd Rev Narragansett LSA Order*

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

*	15	LFTR Implementation: 54th Quarterly Status Report (ER07-476)	Apr 14	ISO-NE files its 54th quarterly report
*	16	ISO-NE FERC Form 3Q (2021/Q4) (not docketed)	Apr 13	ISO-NE submits its 2021 Q4 FERC Form 3Q
*	16	ISO-NE FERC Reporting Requirement 582 (not docketed)	Apr 19	ISO-NE submits 2021 annual report of total MWh of transmission service (approx. 1.24 million MWhs) (roughly 196,671 MWh less than 2020)

IX. Membership Filings

*	16	May 2022 Membership Filing (ER22-1738)	Apr 29	NEPOOL requests that the FERC accept (i) the memberships of Altop Energy Trading; Indra Power Business CT; Indra Power Business MA; Leicester Street Solar; and Nexamp Markets; and (ii) the name change of Salem Harbor Power Development
	17	March 2022 Membership Filing (ER22-1131)	Apr 21	FERC accepts (i) the memberships of Emera Energy Services Subsidiary No. 6 and Tidal Energy USA; and (ii) the name changes of GB II New Haven LLC (f/k/a PSEG New Haven LLC), GB II Connecticut LLC (f/k/a PSEG Power Connecticut LLC) and Generate Colchester Fuel Cells, LLC (f/k/a Bloom Connecticut Clean Energy Company, LLC)
	17	Involuntary Termination Filing: Sunwave USA Holdings Inc. (ER22-1039)	Apr 8	FERC accepts the involuntary termination of the NEPOOL membership and MPSA with ISO-NE (Market Participant status) of Sunwave USA Holdings, Inc. (Supplier Sector), eff. Apr 11, 2022

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

	19	NPCC Bylaws Changes (RR22-2)	Apr 6	NERC and NPCC jointly respond to Public Citizen comments
	20	Rules of Procedure Changes (Reliability Standards Development Revisions) (RR21-8)	Apr 7 Apr 8 Apr 26	Consumers Energy intervenes Public Citizen comments on stakeholder representation in NERC governance NERC answers Public Citizen comments

XI. Misc. - of Regional Interest

	20	203 Application: Pixelle / Spectrum (EC22-49)	Apr 8-14 Apr 18	PJM, PJM IMM, Public Citizen intervene Pixelle supplements application

*	20	Related Facilities Agreement: NSTAR / Ocean State Power (ER22-1675)	Apr 22	NSTAR files RFA; comment deadline ***May 13, 2022***
	21	Maine Power Link Application for Negotiated Rate Authority (ER22-1290)	Apr 15 Apr 19	MPL answers MOPA's Mar 31 protest MOPA answers MPL's Apr 15 answer
	22	ISA Cancellation: NSTAR/Servistar (ER22-1013)	Apr 8	FERC accepts notice of cancellation, eff. Feb 10, 2022
	22	IA Termination: CL&P / Sterling Property (ER21-2860)	Apr 25	Sterling requests clarification and/or rehearing of the *Sterling IA Allegheny Order*
	23	*Orders 864/864-A* (Public Util. Trans. ADIT Rate Changes): New England Compliance Filings (various)	Apr 15 Apr 28	*ER20-2429 (CMP - LNS).* CMP supplements its further Mar 31 *Order 864* compliance filing *ER20-2133 (Versant).* Versant submits changes to Schedule 21-VP in response to the FERC's Feb 28, 2022 order; comment deadline ***May 19, 2022***

XII. Misc. - Administrative & Rulemaking Proceedings

24	NOI: Dynamic Line Ratings (AD22-5)	Apr 14-26	Comments submitted by: ISO-NE; DC Energy; Eversource; Clean Energy Parties; Potomac Economics; CT DEEP; NERC; US DOE; CAISO; MISO; NYISO; Org of MISO States; SPP; SPP MMU; AEP; Alliant; APPA; APS; AZ PUC; Clean Energy Entities; Dayton Power; EEI; ELCON; Entergy; IN Util. Reg. Comm.; ITC; LA DPW; MISO TOs; NRECA; NYISO TOs; PPL; R Street Institute; Southern Co.; TAPS; Tri-State; Electricity Canada; Electric Grid Monitoring; Line Vision; Idaho Power reply comments due ***May 25, 2022***
24	Improving Generating Units Winter Readiness (AD22-4)	Apr 27-28	FERC convenes joint tech conf with NERC and its Regional Entities to discuss how to improve generating unit winter-readiness
24	Joint Federal-State Task Force on Electric Transmission (AD21-15)	Apr 12 Apr 22	Comments suggesting agenda items for third JFSTF meeting were filed by ACPA/AEE/SEIA, ACRE, AEE, NJ BPU, NRDC, PJM, UCS FERC issues agenda for the virtual May 6, 2022 meeting
26	Modernizing Electricity Market Design (AD21-10)	Apr 21	FERC issues order directing each ISO/RTO to submit a report that describes: (i) current system needs given changing resource mixes and load profiles; (ii) how it expects its system needs to change over the next 5 and 10 years; (iii) whether and how it plans to reform its EAS markets to meet expected system needs over the next 5 and 10 years; and (iv) information about any other reforms that would help it meet changes in system needs; Reports due on or before ***Oct 17, 2022***
27	NOI: Industry Assoc'n Dues & Expenses Rate Recovery, Reporting, and Acc'ting Treatment (RM22-5)	Apr 28	Joint RTO Commenters reply to NECOS discussion and characterization of the Initial Joint RTO Comments and a question of First Amendment constitutional law
29	*Transmission NOPR* (RM21-17)	Apr 20 Apr 21	Nov 15 tech conf transcript posted to eLibrary FERC issues *Transmission NOPR*; comment deadline [75 days after NOPR published in the *Federal Register*]; reply comments due [105 days after NOPR published in the *Federal Register*].

XIII. FERC Enforcement Proceedings

35	Rover and ETP (Tuscarawas River HDD Show Cause Order) (IN17-4)	Apr 20	OE Staff replies to Respondent's answer to *Rover/ETP Tuscarawas River HDD Show Cause Order*

36	Total Gas & Power North America, Inc. et al. (IN12-17)	Apr 8	Respondents request reconsideration, or in the alternative, permission to file an interlocutory appeal of the ALJ's Mar 24 order confirming his Mar 15 bench rulings
		Apr 14	OE Staff opposes Respondents' Apr 8 request
		Apr 25	Presiding ALJ denies Respondents' Apr 8 request
		Apr 27	Apr 28 prehearing conference cancelled, rescheduled to May 4, 2022

XIV. Natural Gas Proceedings

37	Iroquois ExC Project (CP20-48)	Apr 18	Iroquois accepts the certificate issued in the *Iroquois Certificate Order*
		Apr 25	The NYU Institute for Policy Integrity submits comments

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

40	NTE CT Petition for Review of Killingly CSO Termination Orders (22-1027)	Apr 5	ISO-NE moves to dismiss case
		Apr 11	FERC files certified index to the record
		Apr 15	FERC supports and NTE opposes ISO-NE's motion to dismiss
		Apr 22	ISO-NE responds to NTE Apr 15 response
41	CSC Request for Regulatory Asset Recovery of Previously-Incurred CIP IROL Costs (21-1275)	Apr 18	FERC files second status report
		Apr 20	CSC amends its petition to include the Feb 24, 2022 *CSC CIP-IROL Costs Allegheny Order*
		Apr 27	Reh'g of *Allegheny Order* denied; motions to govern proceeding due on or before ***May 27, 2022***
42	Mystic 8/9 COS Agreement (20-1343 et al.)(consolidated)	Apr 7	Court allocates time for ***May 5, 2022*** oral argument before Judges Srinivasan, Henderson, Rao
43	*Opinion 531-A* Compliance Filing Undo (20-1329)	Apr 14	FERC files status report indicating that the proceedings before the Commission remain ongoing and that this appeal should continue to remain in abeyance

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: May 3, 2022

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

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"),[1] state regulatory commissions, and the Federal Courts and legislatures through May 3, 2022. If you have questions, please contact us.

I. Complaints/Section 206 Proceedings

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

On March 15, 2022, RENEW Northeast, Inc. ("RENEW") and the American Clean Power Association ("ACPA") filed a FPA section 206 Complaint against ISO-NE seeking a FERC order directing ISO-NE to make changes to its rules for capacity accreditation and operating reserve designations, effective no later than FCA18 with respect to capacity accreditation and promptly with respect to operating reserve designations. RENEW/ACPA asserted that the changes are needed to address undue preferences granted under ISO-NE's rules and procedures to gas-fired generation resources that have neither dual-fuel capability nor dedicated, firm natural gas supply arrangements ("Gas-Only Resources"). Complainants asserted that the undo preferences arise in the context of capacity accreditation through an assumption of 100% fuel availability for Gas-Only Resources, and in the context of operating reserves, through the absence of any pre-dispatch requirements to confirm fuel availability. ISO-NE's response and comments, following a request for extension granted by the FERC on March 28, were due on or before ***April 14, 2022***.

On April 14, 2022, ISO-NE responded to the Complaint. Protests and comments on the Complaint were filed by: NEPOOL, AEE, Calpine, EDF, FirstLight, LS Power, NEPGA, NESCOE, Public Interest Orgs,[2] Vistra/LSP Power, State Parties,[3] EPSA, National Hydropower Assoc., and the Solar Energy Industries Association ("SEIA"). On April 29, RENEW/ACPA answered the ISO-NE and NEPOOL motions to dismiss and answered the protests and comments filed in opposition to the Complaint. Interventions only were filed by AEP, Avangrid, Avangrid Renewables, Borrego, Brookfield, Constellation, CPV Towantic, Dominion, ENE, Excelerate, National Grid, NextEra, NH OCA, North East Offshore, NRG, Public Systems,[4] CT PURA, MA DPU, MPUC, Repsol, APPA, EPSA, the Institute for Policy Integrity at New York University School of Law, and Public Citizen. If you have any questions concerning this

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

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

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

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

matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

On February 14, 2022, the Northern Maine Intendent System Administrator ("NMISA") filed a complaint against the PTO AC (who for these purposes hold exclusive Section 205 rights) for failure to consider and implement a reciprocal discount to the Through and Out ("TOUT") charges applied to transactions between the New England and Northern Maine regions ("TOUT Discount"), one which would be identical in substance to the reciprocity between New England and New York. The PTO AC response and comments on this Complaint were due on or before March 7, 2022. In its March 7 response, the PTO AC offered the following explanations as to why it is not in a position to advocate for the TOUT Discount: (i) differences between NYISO and NMISA, including the absence of an interconnection between New England and NMISA; (ii) the TOUT rate is how the TOs recover their costs for point-to-point transactions with neighboring utility systems and other systems not electrically connected, and NMISA is similarly situated to HQ and NBSO, which are also subject to a TOUT Rate; (iii) TOUT Rate does not apply to transactions sinking in New England; and (iv) NMISA's proposal would increase customer rates in New England. On March 16, NMISA answered the PTO AC's response. NEPOOL, Brookfield, Calpine, Eversource, National Grid, NESCOE, and Versant Power submitted doc-less interventions. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

As previously reported, the FERC instituted on September 7, 2021 a proceeding under FPA Section 206 to consider whether Schedule 25 and Tariff section I.3.10 may be unjust and unreasonable.[5] This proceeding arises out of issues raised in the NECEC Transmission LLC ("NECEC")/Avangrid Complaint Against NextEra/Seabrook (related to the interconnection of the New England Clean Energy Connect transmission project ("NECEC Project")) summarized below (EL21-6). Specifically, the FERC identified a concern that "Schedule 25's definition of Affected Party and Tariff section I.3.10 may be unjust and unreasonable to the extent they may allow generating facilities and their components to be identified as facilities on which adverse impacts must be remedied before an elective transmission upgrade can interconnect to the ISO-NE transmission system, even though generators are not subject to the [FERC]'s open access transmission principles," and could result in upgrades identified on an Affected Party's system without any obligation for the Affected Party to construct the identified upgrades.[6]

Accordingly, the FERC directed ISO-NE to: (1) show cause as to why Schedule 25 and Tariff section I.3.10 remain just and reasonable or (2) explain what changes to Schedule 25 and/or Tariff section I.3.10 it believes would remedy the identified concerns if the FERC were to determine that Schedule 25 and/or Tariff section I.3.10 has become unjust and unreasonable and proceeds to establish a replacement rate. On September 8, 2021, the FERC issued a notice of the proceeding and of the refund effective date, which will be October 13, 2020 (the date the NECEC/Avangrid Complaint Against NextEra/Seabrook was filed). Those interested in participating in this proceeding were required to intervene on or before October 5, 2021.[7] NEPOOL, NESCOE, Brookfield, Calpine, Dominion, Eversource, HQ US, LS Power, MA AG, MMWEC, National Grid, NECEC Transmission, NEPGA, NextEra, NRG, CT DEEP, MA DOER, Pixelle Androscoggin (out-of-time), Vistra (out-of-time), ACPA, EPSA, RENEW, and Public Citizen intervened.

ISO-NE Answer. On November 8, 2021, ISO-NE submitted its answer explaining why Schedule 25 and Tariff section I.3.10 remain just and reasonable. ISO-NE called for the FERC to "assist Affected Parties and

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[5] *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*").

[6] *Id.* at P 20.

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

Interconnection Customers in resolving any disputes pertaining to upgrades on Affected Systems—such as the dispute between NECEC Transmission and NextEra Energy Seabrook, LLC in Docket No. EL21-6—as quickly as possible." Interested parties had until January 7, 2022 to address whether ISO-NE's existing Tariff remains just and reasonable and if not, what changes to ISO-NE's Tariff should be implemented as a replacement rate.

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

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

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

As previously reported, 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[8] and direct NextEra to immediately commence engineering, design, planning and procurement activities that are necessary for NextEra to construct the generator owned transmission upgrades during Seabrook Station's Planned 2021 Outage. 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.

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).[9] Initial briefs[10] were due on

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

[9] *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).

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

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

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

In a related matter, 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. NextEra moved to lodge both an August 29, 2021 filing containing an executed Engineering and Procurement Agreement ("E&P Agreement") between Seabrook and NECEC Transmission, LLC ("NECEC") that was filed with the FERC on August 19, 2021 and the NRC Seabrook Report. Avangrid answered that motion, asserting that the NRC Seabrook Report was outside the scope of the proceeding and the motion to lodge should be denied. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

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

  - ***Base ROE Complaint I (EL11-66)***. In the first Base ROE Complaint proceeding, the FERC concluded that the TOs' ROE had become unjust and unreasonable,[11] 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*

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[11] 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*")).

531-A).[12] However, the FERC's orders were challenged, and in *Emera Maine,*[13] the U.S. Court of Appeals for the D.C. Circuit ("DC Circuit") vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the FERC remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.

- ***Base ROE Complaints II & III (EL13-33 and EL14-86) (consolidated)***. The second (EL13-33)[14] and third (EL14-86)[15] 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.[16] 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[17] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[18] 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.[19] 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*.

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[12] *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*").

[13] *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).

[14] 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%.

[15] 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.

[16] *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*").

[17] 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.

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

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

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.[20] 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*[21] (EL14-12; EL15-45) in Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[22]

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%.[23] 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

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

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

[22] *Id.* at P 19.

[23] *Id.* at P 59.

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[24] for an extension of time to submit briefs, the latest date for filing initial and reply briefs was extended to January 11 and March 8, 2019, respectively. On January 11, initial briefs were filed by EMCOS, Complainant-Aligned Parties, TOs, Edison Electric Institute ("EEI"), Louisiana PSC, Southern California Edison, and AEP. As part of their initial briefs, each of the Louisiana PSC, SEC and AEP also moved to intervene out-of-time. Those interventions were opposed by the TOs on January 24, 2019. The Louisiana PSC answered the TOs' January 24 motion on February 12. Reply briefs were due March 8, 2019 and were submitted by the TOs, Complainant-Aligned Parties, EMCOS, and FERC Trial Staff.

TOs Request to Re-Open Record and file Supplemental Paper Hearing Brief. On December 26, 2019, the TOs filed a Supplemental Brief that addresses the consequences of the November 21 *MISO ROE Order*[25] 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

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

As previously reported, ISO-NE filed on March 21, 2022 the results of the sixteenth FCA ("FCA16") held February 7, 2022 for the June 1, 2025-May 31, 2026 Capacity Commitment Period ("CCP"). ISO-NE reported the following highlights:

- FCA16 Capacity Zones were the Southeastern New England ("SENE") Capacity Zone (the Northeastern Massachusetts ("NEMA")/Boston, Southeastern Massachusetts, and Rhode Island Load Zones), the Northern New England ("NNE") Capacity Zone (the Maine, New Hampshire and Vermont Load Zones), the Maine Capacity Zone (the Maine Load Zone) and the Rest-of-Pool ("ROP") Capacity Zone (the Connecticut and Western/Central Massachusetts Load Zones). SENE was modeled as an import-constrained zone; NNE, as an export-constrained Capacity Zone. The Maine Load Zone was modeled as a separate nested export-constrained Capacity Zone within NNE.
- FCA16 commenced with a starting price of $12.40/kW-mo. and concluded for all Capacity Zones after four rounds.
- Capacity Clearing Prices were as follows (prices expressed per kw-mo.): SENE - $2.639; NNE and Maine - $2.531; ROP - $2.591; imports over the NY AC Ties (837 MW) and the Phase I/II HQ Excess external interface (465 MW) - $2.591; imports over Highgate (58 MW) and New Brunswick (144 MW) - $2.531.
- There were no active demand bids for the substitution auction and, accordingly, the substitution auction was not conducted.
- No resources cleared as Conditional Qualified New Generating Capacity Resources.
- No Long Lead Time Generating Facilities secured a Queue Position to participate as a New Generating Capacity Resource.
- No De-List Bids were rejected for reliability reasons.

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

[25] *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).

ISO-NE asked the FERC to accept the FCA16 rates and results, effective July 19, 2022. Comments on this filing were due on or before ***May 5, 2022***.

Thus far, over 100 individuals and the No Coal No Gas Campaign have submitted comments, largely protesting the continued selection of Merrimack Station in New Hampshire, and urging a more urgent transition from fossil fuel-fired resources to renewable energy resources. NEPOOL, Calpine, Constellation, Dominion, National Grid, and NESCOE have filed doc-less interventions. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

On May 2, the FERC accepted and suspended in part Constellation Mystic Power, LLC's ("Mystic's") changes to its Amended and Restated Cost-of-Service Agreement ("COS Agreement") to reflect Mystic's current upstream ownership.[27] The changes were accepted effective as of Jun 1, 2022, but subject to refund. Specifically, the FERC accepted (i) Mystic's changes throughout the COS Agreement to replace the term "Exelon Generation Company, LLC" with "Constellation Energy Generation, LLC"; and (ii) the addition of language to the true-up methodology that provides that the values included in the true-up methodology exclude costs associated with the Spin Transaction. However, noting that Mystic's contested proposal on the issue of capital structure and cost of debt raises issues of material fact that cannot be resolved based on the record, the FERC accepted and suspended this portion of the COS Agreement for a nominal period, to become effective June 1, 2022, subject to refund and to the outcome of paper hearing procedures. The FERC also directed the appointment of a settlement judge and will hold the paper hearing in abeyance so as to provide the participants an opportunity for settlement discussions.[28] 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).

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

As previously reported, 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[29] 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).[30] Relying on its *Schedule 17 Orders*,[31] 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

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

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

[28] *Id.* at P 24.

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

[30] *Cross-Sound Cable Co., LLC*, 176 FERC ¶ 61,073 (Aug. 31, 2021) ("*CSC CIP-IROL Costs Order*").

[31] *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.[32] The FERC rejected the alternative bases for FERC approval proposed by CSC.[33]

CSC Request for Rehearing. CSC requested rehearing of the *CSC CIP-IROL Costs Order*. On November 1, 2021, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[34] The Notice confirmed that the 60-day period during which a petition for review of the *CSC CIP-IROL Costs Order* could be filed with an appropriate federal court was triggered when the FERC did not act on CSC's request for rehearing of the *CSC CIP-IROL Costs 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 February 24, 2022, the FERC issued that order, modifying the discussion in, but sustaining the results of, the *CSC CIP-IROL Costs Order*.[35] On March 28, 2022, CSC requested rehearing of the *CSC CIP-IROL Costs Allegheny Order.* On April 27, 2022, the FERC issued an order rejecting CSC's March 28 request for rehearing of the *Allegheny Order.*[36]

As previously reported, CSC has appealed the FERC's earlier orders in this proceeding to the DC Circuit. Although that proceeding was being held in abeyance pending FERC action on the appeal of the *CSC CIP-IROL Costs Allegheny Order*, now that rehearing of that Order was rejected, further activity will take place in, and will be reported in the summary of, the DC Circuit case in Section XVI below. 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, each of the *July 17 Orders*[37] and the *Mystic ROE Orders,*[38] which addressed in part or in whole the Cost-of-Service Agreement ("COS Agreement")[39] among Constellation Mystic Power

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[32] *CSC CIP-IROL Costs Order* at P 33.

[33] *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.

[34] *Cross-Sound Cable Co., LLC*, 177 FERC ¶ 62,064 (Nov. 1, 2021) (Notice of Denial By Operation of Law of Rehearings of *CSC CIP-IROL Costs Order*).

[35] *Cross-Sound Cable Co.*, LLC, 178 FERC ¶ 61,134 (Feb. 24, 2022) ("*CSC CIP-IROL Costs Allegheny Order*").

[36] *Cross-Sound Cable Co., LLC*, 179 FERC ¶ 61,064 (Apr. 27, 2022) (order rejecting rehearing requested of the *CSC CIP-IROL Costs Allegheny Order)*.

[37] 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).

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

[39] 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.

("Mystic"), Constellation Energy Generation, LLC[40] ("Constellation") and ISO-NE, have been appealed to, and consolidated before, the DC Circuit (*see* Section XVI below).

Revised ROE (Sixth) Compliance Filing (-014). Still pending is Mystic's December 20, 2021 filing in response to the requirements of the *Mystic ROE Allegheny Order*. The sixth compliance filing revised (i) the Cost of Common Equity figures from 9.33% to 9.19%, for both Mystic 8&9 and Everett Marine Terminal ("Everett"), and (ii) the stated Annual Fixed Revenue Requirements for both the 2022/23 and 2023/24 Capacity Commitment Periods. Comments on the sixth compliance filing were due on or before January 10, 2022; none were filed. The Sixth Compliance Filing is pending before the FERC.

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

On April 28, 2022, the FERC issued an order granting in part, and denying in part, ENECOS' and NESCOE's formal challenges, subject to refund, and established hearing and settlement judge procedures.[41] The FERC summarily denied NESCOE's challenge regarding the update to the AFRR and ENECOS' challenge with regard to the improper booking of items. Those items, and challenges to other underlying projected costs, may be challenged in connection with Mystic's Second Informational Filing (where the informal challenge process begins on April 1, 2022 and the formal challenge process begins on September 15, 202).[42] The FERC reiterated that all items except return on equity and depreciation are subject to the true-up process described in Schedule 3A of the COS Agreement, not just projected capital expenditures. However, with respect to NESCOE's and ENECOS' allegations that Mystic failed to support all of its projected capital expenditures, the FERC found that the First CapEx Projects Info. Filing raised issues of material fact that could not be resolved based on the record and would be more appropriately addressed under hearing and settlement judge procedures.[43] Accordingly, the FERC set these matters for a trial-type evidentiary hearing. The FERC encouraged the parties to make every effort to settle their disputes before hearing procedures are commenced, and to that end, will hold the hearing in abeyance pending the appointment of a settlement judge and completion of settlement judge procedures.[44]

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

- **MOPR Elimination Filing (ER22-1528)**

On March 31, 2022, ISO-NE and NEPOOL jointly filed Tariff changes to eliminate over a two-year period New England's current FCM Minimum Offer Price Rule ("MOPR"). The proposal eliminates MOPR in full beginning with FCA19 and replaces it with a reformed buyer-side market power mitigation review construct ("Reformed Mitigation Construct"). Until then (FCA17 and FCA18), the changes establish a "Transition Mechanism" which

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

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

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

[43] *Id.* at P 26.

[44] *Id.* at P 27.

permits a substantial quantity of state-sponsored policy resources to enter the market without buyer-side market power mitigation review. Two effective dates were requested -- May 30, 2022 for the Transition Mechanism revisions and March 1, 2024 for the Reformed Mitigation Construct revisions. The MOPR Elimination Changes were supported by the Participants Committee at its February 3 meeting.

Comments on the MOPR Elimination Changes were due on or before April 21, 2022. Comments and protests were submitted by: NEPOOL; ISO-NE EMM; ISO-NE IMM; AEE; Calpine/Cogentrix/Vistra; Clean Energy & Consumer Advocates; Great River Hydro; MA AG/MOPA; NESCOE; NEPGA; Shell; CT DEEP; MA Exec. Office of Energy and Environ. Affairs; ACRE; Berkshire Environ. Action Team; E2; EPSA; Nat'l Caucus of Envir. Legislators; and SEIA. In addition, nearly 150 sets of comments were submitted by individuals, most of them urging the FERC require a more rapid transition from the current MOPR than the two-year process proposed by ISO-NE, and articulating strong feelings concerning the need to address climate change. Doc-less interventions by those not commenting were filed by Acadia Center, Avangrid, Borrego, Constellation, CPV Towantic, EDF, Eversource, FirstLight, HQUS, MA AG, NRDC/Sustainable FERC Project, National Grid, North East Offshore, NRG, PowerOptions, Public Systems, Shell, RENEW, CT DEEP, MA DPU, ACPA, MA Climate Action Network, MOPA, Ocean Winds, Public Citizen, and the National Hydropower Association. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

On February 2, 2022, ISO-NE, NEPOOL and the PTO AC ("Filing Parties") submitted Tariff revisions ("*Order 2222* Changes") in response to the requirements of *Order 2222*. The Filing Parties stated that the *Order 2222* Changes create a pathway for Distributed Energy Resource Aggregations ("DERAs") to participate in the New England Markets by: creating new, and modifying existing, market participation models for DERA use; establishing eligibility requirements for DERA participation (including size, location, information and data requirements); setting bidding parameters for DERAs; requiring metering and telemetry arrangements for DERAs and individual Distributed Energy Resources ("DERs"); and providing for coordination with distribution utilities and relevant electric retail regulatory authorities ("RERRAs") for DERA/DER registration, operations, and dispute resolution purposes.

Comments, following an extension of time granted by the FERC in response to a request by Advanced Energy Management Alliance ("AEMA"), were due on or before ***April 1, 2022***. NEPOOL filed supplemental comments on March 28. Protests and comments were filed by: AEE/PowerOptions/SEIA; Environmental Organizations;[45] MA AG; Voltus; AEMA and 4 New England US Senators.[46] Doc-less interventions were filed by: Avangrid (CMP/UI), Calpine, Centrica Business Solutions Optimize (out-of-time), Constellation, ENE, Enerwise, Eversource, FirstLight, MA AG, National Grid, NESCOE, NRG, MA DPU, MPUC (out-of-time), APPA, and EEI. ISO-NE (April 20) and National Grid/Avangrid/Eversource (April 19) filed answers to the protests and adverse comments. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com); Eric Runge (617-345-4735; ekrunge@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

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

IV. OATT Amendments / TOAs / Coordination Agreements

- ***Order 676-J*** **Compliance Filing Part I (CSC-Schedule 18-Attachment Z) (ER22-1168)**
  On March 2, 2022, in response to the requirements of *Order 676-J*,[47] ISO-NE and Cross-Sound Cable Company ("CSC") filed revisions to ISO-NE Tariff Schedule 18 Attachment Z to incorporate the new cybersecurity and PFV standards contained in the North American Energy Standards Board ("NAESB") Wholesale Electric Quadrant ("WEQ") Version 003.3 Standards ("Schedule 18 Order 676-J Part I Changes").[48] An effective date as of the date of the FERC order accepting these changes was requested. Comments on this filing were due on or before March 23, 2022; none were filed. Doc-less interventions were filed by CSC and NEPOOL. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 676-J*** **Compliance Filing Part I (TOs-Schedule 20/21-Common) (ER22-1161)**
  Also on March 2, 2022, in response to the requirements of *Order 676-J*, the PTO AC, ISO-NE, and the Schedule 20A Service Providers ("S20SPs") (collectively, the "TOs") filed revisions to ISO-NE Tariff Schedules 20A-Common and 21-Common to incorporate the new cybersecurity and PFV standards contained in NAESB WEQ Version 003.3 Standards ("Schedule 20/21-Common Order 676-J Part I Changes").[48] An effective date as of the date the FERC may determine was requested. Comments on this filing are due on or before March 23, 2022; none were filed. Doc-less interventions were filed by NEPOOL and Eversource. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 676-J*** **Compliance Filing Part I (ISO-NE-Schedule 24) (ER22-1150)**
  Again on March 2, 2022, in response to the requirements of *Order 676-J*, ISO-NE filed revisions to ISO-NE Tariff Schedule 24 (Incorporation by Reference of NAESB Standards) to incorporate the new cybersecurity and PFV standards contained in NAESB WEQ Version 003.3 Standards ("Schedule 24 Order 676-J Part I Changes").[48] An effective date no earlier than June 2, 2022 was requested. The Transmission Committee recommended that the Participants Committee support the Schedule 24 Order 676-J Part I Changes at its March 23 meeting, and the Participants Committee will consider the changes at the April 7 meeting (Consent Agenda Item # 1). Comments on this filing were due on or before March 23, 2022; none were filed. NEPOOL, Eversource, MA DPU, and National Grid submitted doc-less interventions. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

- **FCM Billing Acceleration and RBA Changes (ER22-1167)**
  On April 28, 2022, the FERC accepted changes jointly filed by ISO-NE and NEPOOL to the ISO-NE Financial Assurance Policy ("FAP") that (i) accelerate the settlement and billing of certain Forward Capacity Market ("FCM") charges and payments from a monthly settlement and billing to a daily settlement and bi-weekly billing (the "FCM Acceleration Changes"); (ii) make several corrections and clarifications to the FCM Cost Allocation provisions

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

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

previously approved by the FERC in 2018 before those go into effect on June 1, 2022 (the "FCM Cost Allocation Changes"); (iii) revise the method to submit Requested Billing Adjustments (the "RBA Changes"); and (iv) make several conforming and clean-up changes (the "Clean-up Changes").[49] The changes were accepted effective as of May 1, 2022 for the RBA Changes and June 1, 2022 for the FCM Acceleration Changes, FCM Cost Allocation Changes and the Clean-Up Changes. Unless the April 28, 2022 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

VI. Schedule 20/21/22/23 Changes

- **Schedule 21-VP: Schedule 21 Name Update (ER22-1115)**

On April 25, 2022, the FERC accepted a revised Schedule 21-VP that renames the Schedule from "Schedule 21-EM" to "Schedule 21-VP" and replaces all references to "Emera Maine" with "Versant Power".[50] The renamed Schedule 21-VP became effective January 1, 2022, as requested. Unless the April 25 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

As previously reported, the FERC accepted on February 18, 2022 a Local Service Agreement ("LSA") among New England Power, The Narragansett Electric Company ("Narragansett") and ISO-NE.[51] As previously reported, the LSA reflects the construction of the new Iron Mine Hill Road Substation and related transmission modifications, and the assessment to Narragansett of a Direct Assignment Facilities Charge ("DAF Charge") associated with the facilities. The Iron Mine Hill Road Substation, a new 115 kV/34.5 kV substation (including modifications necessary to loop Narragansett's existing 115 kV H17 transmission line through the new substation) will connect to a new 34.5 kV distribution feeder, which will serve as the point of interconnection for several distributed generation projects being developed by Green Development, LLC ("Green Development"), located in North Smithfield, Rhode Island. The LSA was accepted effective as of January 1, 2022, as requested. The FERC was not persuaded by Green Development's arguments that the revised Narragansett LSA was unjust and unreasonable and should be rejected.[52]

Request for Rehearing Denied by Operation of Law. On March 18, 2022, Green Development requested rehearing of the *2nd Rev Narragansett LSA Order.* On April 18, 2022, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[53] The Notice confirmed that the 60-day period during which a petition for review of the *2nd Rev Narragansett LSA Order* could be filed with an appropriate federal court was triggered when the FERC did not act on Green Development's request for rehearing of the *2nd Rev Narragansett LSA Order*. The Notice also indicated that the FERC would address, as is its right, the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper." If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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[49] *ISO New England Inc., New England Power Pool Participants Comm.*, Docket No. ER22-1167 (Apr. 28, 2022) (unpublished letter order).

[50] *ISO New England Inc.*, Docket No. ER22-1115 (Apr. 25, 2022).

[51] *ISO New England Inc. and New England Power Co. d/b/a National Grid*, 178 FERC ¶ 61,115 (Feb. 18, 2022) ("*2nd Rev Narragansett LSA Order*").

[52] *Id.* at P 55.

[53] *ISO New England Inc. and New England Power Co. d/b/a National Grid*, 179 FERC ¶ 62,035 (Apr. 18, 2022) (notice of denial of rehearing by operation of law and providing for further consideration).

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

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

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

On November 19, 2021, Versant Power submitted a joint offer of settlement between itself and the MPUC to resolve all issues raised by the MPUC in response to Versant's 2020 annual charges update filed, as previously reported, on June 15, 2020 (the "Versant 2020 Annual Update Settlement Agreement"). Under Part V of Attachment P-EM to Schedule 21-VP, "Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the [Attachment P-EM] Rate Formula. . . ." and follow a dispute resolution procedure set forth there. In accordance with those provisions, the MPUC identified certain disputes with the 2020 Annual Update, all of which are resolved by the Versant 2020 Annual Update Settlement Agreement. Comments on the Versant 2020 Annual Update Settlement Agreement were due on or before December 9, 2021; reply comments, December 19, 2021; none were filed. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-VP: 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 Merger-Related Costs Order,*[54] and certified by Settlement Judge Dring[55] to the Commission.[56] As previously reported, under this 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).

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[54] *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.

[55] 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.

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

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

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

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

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

The TOs' November 2, 2015 refund report documenting resettlements of regional transmission charges by ISO-NE in compliance with *Opinions No. 531-A*[57] *and 531-B*[58] also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

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

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

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

- **Capital Projects Report - 2021 Q4 (ER22-1041)**

On February 10, 2022, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the fourth quarter ("Q4") of calendar year 2021 (the "Report"). ISO-NE is required to file the Report under section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Report highlights include the following new projects: (i) nGEM Hardware Phase II ($4.57 million); (ii) Forecast Enhancements ($1.78 million); (iii) Solar Do-Not-Exceed ("DNE") Dispatch Phase I ($1.595 million); (iv) Physical Security Improvement Project ($1.136 million); (v) Replace Messaging Software ($432,100); (vi) Asset Activation Automation ($408,000); (vii) Browser Standardization ($472,000); (viii) Linear State Estimator Phase I ($362,000); (ix) Short-Term Load Forecast Curve Modification Enhancement ($279,600); (x) FCM Delayed Commercial Resource Treatment Phase II ($253,000); and (xi) Energy Management System Communications Monitoring ($235,200). The one significant change for a Chartered Project was the Replacement of the LMP Monitor (an increase of $265,000). Comments on this filing were due on or before March 3, 2022. NEPOOL filed comments on February 23 supporting the 2021 Q4 Report. Doc-less interventions were filed by Eversource and National Grid. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **LFTR Implementation: 54th Quarterly Status Report (ER07-476; RM06-08)**

ISO-NE filed the 54th of its quarterly status reports regarding LFTR implementation on April 14, 2022. ISO-NE reported that it implemented monthly reconfiguration auctions (accepted in ER12-2122) beginning with the month of October 2019. ISO-NE further reported that, while it will continue to evaluate its as-filed LFTR design and financial assurance issues, including an ongoing evaluation of the FTR market and risk associated with FTRs and LFTRs, it is currently focused on higher priority market-design initiatives. ISO-NE

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

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

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 (32^{nd}) Semi-Annual Report (ER06-613)**

As directed by the original ASM II Order,[59] as modified,[60] ISO-NE submitted its 32nd semi-annual reserve market compliance report on April 1, 2022. In the 32nd report, ISO-NE stated that "In the coming months, the ISO plans to begin discussions with stakeholders regarding the development of day-ahead ancillary services. As those discussions proceed, the ISO will update the Commission regarding the relation of the proposed day-ahead ancillary services to a forward TMSR market, through future reports in this docket." The April 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).

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

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

- **ISO-NE FERC Form 3Q (2021/Q4) (not docketed)**

On April 15, 2022, ISO-NE submitted its 2021/Q4 FERC Form 3Q (Quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is a quarterly regulatory requirement which supplements the annual FERC Form 1 financial reporting requirement. These filings are not noticed for comment.

- **ISO-NE FERC Reporting Requirement 582 (not docketed)**

On April 19, 2022, ISO-NE submitted a report of its total MWh of transmission service during 2021. ISO-NE reported that 123,908,497 MWh of transmission service in interstate commerce was provided during 2021 (roughly 196,671 MWh less than 2020 (124,105,168 MWh)). These filings are not noticed for comment.

- **ISO-NE FERC Form 715 (not docketed)**

On March 28, 2022, ISO-NE submitted its 2021 Annual Transmission Planning and Evaluation Report. These filings are not noticed for public comment.

IX. Membership Filings

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

On April 29, 2022, NEPOOL requested that the FERC accept (i) the following Applicant's membership in NEPOOL: Altop Energy Trading LLC (Supplier Sector); Indra Power Business CT LLC [Related Person to Palmco Power MA, LLC (Supplier Sector)]; Indra Power Business MA LLC [Related Person to Palmco Power MA, LLC

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[59] *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).

[60] *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")).

(Supplier Sector)]; Leicester Street Solar, LLC [Related Person to Agilitas Companies (AR Sector, DG Sub-Sector)]; and Nexamp Markets, LLC [Related Person to Boston Energy Trading and Marketing (Supplier Sector)]; and (ii) the name change of the following Participant: Salem Harbor Power Development LP (f/k/a Footprint Power Salem Harbor Development LP). Comments on this filing are due on or before May20, 2022.

- **April 2022 Membership Filing (ER22-1531)**

On March 31, 2022, NEPOOL requested that the FERC accept the following Applicant's membership in NEPOOL: AMP Solar US Holdings Inc. AR Sector, DG Sub-Sector); NRG Kiosk LLC d/b/a Power Kiosk (Data-Only Member); and Octopus Energy (Supplier Sector). Comments on this filing were due on or before April 21, 2022; none were filed. This matter is pending before the FERC.

- **March 2022 Membership Filing (ER22-1131)**

On April 21, 2022, the FERC accepted (i) the following Applicants' membership in NEPOOL: Emera Energy Services Subsidiary No. 6 [Related Person to Emera Energy Services companies (Supplier Sector)]; and Tidal Energy USA (Supplier Sector); and (ii) the name changes of GB II New Haven LLC (f/k/a PSEG New Haven LLC) and GB II Connecticut LLC (f/k/a PSEG Power Connecticut LLC), each of which are now Related Persons to Great River Hydro (AR Sector; RG Sub-Sector), and Generate Colchester Fuel Cells, LLC (f/k/a Bloom Connecticut Clean Energy Company, LLC).[61] Unless the April 21 order is challenged, this proceeding will be concluded.

- **Involuntary Termination Filing: Sunwave USA Holdings Inc. (ER22-1039)**

On April 8, 2022, the FERC accepted the involuntary termination of the NEPOOL membership and MPSA with ISO-NE (Market Participant status) of Sunwave USA Holdings, Inc. (Supplier Sector), effective April 11, 2022.[62] Unless the April 8 order is challenged, this proceeding will be concluded.

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

Questions concerning any of the ERO Reliability Standards or related rule-making proceedings or filings can be directed to Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Revised Reliability Standard (CIP-014 Compliance Section) (RD22-3)**

On February 16, 2022, NERC filed for approval proposed changes to the compliance section of CIP-014 (Physical Security). The modifications remove from the Compliance section the provision that requires all evidence demonstrating compliance with the standard to be retained at the Transmission Owner's or Transmission Operator's facility. No changes to the mandatory and enforceable provisions of the CIP-014 standard were proposed. Comments on the CIP-014 changes were due on or before March 15, 2022 and were filed by EEI (which protested NERC's proposed change, suggesting that for security reasons the records be required to be maintained at the TOs' facilities. NERC answered EEI's comments on March 21 and EEI answered those comments on March 30. This matter is pending before the FERC.

- **CIP Standards Development: Informational Filings on Virtualization and Cloud Computing Services Projects (RD20-2)**

As previously reported, NERC is required to file on an informational basis quarterly status updates regarding the development of new or modified Reliability Standards pertaining to virtualization and cloud computing services. On March 15, 2022, NERC submitted an informational filing regarding one active CIP standard

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[61] *New England Power Pool Participants Comm.*, Docket No. ER22-1131 (Apr. 21, 2022) (unpublished letter order).

[62] *New England Power Pool Participants Comm. and ISO New England Inc.*, Docket No. ER22-1039 (Apr. 8, 2022) (unpublished letter order).

development project (Project 2016-02 – Modifications to CIP Standards ("Project 2016-02")).[63] Project 2016-02 focuses on modifications to the CIP Reliability Standards to incorporate applicable protections for virtualized environments. A revised schedule for Project 2016-02 calls for final balloting of revised standards in April 2022, NERC Board of Trustees Adoption in May 2022 and filing of the revised standards with the FERC in June 2022.

- **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.[64] On March 25, 2020, Joint Associations[65] 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.

Dec 2021 Informational Filing. In part in response to the comments filed, the FERC, in a December 17, 2020 order,[66] 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. NERC submitted that informational filing on December 17, 2021. In that filing, NERC addressed the status of NERC's formal process to assess the feasibility of voluntarily conducting BES operations in the cloud in a secure manner, evaluated potential modifications to the CIP Standards to facilitate expanded use of the cloud, and considered topic areas raised in comments to the NOI. NERC requested that the FERC accept the informational filing as consistent with the *Order Directing Info. Filing*. NERC committed to continue to consider ways to support industry in securely adopting evolving technologies as necessary, including conducting BES reliability operating services in the cloud. NERC reported that there is no Standard Authorization Request ("SAR") to initiate standards development or a field test, nor had it identified a reliability gap that would necessitate standards development to facilitate BES reliability operating services in the cloud.

- ***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,[67] concluding that the 18 requirements "(1) provide little or no reliability benefit; (2) are administrative in nature or relate

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[63] The other project which had been addressed in prior updates, Project 2019-02, has concluded, and the FERC approved in RD21-6 the Reliability Standards revised as part of that project (CIP-004-7 and CIP-011-3) on Dec. 7, 2021.

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

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

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

[67] *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).

expressly to commercial or business practices; or (3) are redundant with other Reliability Standards."[68] 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.[69]

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*[70] (the "MOD A Reliability Standards"). The FERC intends to coordinate the effective dates for the retirement of the MOD A Reliability Standards with successor NAESB business practice standards (v. 003.3) that include Modeling business practices, which were accepted in *Order 676-J*.[71]

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

On March 11, 2022, NERC and NPCC filed for approval changes to the NPCC Bylaws (the "Bylaws") designed to, among other things: (1) to improve corporate governance; (2) to ensure consistency with the Not-for-Profit Corporation Law of the State of New York ("N-PCL"), pursuant to which NPCC is organized; and (3) to remove extraneous provisions rom the Bylaws, create efficiencies, and reflect changes at NPCC since 2012 (when the last changes to the Bylaws were filed). The Bylaws changes are to take effect upon FERC approval. Comments on this filing were due on or before April 1, 2022. Public Citizen protested the filing, arguing that the FERC should require a change to the composition of NPCC's Board of Directors. Specifically, Public Citizen suggested that NPCC be compelled to ensure that, of NPCC's eight board sectors and 15 voting members, "household consumer advocates" have two voting seats in Sector 7 (Sub-Regional Reliability Councils, Customers, Other Regional Entities and Interested Entities), and that regulators, reliability coordinators, and end-users compose at least half of the voting seats of the board. On April 6, 2022, NERC and NPCC jointly responded to the Public Citizen comments. National Grid filed a doc-less intervention. This matter is pending before the FERC.

- **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 remains pending before the FERC.

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[68] *Order 873* at P 2.

[69] *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.

[70] *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.

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

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

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

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

XI. Misc. - of Regional Interest

- **203 Application: Pixelle / Spectrum (EC22-49)**

On April 1, 2022, as supplemented on April 18, 2022, Pixelle[72] requested authorization for the sale of 100% of the interests in Pixelle Holding by affiliates of the LG Fund to Spectrum Group Buyer, Inc. ("Spectrum"). No comments on the 203 application or the supplement were filed. Doc-less interventions were filed by PJM, the PJM IMM, and Public Citizen. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Howard Wind / Greenbacker Wind (EC22-13)**

On January 11, 2022, the FERC authorized Greenbacker Wind, LLC's acquisition of 100% of the equity interests in Howard Wind LLC from Everpower Wind Holdings, Inc. ("Everpower").[73] Pursuant to the January 11 order, Greenback Wind 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: 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").[74] 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).

- **Related Facilities Agreement: NSTAR / Ocean State Power (ER22-1675)**

On April 22, 2022, NSTAR filed a Related Facilities Agreement ("RFA") with Ocean State Power. The RFA provides the terms and conditions governing NSTAR's activities regarding, and Ocean State Power's cost responsibility for, a replacement disconnect switch and associated equipment located at NSTAR's West Walpole

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[72] "Pixelle" includes Pixelle Specialty Solutions Holding LLC ("Pixelle Holding") and its indirectly, wholly-owned subsidiaries with FERC-jurisdictional facilities, Pixelle Specialty Solutions LLC, Pixelle Androscoggin LLC, and Pixelle Energy Services LLC (a member of the Generation Sector).

[73] *Howard Wind LLC*, 178 FERC ¶ 62,024 (Jan. 11, 2022).

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

Station #447. An April 23, 2022 effective date was requested. Comments on this filing are due on or before May 18, 2022. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **CL&P Att. F App. D Depreciation Rate Change (ER22-1548)**

On April 1, 2022, CL&P proposed changes to the transmission plant depreciation rate for the Norwalk Harbor-Northport underground transmission line set forth in CL&P's Appendix D to Attachment F of the ISO-NE OATT. CL&P stated that the proposed depreciation rate will reduce CL&P's revenue requirement by approximately $215,199 annually. A July 1, 2022 effective was proposed. Comments on this filing were due on or before April 22, 2022; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On March 10, 2022, Maine Power Link, LLC ("MPL") submitted an application for authority to charge negotiated rates associated with transmission capacity rights on its proposed Northern Maine Line transmission project (the "Project").[75] Comments on MPL's application were due on or before March 28, 2022. The Maine Office of Public Advocate ("MOPA") submitted comments urging the FERC to condition its approval of the application subject to a number of additional conditions.[76] On April 15, MPL answered MOPA's comments (asserting that the first two conditions suggested are unnecessary and the other two conditions "can be addressed in the negotiation of the TSA, as part of the Northern Maine RFP process"). On April 19, MOPA answered MPL's April 15 answer. 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).

- **TSA: NSTAR/Park City Wind (ER22-1247)**

On March 8, 2022, NSTAR and Park City Wind LLC ("PCW") requested approval of a Transmission Support Agreement ("TSA") that commits NSTAR to construct, and sets forth the Parties' respective responsibilities to finance and pay for, the transmission facilities required to interconnect PCW's proposed 800 MW wind farm off the coast of Martha's Vineyard to NSTAR's transmission system (near West Barnstable on Cape Cod). Comments on this TSA were due on or before March 29, 2022. On March 22, 2022, Mayflower Wind submitted comments requesting that the FERC, in any approval of the TSA, provide clear guidance that NSTAR must provide comparable treatment to similarly-situated interconnection customers in future transmission support arrangements. NSTAR answered Mayflower on March 25, 2022. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

On March 2, 2022, in response to the requirements of *Order 676-J*, Versant Power filed revisions to Section 4 of the Versant OATT for the Maine Public District ("MPD OATT") to incorporate the new cybersecurity and PFV standards contained in NAESB WEQ Version 003.3 Standards ("Versant MPD OATT Order 676-J Part I Changes").[48] A placeholder effective date was submitted. Comments on this filing were due on or before March 23, 2022; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

[76] The conditions proposed by MOPA included: (i) a demonstration that the MPUC's competitive bidding process will be "sufficiently open, transparent and robust to constrain rates"; (ii) that the rates assessed to the Maine utilities actually reflect the results of the competitive bidding process; (iii) some assurance that the cost of excess capacity on the transmission line is not paid for by Maine customers; and (iv) MPL will bear the full market risk of the project, including the potential for under-recovery of the line's costs if the line is not fully used.

- **ISA Cancellation: NSTAR/Servistar (ER22-1013)**

On April 8, 2022, the FERC accepted NSTAR's notice of termination of the Interconnection Study Agreement ("ISA") between NSTAR and Servistar.[77] NSTAR reported that Servistar withdrew the project and terminated the ISA. The termination was accepted effective as of February 10, 2022, as requested. Unless the April 8 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

As previously reported, the FERC rejected the notice of termination filed by CL&P of a 2002 Interconnection Agreement ("IA") governing interconnection service to what CL&P characterized as a since-decommissioned 26 MW waste-tire fueled generator located in Sterling, Connecticut (the "Facility").[78] In rejecting the notice, the FERC found that CL&P had "not provided adequate justification demonstrating that the Facility has been decommissioned in order to terminate the Interconnection Agreement."[79] However, the FERC noted that its determination did not indicate that Sterling retains any interconnection rights under the IA, stating that there had been no interconnection rights associated with the facility since ISO-NE deemed the Facility retired in 2017.

Requests for Rehearing and/or Clarification Denied by Operation of Law; Sterling IA Allegheny Order. On January 10, 2022, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[80] The Notice confirmed that the 60-day period during which a petition for review of the *Sterling IA Order* can be filed with an appropriate federal court was triggered when the FERC did not act on CL&P's and Brookfield's requests for rehearing of the *Sterling IA Order*.[81] 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 March 24, 2022, the FERC issued that order, modifying the discussion in the *Sterling IA Order* and continuing to reach the same result.[82] On April 25, Sterling requested clarification and/or rehearing of the *Sterling IA Allegheny Order*. The Sterling request is pending before the FERC, with FERC action required on or before May 25, 2022 or the request will be deemed denied by operation of law. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On March 7, 2022, the FERC conditionally accepted Versant Power's proposed revisions to Section 4 of the Versant Power Open Access Transmission Tariff for Maine Public District (the "MPD OATT") to incorporate by reference certain of the revisions required by *Order 676-I*, including waiver of certain of those standards that are not applicable to MPD and/or the MPD OATT.[83] In accepting the filing, the FERC directed Versant to revise the MPD OATT to include a citation to the FEC order originally granting the waiver requests to be continued by the *Versant Order 676-I Compliance Filing Order I*. Versant submitted that compliance filing on April 1, 2022. Comments on that filing were due on or before April 22, 2022; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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[77] *NSTAR Elec. Co.*, Docket No. ER22-1013 (Apr. 8, 2022) (unpublished letter order).

[78] *The Connecticut Light and Power Co.*, 177 FERC ¶ 61,083 (Nov. 8, 2021) ("*Sterling IA Order*").

[79] *Id*. at P 23.

[80] The Conn. Light & Power Co., 178 FERC ¶ 62,015 (Jan. 10, 2022).

[81] CL&P and Brookfield each requested rehearing and/or clarification of the *Sterling IA Order* on Dec. 8, 2021.

[82] *The Conn. Light and Power Co.*, 178 FERC ¶ 61,206 (Mar. 24, 2022) ("*Sterling IA Allegheny Order*").

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

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

In accordance with *Order 864*[84] and *Order 864-A,*[85] and extensions of time granted, New England's transmission-owning public utilities submitted their *Order 864* compliance filings, with specific dockets and filing dates identified in the following table. The FERC has addressed a number of the compliance filings, with some yet to be acted on, and others submitting further compliance filings (generally to reflect a January 27, 2020 effective date). The *Order 864* compliance proceedings that remain open are as follows:

Docket(s)	Transmission Provider	Date of Last Filing	Date Accepted
ER21-1130 ER20-2572	New England TOs (RNS)	Feb 18, 2022	Pending
ER20-2429	Central Maine Power ("CMP") (LNS)	Apr 15, 2022	Pending
ER21-1702	CMP (Schedule 1 Appendix A Implem. Rule)	Feb 28, 2022	Pending
ER21-1654	CL&P (LNS)	Feb 28, 2022	Pending
ER21-1295	Eversource (CL&P, PSNH, NSTAR) (LNS; Schedule 21-ES)	Feb 23, 2022	Pending
ER21-1154	FG&E (LNS)	Feb 23, 2022	Pending
ER21-1694	Green Mountain Power	Feb 18, 2022	Pending
ER20-1089	New England Elec. Trans. Corp.	Feb 18, 2022	Pending
ER20-1087	New England Hydro Trans. Corp.	Feb 18, 2022	Pending
ER20-1088	New England Hydro Trans. Elec. Co.	Feb 18, 2022	Pending
ER21-1241	NEP (LNS)	Feb 28, 2022	Pending
ER20-2551	NEP (Schedule 21-NEP and TSA-NEP-22 Compliance Revisions)	Jul 30, 2020	Pending
ER20-2219	NEP (Tariff No. 1)	Jun 29, 2020	Pending
ER20-2553	NEP (MECO/Nantucket LSA)	Jul 30, 2020	Pending
ER21-1293	NSTAR (LNS)	Feb 23, 2022	Pending
ER21-1709	VTransco (LNS)	Feb 22, 2022	Pending
ER20-2594	VTransco (1991 VTA)	Feb 25, 2022	Pending
ER20-2133 -001, -002	Versant Power	Nov 22, 2021	Conditionally, Feb 28, 2022

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

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

[85] *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*").

♦ ***ER20-2429 (CMP - LNS)***. On April 15, 2022, CMP supplemented its March 31, 2022 compliance filing with redlines, as Attachments 3 & 4, demonstrating the revisions made to CMP's November 8, 2021 filing. No comments on CMP's March 31, 2022 compliance filing were submitted and that filing, as supplemented, is pending before the FERC.

♦ ***ER20-2133 (Versant)***. On April 28, Versant Power submitted changes to Schedule 21-VP in response to the FERC's February 28, 2022 order conditionally accepting Versant Power's *Order 864* filings.[86] Comments on Versant's compliance filing are due on or before May 19, 2022.

XII. Misc. - Administrative & Rulemaking Proceedings[87]

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

On February 17, 2022, the FERC issued a notice of inquiry ("NOI")[88] seeking comments on (i) whether and how the required use of dynamic line ratings ("DLR") is needed to ensure just and reasonable wholesale rates; (ii) whether the lack of DLR requirements renders current wholesale rates unjust and unreasonable; (iii) potential criteria for DLR requirements; (iv) the benefits, costs, and challenges of implementing DLRs; (v) the nature of potential DLR requirements; and (vi) potential timeframes for implementing DLR requirements. This NOI represents the first step in the FERC's effort to gather more information about the costs and benefits, and potentially mandating the use, of DLRs. A more detailed summary was provided to the Transmission Committee and is posted on the Transmission Committee's webpage.

Initial comments were due ***April 25, 2022*** and filed by: ISO-NE; DC Energy; Eversource; Clean Energy Parties; Potomac Economics; CT DEEP; NERC; US DOE; CAISO; MISO; NYISO; Org of MISO States; SPP; SPP MMU; AEP; Alliant; APPA; APS; AZ PUC; Clean Energy Entities; Dayton Power; EEI; ELCON; Entergy; IN Util. Reg. Comm.; ITC; LA DPW; MISO TOs; NRECA; NYISO TOs; PPL; R Street Institute; Southern Co.; TAPS; Tri-State; Electricity Canada; Electric Grid Monitoring; Line Vision; Idaho Power. Reply comments are due on or before ***May 25, 2022***.[89]

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

On April 27-28, 2022, the FERC convened a joint technical conference with NERC and its Regional Entities to discuss how to improve the winter-readiness of generating units, including best practices, lessons learned and increased use of the NERC Guidelines, as recommended in the Joint February 2021 Cold Weather Outages Report.[90] Panels included discussion of (i) cold weather preparedness plans; (ii) planning, engineering and technologies for cold weather preparedness; (iii) implementing cold weather preparedness plans for reliable operations; and (iv) communications, coordination, training, and education for cold weather operations. Speaker materials have been posted in eLibrary.

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

On June 17, 2021,the FERC established a Joint Federal-State Task Force on Electric Transmission ("Transmission Task Force").[91] The Transmission Task Force is comprised of all FERC Commissioners as well as

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[86] *ISO New England Inc. and Versant Power*, 178 FERC ¶ 61,152 (Feb. 28, 2022).

[87] Reporting on the following proceedings has been suspended since the last Report and will be continued if and when there is new activity to report: Electrification and the Grid of the Future (AD21-12); ISO/RTO Credit Principles and Practices (AD21-6); Offshore Wind Integration in RTOs/ISOs (AD20-18); Waiver of Tariff Requirements (PL20-7); FERC's ROE Policy for Natural Gas and Oil Pipelines (PL19-4); and NOI: Certification of New Interstate Natural Gas Facilities (PL18-1).

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

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

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

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

representatives from 10 state commissions (two from each NARUC region). State commission representatives will serve one-year terms from the date of appointment by FERC and in no event will serve on the Task Force for more than three consecutive terms. The Transmission Task Force will convene multiple formal meetings annually, with FERC issuing orders fixing the time and place and agenda for each meeting, and the meetings will be open to the public for listening and observing and on the record. The Transmission Task Force will focus on "topics related to efficiently and fairly planning and paying for transmission, including transmission to facilitate generator interconnection, that provides benefits from a federal and state perspective."[92] New England is represented by Commissioners Riley Allen (VT PUC) and Matt Nelson (Chair, MA DPU).

Public Meetings.

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

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

♦ ***May 6, 2022***. Pursuant to the agenda issued April 22, 2022, discussion at the May 6, 2022 meeting, which will be held virtually, will address (i) generator interconnection queue processes and current backlog; and (ii) cost allocation for generator interconnection-related network upgrades, including participant funding. All interested persons were invited to file by April 12, 2022 comments suggesting agenda items relating to this topic. Comments on agenda items were filed by ACPA/AEE/SEIA, ACRE, AEE, NJ BPU, NRDC, PJM, and UCS.

- **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.

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[92] 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.

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, 2022, Entergy answered the comments submitted by City of New Orleans. This matter is 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. A transcript of the September 30 technical conference was posted in eLibrary on November 16, 2021. On January 7, 2022, the FERC issued a notice inviting post-technical conference comments, either to address the questions raised in the January 7 notice or any other issues raised during the technical conference. Comments were due on or before February 22, 2022 and were filed by: ISO-NE, Americans for a Clean Energy Grid, AGA/APGA, CAISO, EEI, Energy Systems Integration Group, EPSA, Grain Belt Express, Grid Lab, MISO, Natural Gas Council, Natural Gas Supply Association, Public Power Associations. This matter is pending before the FERC.

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

ISO/RTO Reports. On April 21, 2022, the FERC issued an order[93] directing each independent system operator ("ISO") and regional transmission organization ("RTO"), including ISO-NE, to submit on or before ***October 17, 2022*** a report that describes: (1) current system needs given changing resource mixes and load profiles; (2) how it expects its system needs to change over the next five and 10 years; (3) whether and how it plans to reform its energy and ancillary services ("EAS") markets to meet expected system needs over the next five and 10 years; and (4) information about any other reforms, including capacity market reforms and any other resource adequacy reforms that would help it meet changes in system needs. Public comments in response to the RTO/ISO reports may be submitted within 60 days following the filing of the reports. The FERC will review the reports and comments to determine whether further action is appropriate.

2021 Technical Conferences. The *Order Directing Reports* follows a series of staff-led technical conferences, convened in 2021 and summarized in previous Reports, addressing ISO/RTO resource adequacy[94] and energy and ancillary services markets.[95]

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

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

[95] The FERC held two staff-led technical conferences addressing ISO/RTO EAS markets, one on Sept. 14, 2021; the second on Oct. 12, 2021. Transcripts of both technical conferences are posted in eLibrary. In advance of the EAS technical conferences, FERC staff issued on Sept. 7, 2021 a White Paper entitled "Energy and Ancillary Services Market Reforms to Address Changing System Needs" summarizing

- **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 were filed in September 20, 2021.[96]

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 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 remain pending before the FERC.

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

On February 24, 2022, the FERC announced that it will hold its 13th annual technical conference addressing increasing Real-Time and Day-Ahead market efficiency through improved software from June 21-23. A detailed agenda with the list of and times for the selected speakers will be published on the FERC's website[97] and in eLibrary after May 20, 2022.

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

On December 16, 2021, the FERC issued a notice of inquiry[98] seeking comments on (i) the rate recovery, reporting, and accounting treatment of industry association dues and certain civic, political, and related expenses; (ii) the ratemaking implications of potential accounting and reporting changes; (iii) whether additional

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recent EAS markets reforms as well as reforms then under consideration. Initial comments on the topics discussed during the EAS technical conferences were filed by: ISO-NE, Appian Way Energy Partners, Constellation, Dominion, Envir. Defense Fund, FirstLight, LS Power, CAISO, MISO, NYISO, PJM, SPP MMU, ACPA, Clean Energy Organizations, EEI, Energy Trading Institute, EPRI, EPSA, Middle River Power, National Hydropower Assoc., NYSERDA, PJM Providers Group, and Public Citizen. Reply comments were filed by EPRI, NERC and its Regional Entities and Vistra.

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

[97] https://www.ferc.gov/industries-data/electric/power-sales-and-markets/increasing-efficiency-through-improved-software.

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

transparency or guidance is needed with respect to defining donations for charitable, social, or community welfare purposes; and (iv) a framework for guidance should the FERC determine action is necessary to further define the recoverability of industry association dues charged to utilities and/or utilities' expenses from civic, political, and related activities. Initial comments were due February 22, 2022 and were filed by AGA, APPA, EEI, EPRI, Harvard Electricity Law Institute, INGA, Joint RTO Commenters,[99] MA AG, National Grid, NEI, Nexamp, NRECA, Public Citizen, Public Interest Organizations, Ratepayers, Sunova, and UCS. Reply comments were due on or before March 23, 2022 and were filed by, among others: DTE, MA AG, NECOS, AGA, EEI, INGA, Joint Consumer Advocates, and WIRES. Since the last Report, Joint RTO Commenters replied to NECOS' discussion and characterization of the Initial Joint RTO Comments and a question of First Amendment constitutional law. This matter is pending before the FERC.

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

On January 20, 2022, the FERC issued a NOPR[100] proposing to direct NERC to develop and submit for FERC approval new or modified Reliability Standards that require internal network security monitoring ("INSM")[101] within a trusted Critical Infrastructure Protection networked environment for high and medium impact Bulk Electric System ("BES") Cyber Systems. The FERC stated that "including INSM requirements in the CIP Reliability Standards would ensure that responsible entities maintain visibility over communications between networked devices within a trust zone (i.e., within an ESP), not simply monitor communications at the network perimeter access point(s), i.e., at the boundary of an ESP as required by the current CIP requirements. In the event of a compromised ESP, improving visibility within a network would increase the probability of early detection of malicious activities and would allow for quicker mitigation and recovery from an attack."[102]

Comments on the *Internal Network Security Monitoring NOPR* were due on or before March 28, 2022.[103] Comments were filed by: the IRC, NERC, EEI, EPSA, TAPS, Bonneville Power Admin., Consumers Energy, Cynalytica, CA Department of Water Resources, Electricity Canada, Entergy, Idaho Power, Juniper Networks, ITC, Microsoft, North American Generator Forum, Nozomi Networks, Operational Technology Cybersecurity Coalition, the US Bureau of Reclamation, and T. Conway. This matter is pending before the FERC.

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

On November 18, 2021, the FERC issued a notice of inquiry[104] seeking comments on reactive power capability compensation and market design. Specifically, the FERC seeks comments on whether (i) the AEP Methodology remains a just and reasonable approach to determining reactive power revenue requirements in all circumstances; (ii) other potential alternative methodologies not based on the costs of the particular resource(s) at issue in a given proceeding should be considered or better used to develop reactive power capability revenue requirements; and (iii) resources interconnected to a distribution system and participating in wholesale markets are technically capable of providing reactive power to the transmission system in such a way that they should be eligible for reactive power capability compensation through transmission rates. Initial comments were due February 21; Reply Comments, March 23, 2022. Initial comments were filed by over 35 parties. Reply comments

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

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

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

[102] *Id.* at P 2.

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

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

were filed by: Ameren, Clean Energy Coalition, DE Shaw, EDF, EEI, EPSA, Joint Customers,[105] MISO TOs, PJM IMM, PSEG, Vistra, and N. Bhushan. This matter is pending before the FERC.

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

Following its ANOPR process,[106] the FERC issued on April 21, 2022 a NOPR[107] that would require public utility transmission providers to:

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

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

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

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

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

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

A number of the elements of the *Transmission NOPR*, if adopted as part of a final rule, would result in some significant changes to how the region's transmission needs are identified, solutions are evaluated and

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

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

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

selected, and costs recovered and allocated. A more fulsome high-level summary from NEPOOL Counsel of the *Transmission NOPR* was distributed to, and will be reviewed with, the Transmission Committee. Comments on the *Transmission NOPR* are due [75 days after the date of publication in the *Federal Register*] and reply comments are due [105 days after the date of publication in the *Federal Register*] (as of the date of this Report, the *Transmission NOPR* has not been published in the *Federal Register*). If you have any questions concerning the *Transmission NOPR*, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

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

On March 18, 2021, the FERC issued a NOI[108] seeking comments on whether to revise its Demand Response ("DR") Opt-Out regulations established in *Orders 719 and 719-A.* Those regulations require an ISO/RTO not to accept bids from an aggregator of retail customers ("ARC") that aggregates DR of the customers of utilities that distributed more than 4 million MWh in the previous fiscal year, where the relevant electric retail regulatory authority prohibits such customers' DR to be bid into ISO/RTO markets by an ARC. The FERC now seek information to help it examine the potential costs/burdens and benefits, both quantitative and qualitative, of removing the DR Opt-Out, as well as other changes relating to DR since the FERC issued *Orders 719 and 719-A*. The FERC is not seeking comment on the Small Utility Opt-In. Comments on the NOI, following an extension, were due on or before July 23, 2021 and were filed by nearly 30 parties, including by AEE, Voltus, AEMA, APPA/NRECA, EEI, and NARUC. Reply comments were due on or before August 23, 2021, and were filed by AEP, Armada Power, Entergy, Southern Pioneer Electric, Voltus, State Commissions from LA/MS, MI, MO, NC, APPA/NRECA, Assoc. of Bus. Advocating Tariff Equity ("ABATE"), and PIOs. On March 28, 2022, the Mississippi Public Service Commission moved to lodge its Protest and Response filed in a recent Complaint proceeding initiated and subsequently withdrawn by Voltus (EL21-12), to ensure its pleading is a part of the record of this proceeding. On March 29, 2022, the U.S. House Sustainable Energy and Environment Coalition ("SEEC") Power Sector Task Force urged the FERC to proceed to a NOPR that would eliminate the demand response Opt-Out. This matter is pending before the FERC.

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

On December 17, 2020, the FERC issued a NOPR[109] 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.,[110] 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[111] 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.

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[108] *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*").

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

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

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

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

On December 16, 2021, the FERC issued its final rule, *Order 881*, on Managing Transmission Line Ratings.[112] In *Order 881*, the FERC reforms both the *pro forma* OATT and its regulations to improve the accuracy and transparency of transmission line ratings. Specifically, *Order 881* requires:

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

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

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

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

Order 881 will become effective March 14, 2022.[113] Requests for rehearing and/or clarification of *Order 881* were filed by ATC, EEI, ITC Holdings, MISO IMM, and the MISO TOs on January 18, 2022, but may be deemed denied by operation of law. On February 18, 2022, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[114] The Notice confirmed that the 60-day period during which a petition for review of *Order 881* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of *Order 881*. The Notice also indicated that the FERC would address, as is its right, the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper."

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

Supplemental NOPR. In light of comments already received in this proceeding,[115] the FERC issued on April 15, 2021 a *Supplemental NOPR*[116] 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*.[117]

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

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

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

[115] 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.

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

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

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

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.[118] Since the last Report, reply comments were posted from New England State Parties,[119] 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[120] to discuss certain performance-based ratemaking approaches, particularly shared savings, that may foster deployment of transmission technologies. The notice states that the workshop will explore: the maturity of the modeling approaches for various transmission technologies; the data needed to study the benefits/costs of such technologies; issues pertaining to access to or confidentiality of this data; the time horizons that should be considered for such studies; and other issues related to verifying forecasted benefits. The workshop also discussed whether and how to account for circumstances in which benefits do not materialize as anticipated and may explore other performance-based ratemaking approaches for transmission technologies seeking incentives under FPA section 219, particularly market-based incentives. The FERC issued an agenda for the workshop, which included the final workshop program and expected speakers, on August 23, 2021. The FERC supplemented that notice on September 9, 2021. On October 13, 2021, the FERC posted a transcript of the workshop in eLibrary.

Notice Inviting Post-Workshop Comments. On October 18, 2021, the FERC issued a notice inviting those interested to file post-workshop comments to address the issues raised during the workshop concerning incentives and shared savings. Comments were due on or before January 14, 2022 and were filed by APPA, CAISO, Clean Energy Parties,[121] EDF Renewables, EEI, the Industrial Energy Consumers of America ("IECA"), National Grid, PJM IMM, TAPS.

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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.

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

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

[120] 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).

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

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

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- ***Constellation New Energy (IN22-4)***

On March 29, 2022, the FERC approved a Stipulation and Consent Agreement with Constellation NewEnergy, Inc. ("CNE")[122] that resolved OE's investigation into whether CNE complied with pertinent California Independent System Operator ("CAISO") tariff provisions regarding the treatment of imports for Resource Adequacy ("RA") purposes.[123] OE determined that, at certain times when it placed bids in the day-ahead market, CNE lacked a sufficiently reasonable basis to expect to secure electricity in the spot market to support its RA imports (during times when the market was constrained), and therefore, as required under the CAISO tariff, could not reasonably expect to be "available and capable of performing at the levels specified" and "comply with operating instructions issued by [] CAISO". Under the Settlement, in which CNE neither admits nor denies the alleged violations, CNE must ***disgorge $2.3 million***,[124] and ***pay a $2.4 million civil penalty*** to the United States Treasury. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- ***Dynegy Marketing & Trade (IN22-3)***

On March 28, 2022, the FERC approved a Stipulation and Consent Agreement with Dynegy Marketing & Trade, LLC ("Dynegy")[125] that resolved OE's investigation into whether (i) Dynegy's Real-Time energy market offers by ten dual-fuel combustion turbines in PJM misrepresented that the units could ramp to their maximum oil-based output attained during their summer capacity tests while running on gas; (ii) Dynegy failed to comply with PJM arrangements that required each unit to be able to change output at the ramping rate specified in the Offer Data; and (iii) Dynegy violated the FERC's Market Behavior Rules, which among other things, require a Seller to provide accurate and factual information and not submit false or misleading information to an RTO, when it maintained a prospective 16 MW capacity increase for one of its dual-fuel facilities based on (a) unit upgrades that were never completed by the previous owner and (b) the use of auxiliary generators, which was prohibited by PJM. OE determined that Dynegy's Real-Time offers misrepresented the ramping rate for the segment of the Real-Time offer curve that could only be reached on oil, that Dynegy submitted false or misleading information to PJM when it (a) made Real-Time Offers that misrepresented that when running on gas, the dual-fuel units could ramp upward to the oil-based ICAP in one minute and (b) allowed the registration of one of its dual-fuel units to continue at 16 more MWs of capacity than the unit could produce during its summer tests, even when running on oil. Under the Settlement, in which Dynegy neither admits nor denies the alleged violations, Dynegy must ***disgorge $119,425***,[126] and ***pay a***

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[122] *Constellation NewEnergy, Inc.*, 178 FERC ¶ 61,231 (Mar. 29, 2022).

[123] OE found that, entering 2017, CNE had in place a business practice whereby it did not source electricity for import before offering into both the CAISO day-ahead and real-time markets. CNE did not have a specific source of power linked to a specific RA import prior to submitting offers and instead intended to rely on the bilateral spot energy market if needed. As a part of this business practice, CNE regularly offered its import capacity into the CAISO day-ahead market at $399/MWh. If those day-ahead offers cleared, CNE would reoffer the import capacity in the real-time market at either $899/MWh or $999/MWh. In June and August 2017, CNE did not meet RA-related dispatches because it was unable to secure electricity in the bilateral spot market. Following those events, CNE chose to cease this business practice. *Id.* at PP 5-6.

[124] CAISO was directed to distribute the disgorgement *pro rata* to network load.

[125] *Dynegy Marketing and Trade, LLC*, 178 FERC ¶ 61,230 (Mar. 28, 2022).

[126] PJM was directed to use its best efforts to allocate the disgorgement funds on a *pro rata* basis to affected market participants.

$450,000 civil penalty to the United States Treasury. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **PacifiCorp (IN21-6)**

On April 15, 2021, in the FERC's first-ever Show Cause Order addressing alleged violations of NERC Reliability Standards,[127] the FERC directed PacifiCorp to show cause why it should not be found to have violated FPA section 215(b)(1) and section 39.2 of the FERC's regulations by failing to comply with Reliability Standard FAC 009-1 (Establish and Communicate Facility Ratings), Requirement R1, and the successor Reliability Standard FAC-008-3 (Facility Ratings), Requirement R6 (collectively, "FAC-009-1 R1"), which requires a transmission owner to establish and have facility ratings that are consistent with its Facility Ratings Methodology ("FRM"). An Enforcement investigation found that clearance measurements on a majority of PacifiCorp's transmission lines were incorrect under the National Electric Safety Code, which were used to calculate PacifiCorp's facility ratings, thus making PacifiCorp's facility ratings inconsistent with its FRM. Enforcement alleges that PacifiCorp was aware of incorrect clearances on its system since at least 2007 when FAC-009-1 R1 became mandatory, but failed to identify and remedy them in a timely manner, and PacifiCorp's violations began on August 31, 2009, when it implemented its FRM policy, and at least some of the violations continued until August 2017 when PacifiCorp completed remediation of all of its incorrect clearances to make them consistent with its FRM. Enforcement also pointed to the role of the violations in the Wood Hollow, Utah wildfire that lasted from June 23 to July 1, 2012. In light of these alleged violations, the FERC directed PacifiCorp to show cause why it should not be assessed civil penalties in the amount of ***$42 million***.

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

Natural Gas-Related Enforcement Actions

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

On January 20, 2022, the FERC issued an order establishing a hearing to determine whether Rover Pipeline, LLC ("Rover") and its parent company Energy Transfer Partners, L.P. ("ETP" and collectively with Rover, "Respondents") violated section 157.5 of the FERC's regulations and to ascertain certain facts relevant for any application of the FERC's Penalty Guidelines.[128]

As previously reported, on March 18, 2021, the FERC issued a show cause order[129] in which it directed Rover Pipeline, LLC ("Rover") and Energy Transfer Partners, L.P. ("ETP" and together with Rover, "Respondents") to show cause why they should not be found to have violated Section 157.5 of the FERC's regulations by misleading the FERC in its Application for Certificate of Public Convenience and Necessity ("CPCN") under NGA section 7(c).[130] The FERC directed Respondents to show cause why they should not be assessed civil penalties in

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

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

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

[130] Specifically, Rover stated that it was "committed to a solution that results in no adverse effects" to the Stoneman House, an 1843 farmstead located near Rover's largest proposed compressor station. In truth, the OE Staff Report alleges, Rover was simultaneously planning to purchase the house with the intent to demolish it, if necessary, to complete its pipeline. The OE Staff Report alleges that Rover purchased the house in May 2015 and demolished the house in May 2016. The OE Staff Report further finds that despite taking these actions during the year and a half that Rover's application was pending before the FERC, Rover did not notify the FERC that it purchased the Stoneman House, intended to destroy the Stoneman House, and did destroy the Stoneman House. The OE Staff Report therefore concludes that Rover violated section 157.5's requirement for full, complete and forthright applications, through its misrepresentations and omissions,

the amount of ***$20.16 million***. On April 5, 2021, the FERC extended by 60 days, to June 18, 2021, the deadline for Respondents' answer. On June 18, 2021, Rover and ETP answered the *Rover/ETP Show CPCN Cause Order*, asserting that the FERC should dismiss this matter and decline to initiate an enforcement action. On July 21, 2021, Enforcement Staff answered Rover/ETP's answer, stating the evidence supports a finding that Rover violated the FERC's Regulations and should be assessed the civil penalty identified in the *Rover/ETP Show Cause Order*. Rover answered the July 21 answer on September 15.

Hearings. As previously reported, ALJ Joel DeJesus will be the presiding judge for hearings in this matter. On March 8, 2022, Chief Judge Cintron issued an order extending the procedural time standards for this proceeding. Based on that order, the deadlines for the commencement of the hearing is now March 6, 2023 and the deadline to issue the initial decision is now June 20, 2023. A virtual prehearing conference was also held on March 8, a transcript of which is posted in eLibrary.

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

On December 16, 2021, the FERC issued a show cause order[131] in which it directed Rover and ETP (together, "Respondents") to show cause why they should not be found to have violated NGA section 7(e), FERC Regulations (18 C.F.R. § 157.20); and the FERC's Certificate Order,[132] by: (i) intentionally including diesel fuel and other toxic substances and unapproved additives in the drilling mud during its horizontal directional drilling ("HDD") operations under the Tuscarawas River in Stark County, Ohio, in connection with the Rover Pipeline Project;[133] (ii) failing to adequately monitor the right-of-way at the site of the Tuscarawas River HDD operation; and (iii) improperly disposing of inadvertently released drilling mud that was contaminated with diesel fuel and hydraulic oil. The FERC directed Respondents to show why they should not be assessed civil penalties in the amount of ***$40 million***. Following a request from Respondents, the answer period was extended to and including March 21, 2022.

On March 21, 2022, Respondents answered and denied the allegations in the *Rover/ETP CPCN Show Cause Order*. On April 20, 2022, OE Staff answered Respondents' March 21 answer. This matter is pending before the FERC.

- **BP (IN13-15)**

On December 17, 2020, the FERC issued *Opinion 549-A*,[134] a 159-page decision addressing arguments raised on rehearing requested of *Opinion 549.*[135] *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

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when it decided not to tell FERC that it had purchased the house and was considering demolishing it, and when Rover demolished it in May 2016 without notifying FERC.

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

[132] *Rover Pipeline LLC,* 158 FERC ¶ 61,109 (2017), *order on clarification & reh'g*, 161 FERC ¶ 61,244 (2017), *Petition for Rev.*, *Rover Pipeline LLC v. FERC*, No. 18-1032 (D.C. Cir. Jan. 29, 2018) ("Certificate or Certificate Order").

[133] The Rover Pipeline Project is an approximately 711 mile long interstate natural gas pipeline designed to transport gas from the Marcellus and Utica shale supply areas through West Virginia, Pennsylvania, Ohio, and Michigan to outlets in the Midwest and elsewhere.

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

[135] *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*")).

waived any statute of limitations defense by failing to raise it earlier in this proceeding.[136] 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.[137]

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[138] 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.[139]

The FERC also directed TGPNA to show cause why it should not be required to disgorge unjust profits of ***$9.18 million***, plus interest; TGPNA, Tran and Hall to show cause why they should not be assessed civil penalties (TGPNA - ***$213.6 million***; Hall - ***$1 million*** (jointly and severally with TGPNA); and Tran - ***$2 million*** (jointly and severally with TGPNA)). In addition, the FERC directed TGPNA's parent company, Total, S.A. ("Total"), and TGPNA's affiliate, Total Gas & Power, Ltd. ("TGPL"), to show cause why they should not be held liable for TGPNA's, Hall's, and Tran's conduct, and be held jointly and severally liable for their disgorgement and civil penalties based on Total's and TGPL's significant control and authority over TGPNA's daily operations. Respondents filed their answer on July 12, 2016. OE Staff replied to Respondents' answer on September 23, 2016. Respondents answered OE's September 23 answer on January 17, 2017, and OE Staff responded to that answer on January 27, 2017.

Hearing Procedures. On July 15, 2021, the FERC issued and order establishing hearing procedures to determine whether Respondents violated the FERC's Anti-Manipulation Rule, and to ascertain certain facts relevant for any application of the FERC's Penalty Guidelines.[140] On July 27, Chief Judge Cintron designated Judge Suzanne Krolikowski as the Presiding ALJ and established an extended Track III Schedule[141] for the proceeding. Judge Krolikowski scheduled and convened on August 26, 2021 a prehearing conference. Judge Krolikowski issued an order confirming her rulings from the August 26 prehearing conference and establishing a procedural schedule that calls for, among other dates, pre-hearing briefs by July 25, 2022, hearings (estimated to take 2-3 weeks) to

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

[137] *Id*. at P 319.

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

[139] 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.

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

[141] 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.

begin on August 15, 2022, and an initial decision on January 9, 2023. In light of the settlement judge procedures undertaken, Chief Judge Cintron extended the hearing commencement and initial decision deadlines to September 26, 2022, and February 20, 2023, respectively.

Since the last Report, Respondents requested reconsideration or in the alternative permission to file an interlocutory appeal of Judge Krolikowski's March 24 order confirming his bench rulings ("Reconsideration Motion"). OE Staff opposed the Motion. On April 25, finding Respondents had not raised any new arguments that would merit reconsideration of his prior rulings, nor had Respondents identified any "exceptional circumstances" requiring interlocutory appeal, Judge Krolikowski denied Respondents' Reconsideration Motion. Litigation over subpoena requests and the rights of certain individuals to intervene as parties to this proceeding continued. A prehearing conference scheduled for April 28 was cancelled and rescheduled to May 4, 2022.

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 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.
  - On November 12, 2021, FERC staff issued the final EIS for the Project, which responds to comments that were received on the September 30, 2020 Environmental Assessment and June 11, 2021 draft EIS and discloses downstream GHG emissions for the Project. "With the exception of climate change impacts, FERC staff concluded that approval of the proposed Project, with the mitigation measures recommended in this EIS, would not result in significant environmental impacts."

- Iroquois, ConEd and National Grid answered/replied to the December 20, 2021 comments on the final EIS by the U.S. Environmental Protection Agency ("EPA").
- On March 25, 2022, the FERC issued to Iroquois a certificate of public convenience and necessity, authorizing it to construct and operate the proposed facilities.[142] The certificate was conditioned on: (i) Iroquois' completion of construction of the proposed facilities and making them available for service within ***three years*** of the date of the; (ii) Iroquois' compliance with all applicable FERC regulations under the NGA; (iii) Iroquois' compliance with the environmental conditions listed in the appendix to the order; and (iv) Iroquois' filing written statements affirming that it has executed firm service agreements for volumes and service terms equivalent to those in its precedent agreements, prior to commencing construction. The March 25, 2022 order also approved, as modified, Iroquois' proposed incremental recourse rate and incremental fuel retention percentages as the initial rates for transportation on the Enhancement by Compression Project.
- Since the last Report, on April 18, 2022, Iroquois accepted the certificate issued in the *Iroquois Certificate Order* and the NYU Institute for Policy Integrity submitted comments to underscore the FERC's obligation to independently review and scrutinize lifecycle greenhouse gas ("GHG") emission reports submitted by certificate applicants, and to highlight flaws in Iroquois' analysis.

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.[143] 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*.[144] 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,[145] 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.[146] The Allegheny Defense

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

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

[144] *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).

[145] 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).

[146] *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*").

Project and Sierra Club (collectively, "Allegheny") requested rehearing of the *Northern Access Certificate Order*.

- Despite the FERC's *Northern Access Certificate Order*, the project remained halted pending the outcome of National Fuel's fight with the NY DEC's April denial of a Clean Water Act permit. NY DEC found National Fuel's application for a water quality certification under Section 401 of the Clean Water Act, as well as for stream and wetlands disturbance permits, failed to comply with water regulations aimed at protecting wetlands and wildlife and that the pipeline failed to explore construction alternatives. National Fuel appealed the NY DEC's decision to the 2nd Circuit on the grounds that the denial was improper.[147] 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,[148] 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.[149]
- 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, [150] 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.[151]
- On January 28, 2022, Applicants again requested an additional extension of time, this time until December 31, 2024, to complete construction of the Project and enter service. Comments on that request were due on or before February 16, 2022. Many individual comments and protests were received. The NY DEC filed comments opposing the extension request. On March 7, 2022, National Fuel answered the NY DEC protest. This matter is pending before the FERC.

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

[148] 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).

[149] *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).

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

[151] *Id.* at P 10.

XV. State Proceedings & Federal Legislative Proceedings

- **New England States' Vision Statement**

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

Jan 13, 2021	Wholesale Market Reform
Jan 25, 2021	Wholesale Market Reform
Feb 2, 2021	Transmission Planning
Feb 25, 2021	Governance Reform
Mar 18, 2021	Equity and Environmental Justice

Written comments on the topics and discussions addressed in the on the equity and environmental justice topics and discussions were, following an extension, due by May 13, 2021. Comments submitted are posted on **NewEnglandEnergyVision.com**. Recordings of the technical forums, as well as draft notices, agendas, and additional information on these sessions, are also available on the New England States' Vision Statement website (https://newenglandenergyvision.com/).

Report to the Governors. On June 29, 2021, the NESCOE Managers published their Progress Report to the New England Governors Regarding "Advancing the New England Energy Vision". The Report was further discussed at the August 5, 2021 Participants Committee meeting. View Report here.

ISO-NE Board Response. On September 23, 2021, the ISO-NE Board responded to the New England States' Vision Statement and Advancing the Vision Report. A copy of that response was included with the materials for the October 7, 2021 Participants Committee meeting and is posted on the ISO-NE website here.

XVI. Federal Courts

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

- **NTE CT Petition for Review of *Killingly CSO Termination Orders* (22-1027)**
  Underlying FERC Proceeding: ER22-355[152]
  Petitioner: NTE CT
  Status: Briefing Schedule Established; Motion to Dismiss Pending

On February 23, 2022, NTE CT petitioned the DC Circuit for review of the FERC's orders accepting the termination of the Killingly Energy Center's CSO. On March 28, 2022, NTE CT filed a Docketing Statement,

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[152] *ISO New England Inc.*, 178 FERC ¶ 61,001 (Jan. 3, 2022) ("*Killingly CSO Termination Order*") (order accepting CSO termination); *ISO New England Inc.*, 178 FERC ¶ 62,082 (Feb. 11, 2022) (notice denying *reh'g by operation of law and providing for further consideration)*; *ISO New England Inc.*, 178 FERC ¶ 61,130 (Feb. 23, 2022) (order addressing arguments raised on reh'g, sustaining results of *Killingly CSO Termination Order*). Together, these orders referred to as the "*Killingly CSO Termination Orders*".

Statement of Issues, the underlying decisions from which the appeal arises, a proposed briefing schedule, and a request that the Court set oral argument for or before October 2022. On March 30, 2022, the Court granted ISO-NE's and NEPGA's interventions. A Certified Index to the Record was filed by April 11, 2022. On April 4, 2022, the Court established the following briefing schedule (all dates in 2022): May 11 (Petitioner's Brief); July 8 (Respondent's Brief); July 22 (Intervenor for Respondent's Brief(s)); August 5 (Petitioner's Reply Brief); August 12 (Deferred Appendix); and August 17 (Final Briefs).

Since the last Report, ISO-NE moved to dismiss this case. ISO-NE's motion to dismiss was supported by the FERC and opposed by NTE. ISO-NE answered NTE's response on April 22, 2022. ISO-NE's motion to dismiss is pending.

- **CSC Request for Regulatory Asset Recovery of Previously-Incurred CIP IROL Costs (21-1275)**
  Underlying FERC Proceeding: ER21-2334[153]
  Petitioner: CSC
  Status: Motions to Govern Proceedings Due On or Before May 27, 2022

On December 30, 2021, CSC petitioned the DC Circuit Court of Appeals for review of the FERC's orders denying it authorization to establish a regulatory asset that would include all CIP-IROL Costs prudently incurred between January 1, 2016 and May 31, 2021 and to recover those costs under Schedule 17 over a five-year period. Appearances are due February 2, 2022. CSC must file a Docketing Statement, Statement of Issues, any Procedural Motions, and the underlying decision from which the appeal arises by February 2, 2022. Dispositive motions, if any, and a Certified Index to the Record must be filed by February 17, 2022.

NESCOE intervened on January 28, 2022. On February 2, 2022, CSC filed a docketing statement and statement of issues. Also on February 2, the FERC asked that the Court hold the petition for review in abeyance, including suspending the initial filing schedule, until the Commission issues an order addressing Petitioner's request for rehearing. On February 16, 2021, the FERC granted the FERC's motion to hold the petition in abeyance, directing (i) the FERC to file status reports at 30-day intervals (with the first such report due March 18, 2022) and (ii) the parties to file motions to govern future proceedings within 30 days of the completion of FERC's proceedings. Since the last Report, the FERC filed the second of its 30-day status reports on April 18, 2022. On April 20, CSC amended its petition to include the February 24, 2022 *CSC CIP-IROL Costs Allegheny Order*. Given the FERC's April 27, 2022 order rejecting CSC's March 28 request for rehearing of the *Allegheny Order*, which completed the FERC's proceedings on rehearing, the parties must file motions to govern these proceeding on or before May 27, 2022.

- **Mystic ROE (21-1198; 21-1222, 21-1223, 21-1224, 22-1001, 22-1008, 22-1026) (consolidated)**
  Underlying FERC Proceeding: EL18-1639-010, -011,[154] **-013**[155]
  Petitioners: Mystic, CT Parties,[156] **MA AG, ENECOS**
  Status: Filing of Initial Submissions Underway

As previously reported, this case was initiated when, on October 8, 2021, Mystic petitioned the DC Circuit Court of Appeals for review of the FERC's orders setting the base ROE for the Mystic COS Agreement at 9.33%. The *Mystic ROE Order* and subsequent FERC orders addressing the Mystic ROE issues have all also been appealed

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

[154] *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).

[155] *Constellation Mystic Power, LLC,* 178 FERC ¶ 61,116 (Feb. 18, 2022) ("*Mystic ROE Second Allegheny Order*"); *Constellation Mystic Power, LLC,* 178 FERC ¶ 62,028 (Jan. 18, 2022) ("*January 18 Notice*") (Notice of Denial By Operation of Law of Rehearings of Mystic ROE Second Allegheny Order).

[156] In this appeal, "CT Parties" are the Connecticut Public Utilities Regulatory Authority ("CT PURA"), Connecticut Department of Energy and Environmental Protection ("CT DEEP"), and the Connecticut Office of Consumer Counsel ("CT OCC").

by various parties and consolidated under 21-1198. Docketing Statements and Statements of Issues to be Raised, and the Underlying Decision from which the various appeals arise have been filed as new dockets have been opened and then consolidated with 21-1198. As previously reported, the Certified Index to the Record was due, and filed by the FERC, on February 22, 2022. On March 10, 2022, MMWEC and NHEC filed a notice of intent to participate in support of FERC in Case Nos. 21-1198, 22-1008, and 22-1026 and in support of Petitioners in the remaining consolidated cases, and filed a statement of issues. On March 17, 2022, CT Parties moved to intervene. On March 31, 2022, the parties filed a proposed briefing format and schedule. There was no activity in this proceeding since the last Report.

- **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[157]
  Petitioners: Mystic (20-1343), NESCOE (20-1361, 21-1067), MA AG (20-1362), CT Parties (20-1365, 20-1368, 21-1070)
  Status: Briefing Complete; Oral Argument May 5, 2022

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.[158] The cases have been consolidated into Case No. 20-1343. On February 17 and 24, 2021, the Court consolidated with 20-1343 the most recent appeals in cases 21-1067 (NESCOE) and 21-1070 (CT Parties), respectively. On March 25, 2021, the Court issued an order returning this case to its active docket. On March 26, 2021, the Court granted the interventions by MMWEC/NHEC, NESCOE, and ENECOS. Briefing was completed on February 24, 2022. Oral argument is scheduled for ***May 5, 2022*** and will be heard by Judges Srinivasan, Henderson and Rao.

- ***CASPR*** **(20-1333, 21-1031) (consolidated)****
  Underlying FERC Proceeding: ER18-619[159]
  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, 2021, CT Parties and MMWEC and NHEC filed statements of issues and notices that they intend to participate in support of Petitioners. On January 27, 2021, the Court ordered the parties to submit by February 26, 2021, proposed formats for the briefing of these

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

[158] 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.

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

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[160]
  Petitioners: TOs' (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[161] 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*[162] decision. On September 22, 2020, the FERC submitted an unopposed motion to hold this proceeding in abeyance for four months to allow for the Commission to "a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the Commission." On October 2, 2020, the Court granted the FERC's motion, and directed the parties to file motions to govern future proceedings in this case by February 2, 2021. On January 25, 2021, the FERC requested that the Court continue to hold this petition for review in abeyance for an additional three months, with parties to file motions to govern future proceedings at the end of that period. The FERC requested continued abeyance because of its intention to issue a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the FERC. Petitioners consented to the requested abeyance. On February 11, 2021, the Court issued an order that that this case remain in abeyance pending further order of the court. On April 21, 2021, the FERC filed an unopposed motion for continued abeyance of this case *because* the Commission intends to issue a future order on Petitioners' request for rehearing of the challenged Order Rejecting Compliance Filing, and because the remand proceeding in which the challenged order was issued remains ongoing.

On May 4, 2021, the Court ordered that this case remain in abeyance pending further order of the Court, directing the FERC to file a status report by September 1, 2021 and at 120-day intervals thereafter. The parties were directed to file motions to govern future proceedings in this case within 30 days of the completion of agency proceedings. Since the last Report, on April 14, 2022, 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.

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

[161] 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.

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

- **ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224***; 19-1247; 19-1252; 19-1253)(consolidated); Underlying FERC Proceeding: ER19-1428**[163]
  Petitioners: ENECOS (Belmont et al.) (19-1224); MA AG (19-1247); NH PUC/NH OCA (19-1252); Sierra Club/UCS (19-1253)
  Status: Oral Argument Held Oct 21, 2021; Awaiting Decision

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. Following completion of briefing, oral argument was held October 21, 2021 before Judges Wilkins, Katsas and Jackson. This matter is pending before the Court

Other Federal Court Activity of Interest

- ***Order 872* (20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[164]
  Petitioners: SEIA et al.
  Status: Oral Argument Held March 8, 2022; Awaiting Decision

On September 17, 2020, SEIA petitioned the 9th Circuit Court of Appeals for review of *Order 872*.[165] Briefing is complete and oral argument was held March 8, 2022 before Judges Nguyen, Miller and Bumatay. This matter is pending before the Court.

- **Opinion 569/569-A: FERC's Base ROE Methodology (16-1325, 20-1182, 20-1240, 20-1241, 20-1248, 20-1251, 20-1267, 20-1513) (consol.)**
  Underlying FERC Proceeding: EL14-12; EL15-45[166]
  Petitioners: MISO TOs, Transource Energy, Dec 23 Petitioners et al.
  Status: Oral Argument Held Nov 18, 2021; Awaiting Decision

The MISO TOs, Transource and "Dec 23 Petitioners",[167] among others, have appealed *Opinion 569/569-A*. The MISO TOs' case has been consolidated with previous appeals that had been held in abeyance, with the lead case number assigned as 16-1325. Following completion of briefing, oral argument was held on November 18, 2021 before Judges Srinivasan, Katsas and Walker. This matter is pending before the Court.

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[163] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

[164] *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).

[165] *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.

[166] *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).

[167] "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.

- **Algonquin Atlantic Bridge Project Briefing Order (21-1115*, 21-1138, 21-1153, 21-1155) (consol.); Underlying FERC Proceeding: CP16-9-012[168]**
  Petitioners: LS Power, Algonquin, INGA
  Status: Case Being Held in Abeyance; Motions to Govern Future Proceedings Due May 31, 2022

On May 3, 2021, Algonquin petitioned the DC Circuit Court of Appeals for review of the *Briefing Order* and the *April 19 Notice of Denial of Rehearings by Operation of Law*. Appearances, docketing statements and a statement of issues were due and filed June 4, 2021. Also on June 4, 2021, the FERC filed an unopposed motion to hold this proceeding in temporary abeyance, until August 2, 2021, including the fling of the certified index to the record, because "the May 3 petition for review no longer reflects the [FERC]'s latest determination in this matter." The Court granted the first abeyance motion. On November 15, 2021, the Court granted a third abeyance motion by the FERC, directing the parties to file motions to govern future proceedings by January 31, 2022. On January 31, 2022, Algonquin and INGA asked the Court to extend the abeyance by an additional 120 days (to May 31, 2022). On February 15, 2022, the Court issued an order extending the abeyance and directing the Petitioners to file motions to govern future proceedings by May 31, 2022.

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

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