NEPOOL
NEW ENGLAND POWER POOL
Sebastian M. Lombardi
Secretary

April 27, 2023

**VIA ELECTRONIC MAIL**

**TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES**

**RE:** Supplemental Notice of May 4, 2023 NEPOOL Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, initial notice is hereby given that the May meeting of the Participants Committee will be held **in person on Thursday, May 4, 2023, at 10:00 a.m. at the Colonnade Hotel, 120 Huntington Avenue, Boston, MA in the Huntington 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 4 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 4 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 to also log in to WebEx using this link and entering the event password **nepool.** For those eligible and planning to participate virtually in the executive session, separate dial-in information will be provided in the confidential package of materials for that session.

The NEPOOL reservations block at The Colonnade is now closed. If you are still in need of a room, please contact Jaki Sloan (jsloan@daypitney.com) who may be able to assist getting you into The Colonnade or an alternative venue if possible.

***2023 NPC Summer Meeting***. The Participants Committee Summer Meeting will be ***June 27-29, 2023*** (with an opening coffee & dessert reception Monday evening, June 26) at ***The Equinox***, 3567 Main Street, Manchester Village, VT (https://www.equinoxresort.com/). Rooms are going quickly (more than 70 persons have registered so far), so we strongly encourage you to register as soon as you are able. You can make your Equinox room reservation(s) through the Equinox Resort Room Booking Link, via the NEPOOL 2023 Summer Meeting webpage, or by contacting the Equinox (802-362-4700) and identifying yourself as part of NEPOOL. The NEPOOL group discounted room rate is ***$199*** per room, per night (single/double occupancy). The negotiated rate is only available through ***June 5***, after which rooms will only be available on a first-come, first-served basis at the Equinox's rate available at that time. We ask that members register for the meeting, including an indication of which meals/events you plan to attend and the number of family members you expect to join you, by completing the meeting registration available on the NEPOOL Summer Meeting website. We will continue to provide and post on that webpage additional information related to the Summer Meeting as it becomes available.

Respectfully yours,

/s/

Sebastian M. Lombardi, 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 6, 2023 Participants Committee meeting. A copy of the draft minutes, marked to show the changes made since the version circulated with the initial notice, is included with this supplemental notice and posted with the meeting materials.

3. To adopt and approve the actions recommended by the Reliability Committee set forth on the Consent Agenda included with this supplemental notice and posted with the meeting materials.

4. To receive an ISO Chief Executive Officer (CEO) 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 (COO) on the following:

    a. *April 2023 Operations Highlights*. The monthly Operations Report will be circulated and posted in advance of the meeting.

    b. *Winter 2022-23 Operations Report*. Materials for this 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 Market Rule changes proposed in response to the 60-day requirements of the FERC's March 1, 2023 *Order 2222 Compliance Order*. Background materials and a draft resolution are included and posted with this supplemental notice.

7. To consider and take action, as appropriate, on Tariff changes proposed by LS Power to clarify that FCM Repowering Projects are able to unwind their incremental obligations. Background materials and a draft resolution are included and posted with this supplemental notice.

8. 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.

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

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

10. Administrative matters.

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

# M E M O R A N D U M

**TO:** NEPOOL Participants Committee Members and Alternates

**FROM:** Sebastian Lombardi and Pat Gerity, NEPOOL Counsel and Balloting Agent

**DATE:** April 27, 2023

**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 4, 2023 Participants Committee (NPC) meeting to consider endorsing a three-person slate of candidates for the ISO Board recommended by the Joint Nominating Committee (JNC). The slate was identified in a confidential package circulated 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 Phil Bartlett, Maine Public Utilities Commission Chairman. Mr. Roberto Denis chaired the JNC. The confidential package circulated to Members and Alternates includes a transmittal memorandum from Mr. Denis 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 4, 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 of the vote either as "passed" or "failed" before the conclusion of the May 4 meeting, based on completed ballots received. ***Out of respect for the rights of the ISO Board nominees, all Participant representatives are requested to keep the identities of the nominees 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).***

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.

## PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held via teleconference/webex on Thursday, April 6, 2023, at 10:00 a.m. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates, and temporary alternates who participated in the meeting.

Mr. David Cavanaugh, Chair, presided, and Mr. Sebastian Lombardi, Secretary, recorded. Mr. Cavanaugh welcomed the members, alternates and guests who were present.

## APPROVAL OF MARCH 2, 2023 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the March 2, 2023 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of that meeting were unanimously approved as circulated, with an abstention by Mr. Sam Mintz noted.

## CONSENT AGENDA

Mr. Cavanaugh then referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved as circulated, with an abstention by Mr. Mintz noted.

## ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summary of the ISO Board and Board Committee meetings that had occurred since the

March 2, 2023 Participants Committee meeting, which had been circulated and posted with the materials for the meeting. There were no questions on those summaries.

## ISO COO REPORT

### *Operations Highlights Report*

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by referring the Committee to his April operations report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through March 29, 2023, unless otherwise noted. The report highlighted: (i) Energy Market value for March 2023 was $367 million, down $382 million from the updated February 2023 value and down $355 million from March 2022; (ii) March 2023 average natural gas prices were 63% lower than February average prices; (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for March ($31.21/MWh) were 52% lower than February averages; (iv) average March 2023 natural gas prices and Real-Time Hub LMPs over the period were down 55% and 53%, respectively, from March 2022 average prices; (v) average Day-Ahead cleared physical energy during the peak hours as percent of forecasted load was 101% during March (up from 99.6% reported for February), with the minimum value for the month of 95.4% on Friday, March 24; (vi) Daily Net Commitment Period Compensation (NCPC) payments for March totaled $1.3 million, which was down $2 million from February 2023 and down $2.8 million from March 2022. March NCPC payments, which were 0.4% of total Energy Market value, were compromised of (a) $1.3 million in first contingency payments (down $1.7 million from February); and (b) $89,000 in second contingency payments (down $289,000 from February) (there were no voltage or distribution payments in March).

Regarding near-term scheduled transmission outages, Dr. Chadalavada reported that the outages were principally affecting the New York side of the New York-to-New England interface. An outage on the New York-to-Alps-to-New Scotland 345 kV line, which had begun on March 3, 2023, was expected to continue until approximately April 24, limiting the New England-to-New York (NY-NE) interface (accounting for thermal violations) to 500 MW. A member noted that, among the work being completed during that outage~~,~~ was the addition of a phase angle regulator (PAR) and asked Dr. Chadalavada at a future meeting to identify what impact, if any, the addition of the PAR might have on future interface transfer limits. Dr. Chadalavada also identified work scheduled for a few days on the Frost Bridge-to-Long Mountain line. He encouraged those interested in NY-NE interface to closely monitor its status, which could change further based on intraday activity. There were no other major planned outages for April to note.

Addressing behind-the-meter (BTM) photovoltaic (PV) forecasting, Dr. Chadalavada reported that, in March, there were eight days where BTM PV forecasts underestimated early to mid-afternoon output by more than 1,000 MW (resulting during those times in generation over-commitment). He observed that above-average precipitation during March created BTM PV forecast challenges. In addition, the ISO had identified a slight bias in vendor software that resulted in under-forecasting BTM PV output. He stated that the ISO was working with vendors to abate the bias, through short-term fixes and mid- to longer-term modeling improvements. Finally, Dr. Chadalavada emphasized the importance of addressing the BTM PV forecasting issues, given the pace of installations and the critical role BTM PV forecasts play in the overall clearing of the markets. In response to a request, Dr. Chadalavada committed to consider whether additional information related to the shape/scope of BTM PV forecasting error(s) could be added to the monthly market reports.

Turning to the Mystic Cost-of-Service Agreement (Mystic COS Agreement), and expressing dissatisfaction with the overall costs and impact of the Agreement to the region, a member asked the ISO to consider publishing in a more timely, formal way, the monthly cost data for the COS Agreement (accelerating the time data otherwise becomes available through the monthly market and billing reports). Dr. Chadalavada committed to consider the request and come back to the Committee with a response. He added that recent drivers for COS Agreement-related costs would be discussed during his May Committee report on Winter 2022/23 operations, and emphasized that the ISO understood and was mindful of the concerns expressed with the cost and market impacts of the Agreement.

**2023 ANNUAL WORK PLAN UPDATE**

Next, Dr. Chadalavada referred the Committee to the 2023 annual work plan (AWP) update, which had been circulated and posted in advance of the meeting. He reported that the 2023 anchor projects (Resource Capacity Accreditation (RCA), Day-Ahead Ancillary Services Initiative (DASI), nGem Market Clearing Engine, and the 2050 Transmission Study) were all proceeding according to schedule. He highlighted that other notable initiatives, including those that were NEPOOL priorities for 2023 (e.g. FCM Retirement Reforms and the Capacity Network Resource Interconnection Service Time-Out Removal), were also on schedule (or had completed the stakeholder process). He projected that the ISO's analysis of a prompt seasonal market design would likely be completed by Thanksgiving, with discussions amongst the ISO and stakeholders to follow shortly thereafter. He also reviewed in some detail the proposed plans, deliverables, and timeframes for addressing Energy adequacy through the end of the third quarter of 2023. Dr. Chadalavada noted that requests related to the ISO's 2024 work plan would be considered through the NEPOOL business priority-setting process that was underway.

In response to questions and comments, Dr. Chadalavada explained that the implementation of nGem market clearing engine was principally a behind-the-scenes project, and was not expected to materially impact how Market Participants~~'~~ interface with the ISO's market system or how information is shared.

With respect to the broader topic of Energy adequacy, Dr. Chadalavada confirmed that the ISO would not retain the Mystic generating units beyond June 1, 2024, but reiterated the ISO's views on the importance of retaining Everett as an LNG import facility (an outcome/solution space, as previously expressed to the Committee, that the ISO had~~s~~ concluded would be outside of its control or jurisdictional authority). He stated that the ISO, informed by the results of the probabilistic energy adequacy study (Energy Adequacy Study) undertaken with the Electric Power Research Institute (EPRI), intended to identify a problem statement by September 2023, with the process to consider that problem statement to be established in the near future. Members expressed preliminary thoughts on this area and encouraged further discussion and collaboration in advance of the FERC's Second New England Winter Gas-Electric Forum. An overall eagerness to engage with the ISO on the development/refinement of the problem statement and to begin the solution study process was also expressed, including an appeal from some members for the region to prioritize consideration of potential market-based solutions.

## LITIGATION REPORT

Mr. Lombardi referred the Committee to the April 5, 2023 Litigation Report that had been circulated and posted before the meeting. He highlighted the following developments:

(i) *Participants Agreement Amendment No. 12 (ISO Board Member Age Limit Increase) (ER23-980)*. The FERC had accepted a change to the Participants Agreement (§ 9.2.3(a)) jointly filed by NEPOOL and the ISO that raises the age limitation prohibiting the election or re-election of any candidate to the ISO Board of Directors from 70 to 75;

(ii) *FCA17 Results Filing (ER23-1435).* The ISO filed the results of the seventeenth Forward Capacity Auction (FCA17) with the FERC a few weeks earlier, with any comments due on or before May 5, 2023;

(iii) *New England's Order 2222 Compliance Filing (ER22-983)*. Following the FERC's March 1 order accepting in part, and rejecting in part, the ISO's compliance filing (*Order 2222 Compliance Order*), NEPOOL had requested an 8-day extension of time, to May 9, 2023, of the 60-day compliance filing deadline, to provide stakeholders an opportunity to fully review and consider proposed Tariff revisions ahead of their submission to the FERC, particularly at the May 4 Participants Committee meeting. That request was pending before the FERC. In addition, the ISO and certain transmission owners had requested rehearing and/or clarification of the *Order 2222 Compliance Order*; and

(iv) *Mystic COS Agreement (ER18-1639)*. Mystic had, in mid-March, filed a Settlement Agreement to resolve the challenges to its first informational filing on capital expenditures and related costs. Mystic had been authorized on an interim basis to implement settlement rates consistent with the Settlement Agreement and certain COS Agreement true-up deadlines had been waived to permit time for implementation of the terms of the Settlement Agreement. Separately, the FERC issued its *Order on Remand* concerning Everett-related cost allocation and claw back provision issues with the COS Agreement. He encouraged those interested to review the information summarized in the Litigation Report and to reach out to NEPOOL Counsel with any questions.

## COMMITTEE REPORTS

***Markets Committee (MC).*** Ms. Mariah Winkler, MC Chair, reported that there would be two MC meetings in April. The first, scheduled for three days (April 11-13, 2023) in Westborough, MA, would be to discuss RCA, DASI, *Order 2222* 60-day compliance items, and a proposal by LS Power to clarify that FCM Repowering Projects are able to unwind their incremental Forward Capacity Market obligations. The second meeting, to be held virtually on April 25, 2023, would be to take action on both the *Order 2222* 60-day compliance items and the LS Power proposal.

***Reliability Committee (RC).*** Mr. Robert Stein, the RC Vice-Chair, reported that the RC would next meet over two days (April 18-19, 2023), and would consider~~include~~, in addition to the RC's regular business items, ~~discussion on~~ RCA-related items, the 21-day energy assessment to be used in connection with the Energy Adequacy Study, and the final draft values for the long-term energy and demand forecasts to be published in the 2023 Capacity, Energy, Loads, and Transmission (CELT) report.

***Transmission Committee (TC).*** Mr. David Burnham, TC Vice-Chair, reported that the April meeting of the TC had been canceled, and called members' attention to the registration for the July RC/TC summer meeting, which had opened the day before.

***Budget and Finance Subcommittee (B&F).*** Mr. Tom Kaslow, the B&F Subcommittee Chair, reported that the B&F Subcommittee would have a call on April 26, 2023. While the agenda had not yet been finalized, he expected continued discussion on financial assurance changes associated with the RCA project.

***Membership Subcommittee.*** Ms. Sarah Bresolin, Membership Subcommittee Chair, reported that the next Membership Subcommittee meeting was scheduled for April 14, 2023.

***Joint Nominating Committee (JNC)***. Mr. Cavanaugh reported that the JNC had completed its interviews of candidates for the position to be opened when Mr. Roberto Denis completes his term at the end of September. He said that JNC Sector representatives would reach out to their respective members and alternates with information on a proposed candidate for that position and the slate generally, and he encouraged members to provide any relevant feedback on the proposed candidate directly to their respective JNC representative. Following the completion of an ongoing background check of the proposed candidate, the JNC-recommended slate would be presented confidentially to the Committee at the May 4 meeting for discussion in executive session and a vote by confidential written ballot.

## ADMINISTRATIVE MATTERS

Mr. Cavanaugh highlighted that registration for the Participants Committee Summer Meeting at the Equinox in Manchester Village, Vermont was open. He encouraged members to register promptly and to attend. On behalf of NECPUC, Mr. George Twigg, Executive Director, referred members to the preliminary program for NECPUC's May 22-24 Symposium in Stowe, Vermont, which had been widely circulated and posted on the NECPUC website. Mr. Twigg encouraged all those interested to register (via the NECPUC website) and attend.

Mr. Lombardi informed members that the May 4 meeting of the Participants Committee meeting would be held in person at the Colonnade Hotel in Boston, MA.  Further details on the meeting and room block information would be circulated in advance of the meeting.

There being no other business, the meeting adjourned at 11:13 a.m.

Respectfully submitted,

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Sebastian Lombardi, Secretary

## PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN APRIL 6, 2023 TELECONFERENCE MEETING

| PARTICIPANT NAME | SECTOR/ GROUP | MEMBER NAME | ALTERNATE NAME | PROXY |
|---|---|---|---|---|
| Agilitas Companies | AR-DG | Jeff Perry | | |
| Ashburnham Municipal Light Plant | Publicly Owned Entity | | Matt Ide | |
| Associated Industries of Massachusetts (AIM) | End User | | | Mary Smith |
| AVANGRID: CMP/UI | Transmission | Alan Trotta | Jason Rauch | Alex Noviki<br>Zach Teti |
| Bath Iron Works Corporation | End User | | | Bill Short |
| Belmont Municipal Light Department | Publicly Owned Entity | | Dave Cavanaugh | |
| Block Island Utility District | Publicly Owned Entity | Dave Cavanaugh | | |
| Boylston Municipal Light Department | Publicly Owned Entity | Matt Ide | | |
| BP Energy Company | Supplier | | | José Rotger |
| Braintree Electric Light Department | Publicly Owned Entity | | Dave Cavanaugh | |
| Brookfield Renewable Trading and Marketing | Supplier | Aleks Mitreski | | |
| Castleton Commodities Merchant Trading | Supplier | | | Bob Stein |
| Chester Municipal Light Department | Publicly Owned Entity | | Dave Cavanaugh | |
| Chicopee Municipal Lighting Plant | Publicly Owned Entity | | Matt Ide | |
| Clearway Power Marketing LLC | Supplier | | | Pete Fuller |
| Concord Municipal Light Plant | Publicly Owned Entity | | Dave Cavanaugh | |
| Connecticut Municipal Electric Energy Coop. | Publicly Owned Entity | Brian Forshaw | | |
| Connecticut Office of Consumer Counsel | End User | | J.R. Viglione | |
| Conservation Law Foundation (CLF) | End User | Phelps Turner | | |
| Constellation Energy Generation | Supplier | Gretchen Fuhr | | |
| CPV Towantic, LLC | Generation | Joel Gordon | | |
| Cross-Sound Cable Company (CSC) | Supplier | | José Rotger | |
| Danvers Electric Division | Publicly Owned Entity | | Dave Cavanaugh | |
| Dominion Energy Generation Marketing, Inc. | Wes Walker | | | |
| DTE Energy Trading, Inc. | Supplier | | | José Rotger |
| Durgin and Crowell Lumber Co., Inc. | End User | | | Bill Short |
| Dynegy Marketing and Trade, Inc. | Supplier | | Andy Weinstein | |
| ECP Companies<br>Calpine Energy Services, LP<br>New Leaf Energy | Generation | Brett Kruse<br>Liz Delaney | | Alex Chaplin |
| Elektrisola, Inc. | End User | | | Bill Short |
| Enel X North America, Inc. | AR-LR | Alex Worsley | | |
| Engie Energy Marketing NA, Inc. | AR-RG | Sarah Bresolin | | |
| Eversource Energy | Transmission | James Daly | Dave Burnham | Vandan Divatia |
| FirstLight Power Management, LLC | Generation | Tom Kaslow | | |
| Galt Power, Inc. | Supplier | José Rotger | | |
| Garland Manufacturing Company | End User | | | Bill Short |
| Generation Group Member | Generation | | Abby Krich | |
| Georgetown Municipal Light Department | Publicly Owned Entity | | Dave Cavanaugh | |
| Groton Electric Light Department | Publicly Owned Entity | | Matt Ide | |
| Groveland Electric Light Department | Publicly Owned Entity | | Dave Cavanaugh | |
| H.Q. Energy Services (U.S.) Inc. (HQUS) | ~~Supplier~~AR-RG | Louis Guilbault | Bob Stein | |
| Hammond Lumber Company | End User | | | Bill Short |
| Hanover, NH (Town of) | End User | | | Bill Short |
| Harvard Dedicated Energy Limited | End User | | | Jason Frost |
| High Liner Foods (USA) Incorporated | End User | | William P. Short III | |

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN APRIL 6, 2023 TELECONFERENCE MEETING

| PARTICIPANT NAME | SECTOR/ GROUP | MEMBER NAME | ALTERNATE NAME | PROXY |
|---|---|---|---|---|
| Hingham Municipal Lighting Plant | Publicly Owned Entity | | Dave Cavanaugh | |
| Holden Municipal Light Department | Publicly Owned Entity | | Matt Ide | |
| Holyoke Gas & Electric Department | Publicly Owned Entity | | Matt Ide | |
| Hull Municipal Lighting Plant | Publicly Owned Entity | | Matt Ide | |
| Icetec Energy Services, Inc. | AR-LR | Doug Hurley | | |
| Industrial Energy Consumer Group | End User | Dan Collins | | |
| Ipswich Municipal Light Department | Publicly Owned Entity | | Matt Ide | |
| Jericho Power LLC (Jericho) | AR-RG | Ben Griffiths | | |
| Jupiter Power | AR-RG | | | Ron Carrier |
| Littleton (MA) Electric Light and Water Department | Publicly Owned Entity | | Dave Cavanaugh | |
| Littleton (NH) Water & Light Department | Publicly Owned Entity | Craig Kieny | | |
| Long Island Power Authority (LIPA) | Supplier | Bill Kilgoar | | José Rotger |
| Maine Power LLC | Supplier | Jeff Jones | | |
| Maine Public Advocate’s Office | End User | Drew Landry | | |
| Maine Skiing, Inc. | End User | Dan Collins | | |
| Mansfield Municipal Electric Department | Publicly Owned Entity | | Matt Ide | |
| Maple Energy LLC | AR-LR | | | Doug Hurley |
| Marble River | Supplier | | John Brodbeck | |
| Marblehead Municipal Light Department | Publicly Owned Entity | | Matt Ide | |
| Mass. Attorney General’s Office (MA AG) | End User | Ashley Gagnon | Jaimie Donovan | |
| Mass. Bay Transportation Authority | Publicly Owned Entity | | Dave Cavanaugh | |
| Mass. Dept. Capital Asset Management | End User | | Paul Lopes | |
| Mass. Municipal Wholesale Electric Company | Publicly Owned Entity | Matt Ide | | |
| Mercuria Energy America, LLC | Supplier | | | José Rotger |
| Merrimac Municipal Light Department | Publicly Owned Entity | | Dave Cavanaugh | |
| Middleborough Gas & Electric Department | Publicly Owned Entity | | Dave Cavanaugh | |
| Middleton Municipal Electric Department | Publicly Owned Entity | | Dave Cavanaugh | |
| Mintz, Sam | End User | Sam Mintz | | |
| Moore Company | End User | | | Bill Short |
| Narragansett Electric Co. (d/b/a RI Energy) | Transmission | Brian Thomson | | Lindsay Orphanides |
| New England Power (d/b/a National Grid) | Transmission | Tim Brennan | Tim Martin | |
| New England Power Generators Assoc. (NEPGA) | Associate Non-Voting | | Dan Dolan | |
| New Hampshire Electric Cooperative | Publicly Owned Entity | | Brian Callnan | Brian Forshaw |
| New Hampshire Office of Consumer Advocate | End User | | Jason Frost | |
| NextEra Energy Resources, LLC | Generation | Michelle Gardner | Nick Hutchings | |
| 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 | |
| Pawtucket Power Holding Company | Generation | Dan Allegretti | | |
| Paxton Municipal Light Department | Publicly Owned Entity | | Matt Ide | |
| Peabody Municipal Light Department | Publicly Owned Entity | | Matt Ide | |
| Princeton Municipal Light Department | Publicly Owned Entity | Matt Ide | | |
| Reading Municipal Light Department | Publicly Owned Entity | | Dave Cavanaugh | |
| RI Division of Public Utilities Carriers | End User | Paul Roberti | | |

ATTACHMENT 1

**PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES**
**PARTICIPATING IN APRIL 6, 2023 TELECONFERENCE MEETING**

| PARTICIPANT NAME | SECTOR/ GROUP | MEMBER NAME | ALTERNATE NAME | PROXY |
|---|---|---|---|---|
| Rowley Municipal Lighting Plant | Publicly Owned Entity | | Dave Cavanaugh | |
| Russell Municipal Light Dept. | Publicly Owned Entity | | Matt Ide | |
| Saint Anselm College | End User | | | Bill Short |
| Shell Energy North America (US), L.P. | Supplier | Jeff Dannels | | |
| Shipyard Brewing LLC | End User | | | Bill Short |
| Shrewsbury Electric & Cable Operations | Publicly Owned Entity | | Matt Ide | |
| South Hadley Electric Light Department | Publicly Owned Entity | | Matt Ide | |
| Sterling Municipal Electric Light Department | Publicly Owned Entity | | Matt Ide | |
| Stowe Electric Department | Publicly Owned Entity | | Dave Cavanaugh | |
| Sunnova Energy Corporation | AR-DG | | David Skillman | |
| Sunrun Inc. | AR-DG | | | Peter Fuller |
| Tangent Energy | AR-LR | Brad Swalwell | | |
| Taunton Municipal Lighting Plant | Publicly Owned Entity | Devon Tremont | Dave Cavanaugh | |
| Templeton Municipal Lighting Plant | Publicly Owned Entity | | Matt Ide | |
| Tenaska Power Services Co. | Supplier | | Eric Stallings | |
| The Energy Consortium | End User | | Mary Smith | |
| Vermont Electric Cooperative | Publicly Owned Entity | Craig Kieny | | |
| Vermont Electric Power Company (VELCO) | Transmission | Frank Ettori | | |
| Vermont Energy Investment Corporation | AR-LR | Jason Frost | | |
| Vermont Public Power Supply Authority | Publicly Owned Entity | | | Brian Forshaw |
| Village of Hyde Park (VT) Electric Department | Publicly Owned Entity | Dave Cavanaugh | | |
| Wakefield Municipal Gas & Light Department | Publicly Owned Entity | | Matt Ide | |
| Walden Renewables Development LLC | Generation | | | Abby Krich |
| Wallingford DPU Electric Division | Publicly Owned Entity | | Dave Cavanaugh | |
| Wellesley Municipal Light Plant | Publicly Owned Entity | | Dave Cavanaugh | |
| West Boylston Municipal Lighting Plant | Publicly Owned Entity | | Matt Ide | |
| Westfield Gas & Electric Department | Publicly Owned Entity | | Dave Cavanaugh | |
| ZTECH, LLC | End User | | | Bill Short |

## CONSENT AGENDA

### *Reliability Committee (RC)*

***From the previously-circulated notice of actions of the RC's April 18-19, 2023 meeting, dated April 19, 2023.*[1]**

**1. Revisions to OP-5 Appendix B (Biennial Review)**

Support revisions to Appendix B (Outage Request Form) to ISO New England Operating Procedure (OP) No. 5 (Resource Maintenance and Outage Scheduling),[2] as recommended by the RC at its April 18-19, 2023 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was approved unanimously.

**2. Revisions to OP-13 (LCC Response Clarification and Reference Updates)**

Support revisions to OP-13 (Standards for Voltage Reduction and Load Shedding Capability),[3] as recommended by the RC at its April 18-19, 2023 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was approved unanimously.

**3. Revisions to PP-10 (DER Interconnection Rule Modification Conforming Changes)**

Support revisions to ISO New England Planning Procedure (PP) No. 10 (Planning Procedure to Support the Forward Capacity Market),[4] as recommended by the RC at its April 18-19, 2023 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was approved unanimously.

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

[2] The recommended revisions to OP-5 Appendix B (i) remove the FCM Exempt question, (ii) remove the note regarding the use of the Outage-Request Template, and (iii) incorporate minor grammar edits.

[3] The recommended revisions to OP-13 (i) clarify that Market Participants that are not Participating Transmission Owners (i.e. distribution companies) must respond to a Local Control Center (LCC) instruction for voltage reduction or load shedding; and (ii) add references to Tariff and Transmission Operating Agreement (TOA).

[4] The recommended revisions, which conform PP-10 with FERC-accepted Tariff changes that modify the process for interconnection of new Distributed Energy Resources (DERs) and improve coordination of interconnection studies (*see ISO New England Inc. et al.*, 180 FERC ¶ 61,129 (Aug. 26, 2022)), focus on how DERs subject to a state interconnection process participate in the Capacity Network Resource (CNR) Group Study for a Forward Capacity Auction (FCA) qualification process. The proposed changes will be used for FCA18 qualification activities.

# NEPOOL Participants Committee Report

*May 2023*

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

# Table of Contents

# Regular Operations Report - Highlights

# Highlights

**Data is through April 26th unless otherwise noted.**

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: March 2023 Energy Market value totaled $390M
  - April Energy market value was $242M, down $148M from March 2023 and down $349M from April 2022
    - April natural gas prices over the period were 36% lower than March average values
    - Average RT Hub Locational Marginal Prices ($28.09/MWh) over the period were 8% lower than March averages
      - DA Hub: $29.01/MWh
    - Average April 2023 natural gas prices and RT Hub LMPs over the period were down 71% and 53%, respectively, from April 2022 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 101.9% during April, up from 101.4% during March*
    - The minimum value for the month was 97.3% on Thursday, April 6th**

*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

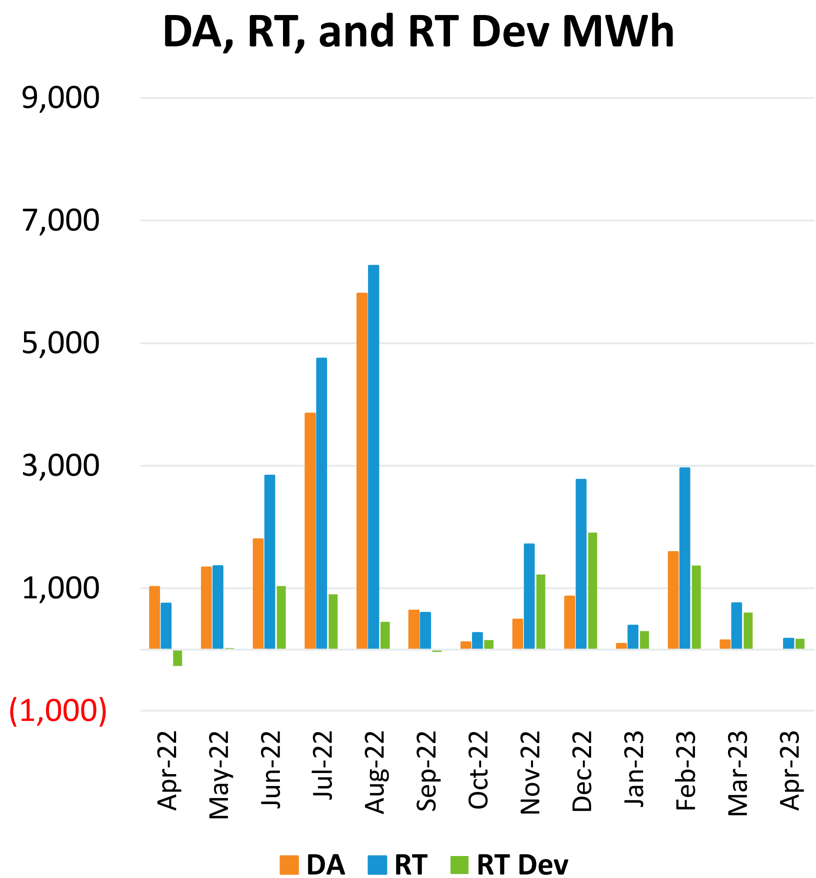
Underlying natural gas data furnished by: ICE Global markets in clear view

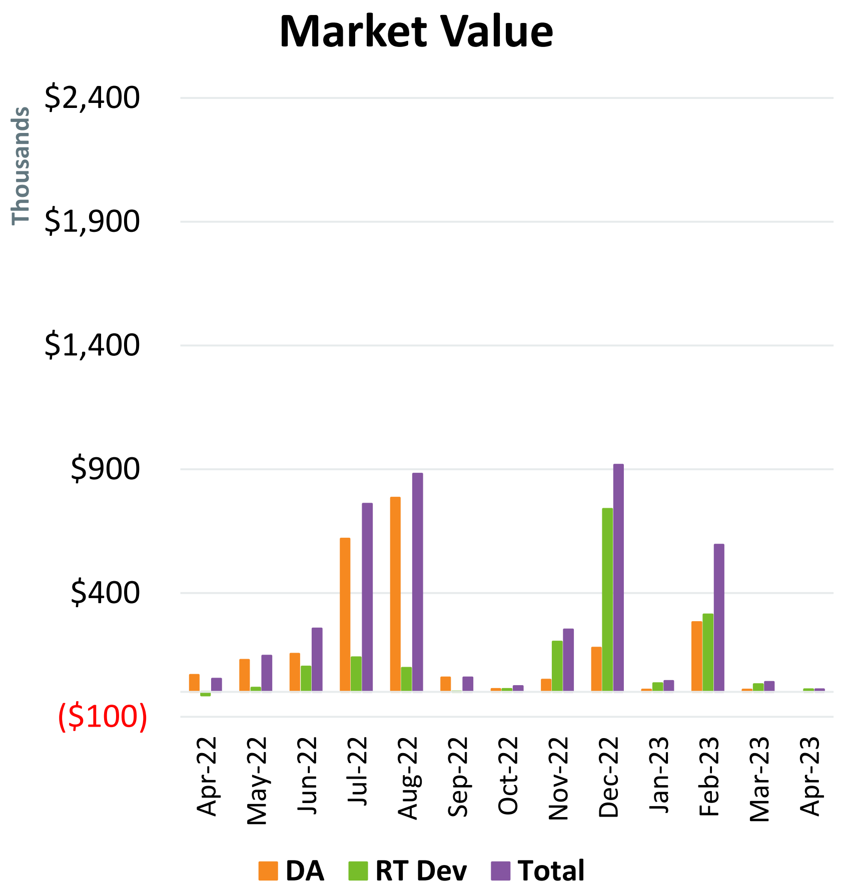
# Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - April 2023 NCPC payments totaled $1.1M over the period, down $0.3M from March and down $1.1M from April 2022
    - First Contingency payments totaled $1.1M, down $0.2M from March
      - $1.1M paid to internal resources, down $0.1M from March
        - » $242K charged to DALO, $501K to RT Deviations, $338K to RTLO*
      - $16K paid to resources at external locations, down $143K from March
        - » $0K charged to DALO at external locations, $15K to RT Deviations
    - Second Contingency payments were zero, down $89K from March
    - Voltage and Distribution payments were both zero
  - NCPC payments over the period as percent of Energy Market value were 0.5%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $200K; Rapid Response Pricing (RRP) Opportunity Cost - $138K; Posturing - $0K; Generator Performance Auditing (GPA) - $0K**

# Price Responsive Demand (PRD) Energy Market Activity by Month




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

# Highlights

- FCA 18 will evaluate the same zones as evaluated in FCA 17
- ISO to kick off PSPC cycle at the May 31 meeting for ICR and related values and tie benefits study for FCA 18
- High-level outline of Future Grid Reliability Study Phase 2 was presented at the April PAC
  - FGRS Phase 2 will be run as the Stakeholder-Requested Scenario in the Economic Planning for the Clean Energy Transition study

# Forward Capacity Market (FCM) Highlights

- CCP 14 (2023-2024)
  - Third and final annual reconfiguration auction (ARA3) was held on March 1-3, and results were posted on March 30
- CCP 15 (2024-2025)
  - Second annual reconfiguration auction (ARA2) will be held on August 1-3, and results will be posted no later than August 31
- CCP 16 (2025-2026)
  - First annual reconfiguration auction (ARA1) will be held on June 1-5, and results will be posted no later than July 3
- CCP 17 (2026-2027)
  - 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 18 (2027-2028)
  - The qualification process has started, and the ISO had provided training
  - ISO shared topology certifications at the January 18 RC meeting
  - FCA 18 will evaluate the same zones as evaluated in FCA 17
    - Potential export-constrained zones:  Northern New England and Maine nested inside Northern New England
    - Potential import-constrained zones:  Southeast New England and Connecticut
  - ISO posted existing capacity values on March 30
  - ISO posted the Retirement and Permanent Delist Bid summary on April 12
  - Show of Interest Submission Window opened on April 24 and closes on May 8
  - ISO to kick off PSPC cycle at the May 31 meeting for ICR and related values and tie benefits study for FCA 18
    - 2023 PSPC schedule and tentative agendas were presented at the April 19 RC meeting

# Load Forecast

- The final electrification, energy and demand forecasts were discussed at the April 14 Load Forecast Committee meeting
- Exploring significant improvements to the long-term load forecast methodology to better support the evolving grid

# Highlights

- The lowest 50/50 and 90/10 Spring Operable Capacity Margins are projected for week beginning May 27, 2023.

- The lowest 50/50 and 90/10 Summer Operable Capacity Margins are projected for week beginning June 3, 2023.

# SYSTEM OPERATIONS

# System Operations

| | | | | |
|---|---|---|---|---|
| **Weather Patterns** | Boston | Temperature: Above Normal (2.2°F)<br>Max: 88°F, Min: 31°F<br>Precipitation: 3.10" – Below Normal<br>Normal: 3.63" | Hartford | Temperature: Above Normal (4.3°F)<br>Max: 96°F, Min: 23°F<br>Precipitation: 6.00" - Above Normal<br>Normal: 3.88" |

| | | | |
|---|---|---|---|
| **Peak Load:** | 14,454 MW | April, 13, 2023 | 20:00 (ending) |

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

| Procedure | Declared | Cancelled | Note |
|---|---|---|---|
| NONE | | | |

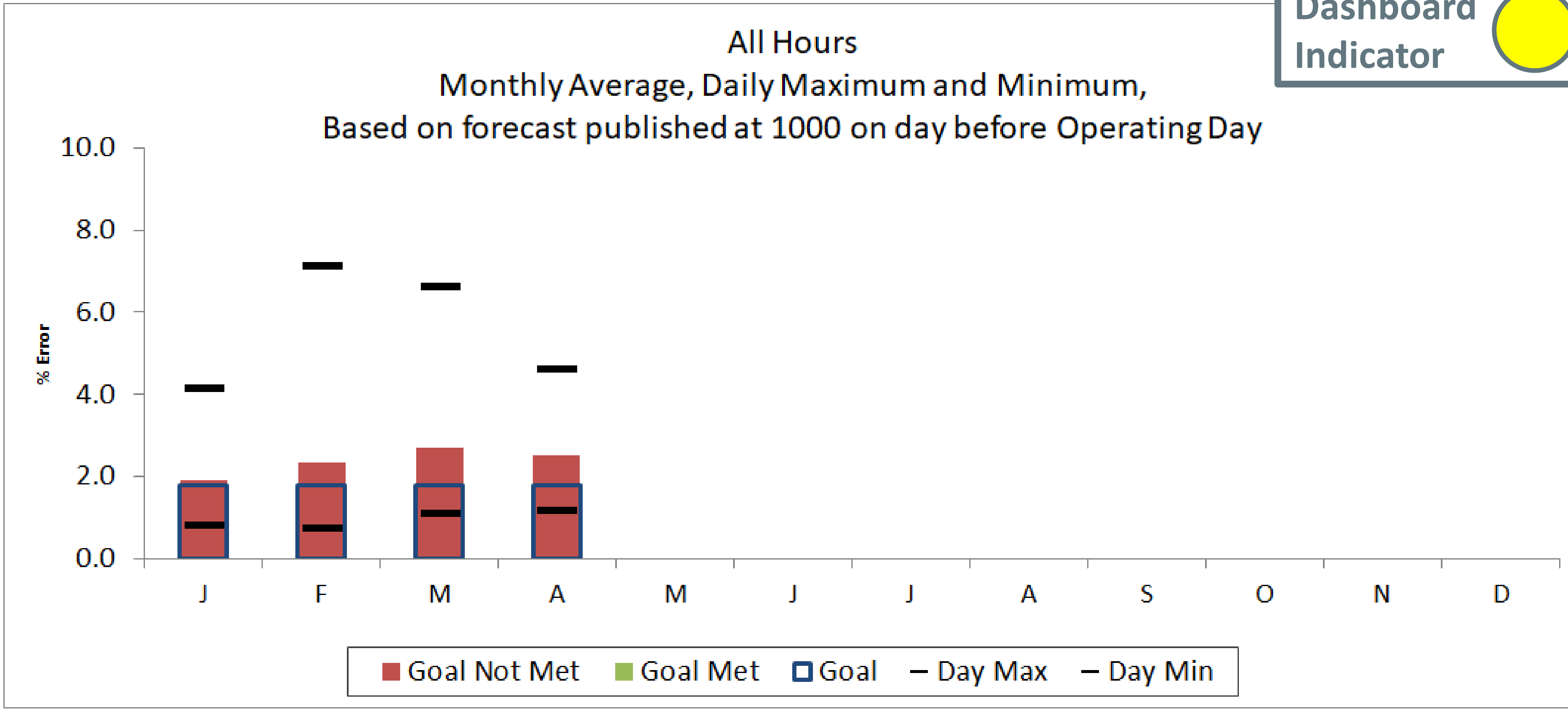
# System Operations

## NPCC Simultaneous Activation of Reserve Events

| Date | Area | MW Lost |
|---|---|---|
| NONE | | |

# 2023 System Operations - Load Forecast Accuracy

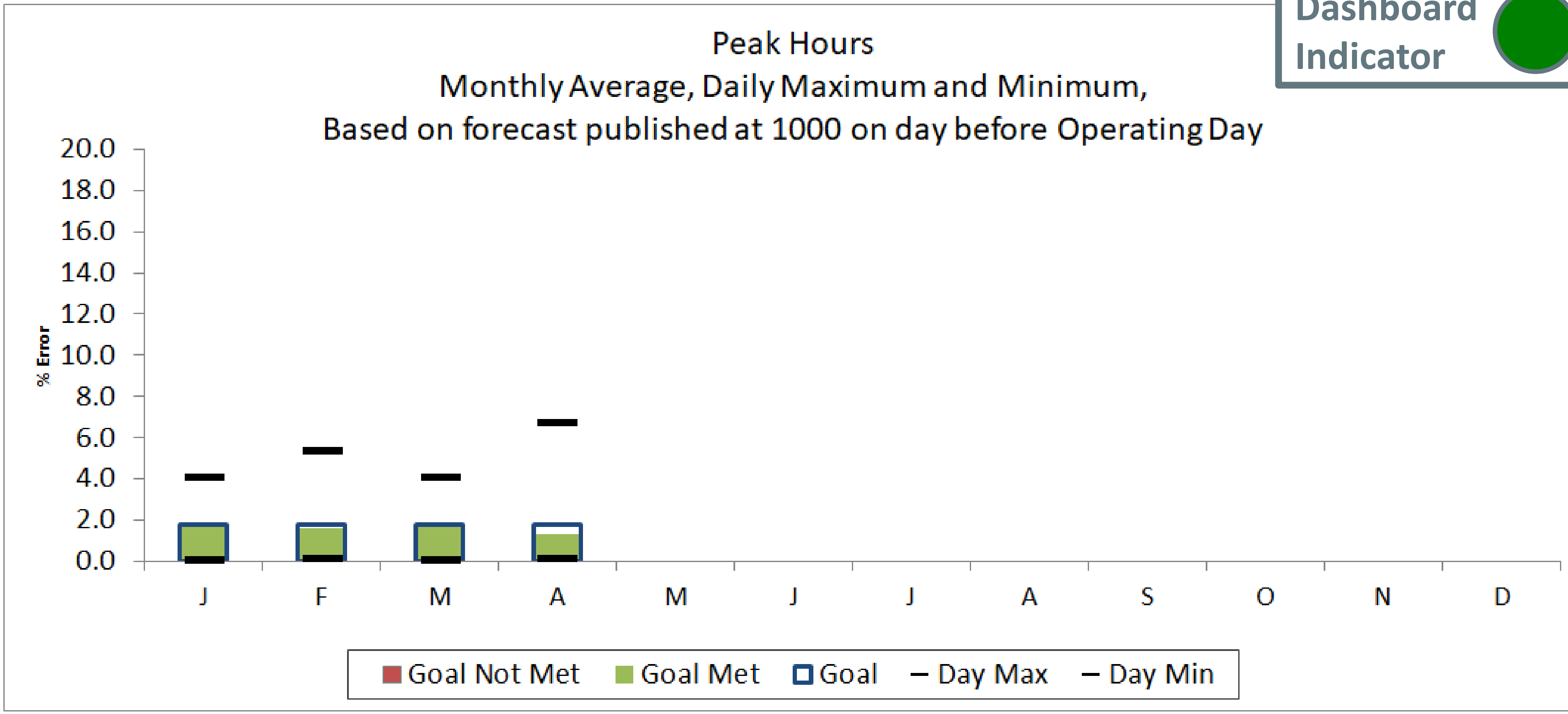
Dashboard Indicator




| Month | J | F | M | A | M | J | J | A | S | O | N | D | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Day Max | 4.14 | 7.12 | 6.59 | 4.61 | | | | | | | | | 7.12 |
| Day Min | 0.80 | 0.74 | 1.08 | 1.17 | | | | | | | | | 0.74 |
| MAPE | 1.91 | 2.34 | 2.70 | 2.52 | | | | | | | | | 2.37 |
| Goal | 1.80 | 1.80 | 1.80 | 1.80 | | | | | | | | | |

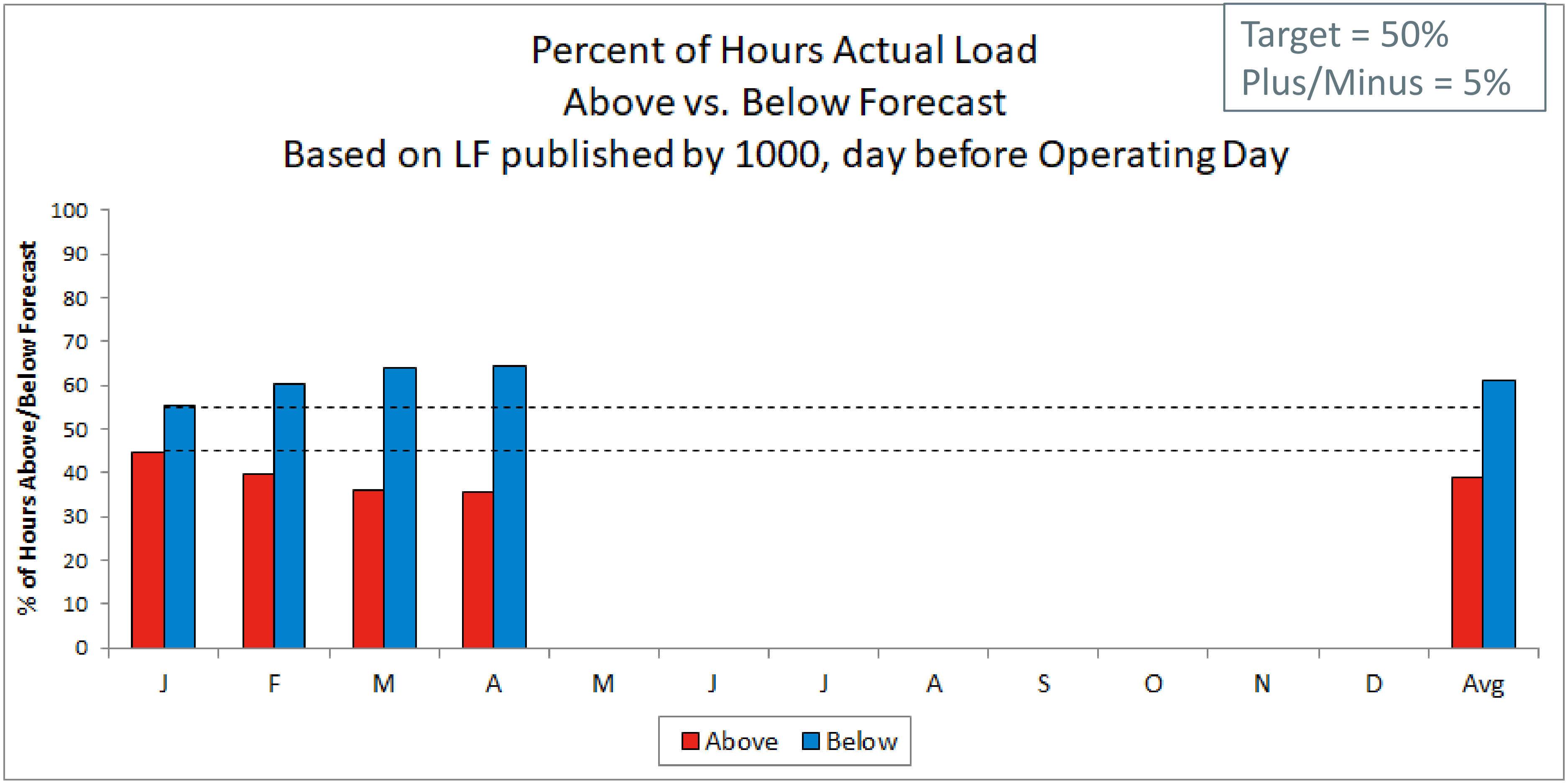
# 2023 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



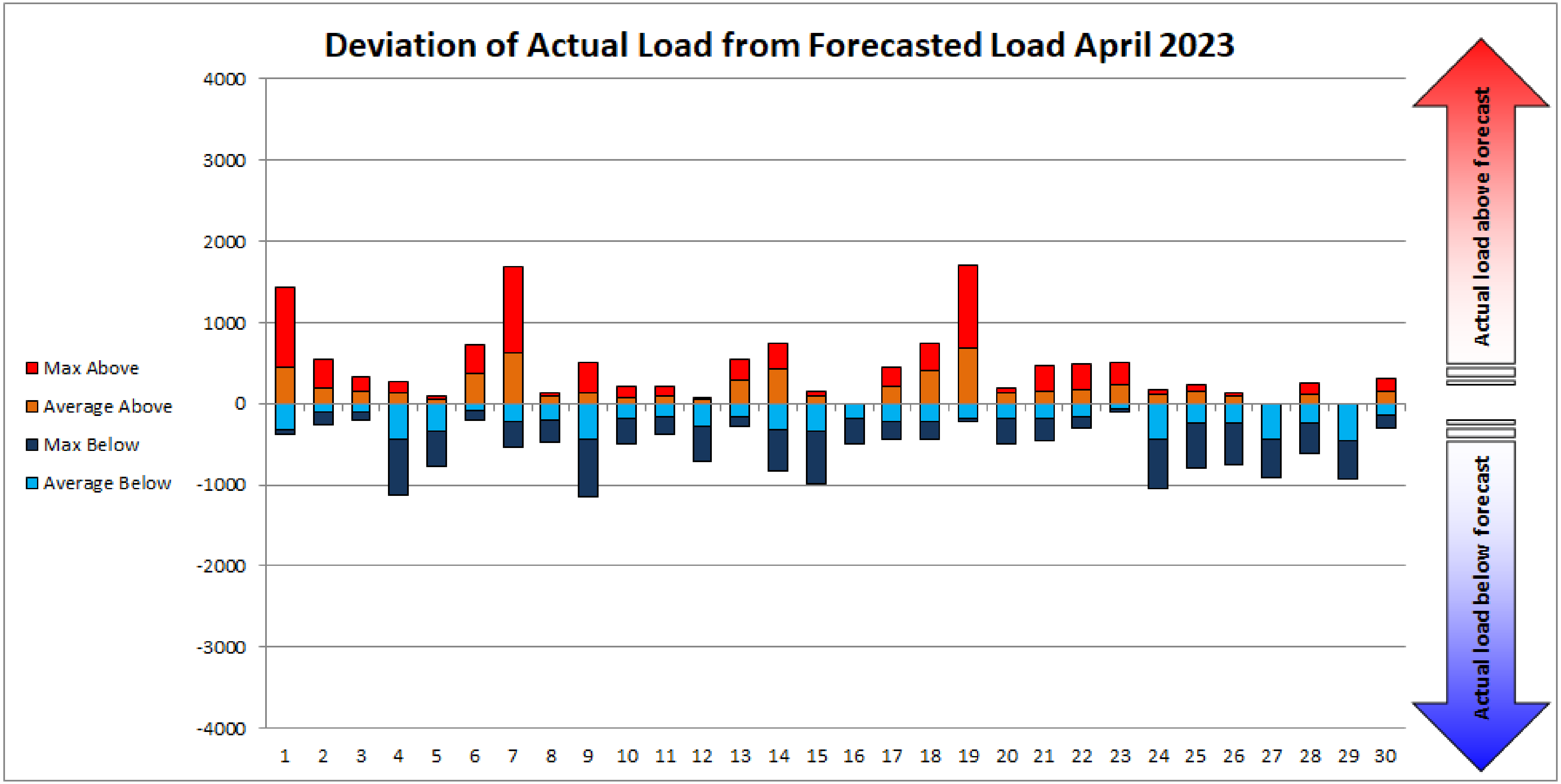

| Month | J | F | M | A | M | J | J | A | S | O | N | D | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Day Max | 4.05 | 5.32 | 4.06 | 6.68 | | | | | | | | | 6.68 |
| Day Min | 0.01 | 0.08 | 0.06 | 0.11 | | | | | | | | | 0.01 |
| MAPE | 1.70 | 1.64 | 1.72 | 1.33 | | | | | | | | | 1.60 |
| Goal | 1.80 | 1.80 | 1.80 | 1.80 | | | | | | | | | |

# 2023 System Operations - Load Forecast Accuracy cont.

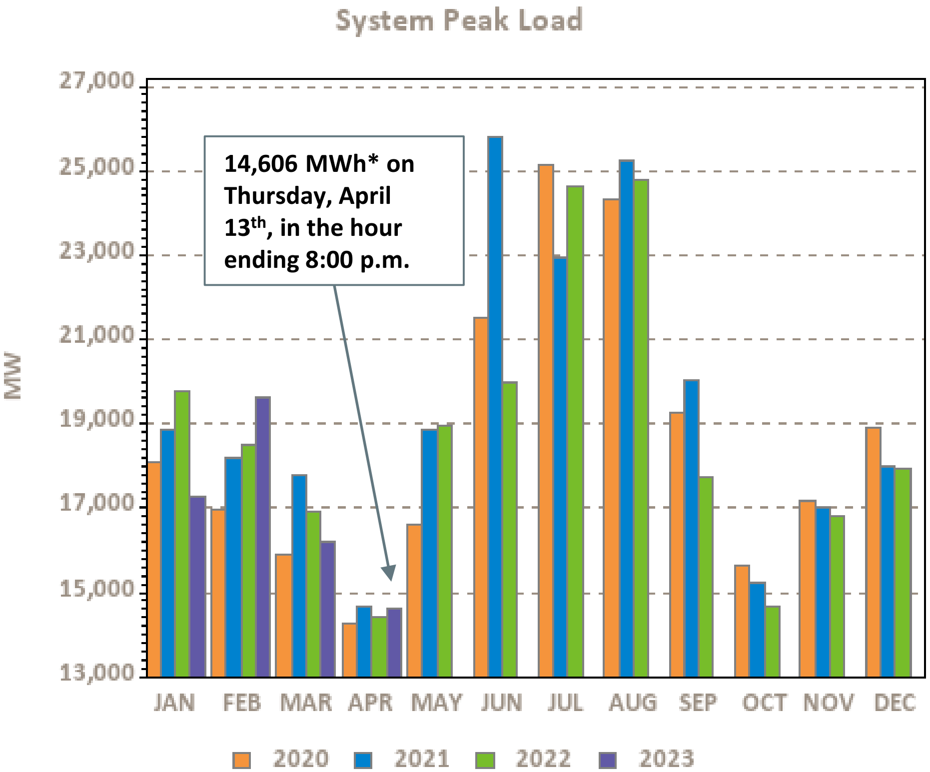



| | J | F | M | A | M | J | J | A | S | O | N | D | Avg |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Above % | 44.6 | 39.7 | 36.2 | 35.7 | | | | | | | | | 39 |
| Below % | 55.4 | 60.3 | 63.8 | 64.3 | | | | | | | | | 61 |
| Avg Above | 235.7 | 228 | 172.9 | 194.5 | | | | | | | | | 236 |
| Avg Below | -197.3 | -248.9 | -328.3 | -245.0 | | | | | | | | | -328 |
| Avg All | -10 | -28 | -142 | -74 | | | | | | | | | -64 |

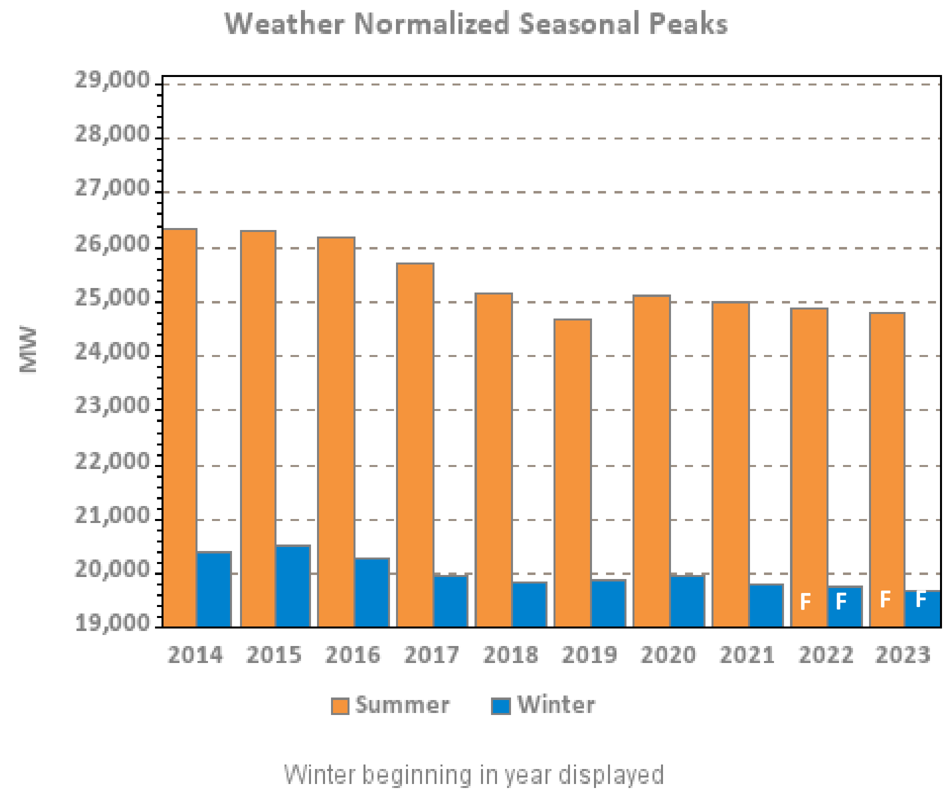
# 2023 System Operations - Load Forecast Accuracy cont.



# Monthly Peak Loads and Weather Normalized Seasonal Peak History

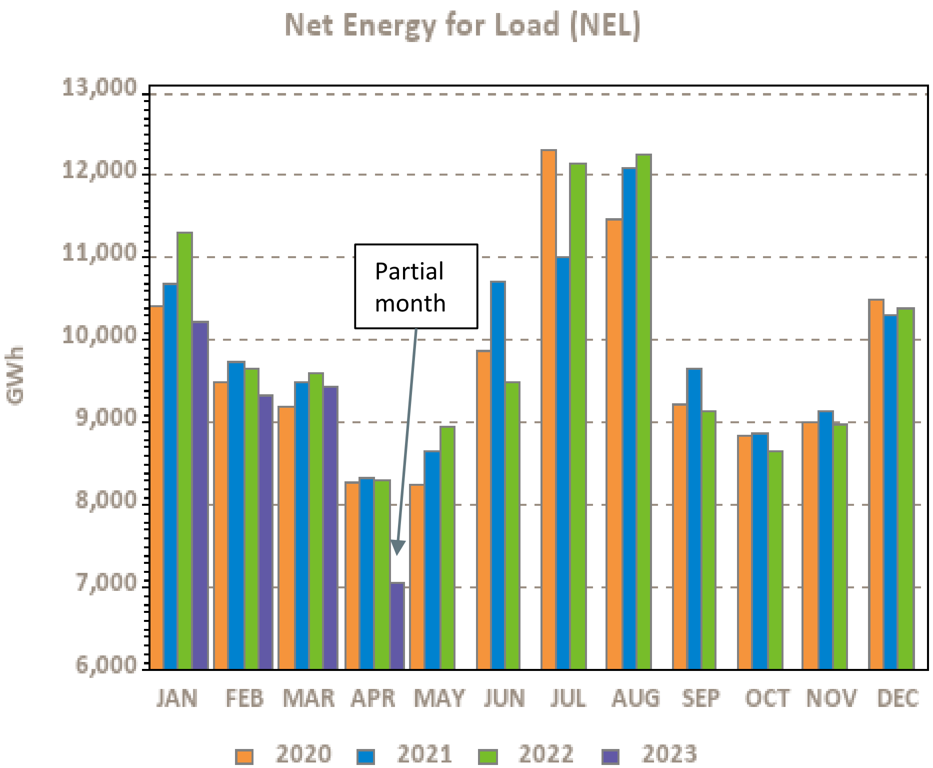



*Revenue quality metered value

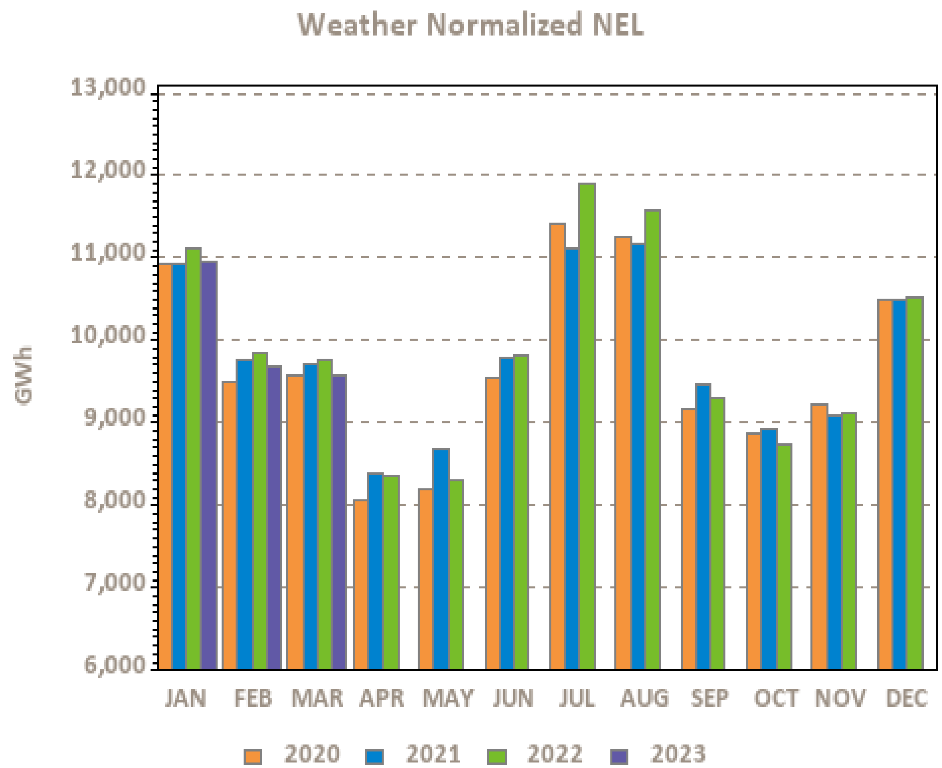



**F – designates forecasted values, which are typically updated in April/May of the following year; represents "net forecast" (i.e., the gross forecast net of passive demand response and behind-the-meter solar demand)**

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




Ann Tot (TWh): 116.9 118.8 118.9 36.1

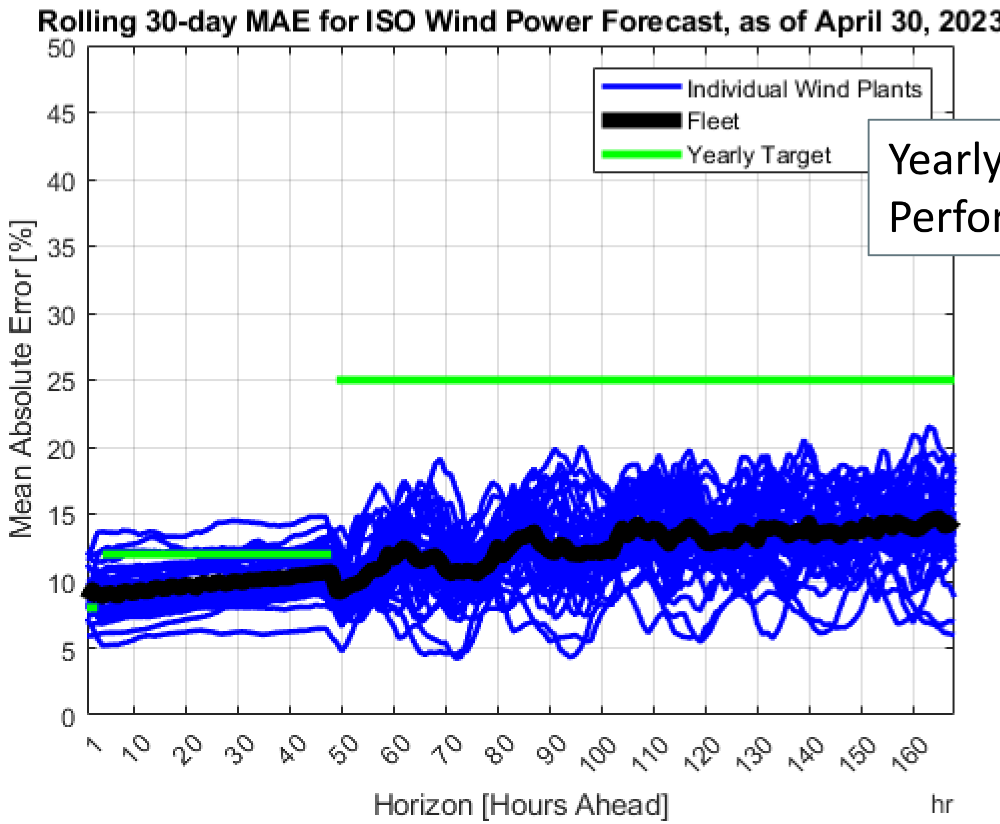



Ann Tot (TWh): 116.3 117.6 118.3 30.2

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

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

Dashboard Indicator

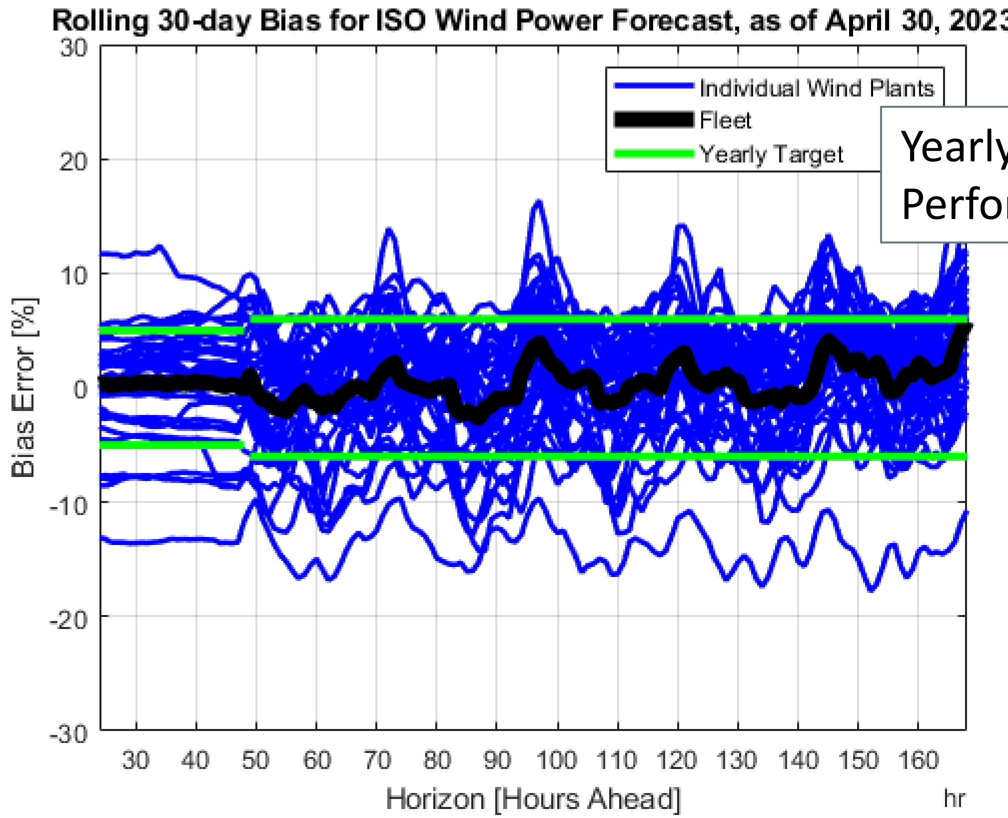



Yearly Fleet Performance targets

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

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

Dashboard Indicator

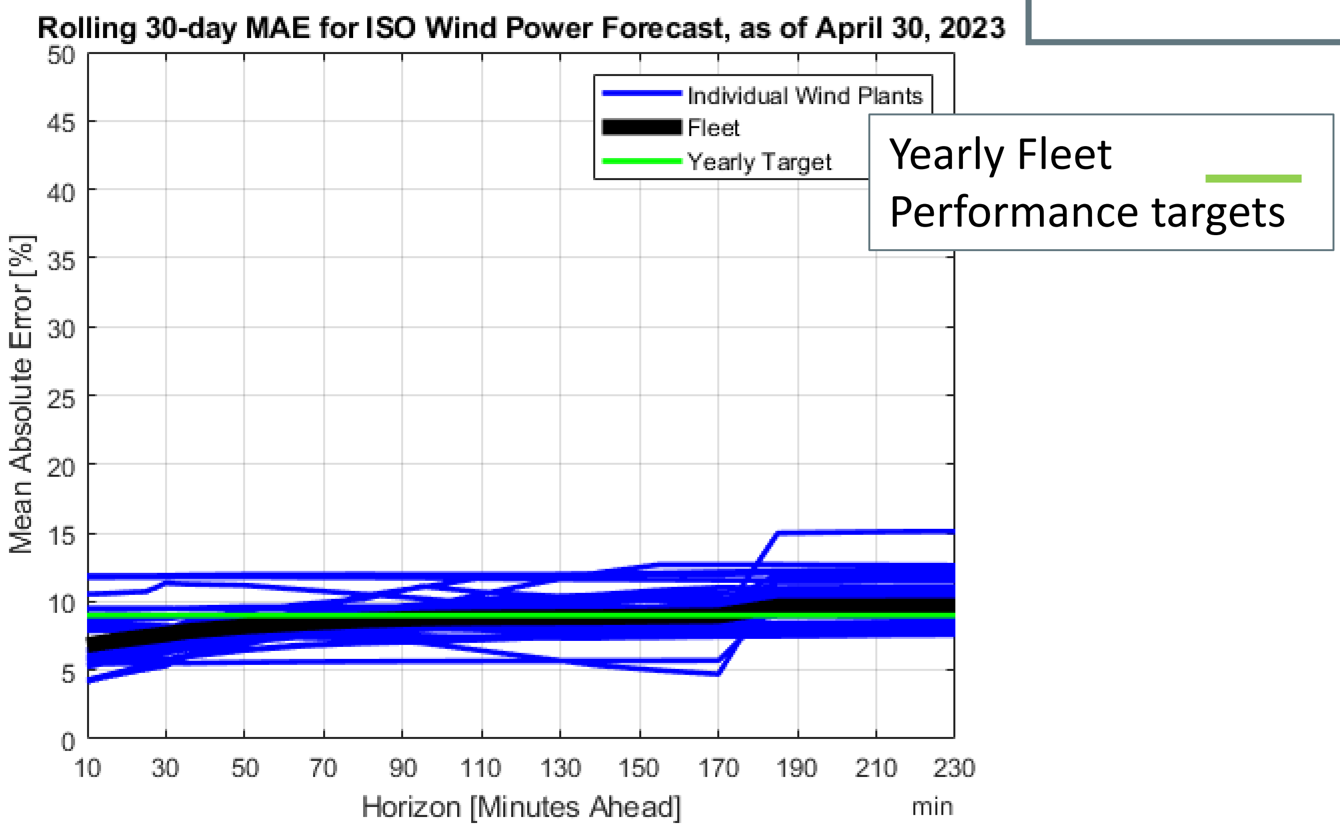



Yearly Fleet Performance targets

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

# Wind Power Forecast Error Statistics: Short Term Forecast MAE

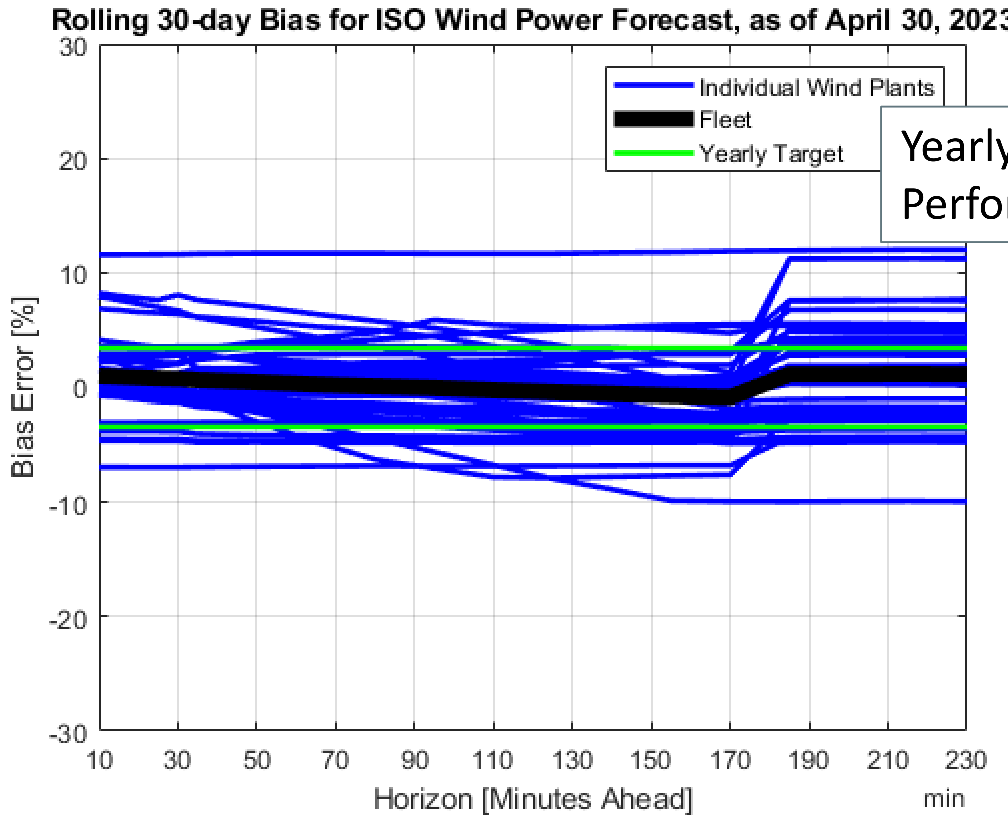
Dashboard Indicator




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. While the forecast compares with industry standards, monthly MAE is outside yearly performance targets after the 180 minute look-ahead horizon. Input data corrections are continuing to reduce error of dataset.

# Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator

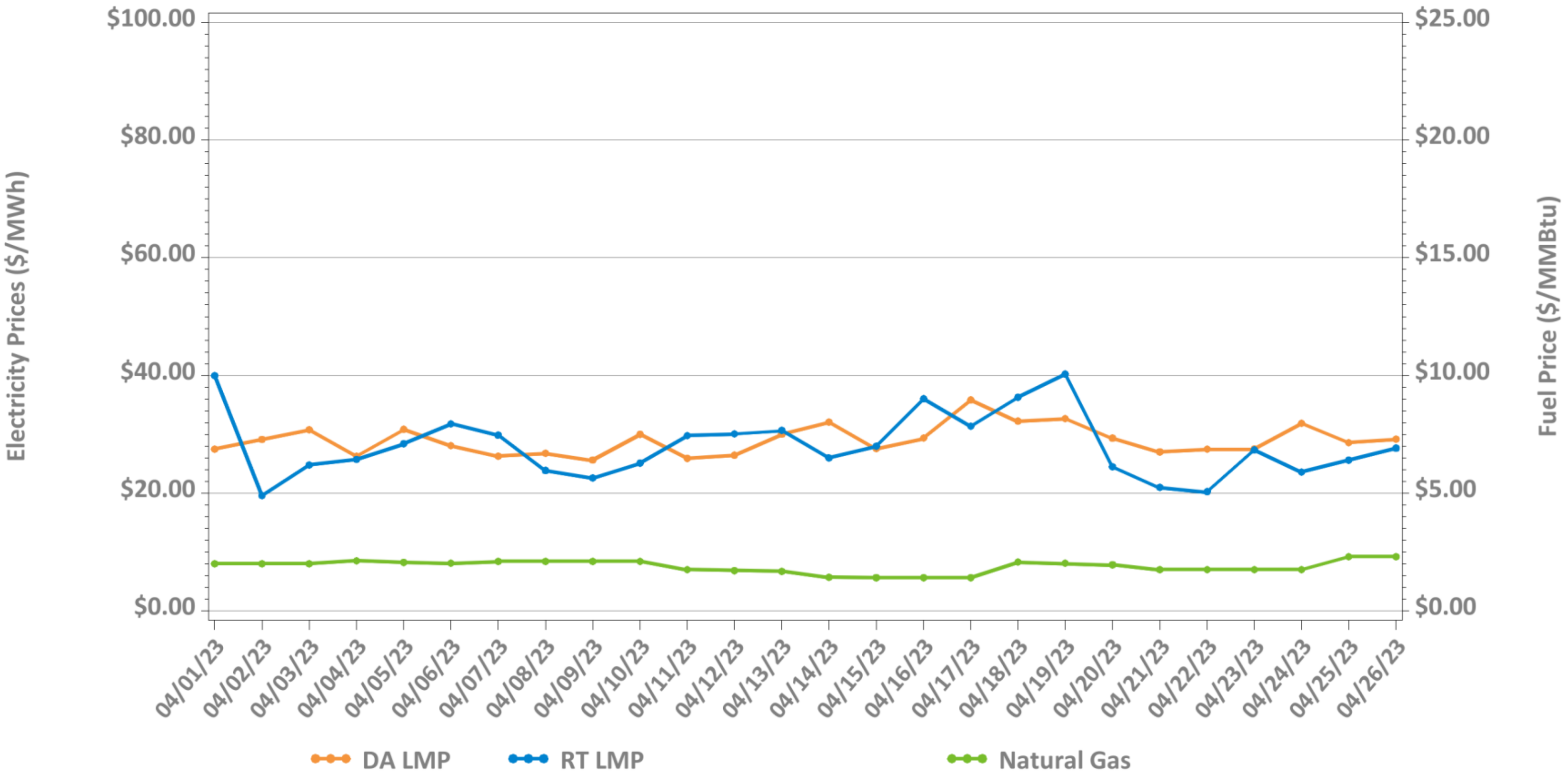



Yearly Fleet Performance targets

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 1-26, 2023

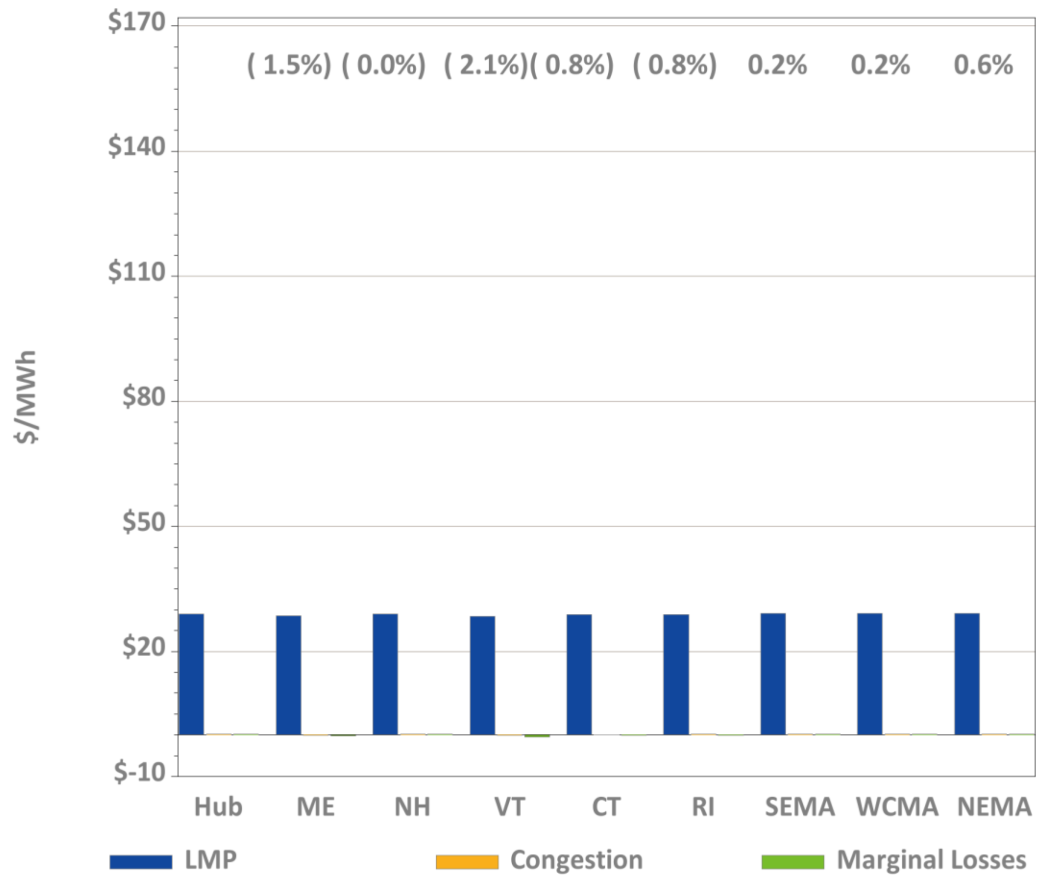



Underlying natural gas data furnished by:

ICE Global markets in clear view

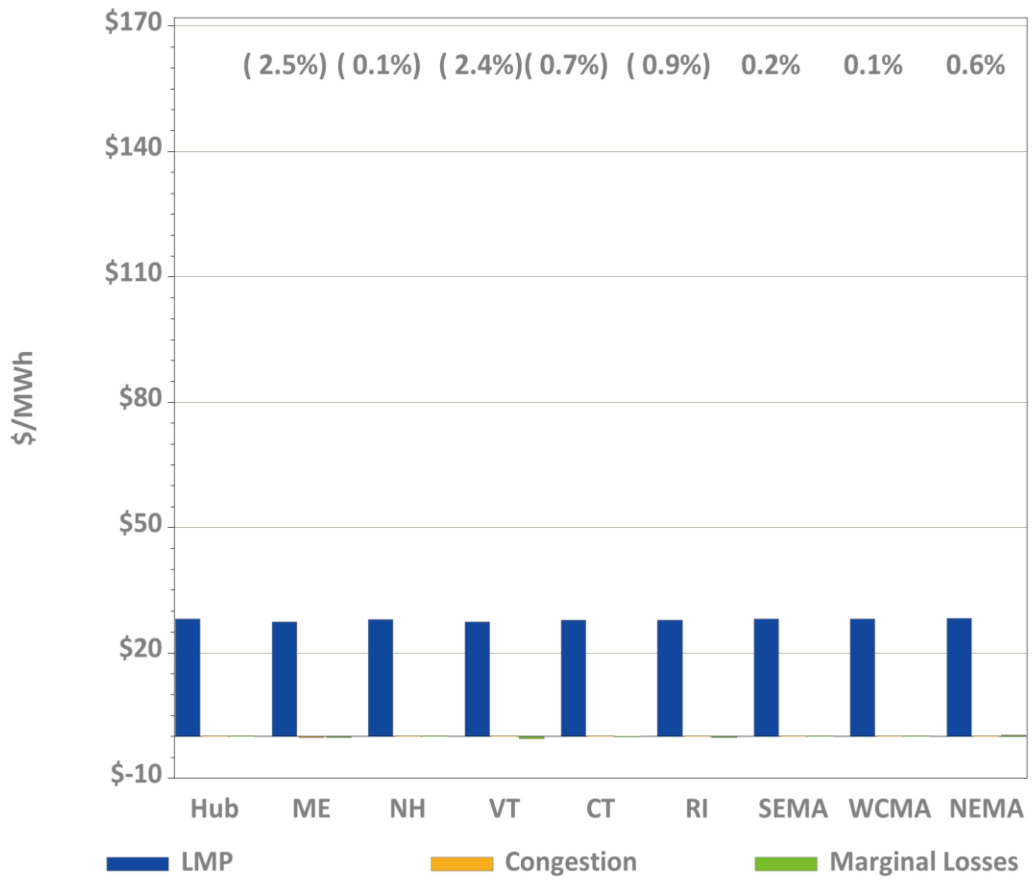
Average price difference over this period (DA-RT): $0.94
Average price difference over this period ABS(DA-RT): $4.52
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 16%
Gas price is average of Massachusetts delivery points

# DA LMPs Average by Zone & Hub, April 2023




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

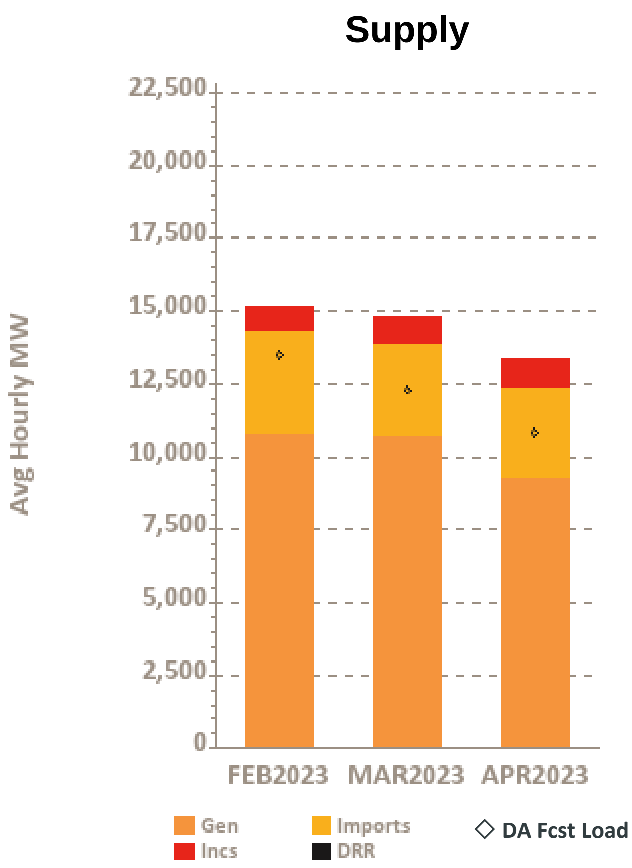
# RT LMPs Average by Zone & Hub, April 2023

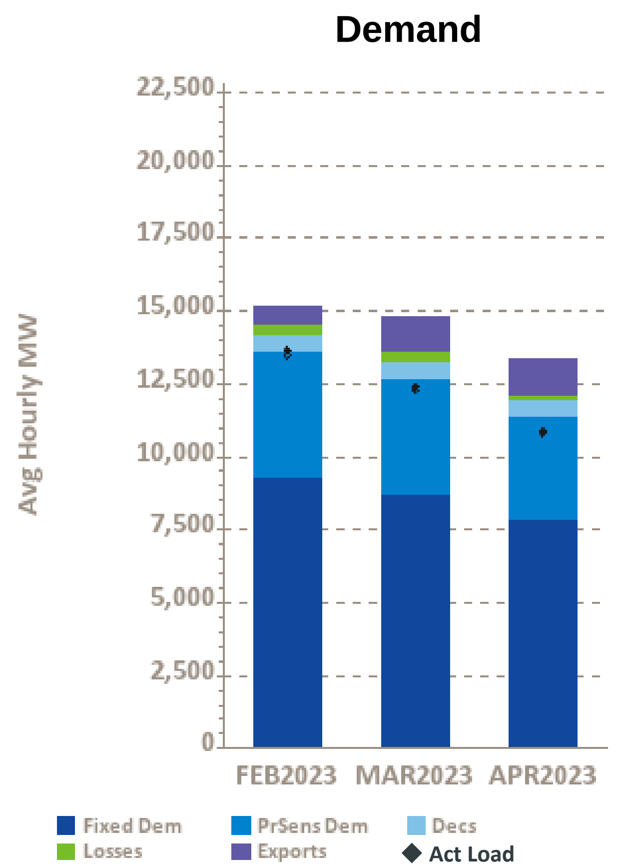


# Definitions

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

# Components of Cleared DA Supply and Demand – Last Three Months

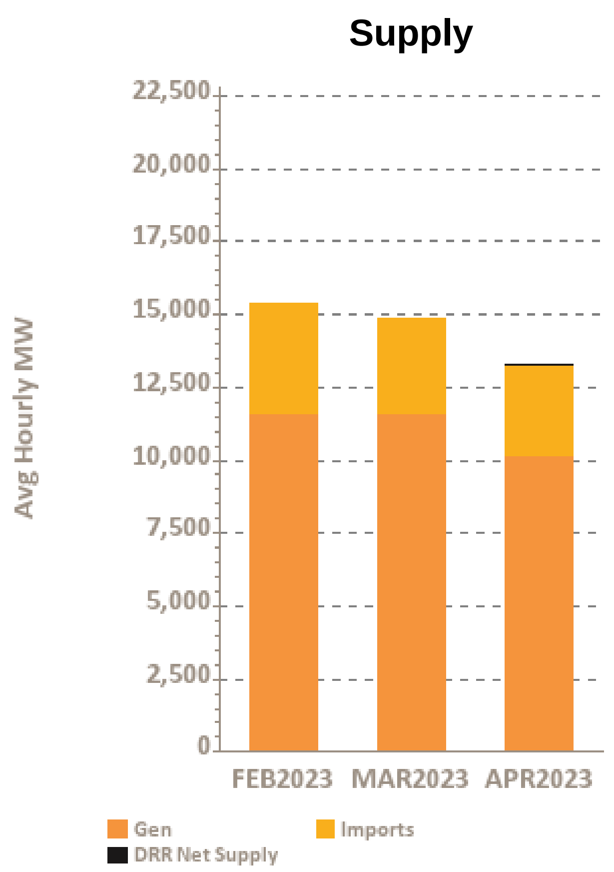


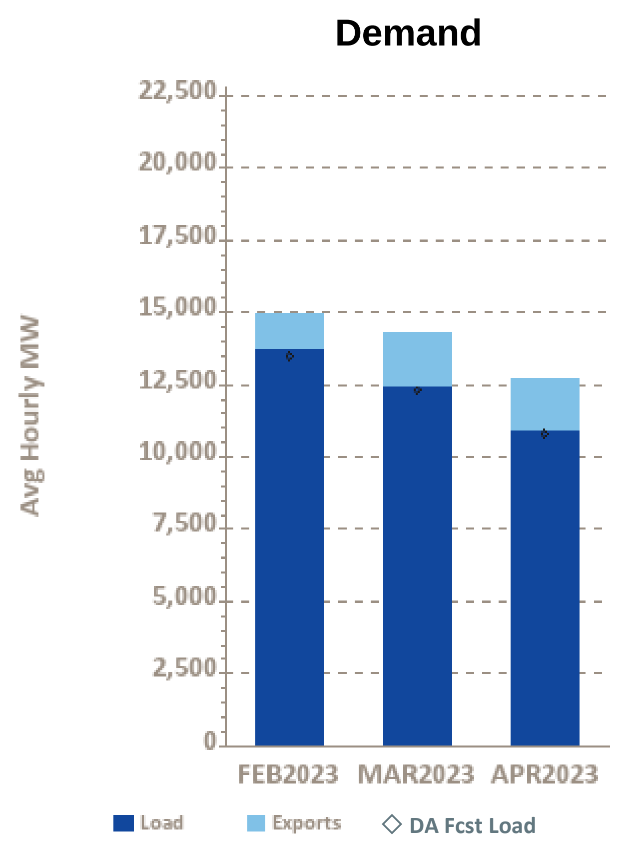




Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

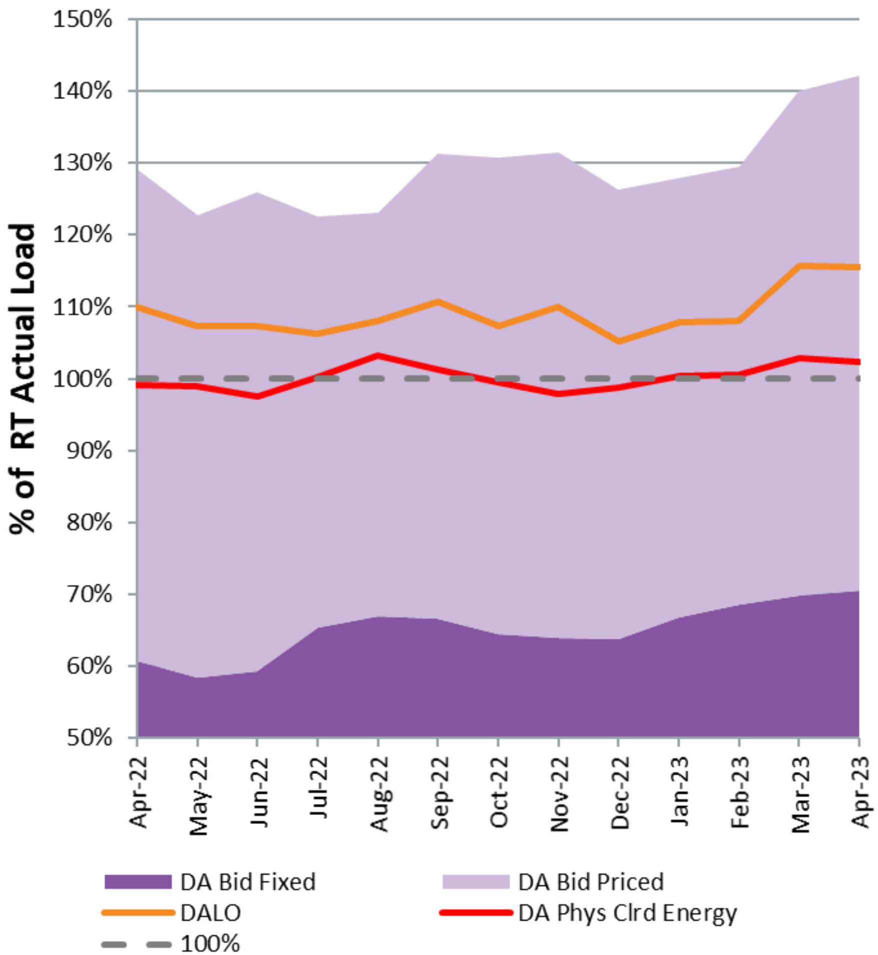
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

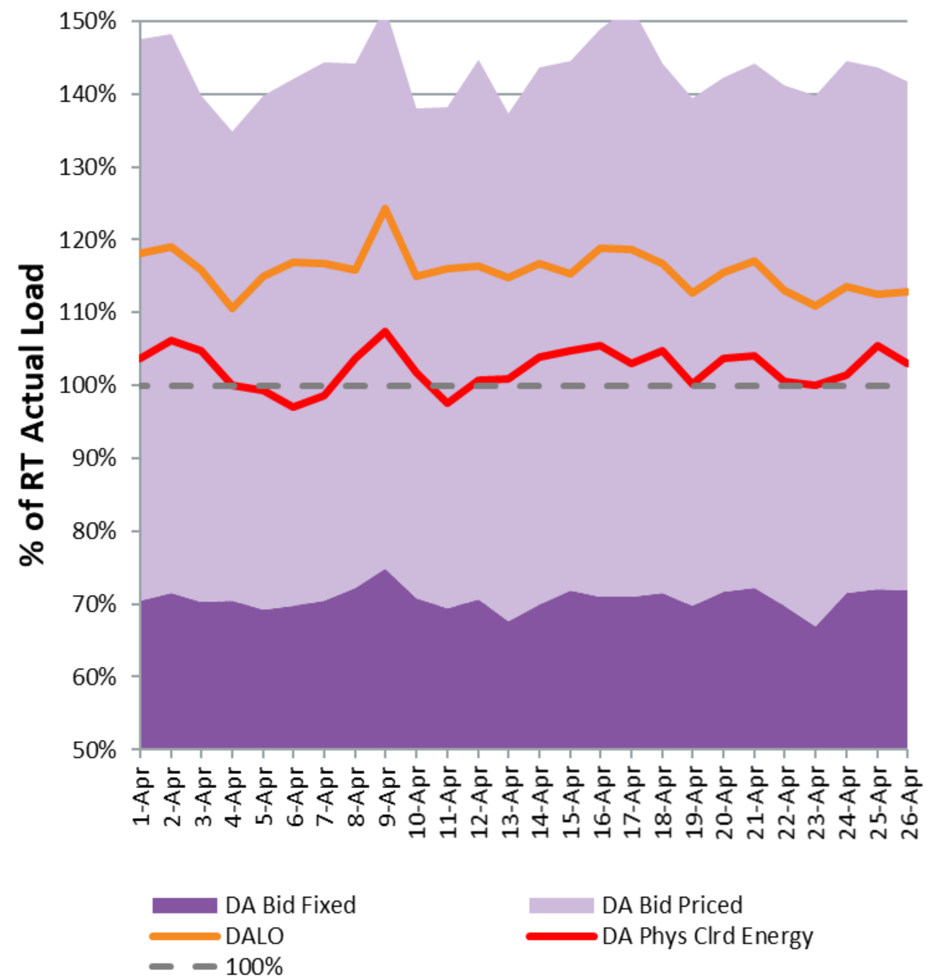
# Components of RT Supply and Demand – Last Three Months



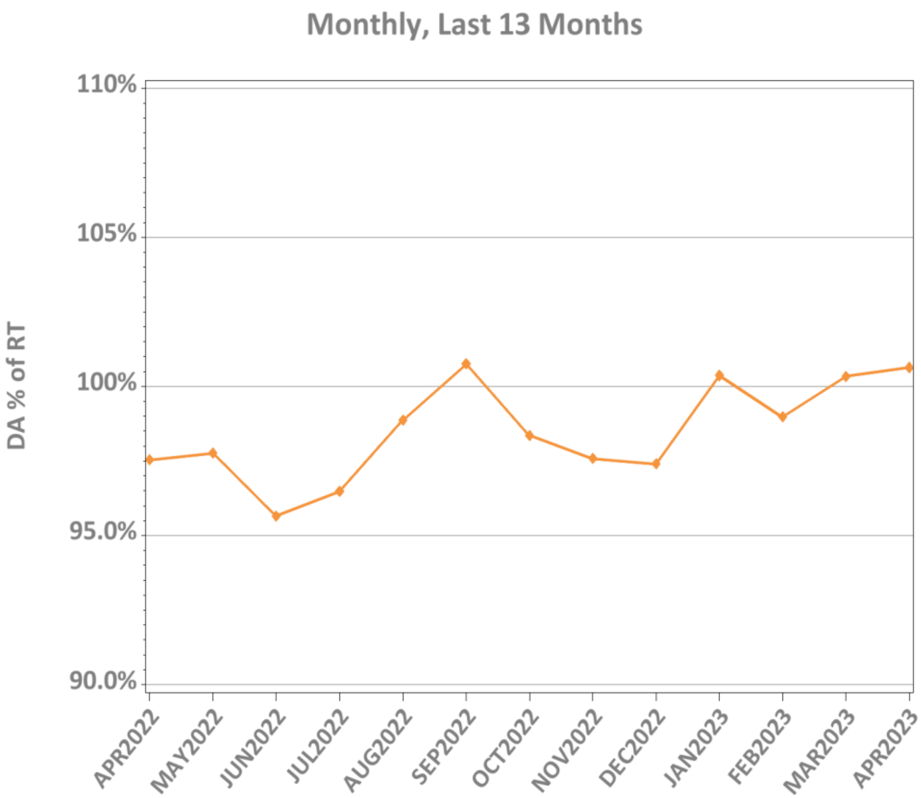
# DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

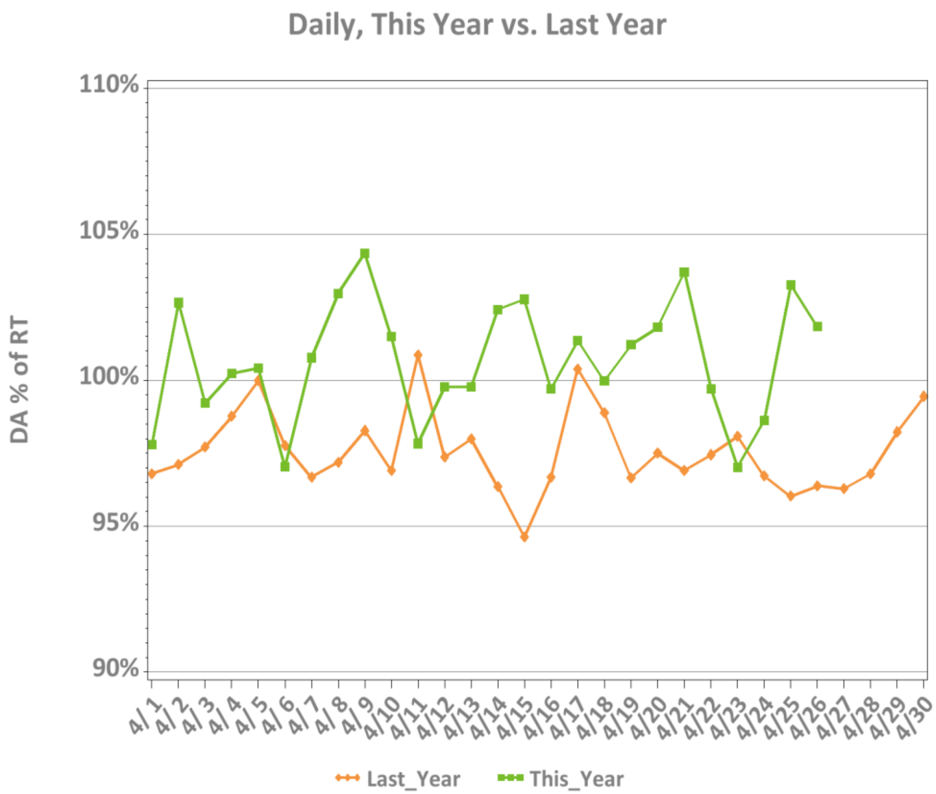



Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

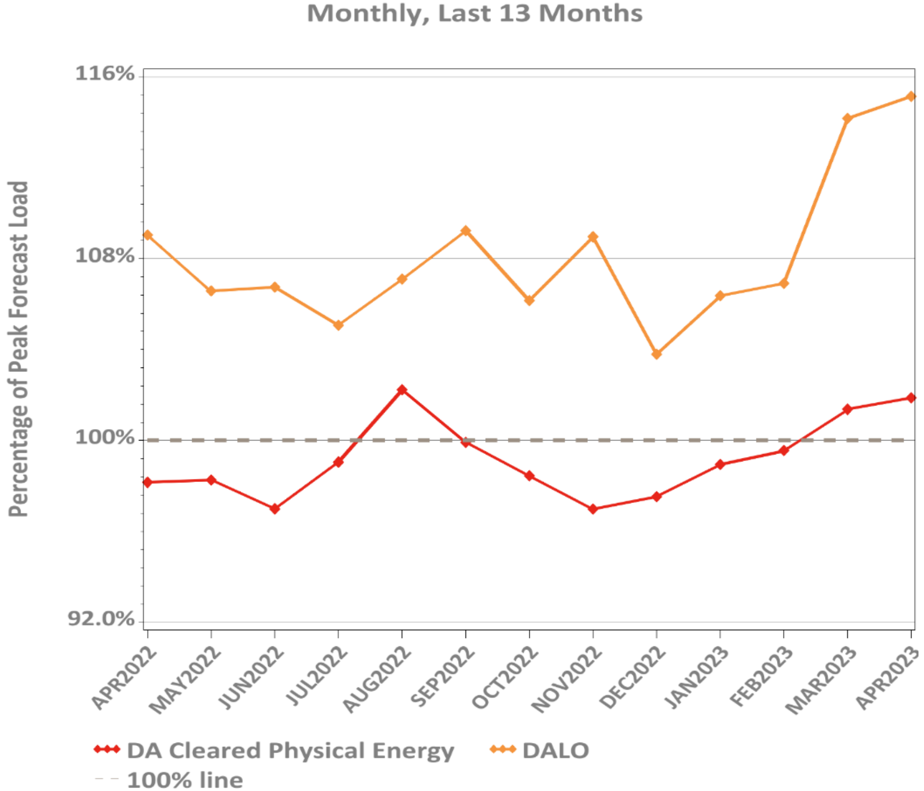
# DA vs. RT Load Obligation: April, This Year vs. Last Year

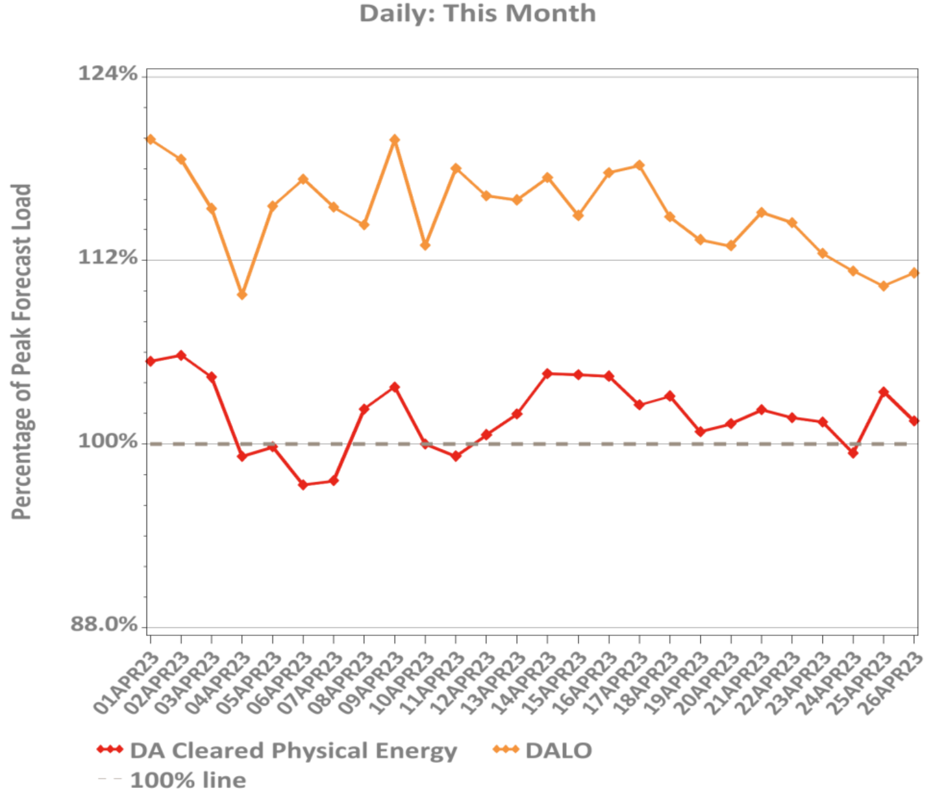



*Hourly average values

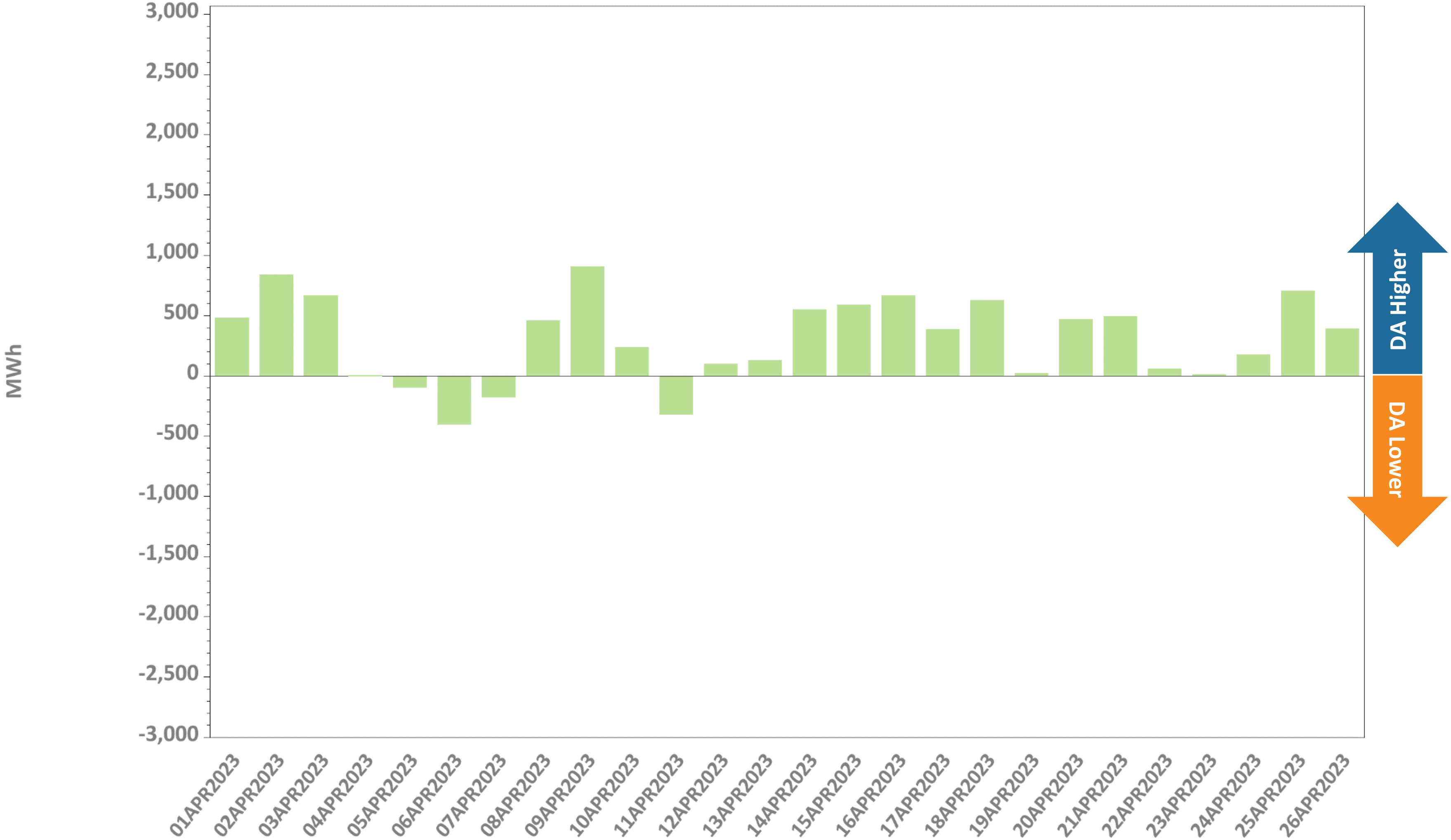
# DA Volumes as % of Forecast in Peak Hour



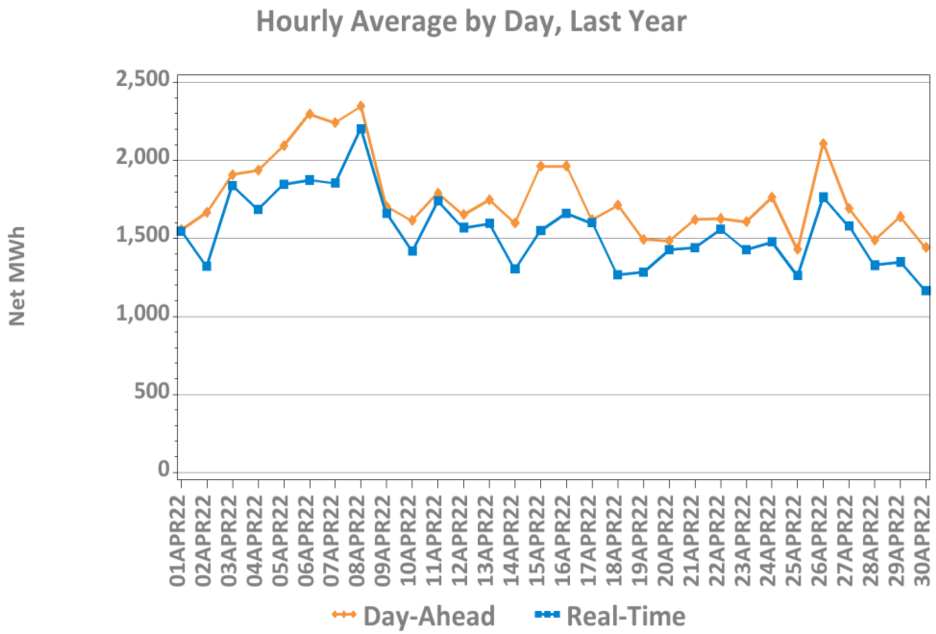

Note: There were no system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month.

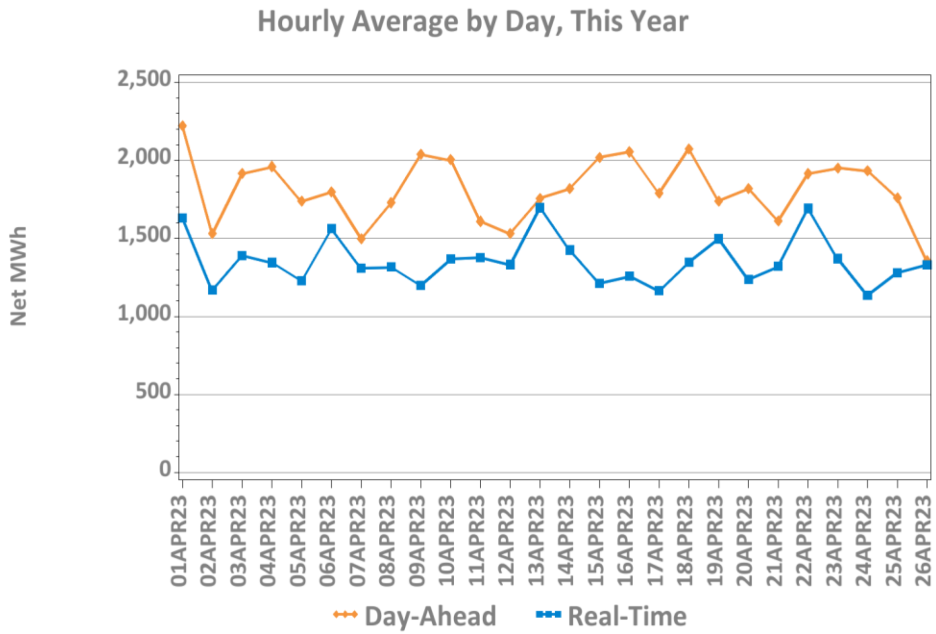
# DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*




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

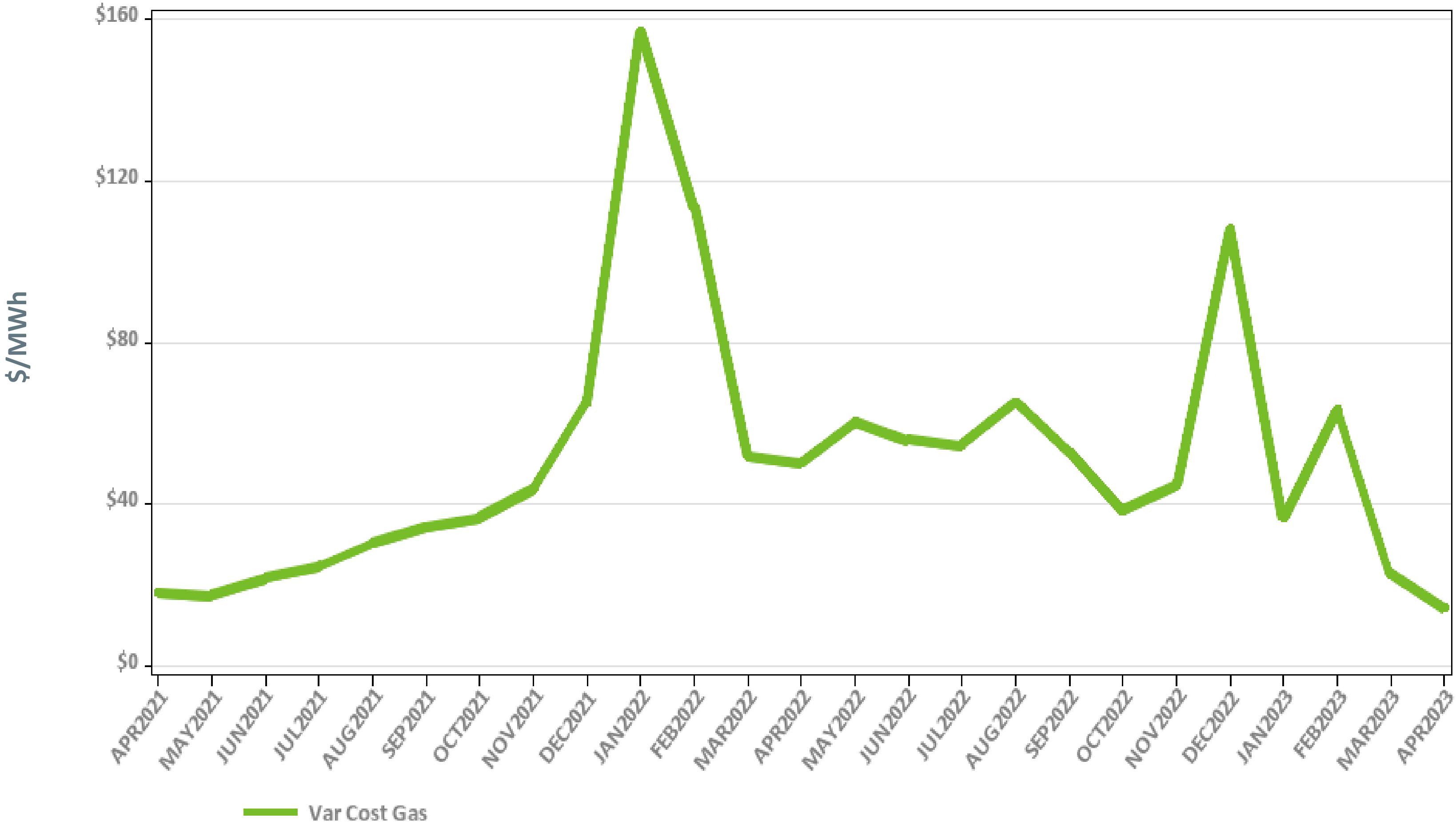
# DA vs. RT Net Interchange
# April 2023 vs. April 2022




**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

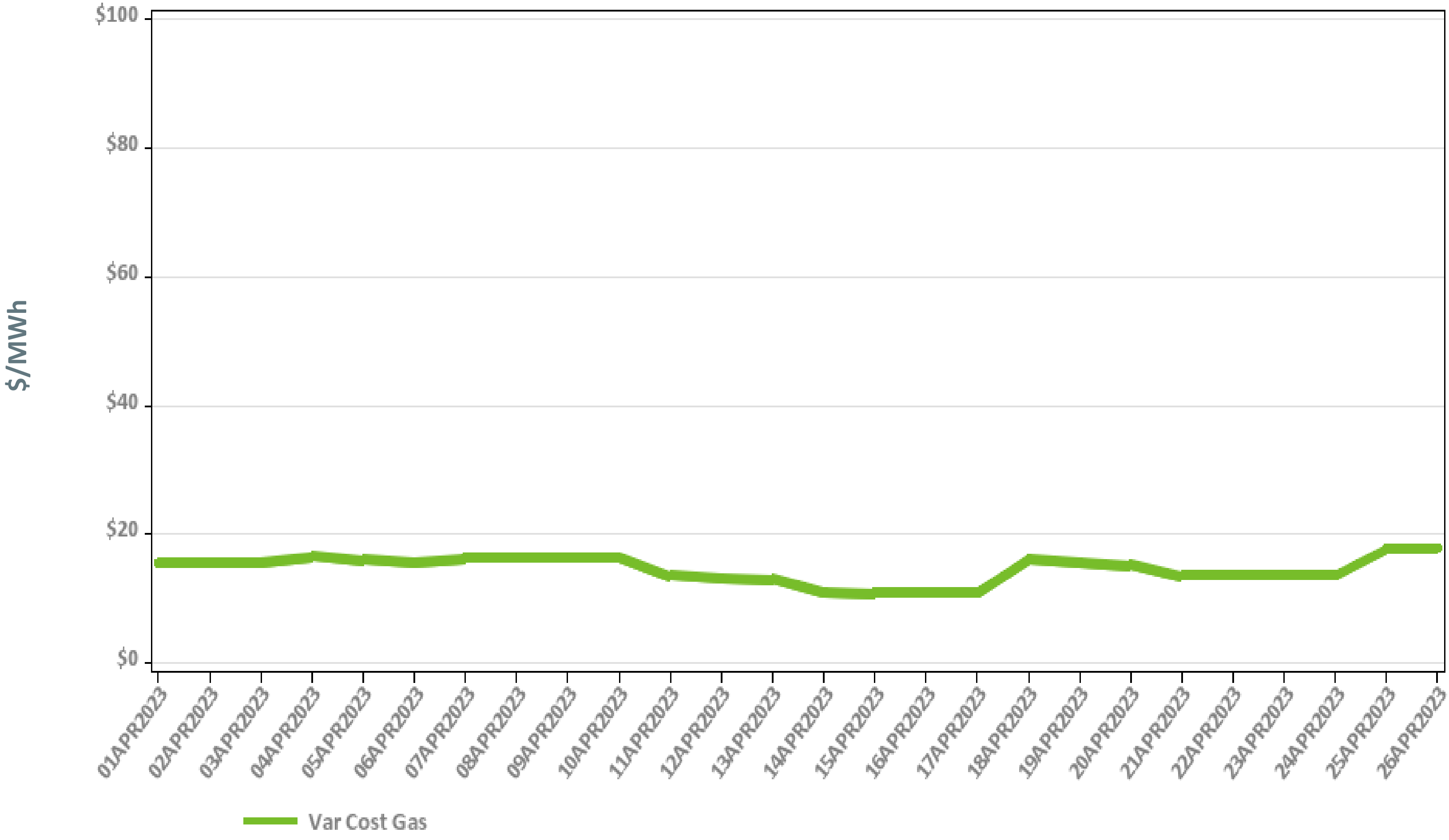



Underlying natural gas data furnished by:

ice Global markets in clear view

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

# Variable Production Cost of Natural Gas: Daily

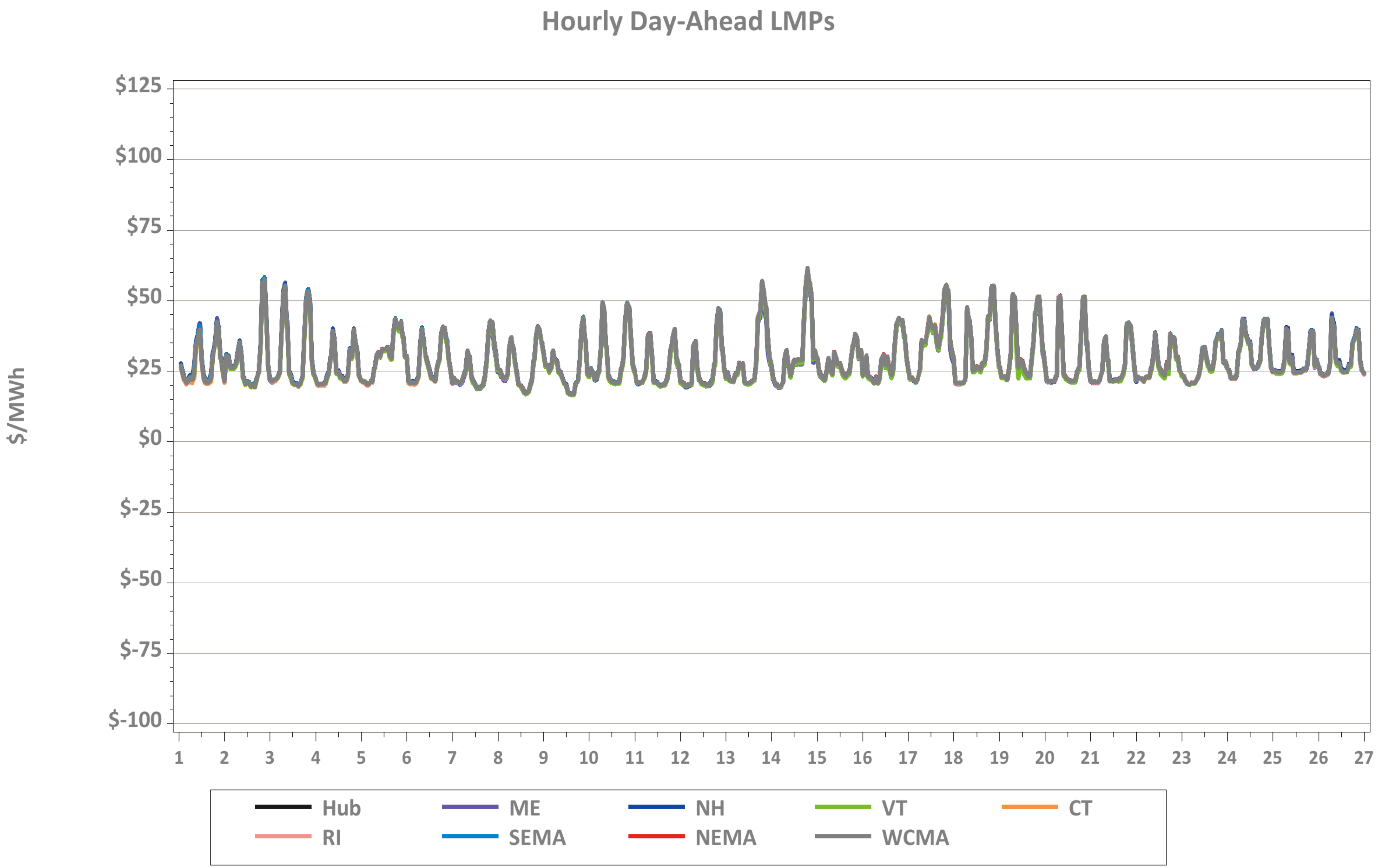



Underlying natural gas data furnished by:

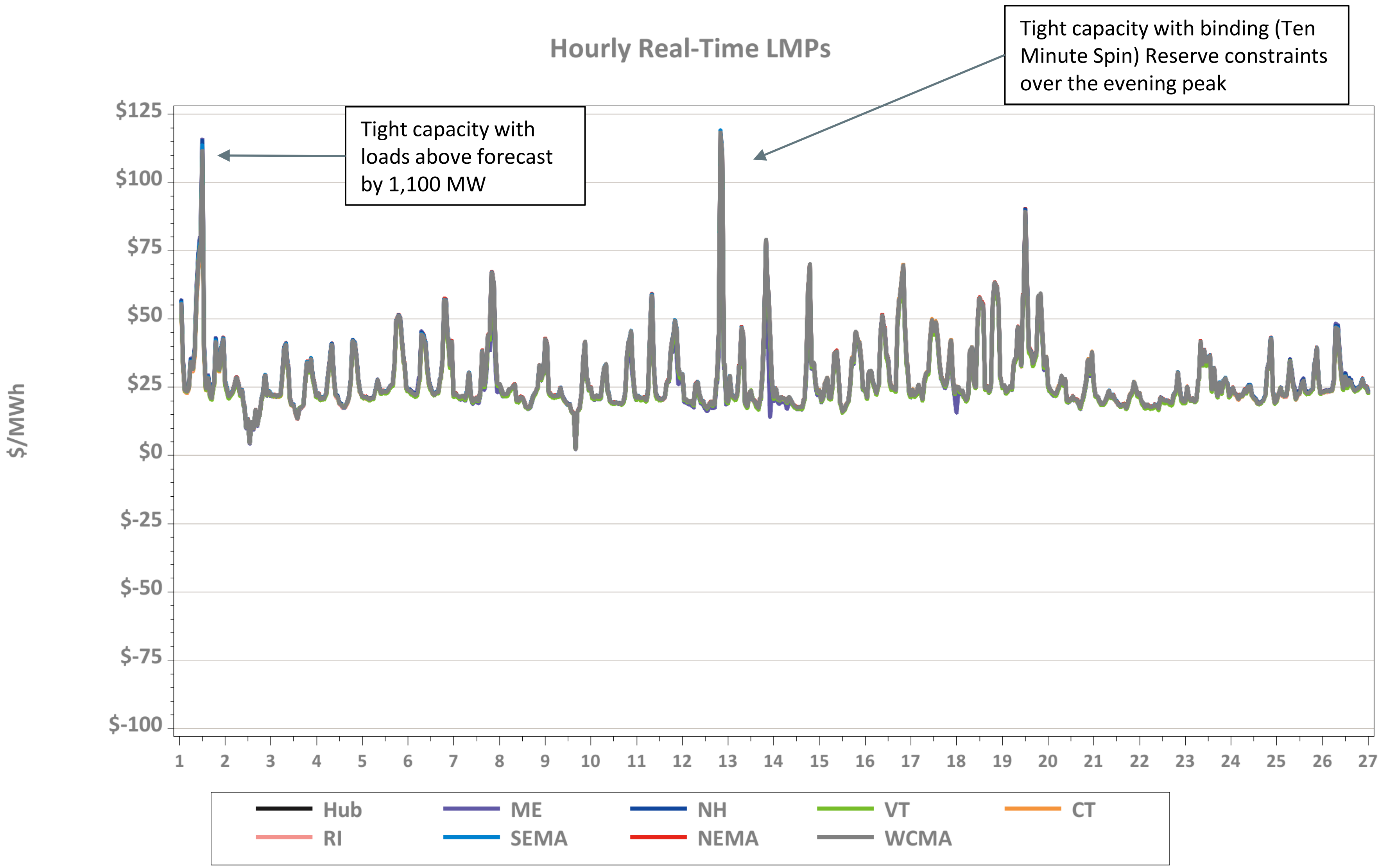
ICE Global markets in clear view

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

# Hourly DA LMPs, April 1-26, 2023

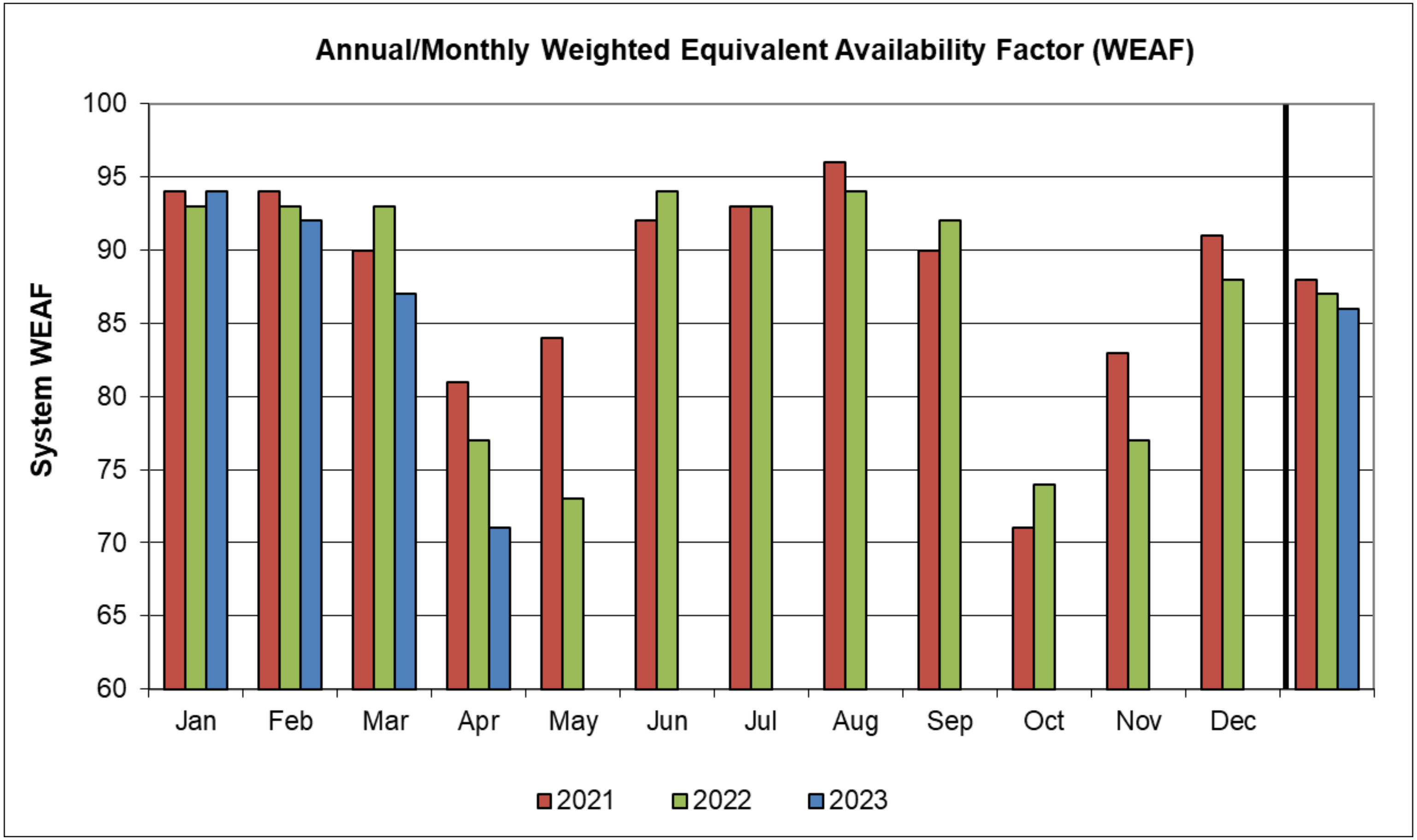


# Hourly RT LMPs, April 1-26, 2023




* BTM (Behind the meter)

# System Unit Availability




| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | YTD |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **2023** | 94 | 92 | 87 | 71 | | | | | | | | | 86 |
| **2022** | 93 | 93 | 93 | 77 | 73 | 94 | 93 | 94 | 92 | 74 | 77 | 88 | 87 |
| **2021** | 94 | 94 | 90 | 81 | 84 | 92 | 93 | 96 | 90 | 71 | 83 | 91 | 88 |

Data as of 4/25/2023

# BACK-UP DETAIL

# DEMAND RESPONSE

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

| Load Zone | ADCR* | On Peak | Seasonal Peak | Total |
|---|---|---|---|---|
| ME | 49.9 | 217.2 | 0.0 | 267.1 |
| NH | 38.9 | 189.8 | 0.0 | 228.8 |
| VT | 38.1 | 136.8 | 0.0 | 174.9 |
| CT | 122.8 | 238.5 | 622.4 | 983.7 |
| RI | 31.1 | 344.1 | 0.0 | 375.2 |
| SEMA | 40.6 | 513.1 | 0.0 | 553.7 |
| WCMA | 78.9 | 543.5 | 35.2 | 657.6 |
| NEMA | 59.6 | 865.3 | 0.0 | 924.9 |
| **Total** | **459.9** | **3,048.3** | **657.5** | **4,165.7** |

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

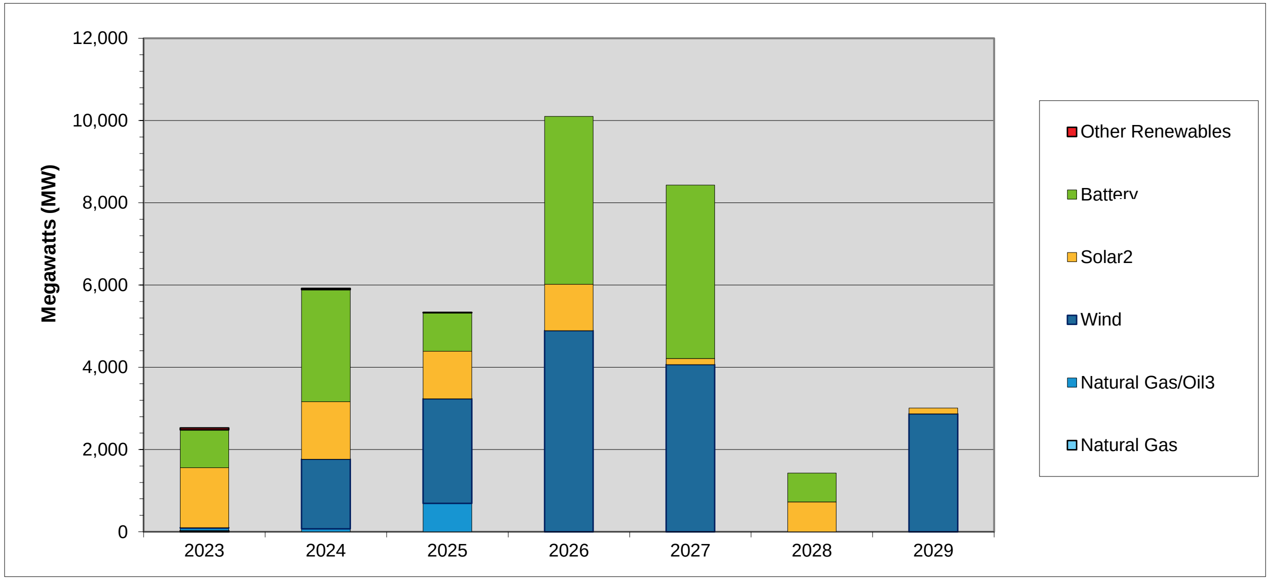
# NEW GENERATION

# New Generation Update
## *Based on Queue as of 4/28/23*

- Nine projects totaling 1,785 MW were added to the interconnection queue since the last update
  - Six battery projects, two solar projects and one wind project with in-service dates of 2026 to 2028
- In total, 359 generation projects are currently being tracked by the ISO, totaling approximately 37,621 MW

# Actual and Projected Annual Capacity Additions

## *By Supply Fuel Type and Demand Resource Type*




| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | Total MW | % of Total[1] |
|---|---|---|---|---|---|---|---|---|---|
| Other Renewables | 47 | 30 | 2 | 0 | 0 | 0 | 0 | 79 | 0.2 |
| Battery | 918 | 2,724 | 940 | 4,079 | 4,220 | 702 | 0 | 13,583 | 37.0 |
| Solar[2] | 1,456 | 1,396 | 1,157 | 1,128 | 150 | 725 | 139 | 6,151 | 16.7 |
| Wind | 12 | 1,693 | 2,545 | 4,893 | 4,064 | 0 | 2,870 | 16,077 | 43.8 |
| Natural Gas/Oil[3] | 62 | 73 | 688 | 0 | 0 | 0 | 0 | 823 | 2.2 |
| Natural Gas | 26 | 0 | 0 | 0 | 0 | 0 | 0 | 26 | 0.1 |
| **Totals** | **2,521** | **5,916** | **5,332** | **10,100** | **8,434** | **1,427** | **3,009** | **36,739** | **100.0** |

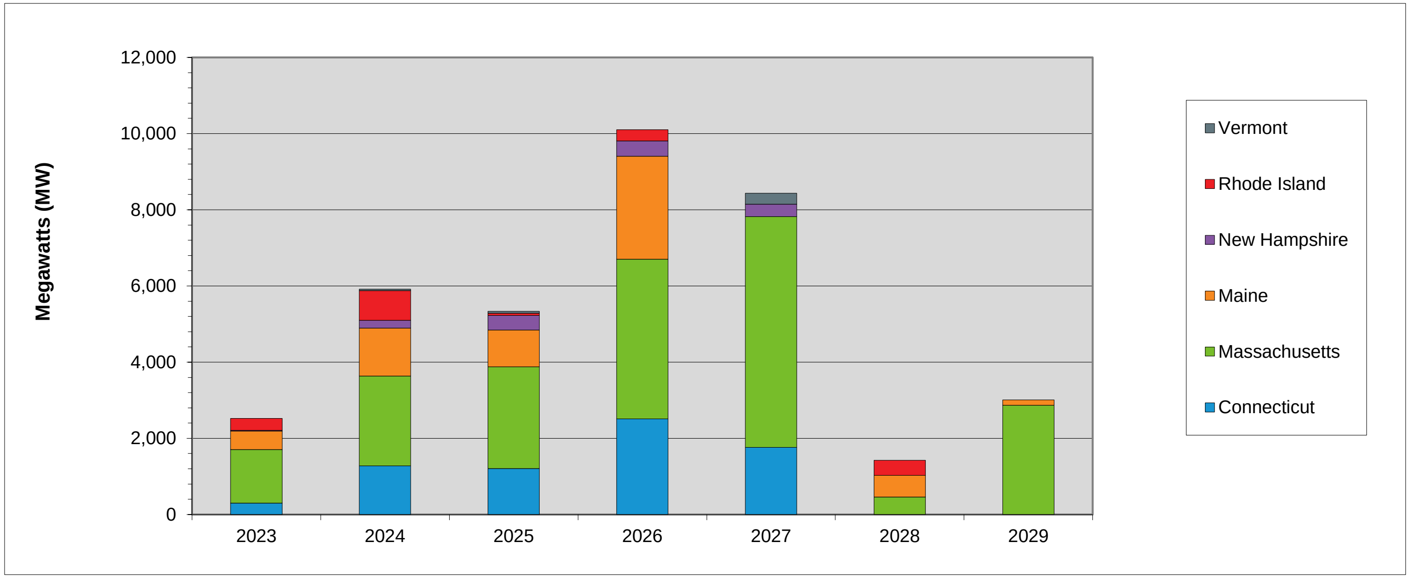
[1] Sum may not equal 100% due to rounding

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

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

# Actual and Projected Annual Generator Capacity Additions

## *By State*




| | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | Total MW | % of Total[1] |
|---|---|---|---|---|---|---|---|---|---|
| **Vermont** | 0 | 40 | 50 | 0 | 285 | 0 | 0 | 375 | 1.0 |
| **Rhode Island** | 308 | 777 | 54 | 295 | 0 | 400 | 0 | 1,834 | 5.0 |
| **New Hampshire** | 25 | 208 | 388 | 402 | 328 | 0 | 0 | 1,351 | 3.7 |
| **Maine** | 483 | 1,254 | 964 | 2,698 | 0 | 567 | 139 | 6,105 | 16.6 |
| **Massachusetts** | 1,405 | 2,362 | 2,670 | 4,196 | 6,060 | 460 | 2,870 | 20,023 | 54.5 |
| **Connecticut** | 300 | 1,275 | 1,206 | 2,509 | 1,761 | 0 | 0 | 7,051 | 19.2 |
| **Totals** | **2,521** | **5,916** | **5,332** | **10,100** | **8,434** | **1,427** | **3,009** | **36,739** | **100.0** |

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

# New Generation Projection

## *By Fuel Type*

| Unit Type | Total | | Green | | Yellow | |
|---|---|---|---|---|---|---|
| | No. of Projects | Capacity (MW) | No. of Projects | Capacity (MW) | No. of Projects | Capacity (MW) |
| Biomass/Wood Waste | 0 | 0 | 0 | 0 | 0 | 0 |
| Battery Storage | 95 | 13,583 | 2 | 24 | 93 | 13,559 |
| Fuel Cell | 4 | 46 | 0 | 0 | 4 | 46 |
| Hydro | 2 | 33 | 1 | 5 | 1 | 28 |
| Natural Gas | 3 | 26 | 0 | 0 | 3 | 26 |
| Natural Gas/Oil | 4 | 823 | 1 | 62 | 3 | 761 |
| Nuclear | 0 | 0 | 0 | 0 | 0 | 0 |
| Solar | 223 | 6,151 | 16 | 361 | 207 | 5,790 |
| Wind | 28 | 16,959 | 0 | 0 | 28 | 16,959 |
| Total | 359 | 37,621 | 20 | 452 | 339 | 37,169 |

- Projects in the Natural Gas/Oil category may have either gas or oil as the primary fuel
- Green denotes projects with a high probability of going into service within the next 12 months
- Yellow denotes projects with a lower probability of going into service or new applications

# New Generation Projection

## *By Operating Type*

| Operating Type | Total | | Green | | Yellow | |
|---|---|---|---|---|---|---|
| | No. of Projects | Capacity (MW) | No. of Projects | Capacity (MW) | No. of Projects | Capacity (MW) |
| Baseload | 7 | 88 | 1 | 5 | 6 | 83 |
| Intermediate | 3 | 761 | 0 | 0 | 3 | 761 |
| Peaker | 321 | 19,813 | 19 | 447 | 302 | 19,366 |
| Wind Turbine | 28 | 16,959 | 0 | 0 | 28 | 16,959 |
| Total | 359 | 37,621 | 20 | 452 | 339 | 37,169 |

- Green denotes projects with a high probability of going into service within the next 12 months
- Yellow denotes projects with a lower probability of going into service or new applications

# New Generation Projection

## *By Operating Type and Fuel Type*

| Unit Type | Total | | Baseload | | Intermediate | | Peaker | | Wind Turbine | |
|---|---|---|---|---|---|---|---|---|---|---|
| | No. of Projects | Capacity (MW) | No. of Projects | Capacity (MW) | No. of Projects | Capacity (MW) | No. of Projects | Capacity (MW) | No. of Projects | Capacity (MW) |
| Biomass/Wood Waste | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Battery Storage | 95 | 13,583 | 0 | 0 | 0 | 0 | 95 | 13,583 | 0 | 0 |
| Fuel Cell | 4 | 46 | 4 | 46 | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydro | 2 | 33 | 2 | 33 | 0 | 0 | 0 | 0 | 0 | 0 |
| Natural Gas | 3 | 26 | 1 | 9 | 0 | 0 | 2 | 17 | 0 | 0 |
| Natural Gas/Oil | 4 | 823 | 0 | 0 | 3 | 761 | 1 | 62 | 0 | 0 |
| Nuclear | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Solar | 223 | 6,151 | 0 | 0 | 0 | 0 | 223 | 6,151 | 0 | 0 |
| Wind | 28 | 16,959 | 0 | 0 | 0 | 0 | 0 | 0 | 28 | 16,959 |
| Total | 359 | 37,621 | 7 | 88 | 3 | 761 | 321 | 19,813 | 28 | 16,959 |

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

# FORWARD CAPACITY MARKET

# Capacity Supply Obligation FCA 14

| Resource Type | Resource Type | | FCA | ARA 1 | | ARA 2 | | ARA 3 | |
|---|---|---|---|---|---|---|---|---|---|
| | | | CSO | CSO | Change | CSO | Change | CSO | Change |
| | | | MW | MW | MW | MW | MW | MW | MW |
| Demand | *Active Demand* | | 592.043 | 688.07 | 96.027 | 659.671 | -28.399 | 564.371 | -95.3 |
| | *Passive Demand* | | 3,327.071 | 3,327.932 | 0.861 | 3,315.207 | -12.725 | 3,253.179 | -62.028 |
| **Demand Total** | | | **3,919.114** | **4,016.002** | **96.888** | **3,974.878** | **-41.124** | **3,817.550** | **-157.328** |
| Generator | | *Non-Intermittent* | 27,816.902 | 28,275.143 | 458.241 | 27,697.714 | -577.429 | 27,684.252 | -13.462 |
| | | *Intermittent* | 1,160.916 | 1,128.446 | -32.47 | 925.942 | -202.504 | 893.444 | -32.498 |
| **Generator Total** | | | **28,977.818** | **29,403.589** | **425.771** | **28,623.656** | **-779.933** | **28,577.696** | **-45.96** |
| **Import Total** | | | **1,058.72** | **1,058.72** | **0** | **1,029.800** | **-28.92** | **958.380** | **-71.42** |
| **Grand Total*** | | | **33,955.652** | **34,478.311** | **522.661** | **33,628.334** | **-849.977** | **33,353.626** | **-274.708** |
| **Net ICR (NICR)** | | | **32,490** | **32,980** | **490** | **31,480** | **-1,500** | **31,690** | **210** |

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2023 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

# Capacity Supply Obligation FCA 15

| Resource Type | Resource Type | FCA | ARA 1 | | ARA 2 | | ARA 3 | |
|---|---|---|---|---|---|---|---|---|
| | | CSO | CSO | Change | CSO | Change | CSO | Change |
| | | MW | MW | MW | MW | MW | MW | MW |
| Demand | *Active Demand* | 677.673 | 673.401 | -4.272 | | | | |
| | *Passive Demand* | 3,212.865 | 3,211.403 | -1.462 | | | | |
| **Demand Total** | | **3,890.538** | **3,884.804** | **-5.734** | | | | |
| Generator | *Non-Intermittent* | 28,154.203 | 27,714.778 | -439.425 | | | | |
| | *Intermittent* | 1,089.265 | 1,073.794 | -15.471 | | | | |
| **Generator Total** | | **29,243.468** | **28,788.572** | **-454.896** | | | | |
| **Import Total** | | **1,487.059** | **1297.132** | **-189.927** | | | | |
| **Grand Total*** | | **34,621.065** | **33,970.508** | **-650.557** | | | | |
| **Net ICR (NICR)** | | **33,270** | **31,775** | **-1,495** | | | | |

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond and reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2023 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

# Capacity Supply Obligation FCA 16

| Resource Type | Resource Type | FCA | ARA 1 | | ARA 2 | | ARA 3 | |
|---|---|---|---|---|---|---|---|---|
| | | CSO | CSO | Change | CSO | Change | CSO | Change |
| | | MW | MW | MW | MW | MW | MW | MW |
| **Demand** | *Active Demand* | 765.35 | | | | | | |
| | *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 reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2023 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

# Capacity Supply Obligation FCA 17

| Resource Type | Resource Type | FCA | ARA 1 | | ARA 2 | | ARA 3 | |
|---|---|---|---|---|---|---|---|---|
| | | CSO | CSO | Change | CSO | Change | CSO | Change |
| | | MW | MW | MW | MW | MW | MW | MW |
| Demand | *Active Demand* | 622.854 | | | | | | |
| | *Passive Demand* | 2,316.815 | | | | | | |
| **Demand Total** | | **2,939.669** | | | | | | |
| Generator | *Non-Intermittent* | 26,507.420 | | | | | | |
| | *Intermittent* | 1,356.084 | | | | | | |
| **Generator Total** | | **27,863.504** | | | | | | |
| **Import Total** | | **566.998** | | | | | | |
| **Grand Total*** | | **31,370.171** | | | | | | |
| **Net ICR (NICR)** | | **30,305** | | | | | | |

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond reconfiguration auctions may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2023 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

# Active/Passive Demand Response

## *CSO Totals by Commitment Period*

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

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

# What are Daily NCPC Payments?

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

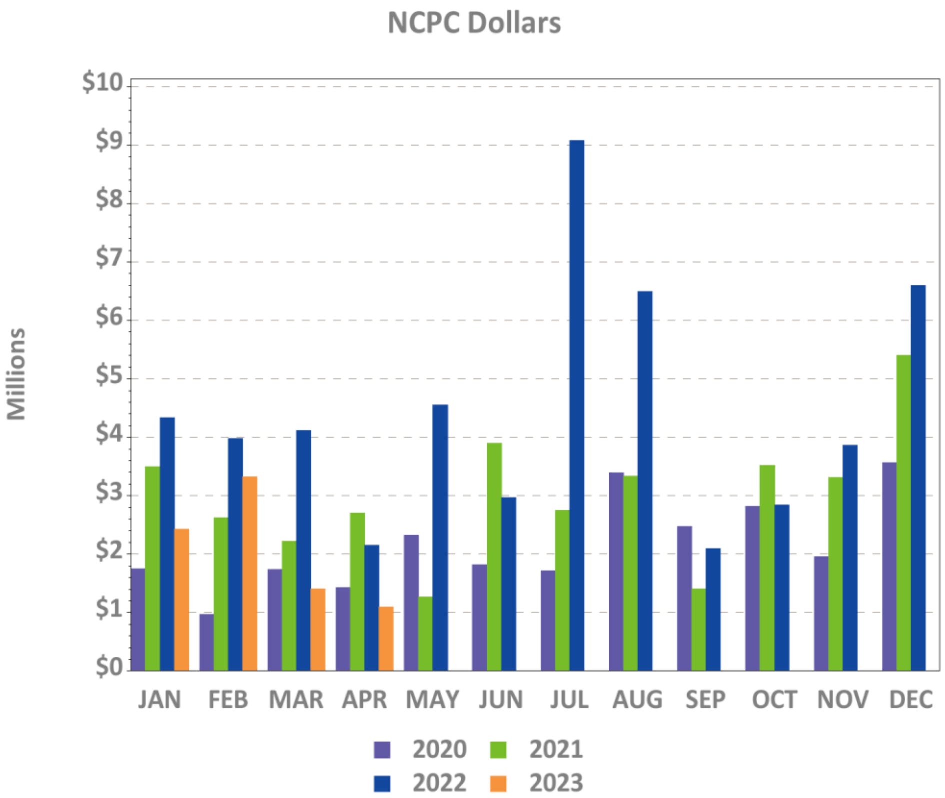
# Definitions

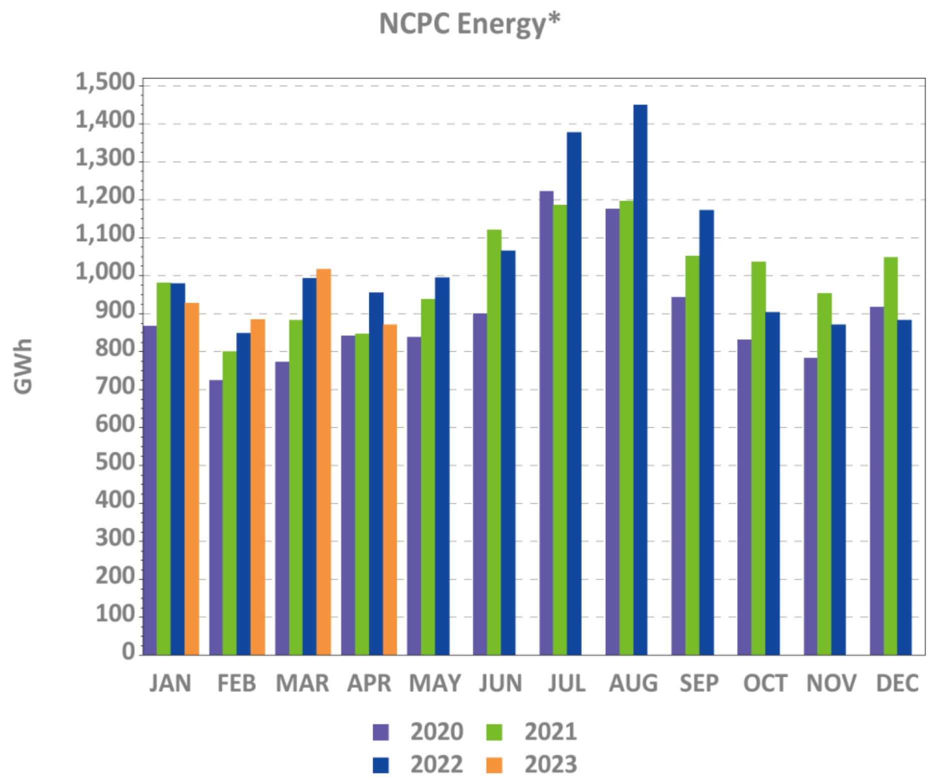
| | |
|---|---|
| 1st Contingency NCPC Payments | Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally |
| 2nd Contingency NCPC Payments | Reliability costs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

# Charge Allocation Key

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

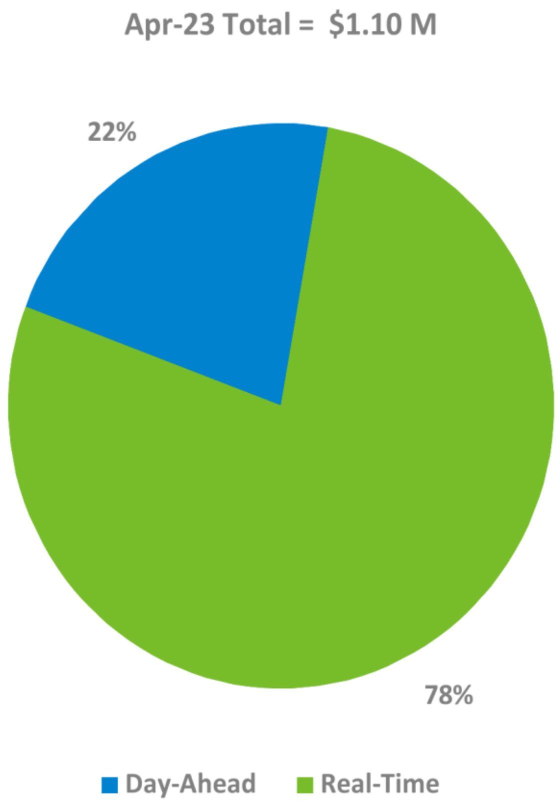
# Year-Over-Year Total NCPC Dollars and Energy

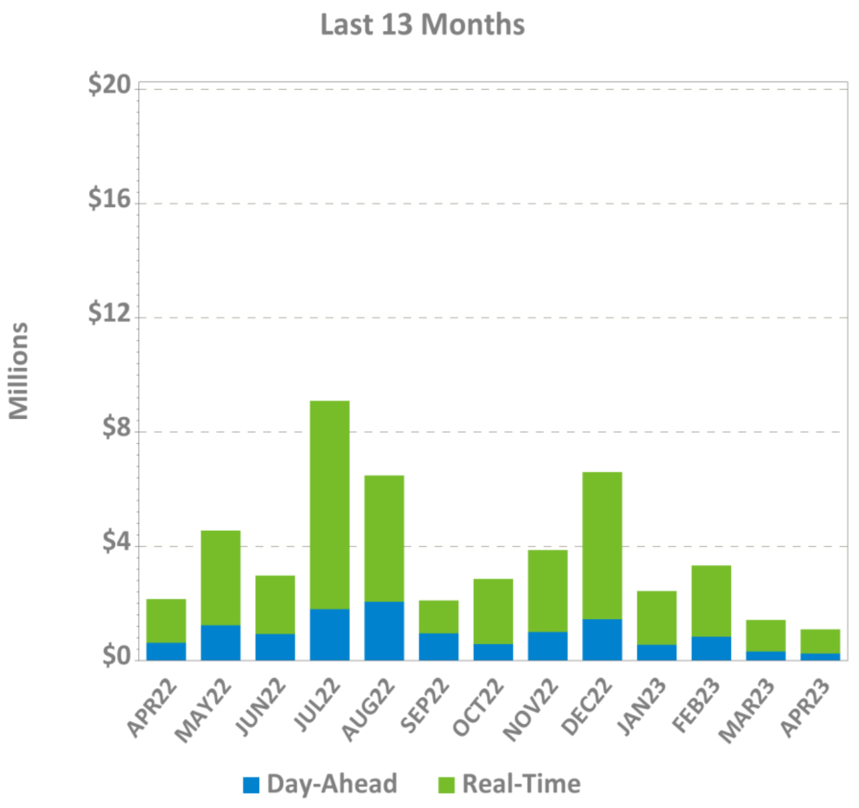


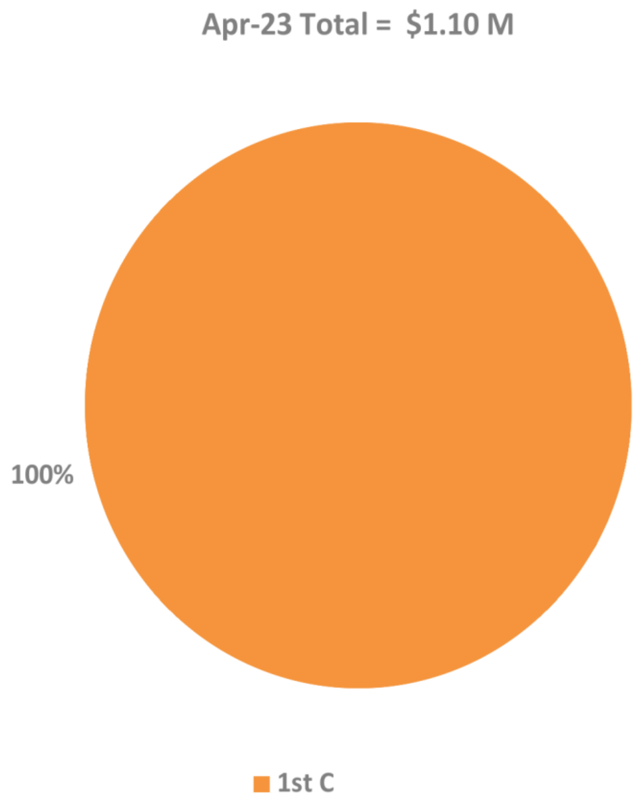

*** NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

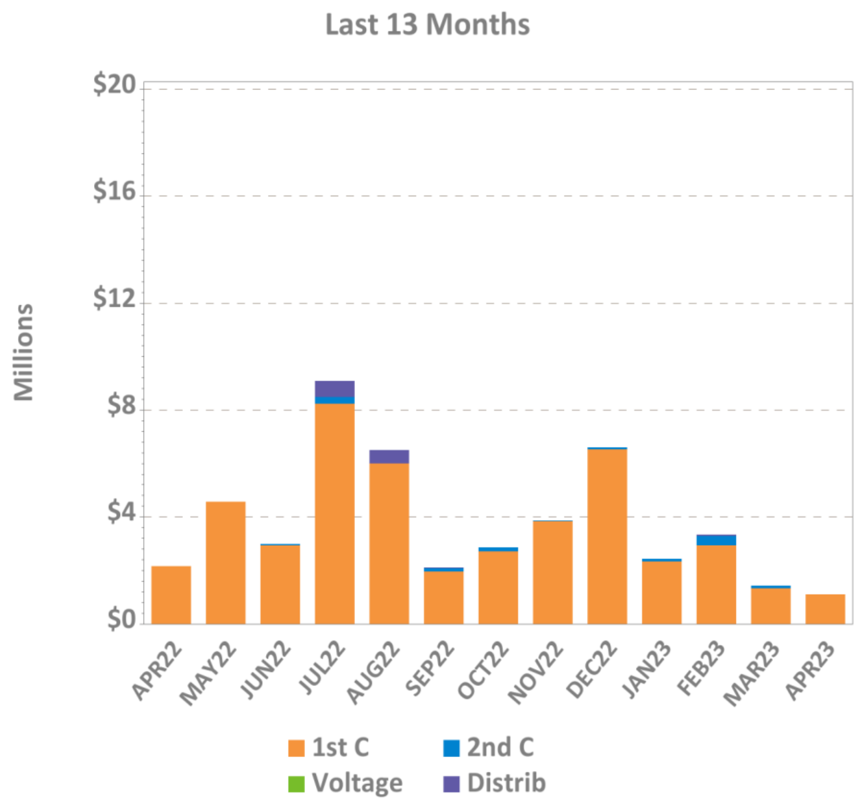
# DA and RT NCPC Charges



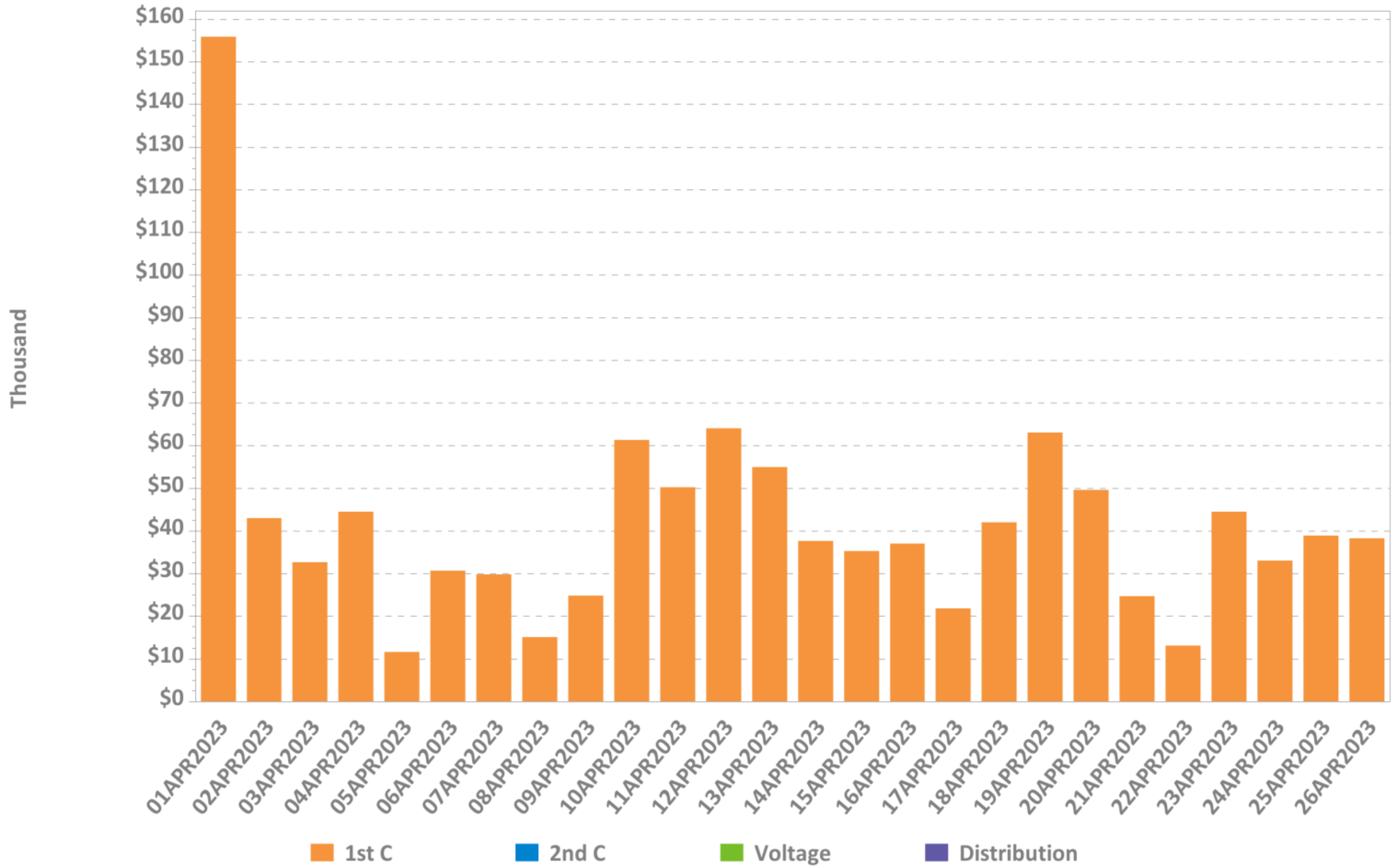
# NCPC Charges by Type



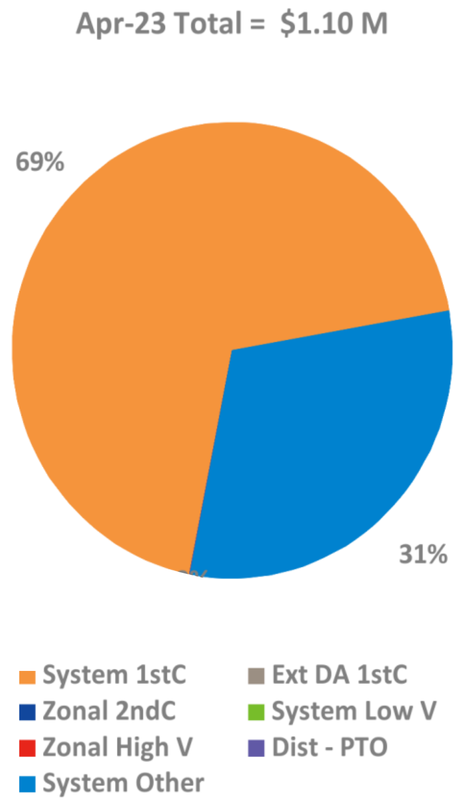



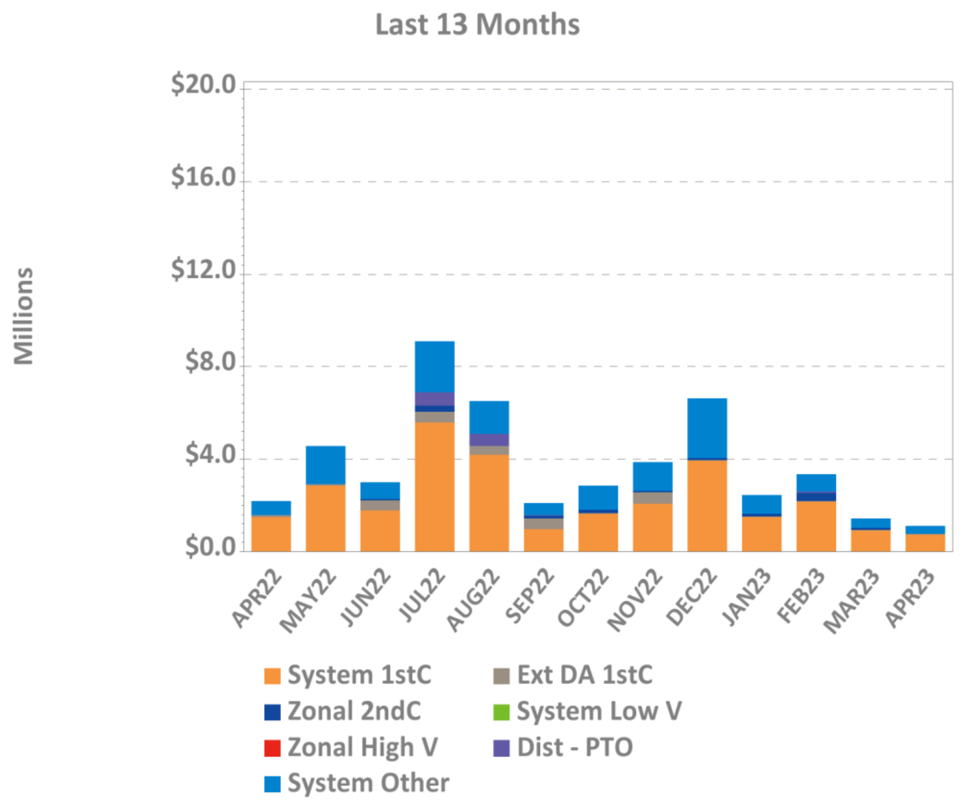

1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

# Daily NCPC Charges by Type



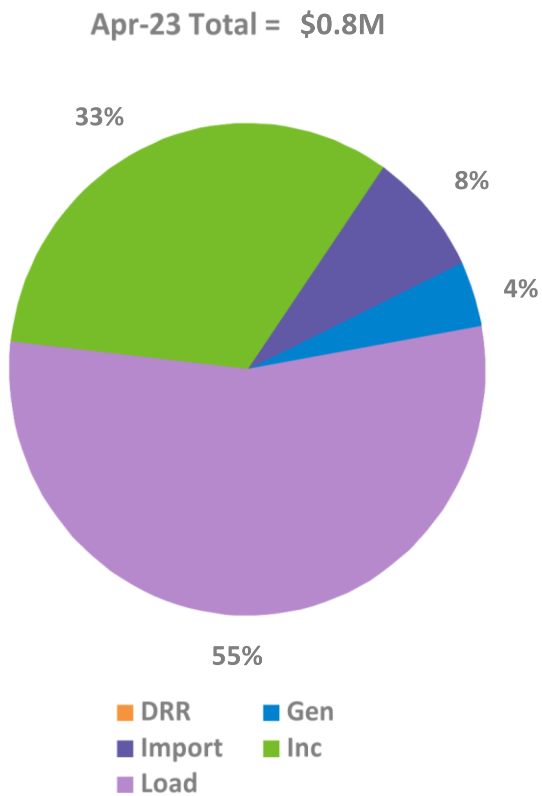
# NCPC Charges by Allocation

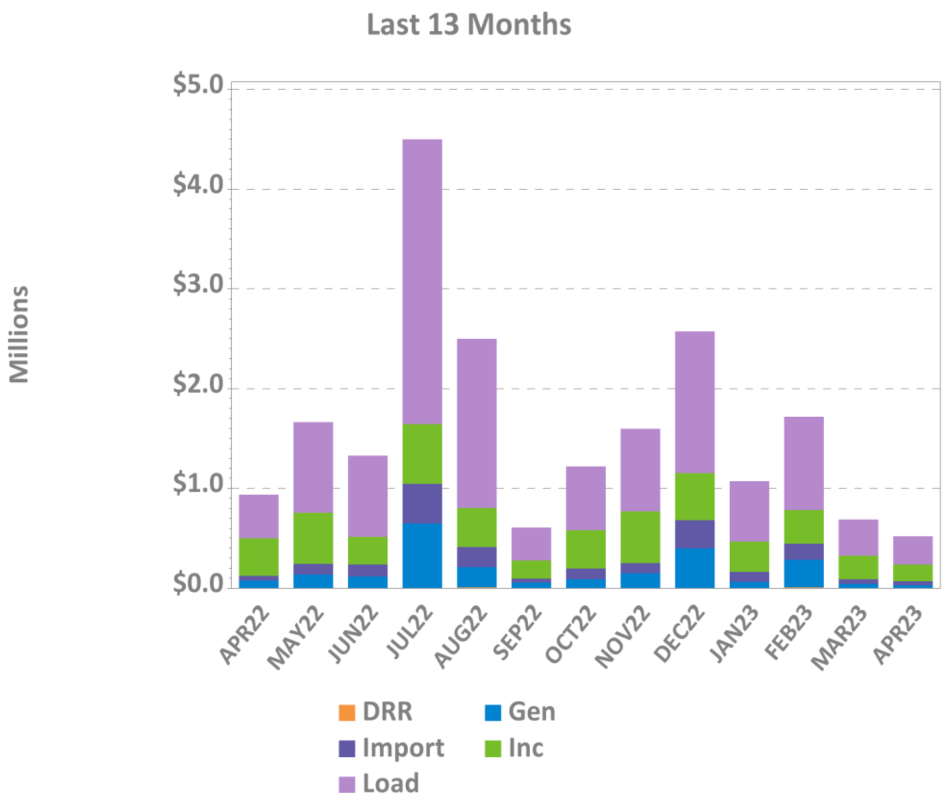



Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

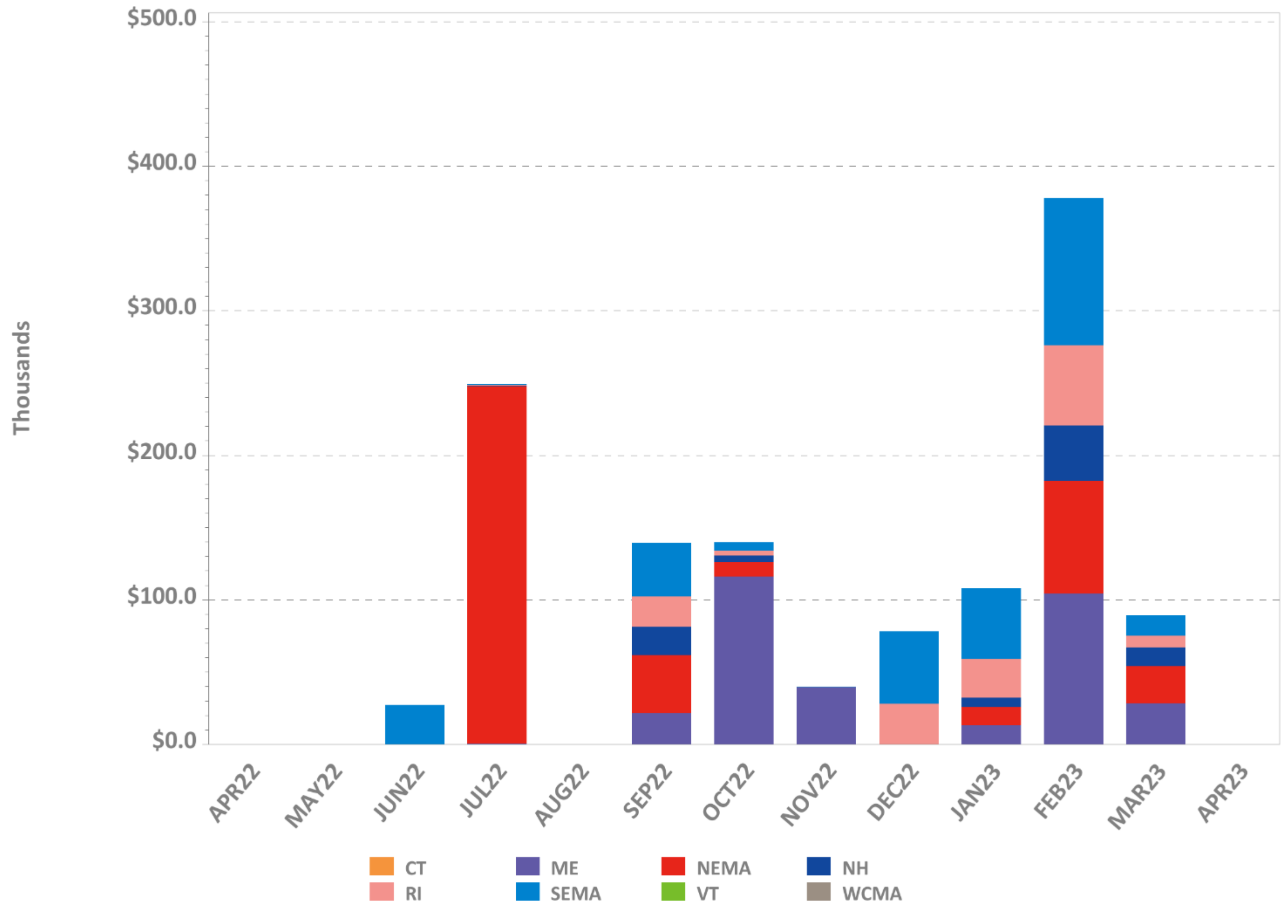
# RT First Contingency Charges by Deviation Type




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

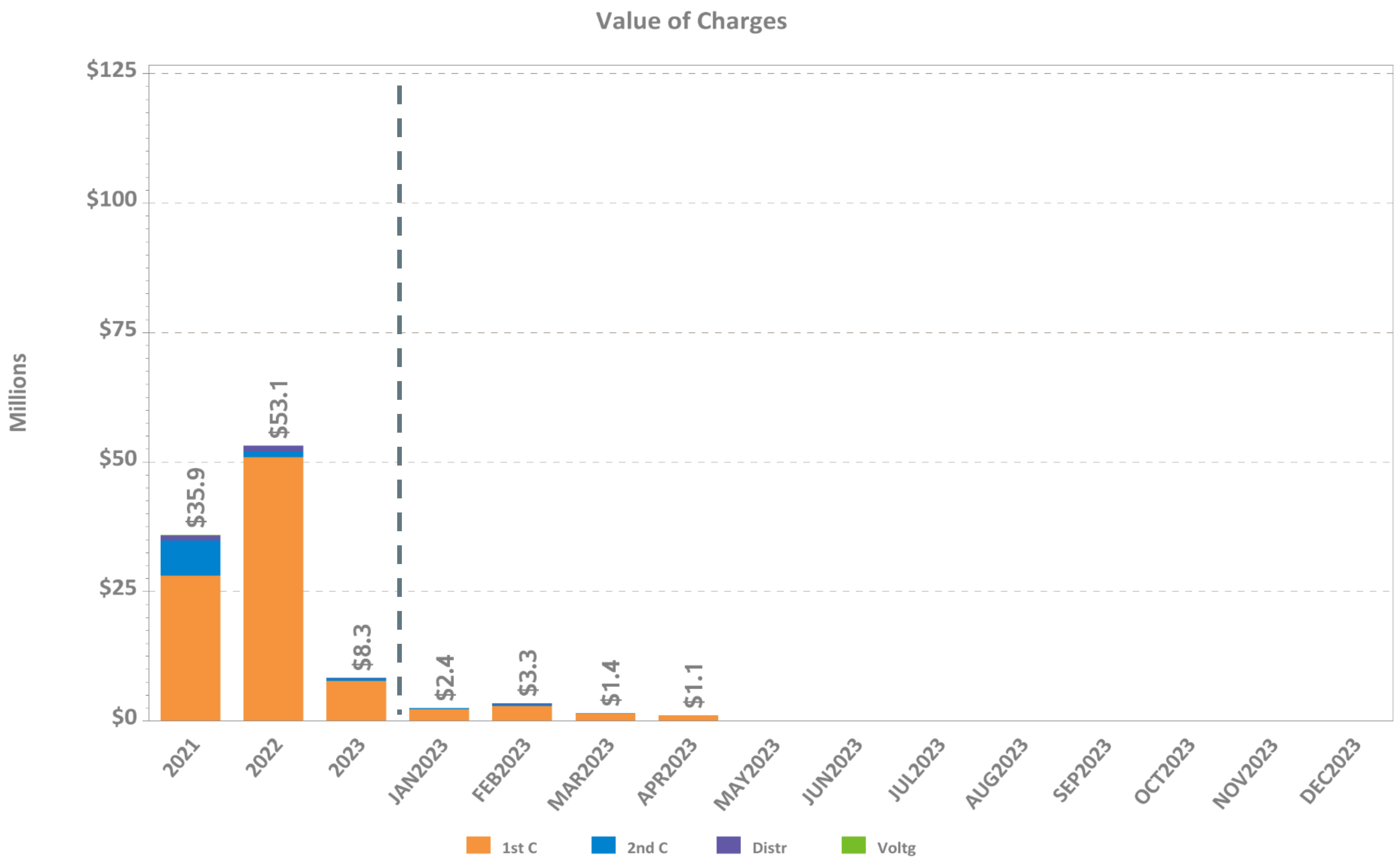
# LSCPR Charges by Reliability Region



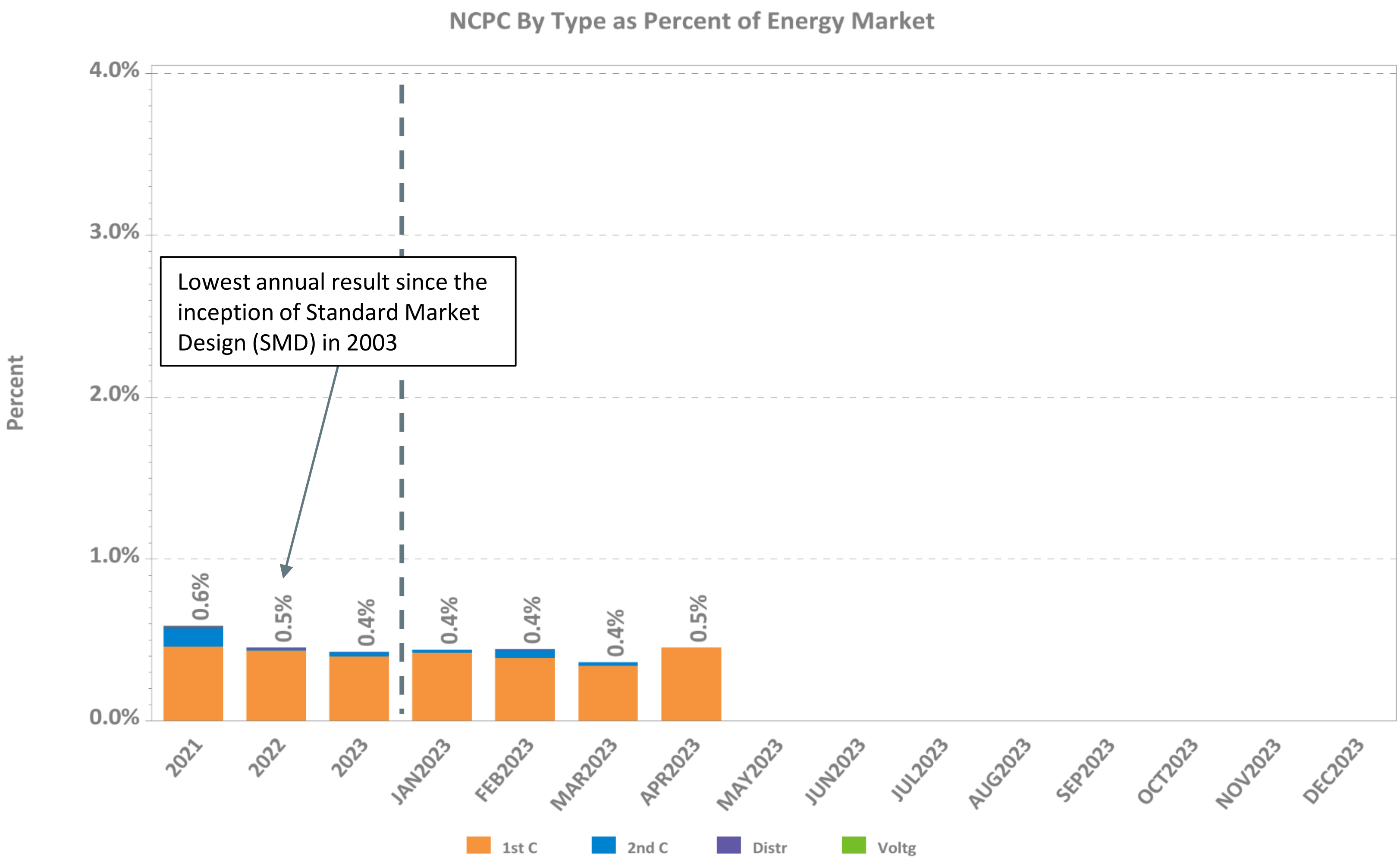

CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

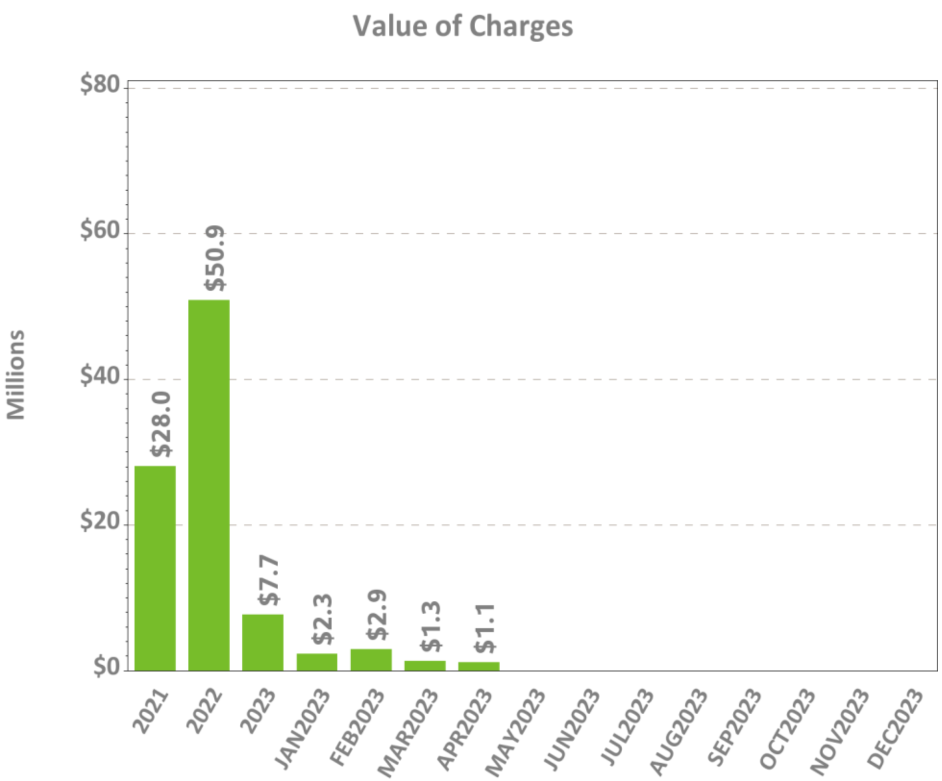
# NCPC Charges by Type

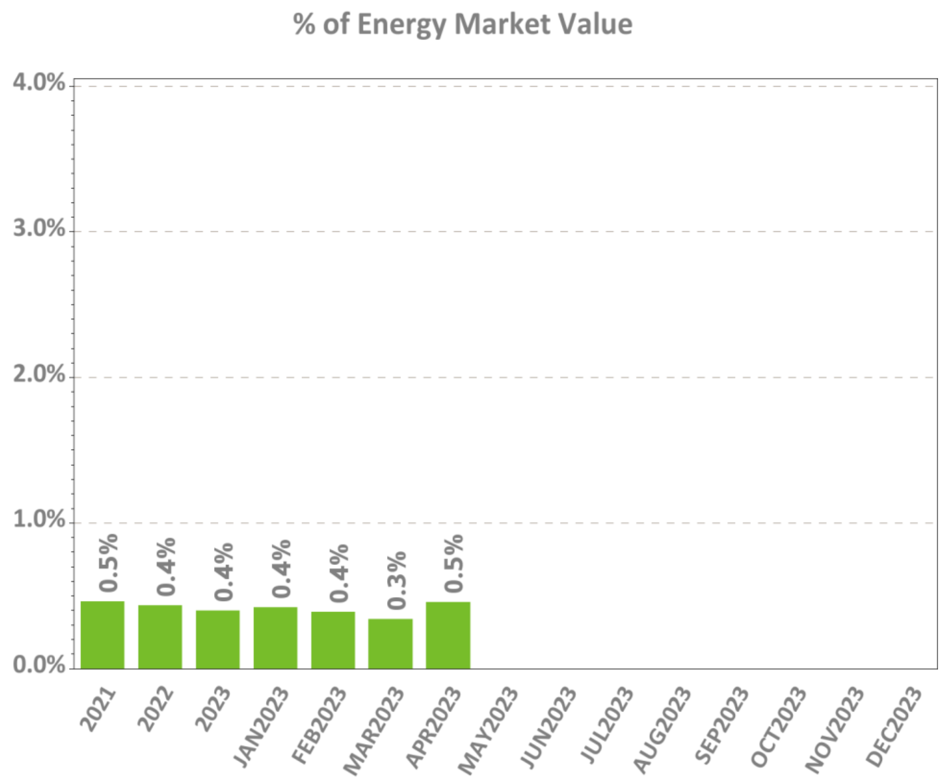


# NCPC Charges as Percent of Energy Market



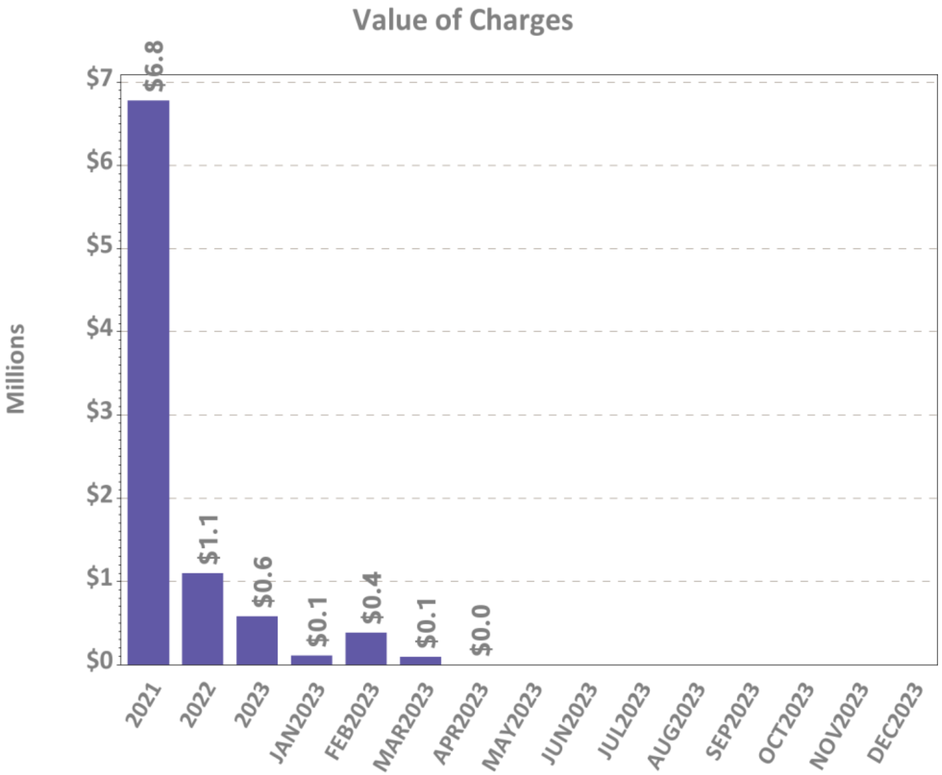
# First Contingency NCPC Charges

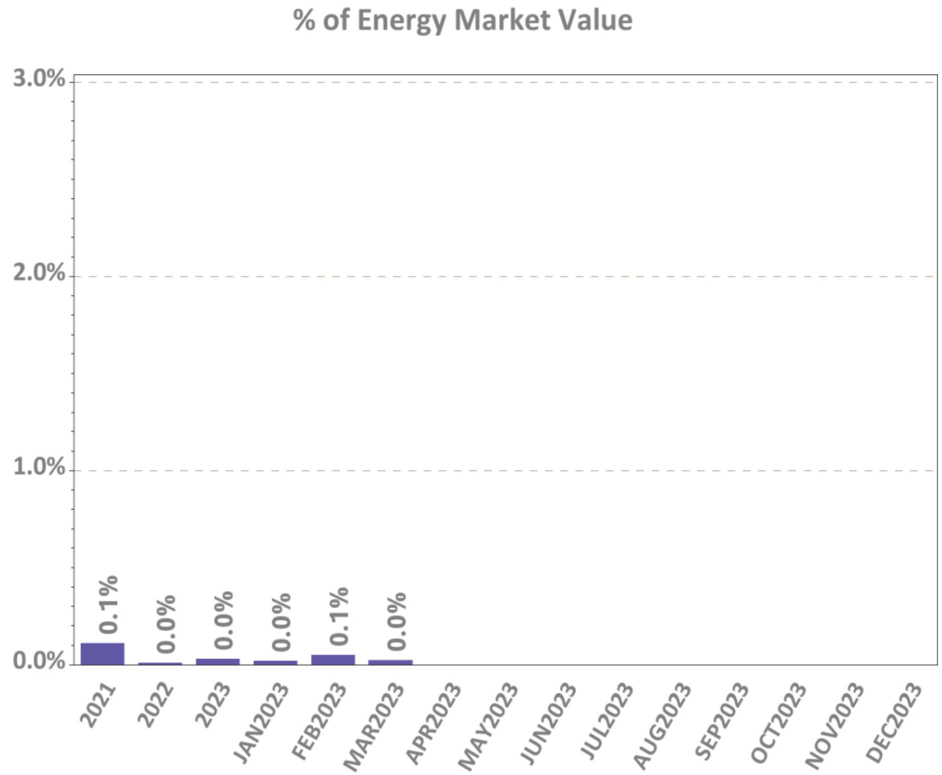



**Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market**

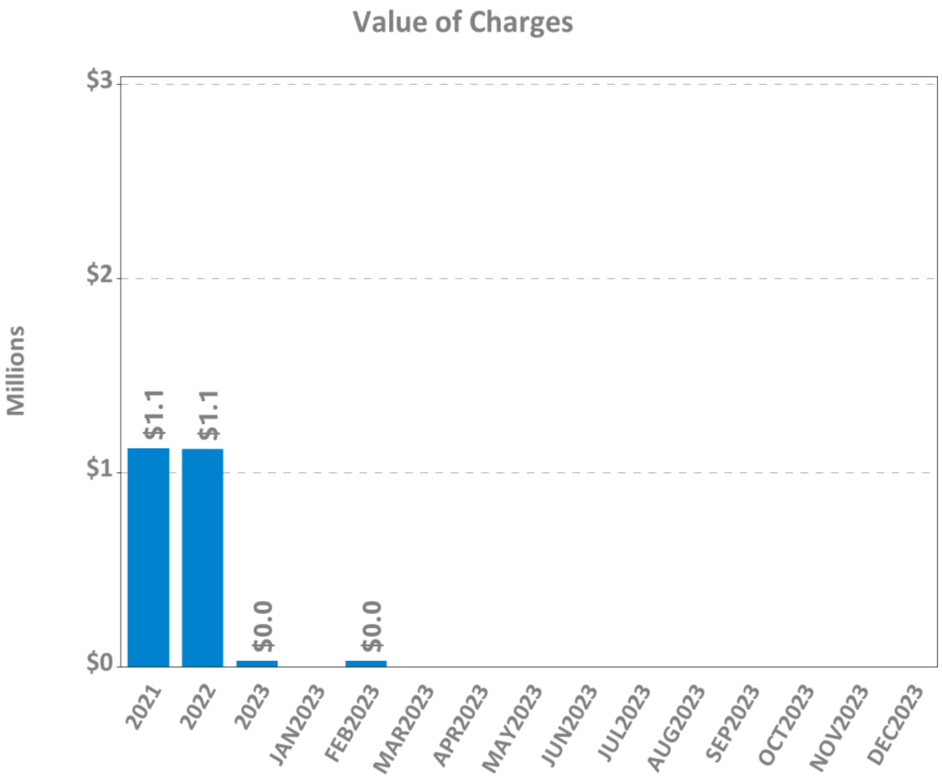
# Second Contingency NCPC Charges

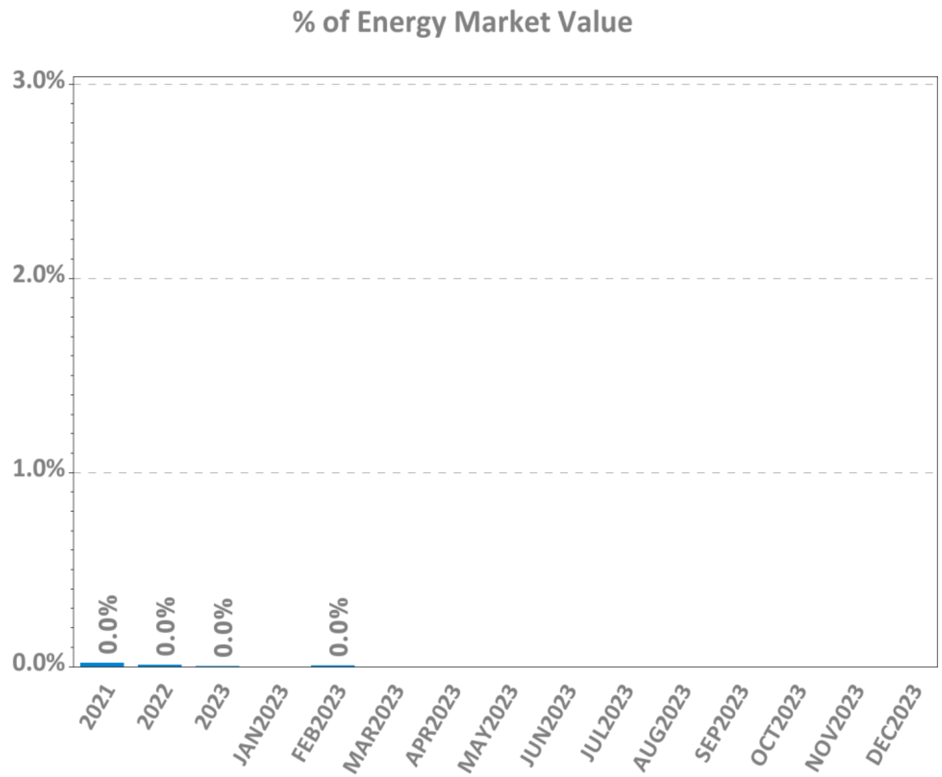



**Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market**

# Voltage and Distribution NCPC Charges




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

# DA vs. RT Pricing

**The following slides outline:**

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

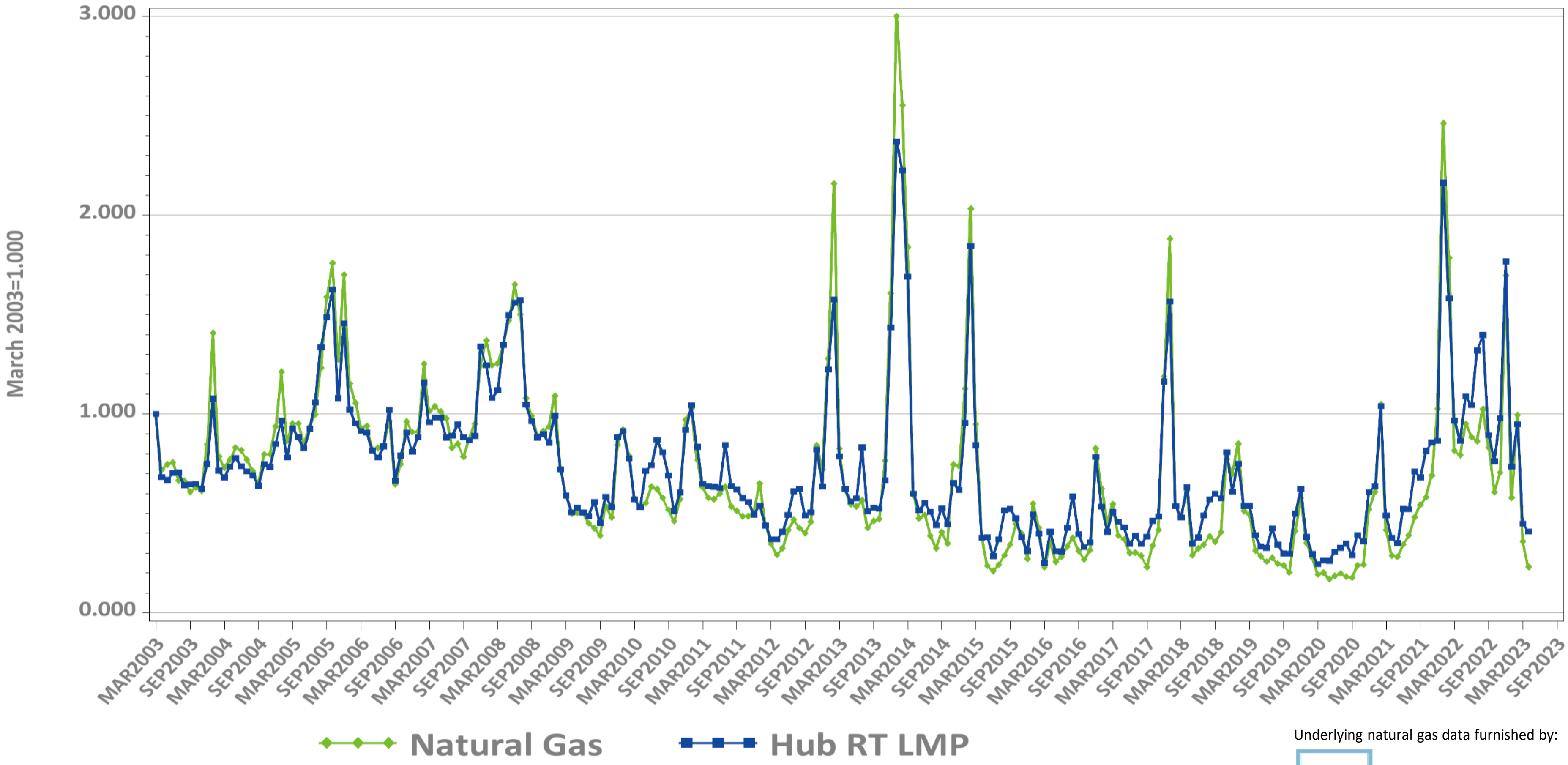
# DA vs. RT LMPs ($/MWh)

Arithmetic Average

| Year 2021 | NEMA | CT | ME | NH | VT | RI | SEMA | WCMA | Hub |
|---|---|---|---|---|---|---|---|---|---|
| Day-Ahead | $46.54 | $44.60 | $45.52 | $46.27 | $45.05 | $45.88 | $46.38 | $45.91 | $45.92 |
| Real-Time | $45.25 | $43.97 | $44.28 | $45.10 | $44.15 | $44.61 | $45.09 | $44.85 | $44.84 |
| RT Delta % | -2.8% | -1.4% | -2.7% | -2.5% | -2.0% | -2.8% | -2.8% | -2.3% | -2.3% |
| Year 2022 | NEMA | CT | ME | NH | VT | RI | SEMA | WCMA | Hub |
| Day-Ahead | $86.07 | $84.05 | $84.15 | $85.73 | $84.46 | $85.35 | $86.01 | $85.66 | $85.55 |
| Real-Time | $85.42 | $83.83 | $83.06 | $85.07 | $83.67 | $84.71 | $85.37 | $85.00 | $84.92 |
| RT Delta % | -0.8% | -0.3% | -1.3% | -0.8% | -0.9% | -0.7% | -0.7% | -0.8% | -0.7% |

| April-22 | NEMA | CT | ME | NH | VT | RI | SEMA | WCMA | Hub |
|---|---|---|---|---|---|---|---|---|---|
| Day-Ahead | $62.65 | $62.47 | $59.39 | $61.47 | $60.35 | $62.49 | $62.91 | $62.50 | $62.37 |
| Real-Time | $59.62 | $59.56 | $55.42 | $58.36 | $57.33 | $59.45 | $59.85 | $59.42 | $59.39 |
| RT Delta % | -4.8% | -4.7% | -6.7% | -5.1% | -5.0% | -4.9% | -4.9% | -4.9% | -4.8% |
| April-23 | NEMA | CT | ME | NH | VT | RI | SEMA | WCMA | Hub |
| Day-Ahead | $29.17 | $28.79 | $28.55 | $28.98 | $28.37 | $28.77 | $29.07 | $29.06 | $29.01 |
| Real-Time | $28.27 | $27.91 | $27.34 | $28.04 | $27.42 | $27.84 | $28.14 | $28.11 | $28.09 |
| RT Delta % | -3.1% | -3.0% | -4.2% | -3.2% | -3.4% | -3.2% | -3.2% | -3.2% | -3.1% |
| Annual Diff. | NEMA | CT | ME | NH | VT | RI | SEMA | WCMA | Hub |
| Yr over Yr DA | -53.4% | -53.9% | -51.9% | -52.8% | -53.0% | -54.0% | -53.8% | -53.5% | -53.5% |
| Yr over Yr RT | -52.6% | -53.1% | -50.7% | -52.0% | -52.2% | -53.2% | -53.0% | -52.7% | -52.7% |

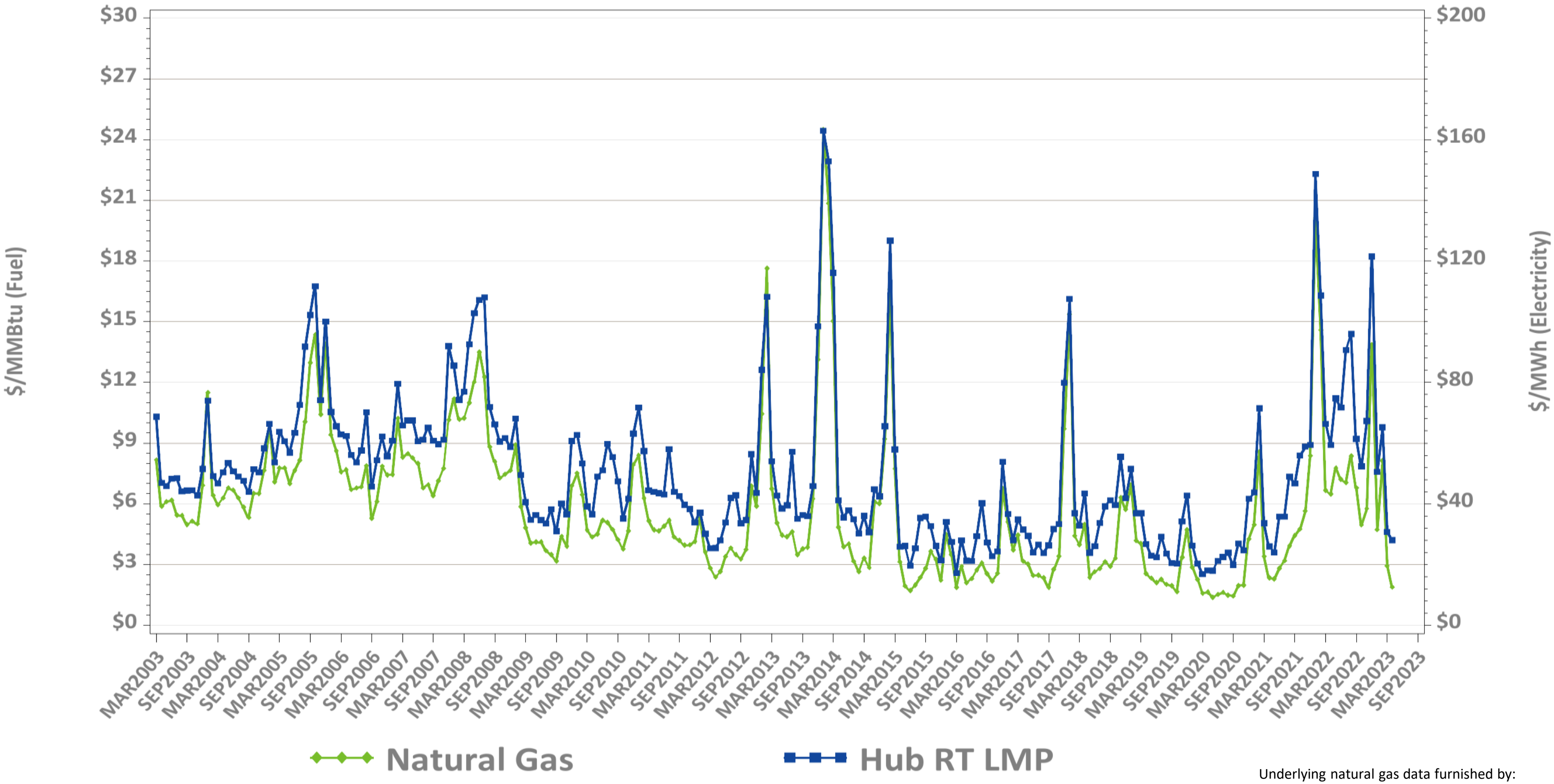
# Monthly Average Fuel Price and RT Hub LMP Indexes




Underlying natural gas data furnished by:

ice Global markets in clear view

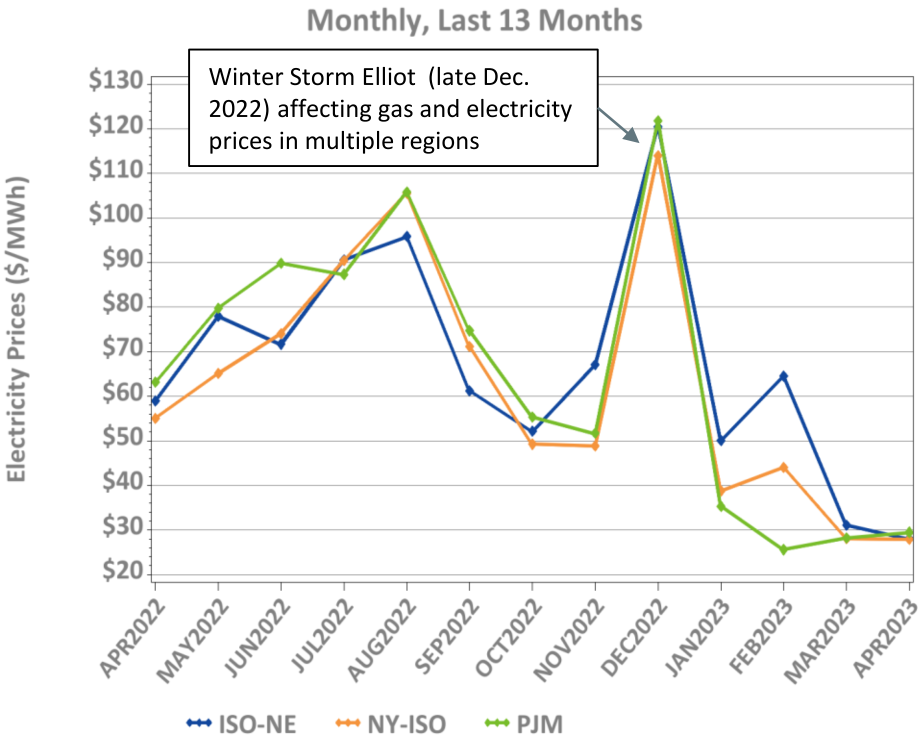
# Monthly Average Fuel Price and RT Hub LMP



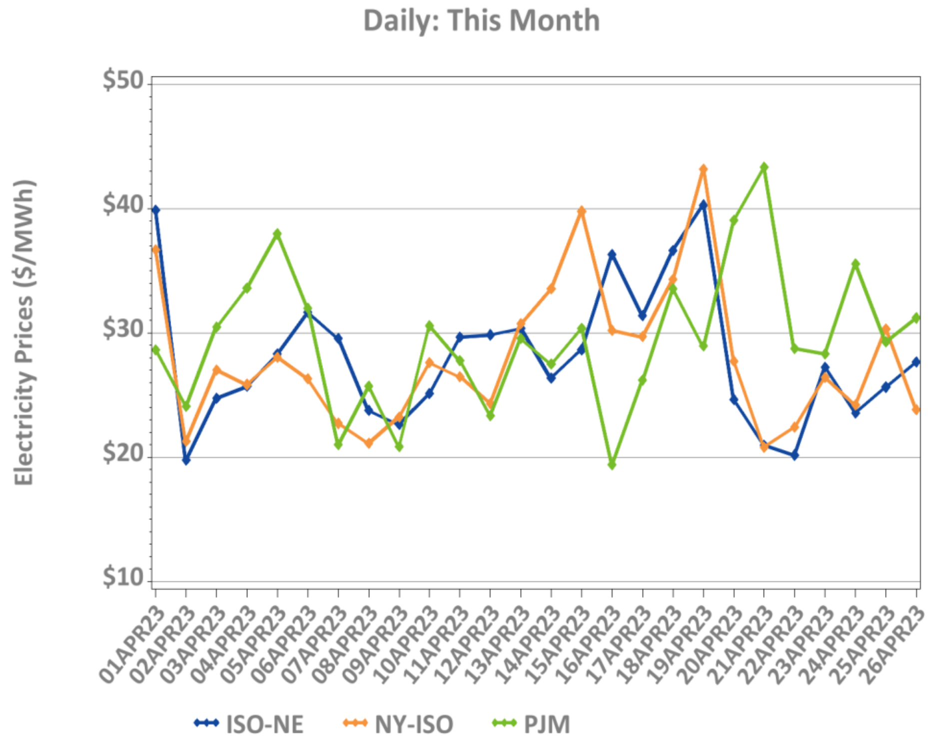

Underlying natural gas data furnished by:

ice Global markets in clear view

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



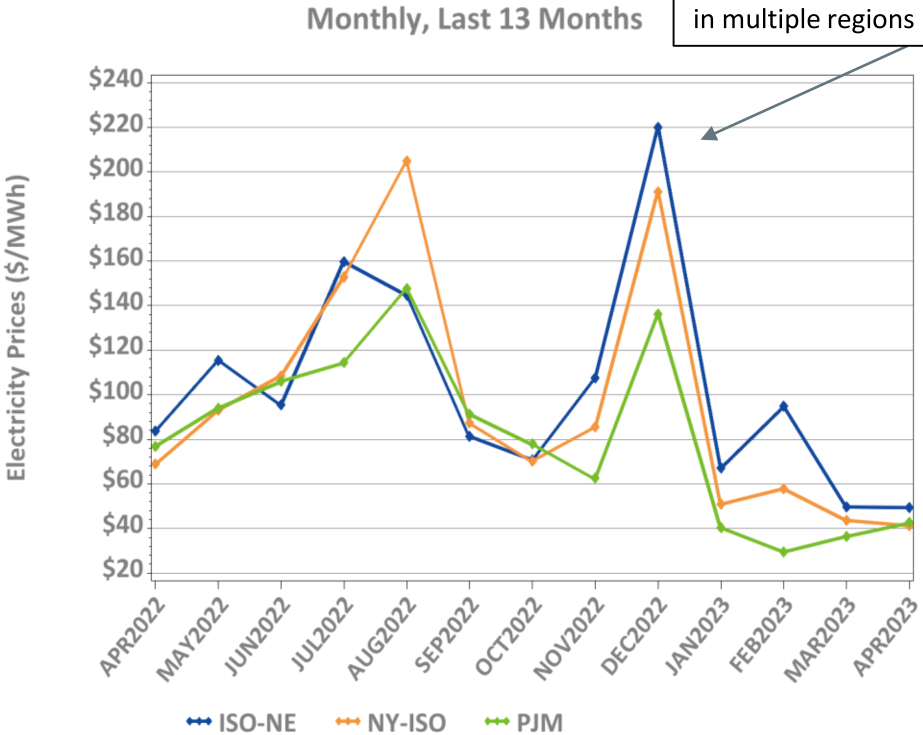

*Note: Hourly average prices are shown.

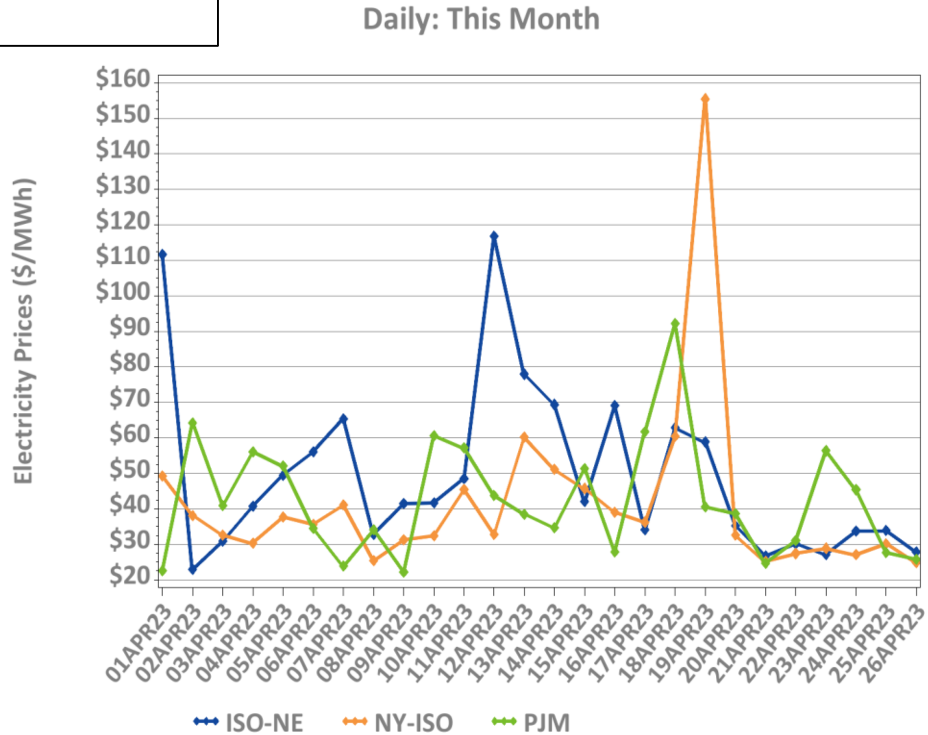



*Note: Hourly average prices are shown.

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

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



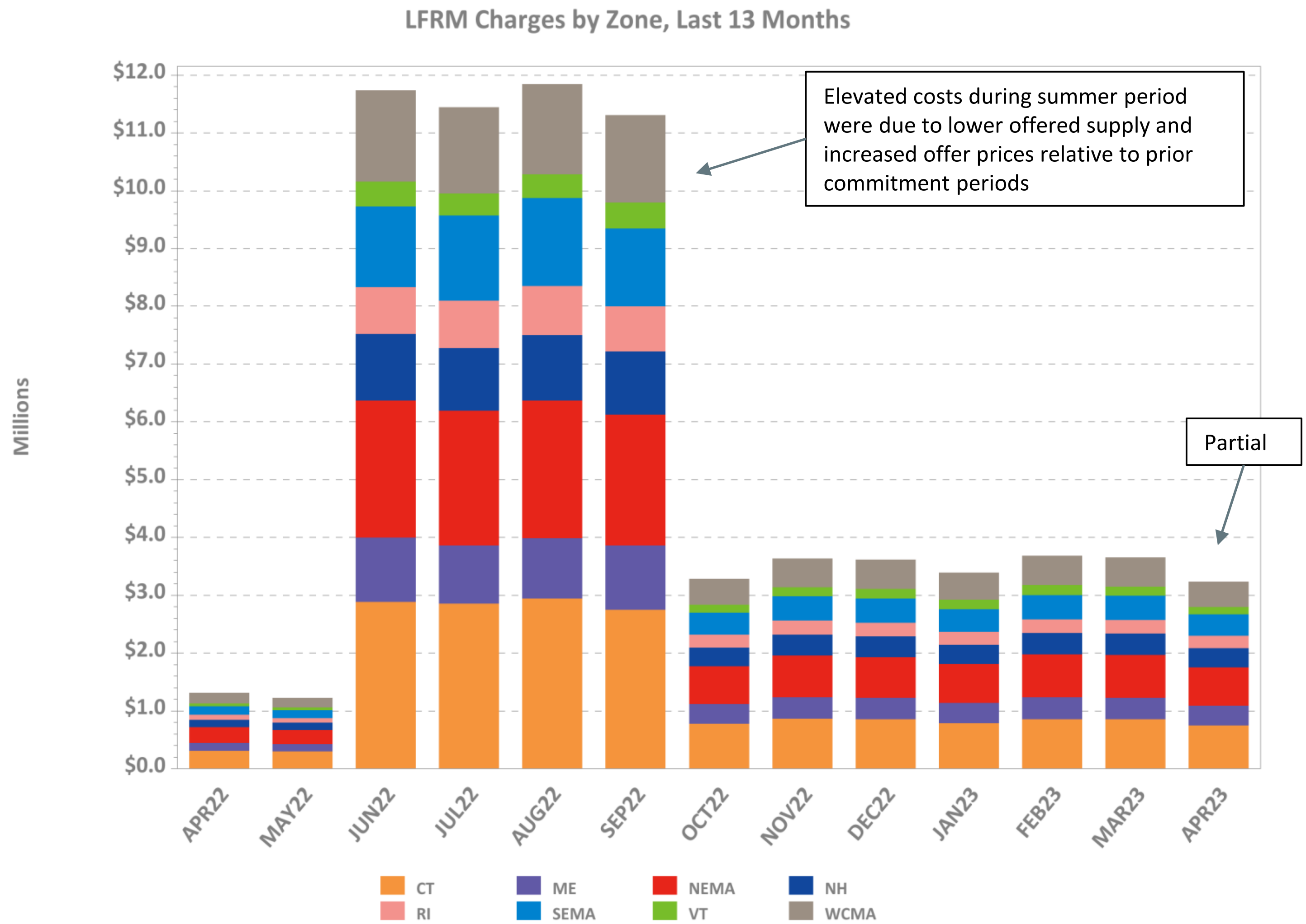

***Forecasted New England daily peak hours reflected**

# Reserve Market Results – April 2023

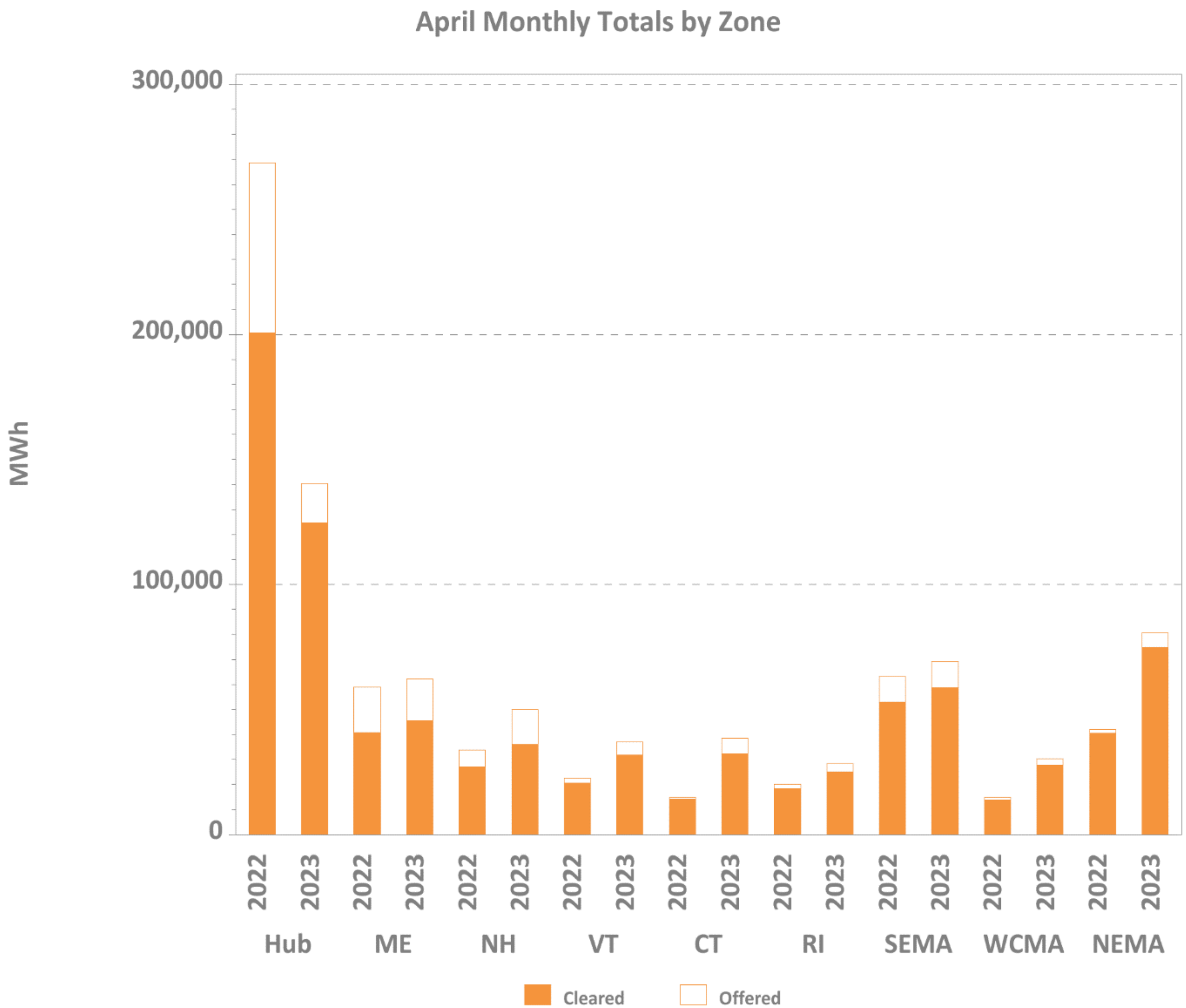
- Maximum potential Forward Reserve Market payments of $3.4M were reduced by credit reductions of $58K, failure-to-reserve penalties of $89K and negligible failure-to-activate penalties, resulting in a net payout of $3.2M or 96% of maximum
  – Rest of System: $2.24M/2.33M (96%)
  – Southwest Connecticut: $0.04M/0.04M (100%)
  – Connecticut: $0.96M/1.01M (95%)
- $546K total Real-Time credits were reduced by $146K in Forward Reserve Energy Obligation Charges for a net of $400K in Real-Time Reserve payments
  – Rest of System: 159 hours, $260K
  – Southwest Connecticut: 159 hours, $81K
  – Connecticut: 159 hours, $33K
  – NEMA: 159 hours, $26K

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

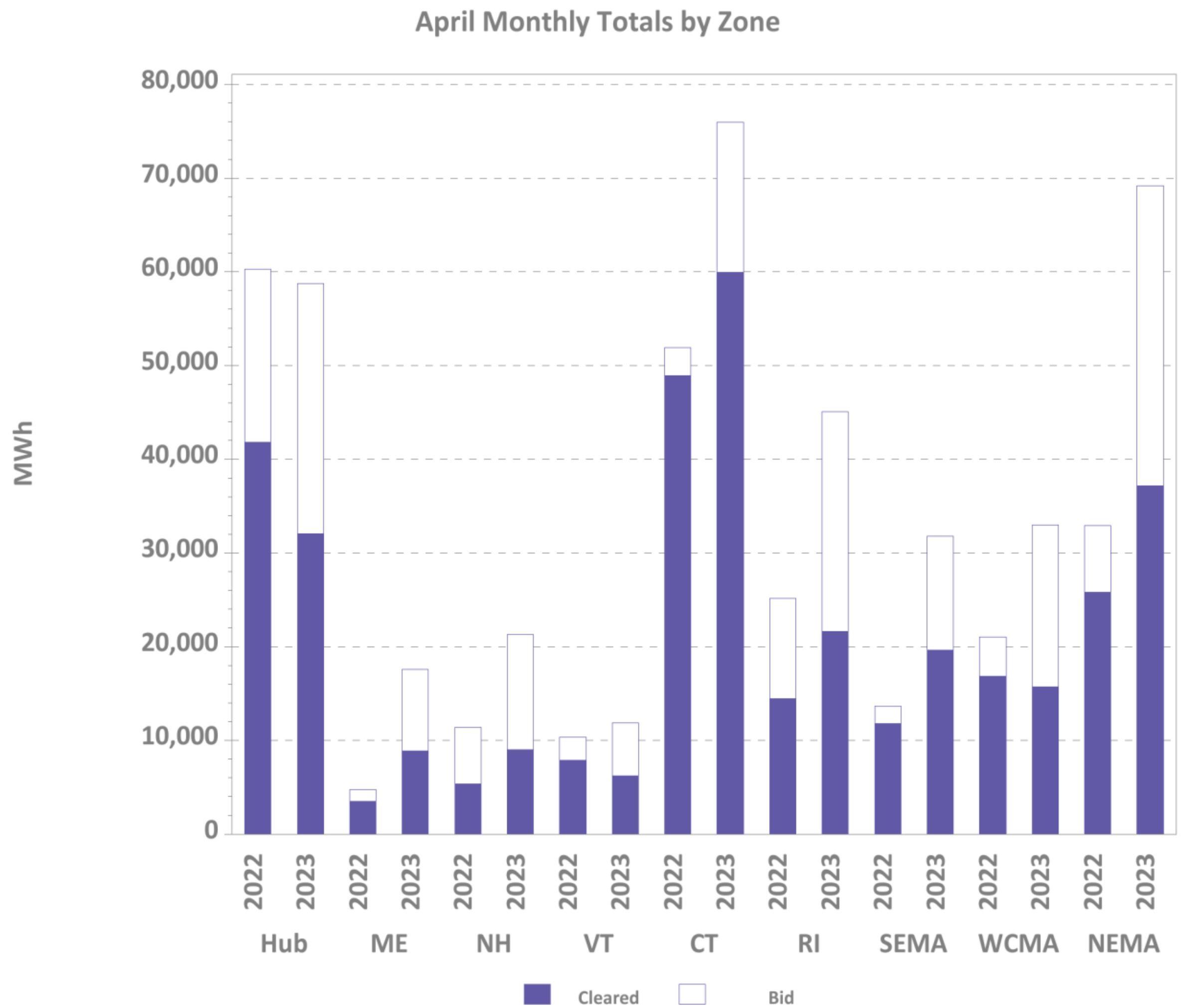
# LFRM Charges to Load by Load Zone ($)



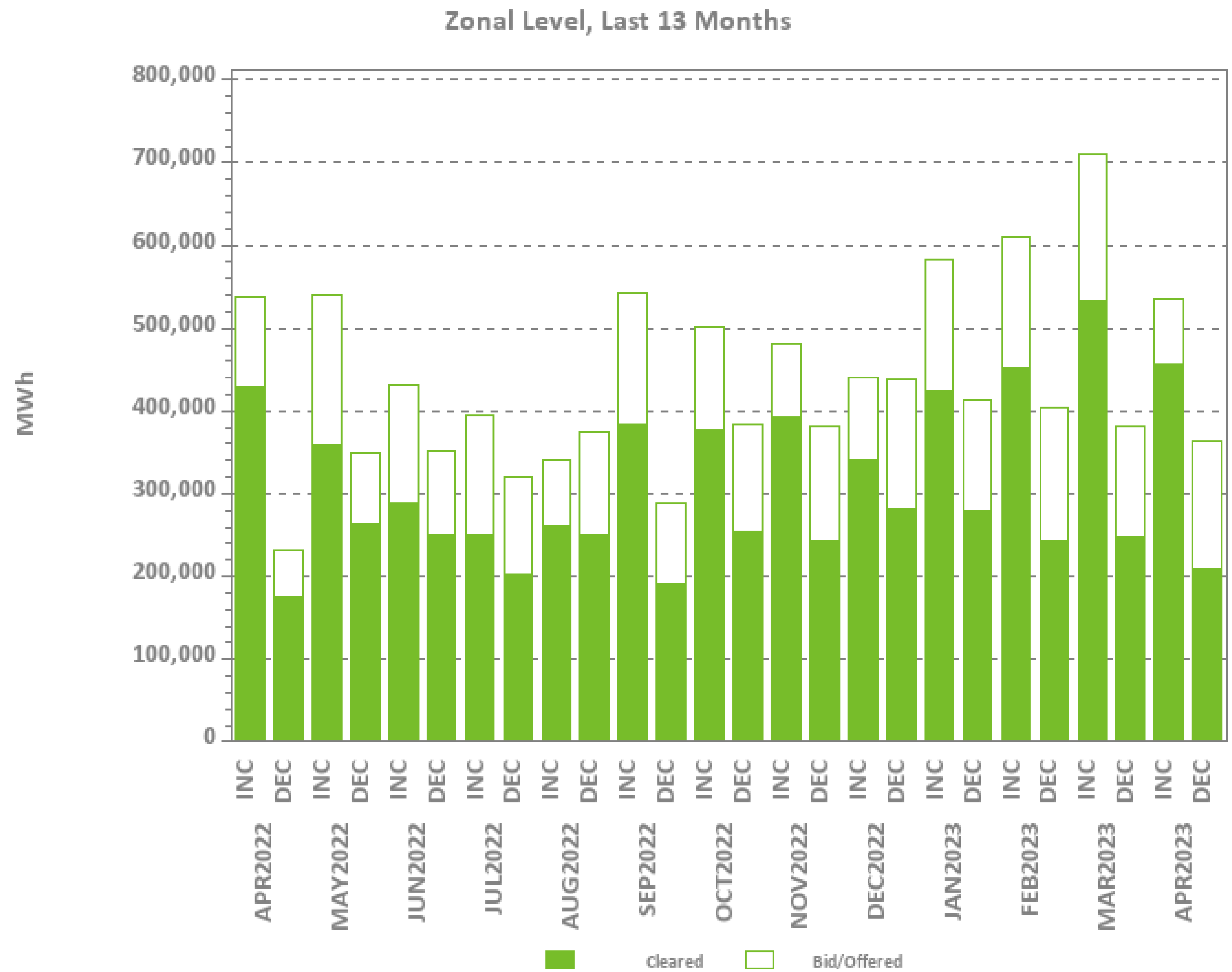
# Zonal Increment Offers and Cleared Amounts



# Zonal Decrement Bids and Cleared Amounts

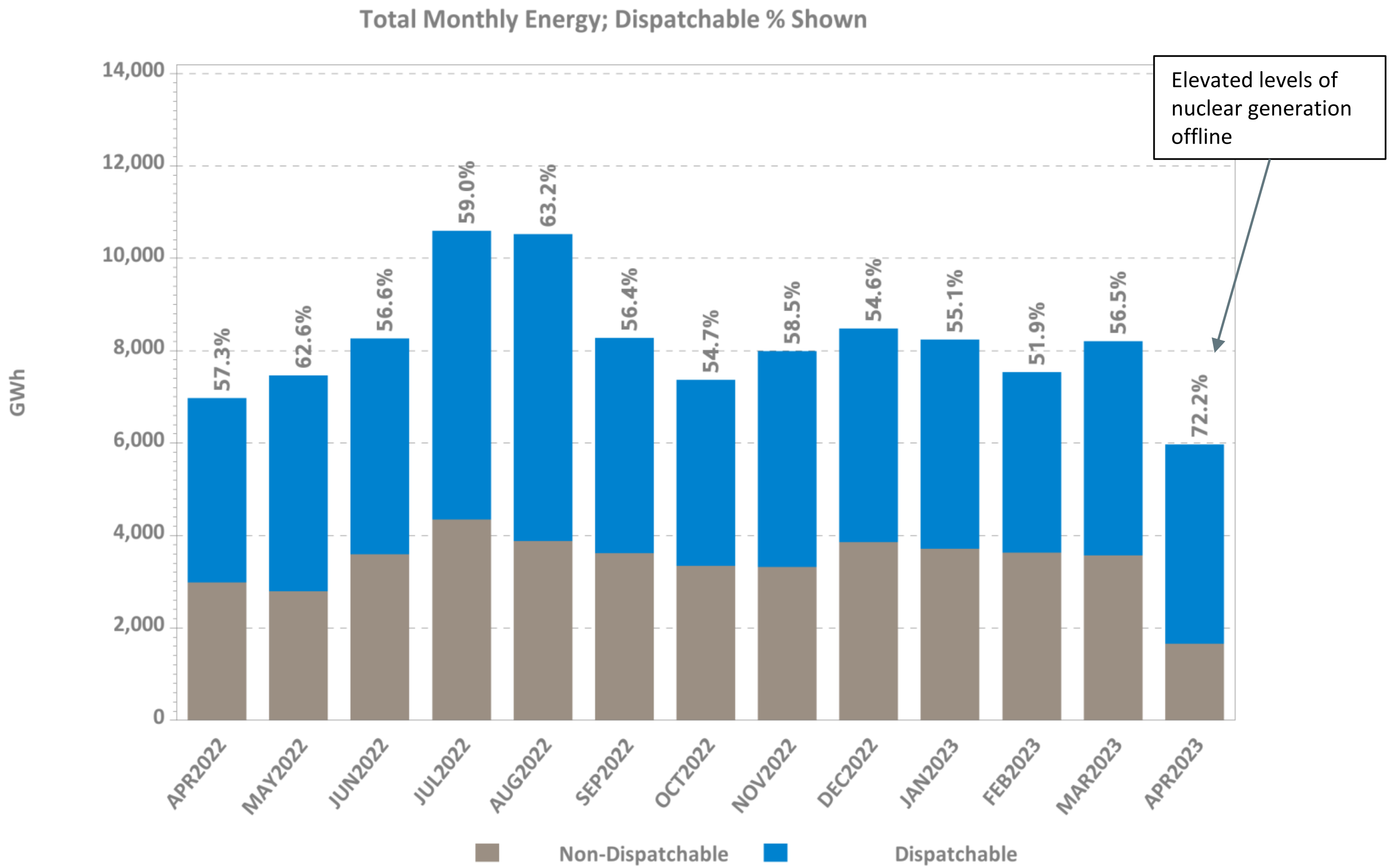


# Total Increment Offers and Decrement Bids




**Data excludes nodal offers and bids**

# Dispatchable vs. Non-Dispatchable Generation




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

# REGIONAL SYSTEM PLAN (RSP)

# Regional System Plan (RSP)

- 2023 is an RSP publication year
- 2023-24 RSP will continue the streamlining efforts started with the 2021 RSP
- 2023-24 RSP will focus on being an overview narrative about ISO's system planning and the outlook for the New England grid
- 2023-24 RSP Public Meeting date is set for November 1 and will be held concurrently with the ISO Open Board Meeting

# Planning Advisory Committee (PAC)

- May 18 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - Adams #21 Substation Relocation (National Grid)
    - 1704/1722 Underground Cable Rebuild Project (Eversource)
    - Northern New Hampshire Rebuilds 115 kV Lines B-112, Q-195, U-199 (Eversource)
    - New Hampshire Wood Structure Replacements & OPGW Installations (Eversource)

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

# Transmission Planning for the Clean Energy Transition (TPCET)

- On 9/24/20, the ISO initiated discussions with the PAC about proposed refinements to transmission planning study assumptions that better reflect long-term trends, such as increased amounts of distributed-energy resources (primarily solar PV), offshore wind generation, and battery energy storage
- A follow-up presentation at the 11/19/20, 12/16/20, and 1/21/21 PAC meetings outlined a proposal for a pilot study, with the following goals:
  - Explore transmission reliability concerns that may result from various system conditions possible by 2030
  - Quantify trade-offs necessary between transmission system reliability/flexibility and transmission investment cost
  - Inform future discussions on transmission planning study assumptions
- Results were discussed at the 6/16/21, 7/22/21, and 8/18/21 PAC meetings
- The ISO published final revisions to the Transmission Planning Technical Guide reflecting these changes on 9/30/21
- CEII supplement to the PAC presentations was released on 10/5/21
- The final TPCET Pilot Study Report was posted to the PAC website on 1/14/22
- Status updates on ongoing transient stability modeling and performance criteria were discussed at the 4/28/22, 5/18/22, 6/15/22, and 8/24/22 PAC meetings
- Revised Transmission Planning Technical Guide (TPTG) that reflects these assumption changes was discussed at the 11/15/22 PAC meeting and posted on 3/24/23

# 2050 Transmission Study

- A meeting with the states was held on 10/15/21 to review the draft study scope
- The draft study scope was discussed with the PAC on 11/17/21
- Written stakeholder comments were due on 12/2/21
- ISO worked with NESCOE to address the comments and finalized the scope on 12/22/21
- ISO provided initial results at the 3/16/22 PAC meeting
- Sensitivity results, as well as a high-level approach to solutions development, were discussed at the 4/28/22 PAC meeting
- ISO discussed updated results and the approximate duration of overloads at the 7/20/22 PAC meeting
- ISO began initial discussions on solution development and lessons learned at the 12/13/22 PAC meeting
- Consultant to perform cost estimates has been selected – Electrical Consultants Inc. (ECI)
- ECI is working on developing cost estimates for potential transmission additions
- Development of transmission solutions will continue throughout the first half of 2023
- Additional discussion on solution development occurred at the 4/20/23 PAC meeting

# Economic Studies

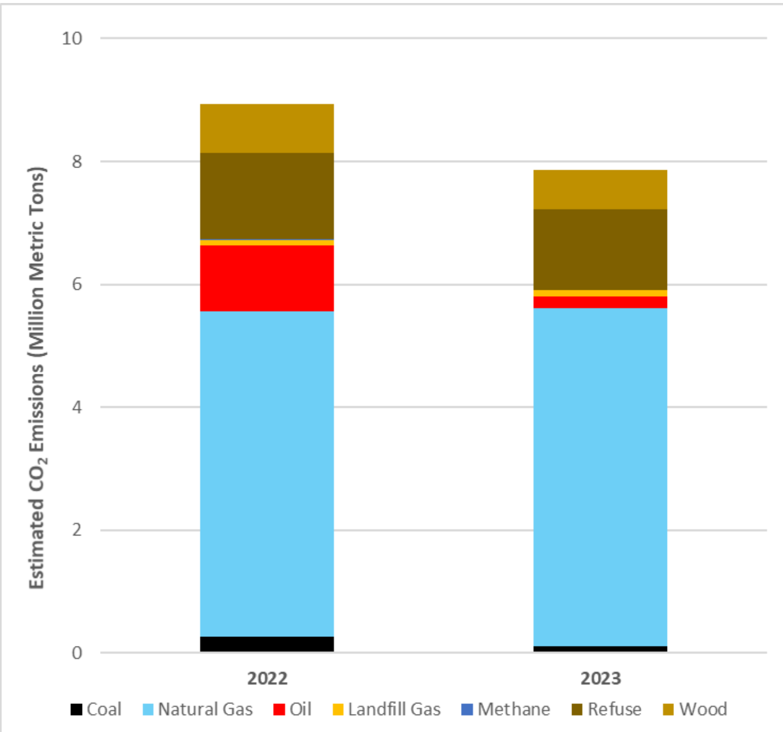
- Economic Planning for the Clean Energy Transition (EPCET) Pilot Study
  - New effort is to review all assumptions in economic planning and perform a test study consistent with the changes to the Tariff
  - PAC presentations began in April 2022. To date, the ISO has presented new modeling features, assumptions and results from the Benchmark and Market Efficiency Need scenarios, an overview of the capacity expansion model and how it will be used in the Policy scenario. The ISO presented the first round of Policy scenario assumptions in April 2023
    - FGRS Phase 2 is now the Stakeholder-Requested Scenario in EPCET

# Future Grid Reliability Study (FGRS)

- Phase 1
  - Studies included: Production Cost Simulations; Ancillary Services Simulations; Resource Adequacy Screen; and Probabilistic Resource Availability Analysis
  - Phase 1 work was completed as the 2021 Economic Study
- Phase 2
  - In Phase 2, modeling tools and assumptions from the Pathways and FGRS Phase 1 studies will be used to solve for the set of clean-energy resources that are revenue sufficient and meet the 1-in-10 resource adequacy standard
  - Reliability attributes/capabilities of this revenue-sufficient resource mix and any potential reliability "gaps" that remain will be identified
  - High-level outline was presented at the April PAC

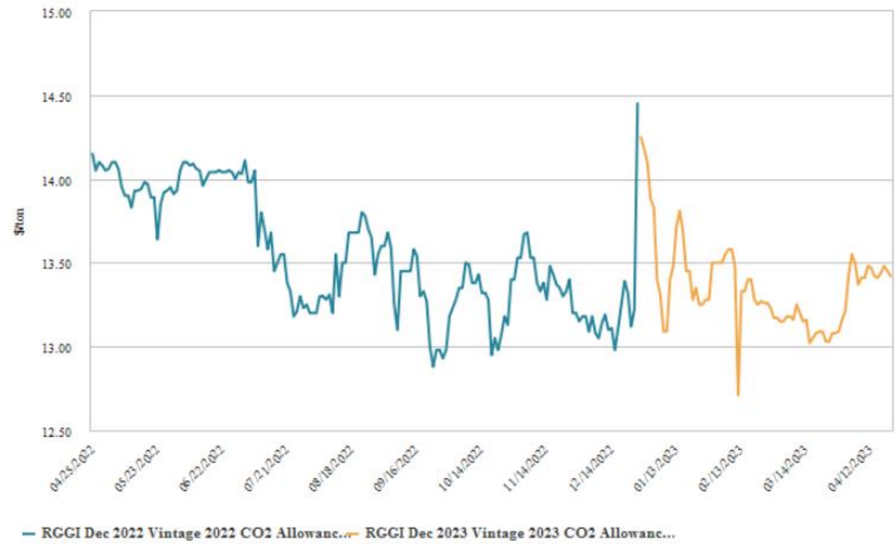
# New England Power System Carbon Emissions

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




Data as of 04/16/2023

## RGGI Allowance Prices




- 04/20/23: RGGI allowance spot price - $13.42
- 03/08/23 59th RGGI auction cleared at $12.50 per ton
  - 21,522,877 $CO_2$ allowances sold
  - 11,245,778 Cost Containment Reserve (CCR) allowances available
  - CCR trigger price is $14.88 per ton in 2023; therefore, no CCR allowances were sold
- Acadia Center published a report on the impacts of RGGI and provided recommendations for the Third Program Review

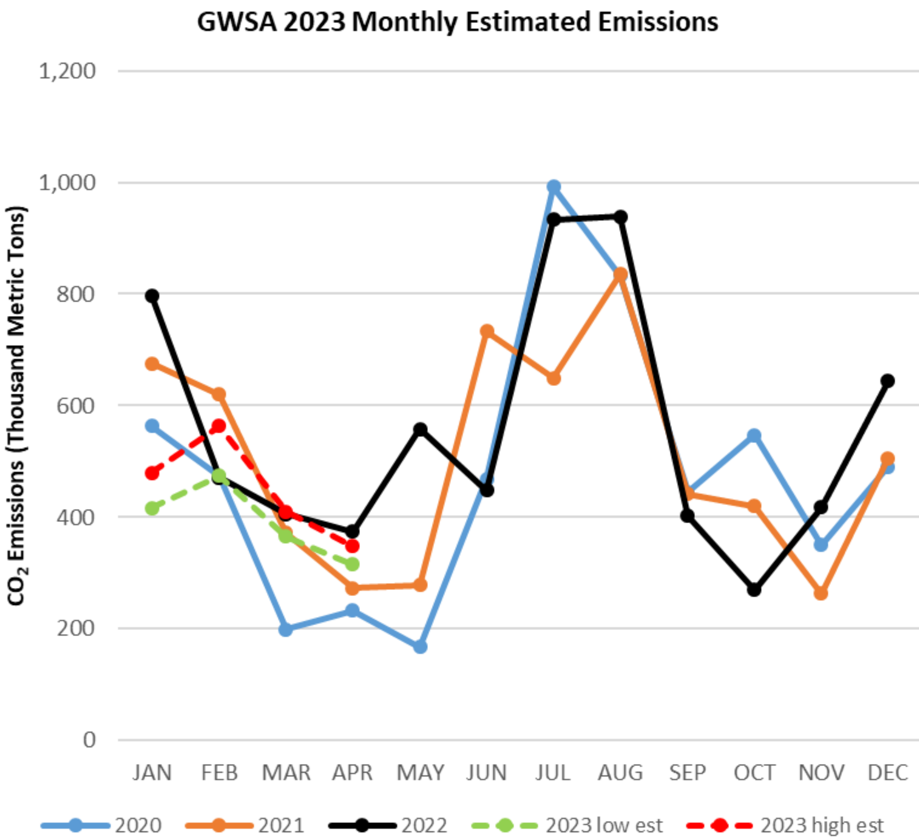
RGGI – Regional Greenhouse Gas Initiative

# Massachusetts $CO_2$ Generator Emissions Cap

## 2023 Estimated Emissions Under $CO_2$ Cap

- As of 04/24/23, estimated GWSA $CO_2$ emissions range between **315,172** and **347,838** metric tons
  - **20%** and **23%** of the 2023 cap of 7.84 MMT
- 03/15/23: Latest GWSA auction included two offerings: one offering for the current vintage (2023) and one offering for future vintage (2024)
- 2023: 1,175,351 CO2 allowances offered
  - clearing price of $12.05/metric ton
- 2024: 380,590 CO2 allowances offered (5% of 2024 cap)
  - clearing price of $5.85/metric ton

## 2020-2023 Estimated Monthly Emissions (Thousand Metric tons)




GWSA – Global Warming Solutions Act
MMT – Million Metric Tons

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

# RSP Project Stage Descriptions

| Stage | Description |
|---|---|
| 1 | Planning and Preparation of Project Configuration |
| 2 | Pre-construction (e.g., material ordering, project scheduling) |
| 3 | Construction in Progress |
| 4 | In Service |

Note: The listings in this section focus on major transmission line construction and rebuilding.

# Greater Boston Projects

## *Status as of 4/24/2023*

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

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

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

# Greater Boston Projects, cont.

*Status as of 4/24/2023*

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

| RSP Project List ID | Upgrade | Expected/ Actual In-Service | Present Stage |
|---|---|---|---|
| 1330 | Separate X-24 and E-157W DCT | Dec-18 | 4 |
| 1363 | Separate Q-169 and F-158N DCT | Dec-15 | 4 |
| 1637, 1640 | Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap | May-17 | 4 |
| 1516 | Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook | Sep-20 | 4 |
| 965 | Install third 115 kV line from West Walpole to Holbrook | Sep-20 | 4 |
| 1558 | Install new 345 kV breaker in series with the 104 breaker at Stoughton | May-16 | 4 |
| 1199 | Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury | Dec-17 | 4 |
| 1335 | Install a new 115 kV line from Sudbury to Hudson | Dec-23 | 3 |

# Greater Boston Projects, cont.

*Status as of 4/24/2023*

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

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

# Greater Boston Projects, cont.

*Status as of 4/24/2023*

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

| RSP Project List ID | Upgrade | Expected/ Actual In-Service | Present Stage |
|---|---|---|---|
| 1356 | Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line | Dec-23 | 3 |
| 1357 | Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station. | May-19 | 4 |
| 1518 | Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard | Mar-19 | 4 |
| 1519 | Relocate the Chelsea capacitor bank to the 128-518 termination postion | Dec-16 | 4 |

# Greater Boston Projects, cont.

*Status as of 4/24/2023*

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

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

# SEMA/RI Reliability Projects

*Status as of 4/24/2023*

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

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

# SEMA/RI Reliability Projects, cont.

*Status as of 4/24/2023*

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

| RSP Project List ID | Upgrade | Expected/ Actual In-Service | Present Stage |
|---|---|---|---|
| 1718 | Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line | Mar-22 | 4 |
| 1719 | Install 45.0 MVAR capacitor bank at Berry Street substation | Cancelled* | N/A |
| 1720 | Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations | Mar-26 | 2 |
| 1721 | Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor | Aug-23 | 3 |
| 1722 | Extend the Line 114 from the Dartmouth town line (Eversource-National Grid border) to Bell Rock substation | Dec-24 | 2 |
| 1723 | Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap | Cancelled* | N/A |

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

# SEMA/RI Reliability Projects, cont.

*Status as of 4/24/2023*

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

| RSP Project List ID | Upgrade | Expected/ Actual In-Service | Present Stage |
|---|---|---|---|
| 1725 | Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work | May-24 | 3 |
| 1726 | Separate the 135/122 DCT from West Barnstable to Barnstable substations | Dec-21 | 4 |
| 1727 | Retire the Barnstable SPS | Nov-21 | 4 |
| 1728 | Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal | Jun-23 | 3 |
| 1729 | Install a new bay position at Kingston substation to accommodate new 115 kV line | Jun-23 | 3 |
| 1730 | Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap | Dec-24 | 1 |

# SEMA/RI Reliability Projects, cont.

*Status as of 4/24/2023*

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

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

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

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

# SEMA/RI Reliability Projects, cont.

*Status as of 4/24/2023*

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

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

# Eastern CT Reliability Projects

*Status as of 4/24/2023*

*Project Benefit: Addresses system needs in the Eastern Connecticut area*

| RSP Project List ID | Upgrade | Expected/ Actual In-Service | Present Stage |
|---|---|---|---|
| 1815 | Reconductor the L190-4 and L190-5 line sections | Dec-24 | 3 |
| 1850 | Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation | Dec-22 | 4 |
| 1851 | Upgrade Card 115 kV to BPS standards | Dec-22 | 4 |
| 1852 | Install one 115 kV circuit breaker in series with Card substation 4T | Feb-23 | 4 |
| 1853 | Convert Gales Ferry substation from 69 kV to 115 kV | Dec-23 | 3 |
| 1854 | Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV | Jun-23 | 3 |

# Eastern CT Reliability Projects, cont.

*Status as of 4/24/2023*

*Project Benefit: Addresses system needs in the Eastern Connecticut area*

| RSP Project List ID | Upgrade | Expected/ Actual In-Service | Present Stage |
|---|---|---|---|
| 1855 | Re-terminate the 100 Line at Montville station and associated work. Energize the 100 Line at 115 kV | Dec-23 | 3 |
| 1856 | Rebuild 400-1 Line section to allow operation at 115 kV (Tunnel to Ledyard Jct.) | Feb-23 | 4 |
| 1857 | Add one 115 kV circuit breaker and re-terminate the 400-1 line section into Tunnel substation. Energize 400 Line at 115 kV | Dec-23 | 3 |
| 1858 | Rebuild 400-2 Line section to allow operation at 115 kV (Ledyard Jct. to Border Bus with CMEEC) | Sept-22 | 4 |
| 1859 | Rebuild the 400-3 Line Section to allow operation at 115 kV (Gales Ferry to Ledyard Jct.) | Feb-23 | 4 |
| 1860 | Install a 25.2 MVAR 115 kV capacitor and one capacitor breaker at Killingly | Dec-21 | 4 |

# Eastern CT Reliability Projects, cont.

*Status as of 4/24/2023*

*Project Benefit: Addresses system needs in the Eastern Connecticut area*

| RSP Project List ID | Upgrade | Expected/ Actual In-Service | Present Stage |
|---|---|---|---|
| 1861 | Install one 345 kV series breaker with the Montville 1T | Nov-21 | 4 |
| 1862 | Install a +55/-29 MVAR synchronous condenser with two 115 kV breakers at Shunock | Dec-23 | 3 |
| 1863 | Install a 1% series reactor with bypass switch at Mystic, CT on the 1465 Line | Mar-22 | 4 |
| 1864 | Convert the 400-2 Line Section to 115 kV (Border Bus to Buddington) | Dec-23 | 3 |
| 1904 | Convert 69 kV equipment at Buddington to 115 kV to facilitate the conversion of the 400-2 line to 115 kV | Dec-23 | 3 |

# Boston Area Optimized Solution Projects

*Status as of 4/24/2023*

*Project Benefit: Addresses system needs in the Boston area*

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

# New Hampshire Solution Projects

*Status as of 4/24/2023*

*Project Benefit: Addresses system needs in the New Hampshire area*

| RSP Project List ID | Upgrade | Expected/ Actual In-Service | Present Stage |
|---|---|---|---|
| 1878 | Install a +55/-32.2 MVAR synchronous condenser at N. Keene 115 kV Substation with a 115 kV breaker | Dec-23 | 3 |
| 1879 | Install a +55/-32.2 MVAR synchronous condenser at Huckins Hill 115 kV Substation with a 115 kV breaker | Dec-23 | 3 |
| 1880 | Install a +127/-50 MVAR synchronous condenser at Amherst 345 kV Substation with two 345 kV breakers | Mar-24 | 3 |
| 1881 | Install two 50 MVAR capacitors on Line 363 near Seabrook Station with three 345 kV breakers | Oct-23 | 2 |

# Upper Maine Solution Projects

*Status as of 4/24/2023*

*Project Benefit: Addresses system needs in the Upper Maine area*

| RSP Project List ID | Upgrade | Expected/ Actual In-Service | Present Stage |
|---|---|---|---|
| 1882 | Rebuild 21.7 miles of the existing 115 kV line Section 80 Highland-Coopers Mills 115 kV line | Dec-24 | 2 |
| 1883 | Convert the Highland 115 kV substation to an eight breaker, breaker-and-a-half configuration with a bus connected 115/34.5 kV transformer | Dec-27 | 1 |
| 1884 | Install a 15 MVAR capacitor at Belfast 115 kV substation | Dec-27 | 1 |
| 1885 | Install a +50/-25 MVAR synchronous condenser at Highland 115 kV substation | Dec-27 | 1 |
| 1886 | Install +50/-25 MVAR synchronous condenser at Boggy Brook 115 kV substation, and install a new 115 kV breaker to separate Line 67 from the proposed solution elements | Jun-24 | 2 |

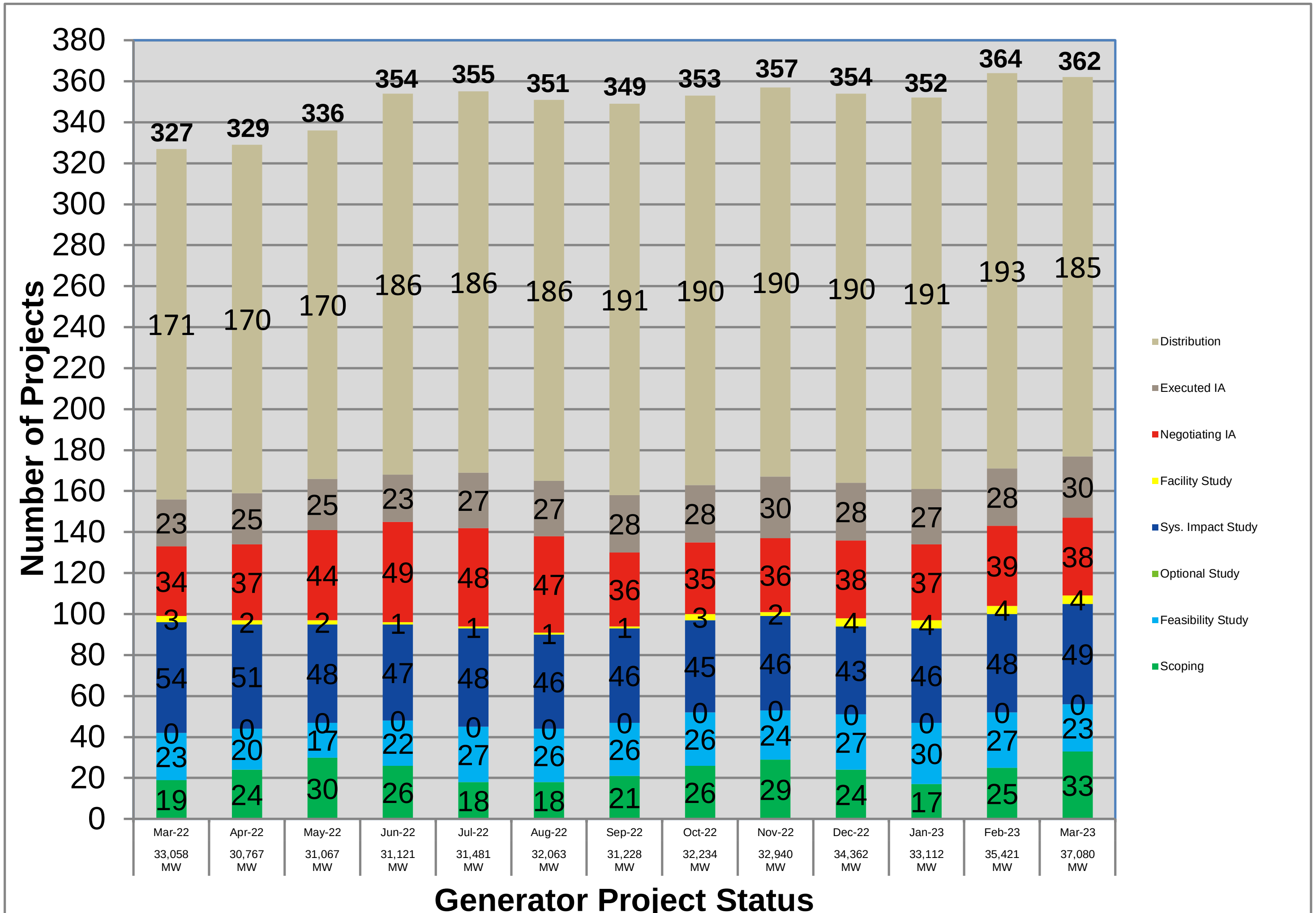
# Upper Maine Solution Projects, cont.

*Status as of 4/24/2023*

*Project Benefit: Addresses system needs in the Upper Maine area*

| RSP Project List ID | Upgrade | Expected/ Actual In-Service | Present Stage |
|---|---|---|---|
| 1887 | Install 25 MVAR reactor at Boggy Brook 115 kV substation | Jun-24 | 2 |
| 1888 | Install 10 MVAR reactor at Keene Road 115 kV substation | Jun-24 | 2 |
| 1889 | Install three remotely monitored and controlled switches to split the existing Orrington reactors between the two Orrington 345/115 kV autotransformers | Dec-23 | 2 |

# Status of Tariff Studies as of April 1, 2023



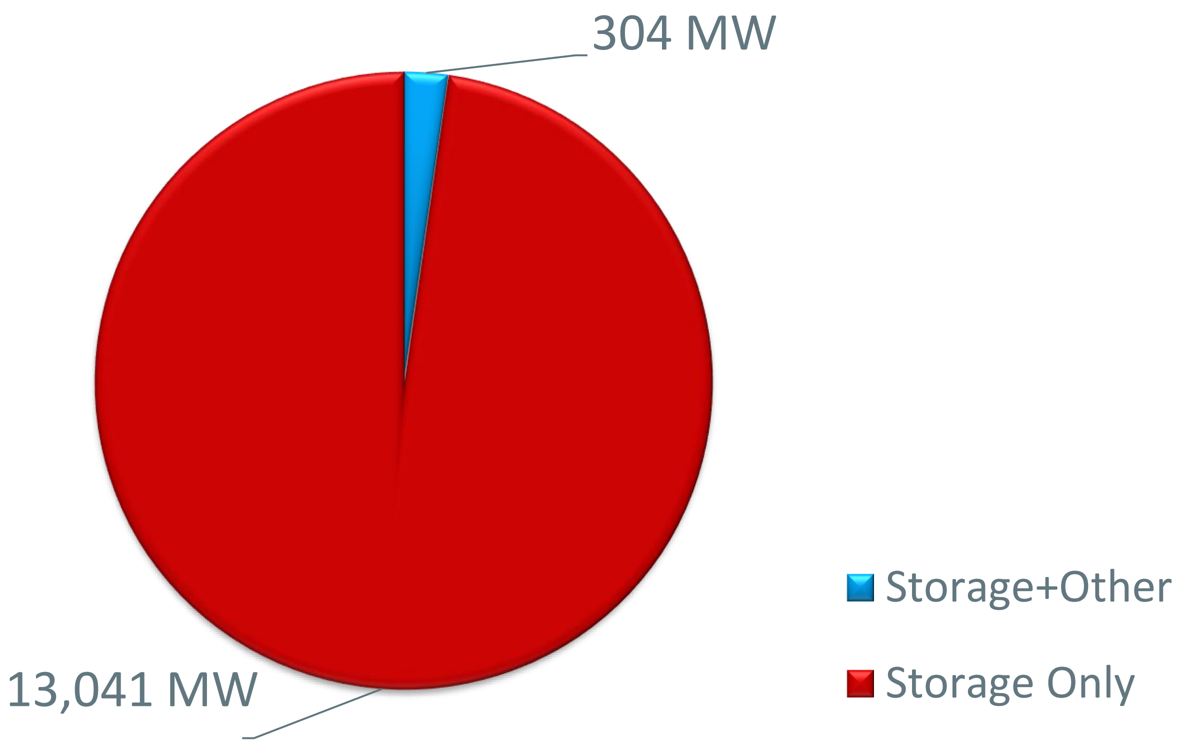

9 ETUs in Scoping, 6 in FS, 0 in SIS, 0 in OIS, 0 in FAC, 2 Negotiating IA, and 3 with Executed IA

Transmission Service Requests needing study: 1 in Scoping and 3 in SIS

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

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

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



# OPERABLE CAPACITY ANALYSIS

*Spring and Summer 2023*

# Spring 2023 Operable Capacity Analysis

| 50/50 Load Forecast (Reference) | May - 2023[2] CSO (MW) | May - 2023[2] SCC (MW) |
|---|---|---|
| Operable Capacity MW [1] | 28,103 | 28,877 |
| Active Demand Capacity Resource (+) [5] | 426 | 444 |
| External Node Available Net Capacity, CSO imports minus firm capacity exports (+) | 1,094 | 937 |
| Non Commercial Capacity (+) | 10 | 10 |
| Non Gas-fired Planned Outage MW (-) | 2,956 | 3,454 |
| Gas Generator Outages MW (-) | 772 | 414 |
| 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) | 22,505 | 23,000 |
| Peak Load Forecast MW(adjusted for Other Demand Resources) [2] | 20,836 | 20,836 |
| Operating Reserve Requirement MW | 2,305 | 2,305 |
| Operable Capacity Required (NET LOAD OBLIGATION MW) | 23,141 | 23,141 |
| Operable Capacity Margin | -636 | -141 |

[1] Operable Capacity is based on data as of **April 25, 2023** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **April 25, 2023.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 27, 2023.**

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

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

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

# Spring 2023 Operable Capacity Analysis

| 90/10 Load Forecast | May - 2023[2] CSO (MW) | May - 2023[2] SCC (MW) |
|---|---|---|
| Operable Capacity MW [1] | 28,103 | 28,877 |
| Active Demand Capacity Resource (+) [5] | 426 | 444 |
| External Node Available Net Capacity, CSO imports minus firm capacity exports (+) | 1,094 | 937 |
| Non Commercial Capacity (+) | 10 | 10 |
| Non Gas-fired Planned Outage MW (-) | 2,956 | 3,454 |
| Gas Generator Outages MW (-) | 772 | 414 |
| 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) | 22,505 | 23,000 |
| Peak Load Forecast MW(adjusted for Other Demand Resources) [2] | 22,396 | 22,396 |
| Operating Reserve Requirement MW | 2,305 | 2,305 |
| Operable Capacity Required (NET LOAD OBLIGATION MW) | 24,701 | 24,701 |
| Operable Capacity Margin | -2,196 | -1,701 |

[1]Operable Capacity is based on data as of **April 25, 2023** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **April 25, 2023.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 27, 2023.**

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

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

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

# Spring 2023 Operable Capacity Analysis
# 50/50 Forecast (Reference)

## ISO-NE OPERABLE CAPACITY ANALYSIS

### *April 25, 2023 - 50-50 FORECAST using CSO MW*

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

Report created: 4/25/2023

| Study Week (Week Beginning , Saturday) | CSO Supply Resource Capacity MW | CSO Demand Resource Capacity MW | External Node Capacity MW | Non-Commercial Capacity MW | CSO Non Gas-Only Generator Planned Outages MW | CSO Gas-Only Generator Planned Outages MW | Unplanned Outages Allowance MW | CSO Generation at Risk Due to Gas Supply 50-50PLE MW | CSO Net Available Capacity MW | Peak Load Forecast 50-50PLE MW | Operating Reserve Requirement MW | CSO Net Required Capacity MW | CSO Operable Capacity Margin MW | Season Min Opcap Margin Flag | Season_Label |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 |
| 5/13/2023 | 28103 | 426 | 1043 | 10 | 2578 | 2727 | 3400 | 0 | 20877 | 18951 | 2305 | 21256 | -379 | N | Spring 2023 |
| 5/20/2023 | 28103 | 426 | 1094 | 10 | 1480 | 1875 | 3400 | 0 | 22878 | 19849 | 2305 | 22154 | 724 | N | Spring 2023 |
| 5/27/2023 | 28103 | 426 | 1094 | 10 | 2956 | 772 | 3400 | 0 | 22505 | 20836 | 2305 | 23141 | -636 | Y | Spring 2023 |

### Column Definitions

**1. CSO Supply Resource Capacity MW:** Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
**2. CSO Demand Resource Capacity MW:** Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
**3. External Node Capacity MW:** Sum of external Capacity Supply Obligations (CSO) imports and exports.
**4. Non-Commercial capacity MW:** New resources and generator improvements that have acquired a CSO but have not become commercial.
**5. CSO Non Gas-Only Generator Planned Outages MW:** All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
**6. CSO Gas-Only Generator Planned Outages MW:** All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
**7. Unplanned Outage Allowance MW:** Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
**8. CSO Generation at Risk Due to Gas Supply Mw:** Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
**9. CSO Net Available Capacity MW:** the summation of columns (1+2+3+4-5-6-7-8=9)
**10. Peak Load Forecast MW:** Provided in the annual 2023 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
**11. Operating Reserve Requirement MW:** 120% of first largest contingency plus 50% of the second largest contingency.
**12. CSO Net Required Capacity MW:** (Net Load Obligation) (10+11=12)
**13. CSO Operable Capacity Margin MW:** CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
**14. Operable Capacity Season Label:** Applicable season and year.
**15. Season Minimum Operable Capacity Flag:** this column indicates whether or not a week has the lowest capacity margin for its applicable season.

# Spring 2023 Operable Capacity Analysis
# 90/10 Forecast

## ISO-NE OPERABLE CAPACITY ANALYSIS

***April 25, 2023 - 90/10 FORECAST using CSO MW***

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

Report created: 4/25/2023

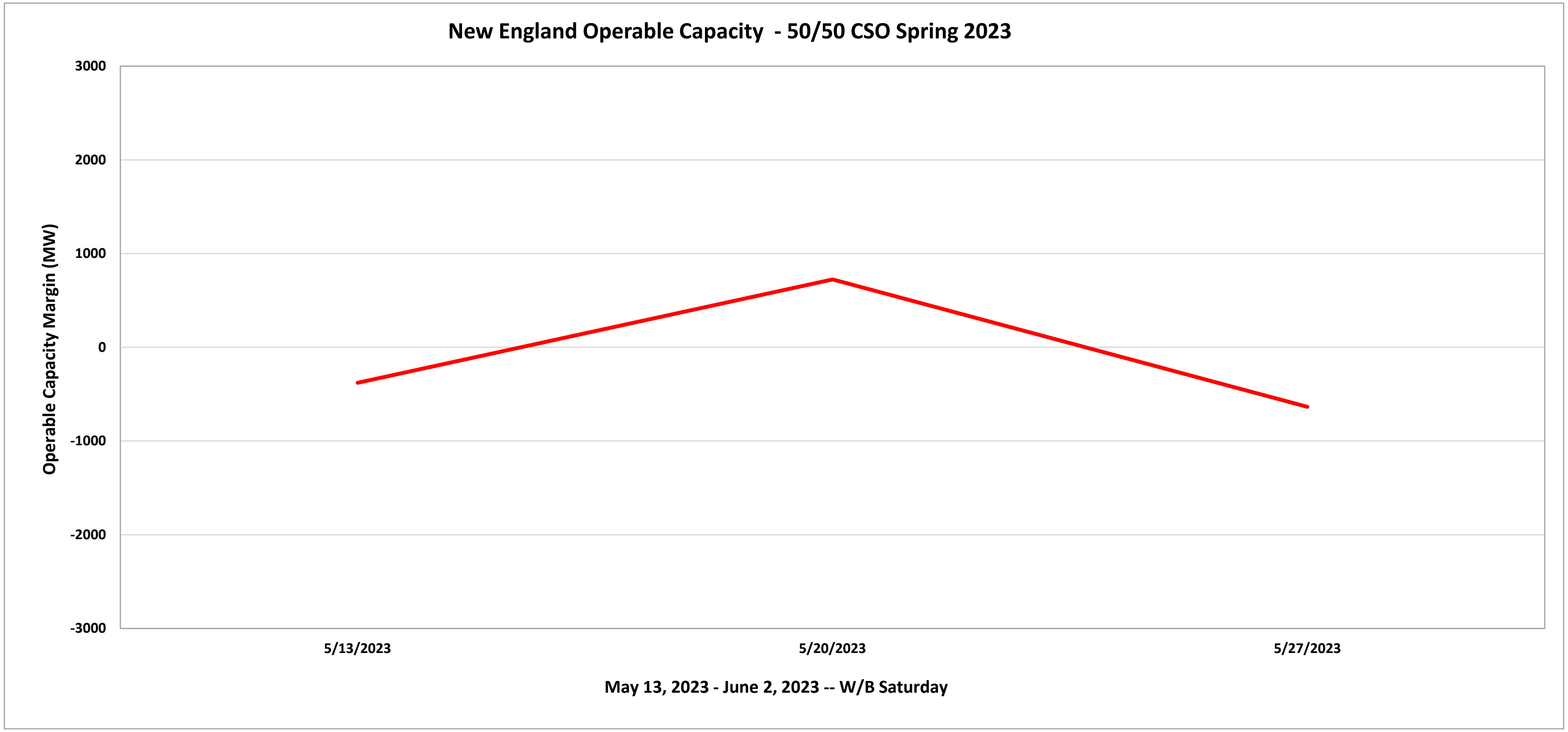
| Study Week (Week Beginning, Saturday) | CSO Supply Resource Capacity MW | CSO Demand Resource Capacity MW | External Node Capacity MW | Non-Commercial Capacity MW | CSO Non Gas-Only Generator Planned Outages MW | CSO Gas-Only Generator Planned Outages MW | Unplanned Outages Allowance MW | CSO Generation at Risk Due to Gas Supply 90-10PLE MW | CSO Net Available Capacity MW | Peak Load Forecast 90-10PLE MW | Operating Reserve Requirement MW | CSO Net Required Capacity MW | CSO Operable Capacity Margin MW | Season Min Opcap Margin Flag | Season_Label |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 |
| 5/13/2023 | 28103 | 426 | 1043 | 10 | 2578 | 2727 | 3400 | 0 | 20877 | 20386 | 2305 | 22691 | -1814 | N | Spring 2023 |
| 5/20/2023 | 28103 | 426 | 1094 | 10 | 1480 | 1875 | 3400 | 0 | 22878 | 21344 | 2305 | 23649 | -771 | N | Spring 2023 |
| 5/27/2023 | 28103 | 426 | 1094 | 10 | 2956 | 772 | 3400 | 0 | 22505 | 22396 | 2305 | 24701 | -2196 | Y | Spring 2023 |

### Column Definitions

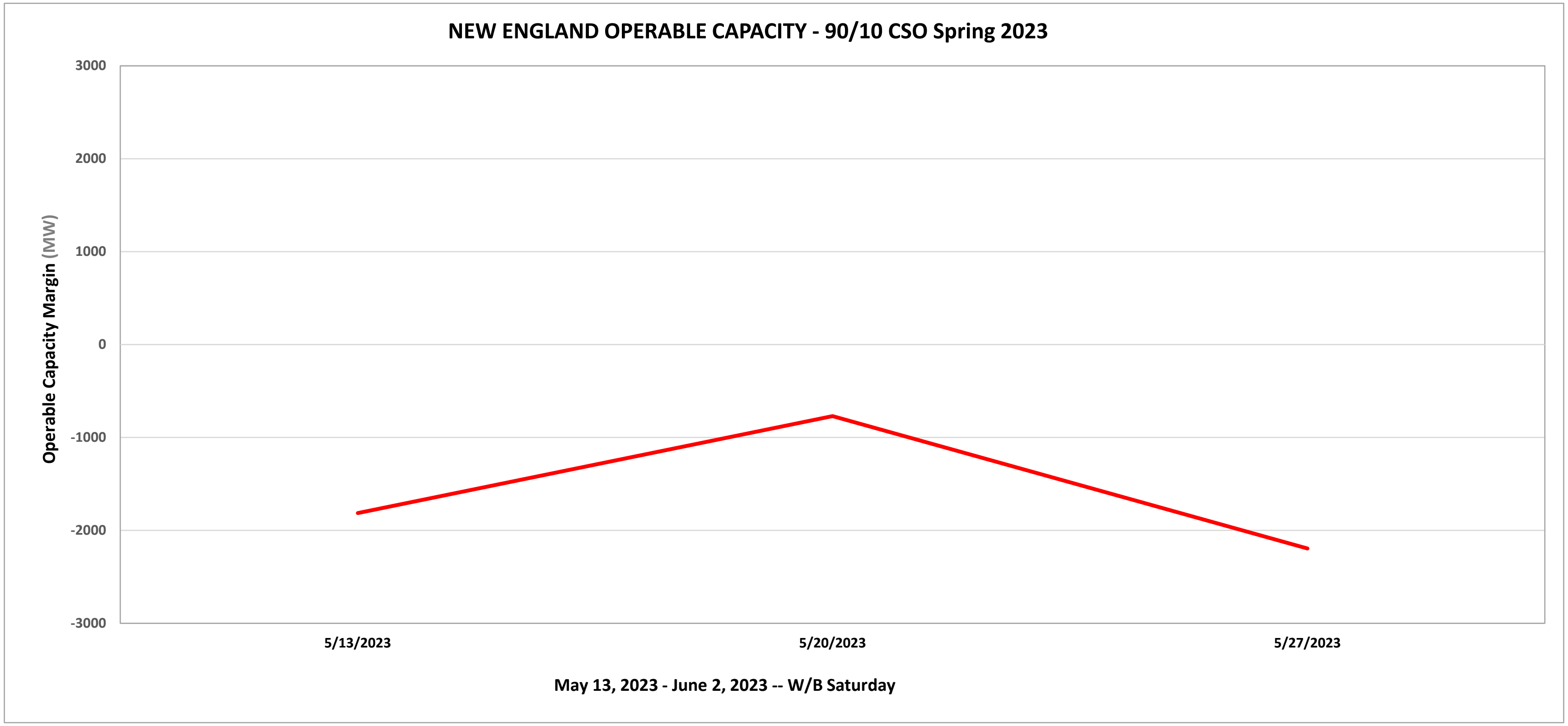
**1. CSO Supply Resource Capacity MW:** Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
**2. CSO Demand Resource Capacity MW:** Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
**3. External Node Capacity MW:** Sum of external Capacity Supply Obligations (CSO) imports and exports.
**4. Non-Commercial capacity MW:** New resources and generator improvements that have acquired a CSO but have not become commercial.
**5. CSO Non Gas-Only Generator Planned Outages MW:** All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
**6. CSO Gas-Only Generator Planned Outages MW:** All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
**7. Unplanned Outage Allowance MW:** Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
**8. CSO Generation at Risk Due to Gas Supply Mw:** Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
**9. CSO Net Available Capacity MW:** the summation of columns (1+2+3+4-5-6-7-8=9)
**10. Peak Load Forecast MW:** Provided in the annual 2023 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
**11. Operating Reserve Requirement MW:** 120% of first largest contingency plus 50% of the second largest contingency.
**12. CSO Net Required Capacity MW:** (Net Load Obligation) (10+11=12)
**13. CSO Operable Capacity Margin MW:** CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
**14. Operable Capacity Season Label:** Applicable season and year.
**15. Season Minimum Operable Capacity Flag:** this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

# Spring 2023 Operable Capacity Analysis
# 50/50 Forecast (Reference)



# Spring 2023 Operable Capacity Analysis
# 90/10 Forecast



# OPERABLE CAPACITY ANALYSIS

*Summer 2023 Analysis*

# Summer 2023 Operable Capacity Analysis

| 50/50 Load Forecast (Reference) | June - 2023[2] CSO (MW) | June - 2023[2] SCC (MW) |
|---|---|---|
| Operable Capacity MW [1] | 28,057 | 28,877 |
| Active Demand Capacity Resource (+) [5] | 404 | 444 |
| External Node Available Net Capacity, CSO imports minus firm capacity exports (+) | 937 | 937 |
| Non Commercial Capacity (+) | 34 | 34 |
| Non Gas-fired Planned Outage MW (-) | 121 | 412 |
| Gas Generator Outages MW (-) | 6 | 136 |
| Allowance for Unplanned Outages (-) [4] | 2,800 | 2,800 |
| Generation at Risk Due to Gas Supply (-) [3] | 0 | 0 |
| Net Capacity (NET OPCAP SUPPLY MW) | 26,505 | 26,944 |
| Peak Load Forecast MW(adjusted for Other Demand Resources) [2] | 24,605 | 24,605 |
| Operating Reserve Requirement MW | 2,305 | 2,305 |
| Operable Capacity Required (NET LOAD OBLIGATION MW) | 26,910 | 26,910 |
| Operable Capacity Margin | -405 | 34 |

[1]Operable Capacity is based on data as of **April 25, 2023** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **April 25, 2023.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 3, 2023.**

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

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

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

# Summer 2023 Operable Capacity Analysis

| 90/10 Load Forecast | June - 2023[2] CSO (MW) | June - 2023[2] SCC (MW) |
|---|---|---|
| Operable Capacity MW [1] | 28,057 | 28,877 |
| Active Demand Capacity Resource (+) [5] | 404 | 444 |
| External Node Available Net Capacity, CSO imports minus firm capacity exports (+) | 937 | 937 |
| Non Commercial Capacity (+) | 34 | 34 |
| Non Gas-fired Planned Outage MW (-) | 121 | 412 |
| Gas Generator Outages MW (-) | 6 | 136 |
| Allowance for Unplanned Outages (-) [4] | 2,800 | 2,800 |
| Generation at Risk Due to Gas Supply (-) [3] | 0 | 0 |
| Net Capacity (NET OPCAP SUPPLY MW) | 26,505 | 26,944 |
| Peak Load Forecast MW(adjusted for Other Demand Resources) [2] | 26,421 | 26,421 |
| Operating Reserve Requirement MW | 2,305 | 2,305 |
| Operable Capacity Required (NET LOAD OBLIGATION MW) | 28,726 | 28,726 |
| Operable Capacity Margin | -2,221 | -1,782 |

[1] Operable Capacity is based on data as of **April 25, 2023** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **April 25, 2023.**

[2] Load forecast that is based on the 2023 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **June 3, 2023.**

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

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

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

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

## ISO-NE OPERABLE CAPACITY ANALYSIS

*April 25, 2023 - 50-50 FORECAST using CSO MW*

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

Report created: 4/25/2023

| Study Week (Week Beginning , Saturday) | CSO Supply Resource Capacity MW | CSO Demand Resource Capacity MW | External Node Capacity MW | Non-Commercial Capacity MW | CSO Non Gas-Only Generator Planned Outages MW | CSO Gas-Only Generator Planned Outages MW | Unplanned Outages Allowance MW | CSO Generation at Risk Due to Gas Supply 50-50PLE MW | CSO Net Available Capacity MW | Peak Load Forecast 50-50PLE MW | Operating Reserve Requirement MW | CSO Net Required Capacity MW | CSO Operable Capacity Margin MW | Season Min Opcap Margin Flag | Season_Label |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 |
| 6/3/2023 | 28057 | 404 | 937 | 34 | 121 | 6 | 2800 | 0 | 26505 | 24605 | 2305 | 26910 | -405 | Y | Summer 2023 |
| 6/10/2023 | 28057 | 404 | 937 | 34 | 52 | 6 | 2800 | 0 | 26574 | 24605 | 2305 | 26910 | -336 | N | Summer 2023 |
| 6/17/2023 | 28057 | 404 | 937 | 34 | 55 | 0 | 2800 | 0 | 26577 | 24605 | 2305 | 26910 | -333 | N | Summer 2023 |
| 6/24/2023 | 28057 | 404 | 937 | 34 | 55 | 0 | 2800 | 0 | 26577 | 24605 | 2305 | 26910 | -333 | N | Summer 2023 |
| 7/1/2023 | 28004 | 519 | 958 | 198 | 346 | 0 | 2100 | 0 | 27233 | 24605 | 2305 | 26910 | 323 | N | Summer 2023 |
| 7/8/2023 | 28004 | 519 | 958 | 198 | 462 | 0 | 2100 | 0 | 27117 | 24605 | 2305 | 26910 | 207 | N | Summer 2023 |
| 7/15/2023 | 28004 | 519 | 958 | 198 | 442 | 0 | 2100 | 0 | 27137 | 24605 | 2305 | 26910 | 227 | N | Summer 2023 |
| 7/22/2023 | 28004 | 519 | 958 | 198 | 458 | 0 | 2100 | 0 | 27121 | 24605 | 2305 | 26910 | 211 | N | Summer 2023 |
| 7/29/2023 | 28004 | 519 | 958 | 198 | 461 | 0 | 2100 | 0 | 27118 | 24605 | 2305 | 26910 | 208 | N | Summer 2023 |
| 8/5/2023 | 28004 | 519 | 958 | 198 | 464 | 0 | 2100 | 0 | 27115 | 24605 | 2305 | 26910 | 205 | N | Summer 2023 |
| 8/12/2023 | 28004 | 519 | 958 | 198 | 456 | 0 | 2100 | 0 | 27123 | 24605 | 2305 | 26910 | 213 | N | Summer 2023 |
| 8/19/2023 | 28004 | 519 | 958 | 198 | 348 | 0 | 2100 | 0 | 27231 | 24605 | 2305 | 26910 | 321 | N | Summer 2023 |
| 8/26/2023 | 28004 | 519 | 958 | 198 | 347 | 0 | 2100 | 0 | 27232 | 24605 | 2305 | 26910 | 322 | N | Summer 2023 |
| 9/2/2023 | 28004 | 519 | 958 | 198 | 431 | 0 | 2100 | 0 | 27148 | 24605 | 2305 | 26910 | 238 | N | Summer 2023 |
| 9/9/2023 | 28004 | 519 | 958 | 198 | 599 | 261 | 2100 | 0 | 26719 | 24605 | 2305 | 26910 | -191 | N | Summer 2023 |

### Column Definitions

**1. CSO Supply Resource Capacity MW:** Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
**2. CSO Demand Resource Capacity MW:** Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
**3. External Node Capacity MW:** Sum of external Capacity Supply Obligations (CSO) imports and exports.
**4. Non-Commercial capacity MW:** New resources and generator improvements that have acquired a CSO but have not become commercial.
**5. CSO Non Gas-Only Generator Planned Outages MW:** All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
**6. CSO Gas-Only Generator Planned Outages MW:** All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
**7. Unplanned Outage Allowance MW:** Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
**8. CSO Generation at Risk Due to Gas Supply Mw:** Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
**9. CSO Net Available Capacity MW:** the summation of columns (1+2+3+4-5-6-7-8=9)
**10. Peak Load Forecast MW:** Provided in the annual 2023 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
**11. Operating Reserve Requirement MW:** 120% of first largest contingency plus 50% of the second largest contingency.
**12. CSO Net Required Capacity MW:** (Net Load Obligation) (10+11=12)
**13. CSO Operable Capacity Margin MW:** CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
**14. Operable Capacity Season Label:** Applicable season and year.
**15. Season Minimum Operable Capacity Flag:** this column indicates whether or not a week has the lowest capacity margin for its applicable season.

# Summer 2023 Operable Capacity Analysis
# 90/10 Forecast

## ISO-NE OPERABLE CAPACITY ANALYSIS

### *April 25, 2023 - 90/10 FORECAST using CSO MW*

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

Report created: 4/25/2023

| Study Week (Week Beginning, Saturday) | CSO Supply Resource Capacity MW | CSO Demand Resource Capacity MW | External Node Capacity MW | Non-Commercial Capacity MW | CSO Non Gas-Only Generator Planned Outages MW | CSO Gas-Only Generator Planned Outages MW | Unplanned Outages Allowance MW | CSO Generation at Risk Due to Gas Supply 90-10PLE MW | CSO Net Available Capacity MW | Peak Load Forecast 90-10PLE MW | Operating Reserve Requirement MW | CSO Net Required Capacity MW | CSO Operable Capacity Margin MW | Season Min Opcap Margin Flag | Season_Label |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 |
| 6/3/2023 | 28057 | 404 | 937 | 34 | 121 | 6 | 2800 | 0 | 26505 | 26421 | 2305 | 28726 | -2221 | Y | Summer 2023 |
| 6/10/2023 | 28057 | 404 | 937 | 34 | 52 | 6 | 2800 | 0 | 26574 | 26421 | 2305 | 28726 | -2152 | N | Summer 2023 |
| 6/17/2023 | 28057 | 404 | 937 | 34 | 55 | 0 | 2800 | 0 | 26577 | 26421 | 2305 | 28726 | -2149 | N | Summer 2023 |
| 6/24/2023 | 28057 | 404 | 937 | 34 | 55 | 0 | 2800 | 0 | 26577 | 26421 | 2305 | 28726 | -2149 | N | Summer 2023 |
| 7/1/2023 | 28004 | 519 | 958 | 198 | 346 | 0 | 2100 | 0 | 27233 | 26421 | 2305 | 28726 | -1493 | N | Summer 2023 |
| 7/8/2023 | 28004 | 519 | 958 | 198 | 462 | 0 | 2100 | 0 | 27117 | 26421 | 2305 | 28726 | -1609 | N | Summer 2023 |
| 7/15/2023 | 28004 | 519 | 958 | 198 | 442 | 0 | 2100 | 0 | 27137 | 26421 | 2305 | 28726 | -1589 | N | Summer 2023 |
| 7/22/2023 | 28004 | 519 | 958 | 198 | 458 | 0 | 2100 | 0 | 27121 | 26421 | 2305 | 28726 | -1605 | N | Summer 2023 |
| 7/29/2023 | 28004 | 519 | 958 | 198 | 461 | 0 | 2100 | 0 | 27118 | 26421 | 2305 | 28726 | -1608 | N | Summer 2023 |
| 8/5/2023 | 28004 | 519 | 958 | 198 | 464 | 0 | 2100 | 0 | 27115 | 26421 | 2305 | 28726 | -1611 | N | Summer 2023 |
| 8/12/2023 | 28004 | 519 | 958 | 198 | 456 | 0 | 2100 | 0 | 27123 | 26421 | 2305 | 28726 | -1603 | N | Summer 2023 |
| 8/19/2023 | 28004 | 519 | 958 | 198 | 348 | 0 | 2100 | 0 | 27231 | 26421 | 2305 | 28726 | -1495 | N | Summer 2023 |
| 8/26/2023 | 28004 | 519 | 958 | 198 | 347 | 0 | 2100 | 0 | 27232 | 26421 | 2305 | 28726 | -1494 | N | Summer 2023 |
| 9/2/2023 | 28004 | 519 | 958 | 198 | 431 | 0 | 2100 | 0 | 27148 | 26421 | 2305 | 28726 | -1578 | N | Summer 2023 |
| 9/9/2023 | 28004 | 519 | 958 | 198 | 599 | 261 | 2100 | 0 | 26719 | 26421 | 2305 | 28726 | -2007 | N | Summer 2023 |

### Column Definitions

**1. CSO Supply Resource Capacity MW:** Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
**2. CSO Demand Resource Capacity MW:** Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
**3. External Node Capacity MW:** Sum of external Capacity Supply Obligations (CSO) imports and exports.
**4. Non-Commercial capacity MW:** New resources and generator improvements that have acquired a CSO but have not become commercial.
**5. CSO Non Gas-Only Generator Planned Outages MW:** All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
**6. CSO Gas-Only Generator Planned Outages MW:** All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
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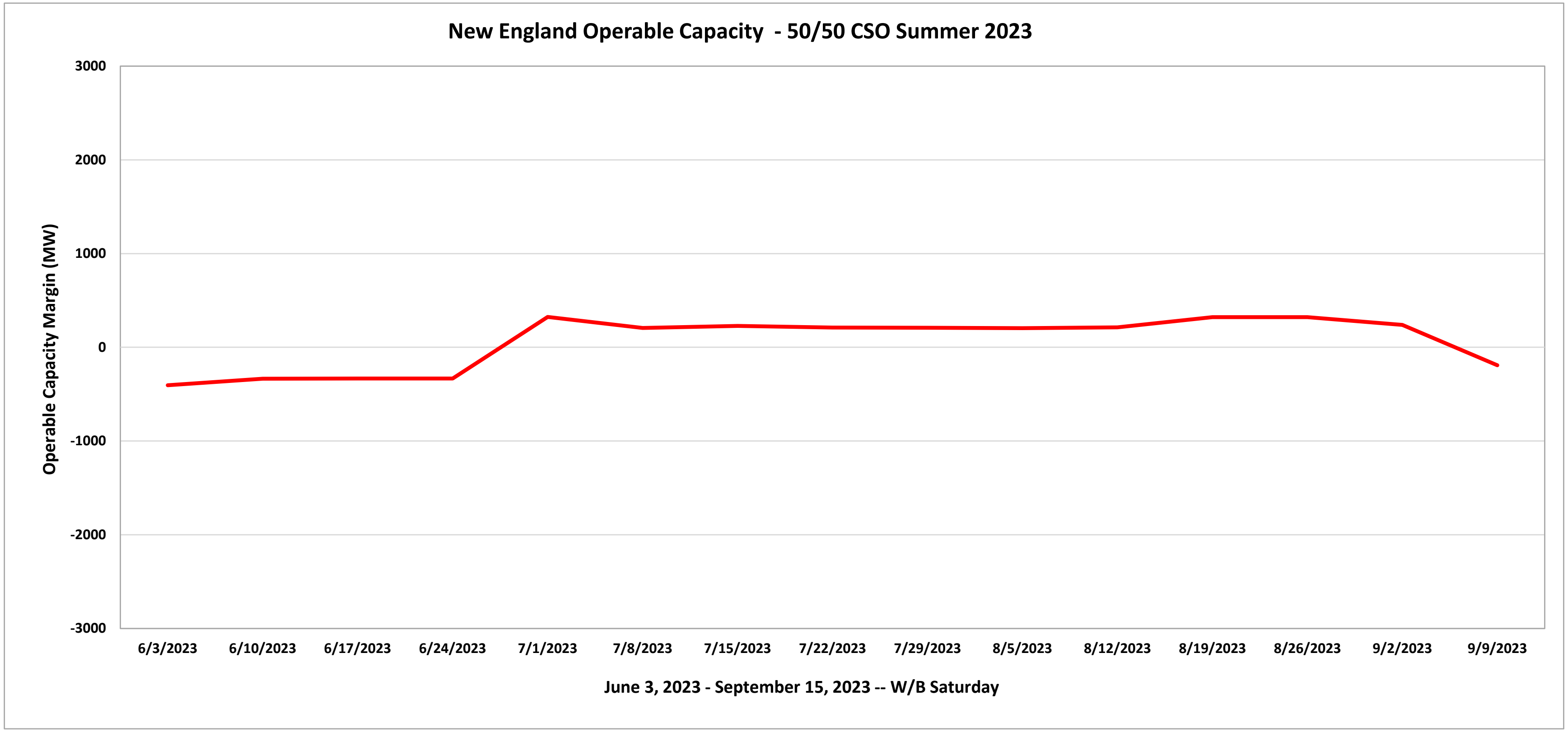
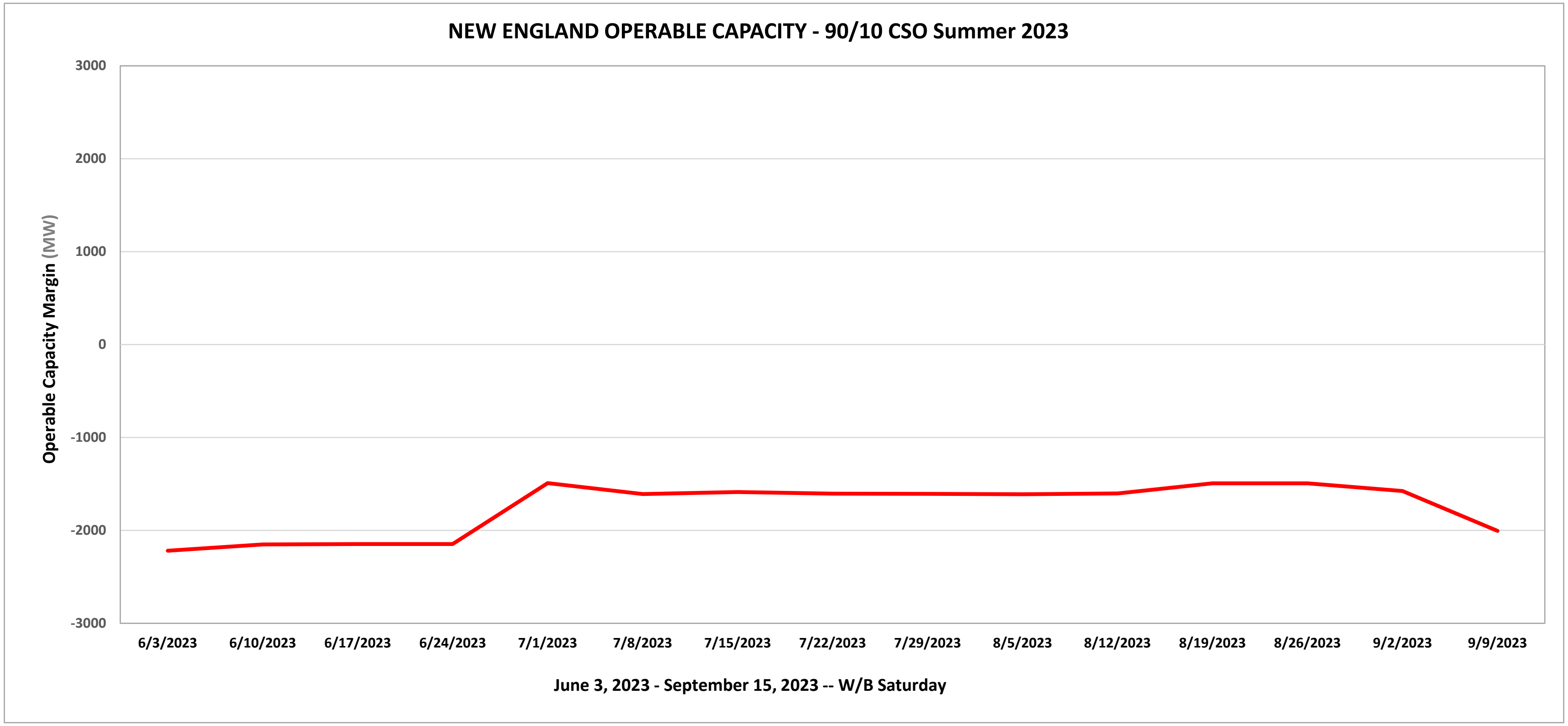
**15. Season Minimum Operable Capacity Flag:** this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

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



# Summer 2023 Operable Capacity Analysis
# 90/10 Forecast



# OPERABLE CAPACITY ANALYSIS

*Appendix*

# Possible Relief Under OP4: Appendix A

| OP 4 Action Number | Page 1 of 2<br>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.<br>Begin to allow the depletion of 30-minute reserve. | 0 [1]<br><br>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<br>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.<br><br>Voluntary Load Curtailment by Large Industrial and Commercial Customers. | 5<br><br>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

# 2022/2023 Winter Review

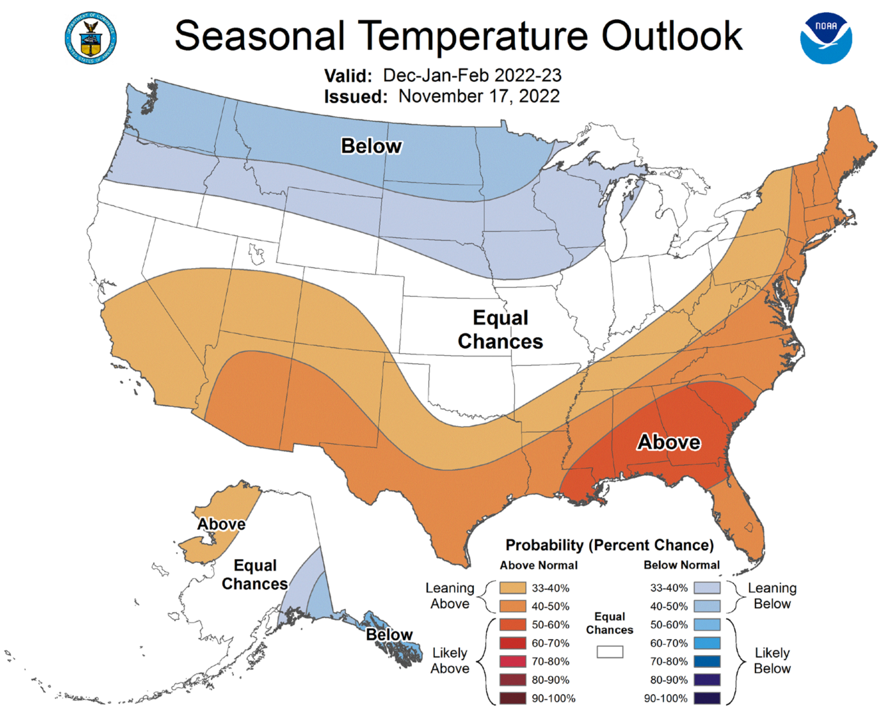
# Highlights

- The New England average winter temperature departure from normal of +4.8°F was consistent with NOAA's seasonal outlook of above normal temperatures
- The New England generation fleet and transmission system performed well overall
- LNG supplies were adequate and sendouts were minimal
- Fuel oil supplies were adequate; inventories ended the winter ~7M gallons above starting inventories
- With the exception of a brief capacity deficiency (OP-4) on December 24, surplus generating capacity was available throughout the winter
- No OP-21 Energy Alert or Energy Emergency actions were implemented this winter

# Winter Preparations 2022/2023

- ISO System Operations staff hosted a WebEx Generator Winter Readiness Seminar with Market Participants on November 14, 2022
- ISO staff met with industry and governmental officials to review seasonal expectations including capacity and demand forecasts and communication protocols
- Annual Winter Generator Readiness Survey was distributed to all generating resources in the region
- Annual Natural Gas Critical Infrastructure Survey process was completed in order to ensure critical infrastructure is not part of automatic or manual load shed schemes

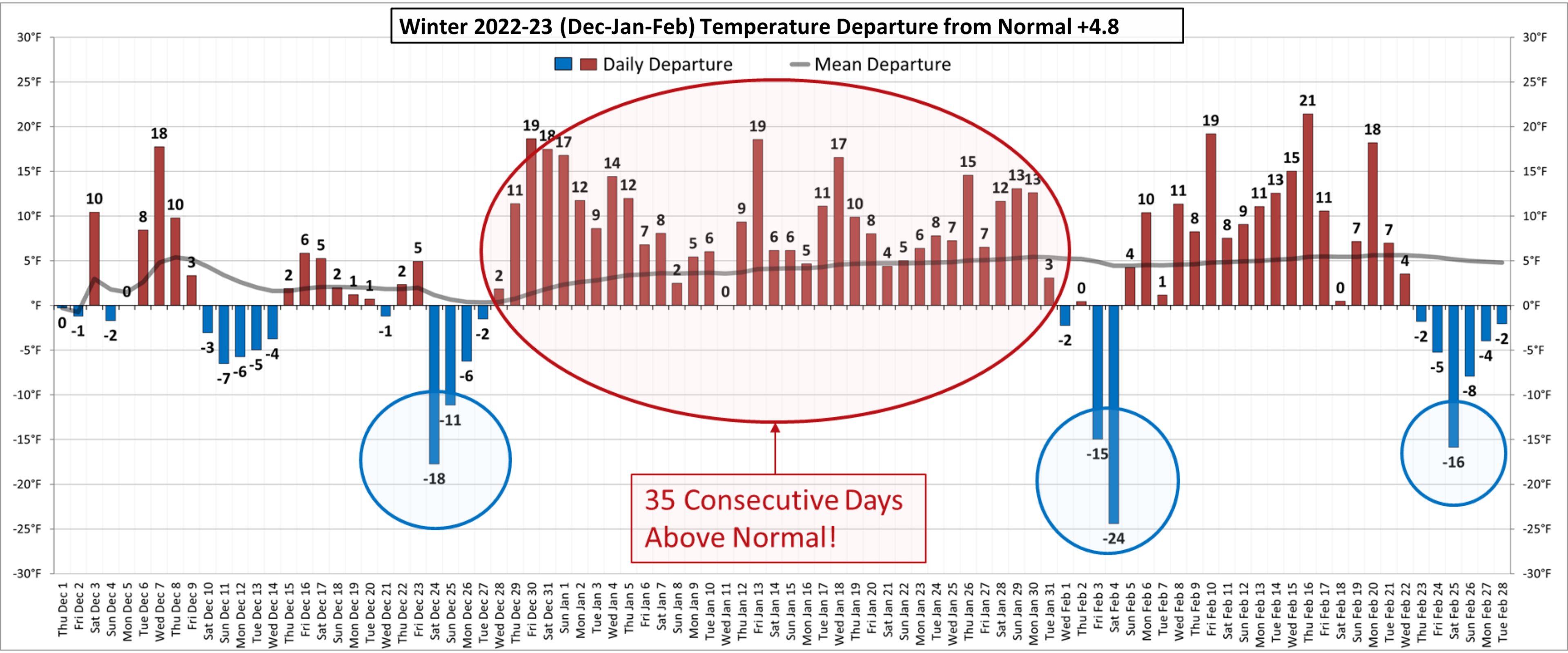
# Observed Winter Temperatures - Summary




- December was mild (+1.9°F) followed by a much warmer than average January (+8.9°F) and a milder than average February (+3.6°F)
- Three brief but notable cold snaps impacted the region; during the February 3-4 cold snap the mean temperature on Feb. 4 fell to 24°F below normal with some individual cities as much as 33°F below normal
- A remarkable stretch of 35 consecutive days of above normal temperatures were observed from December 28 through January 31

# Winter 2022/2023 Was Mild – 4.8°F Above Normal

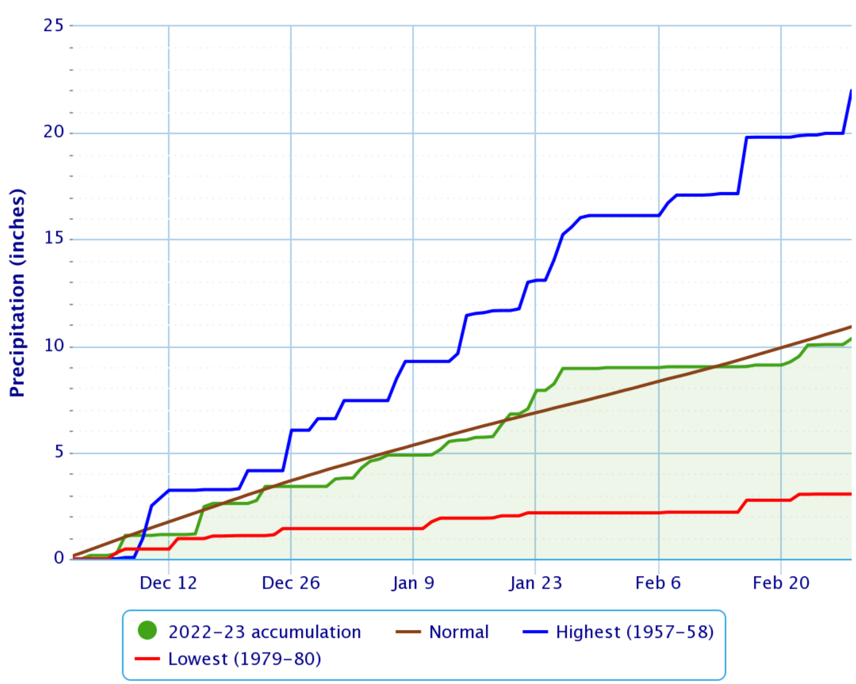
- Three notable, but short-duration cold weather events were observed, one in December and two in February



# Regional Total Precipitation Was 1.4” Above Normal While Snowfall Amounts Were Below Normal

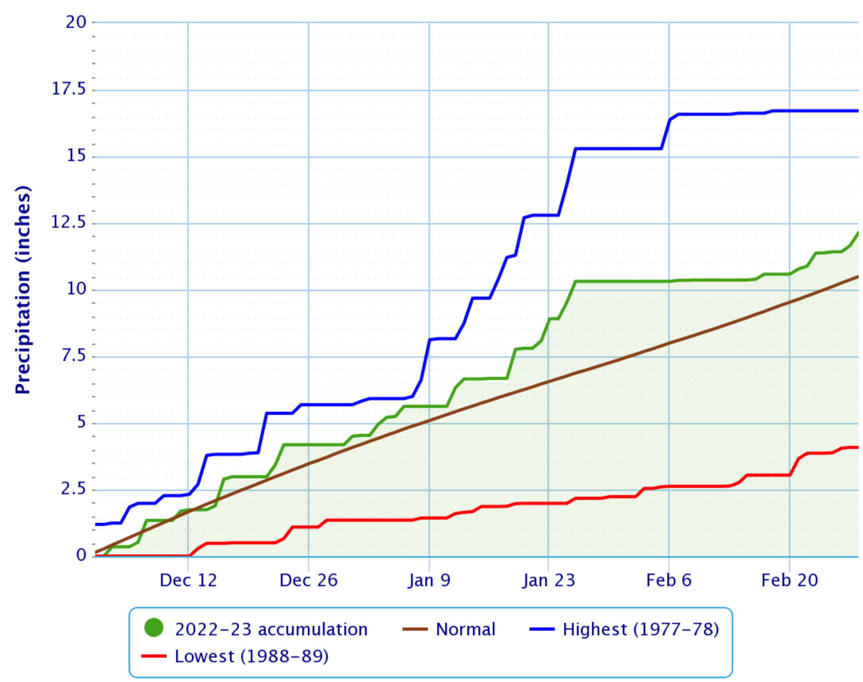
- Boston
  - Total precipitation was 0.6” below normal
  - 10.4” of snowfall recorded; 27.3” below normal

Accumulated Precipitation – Boston, MA



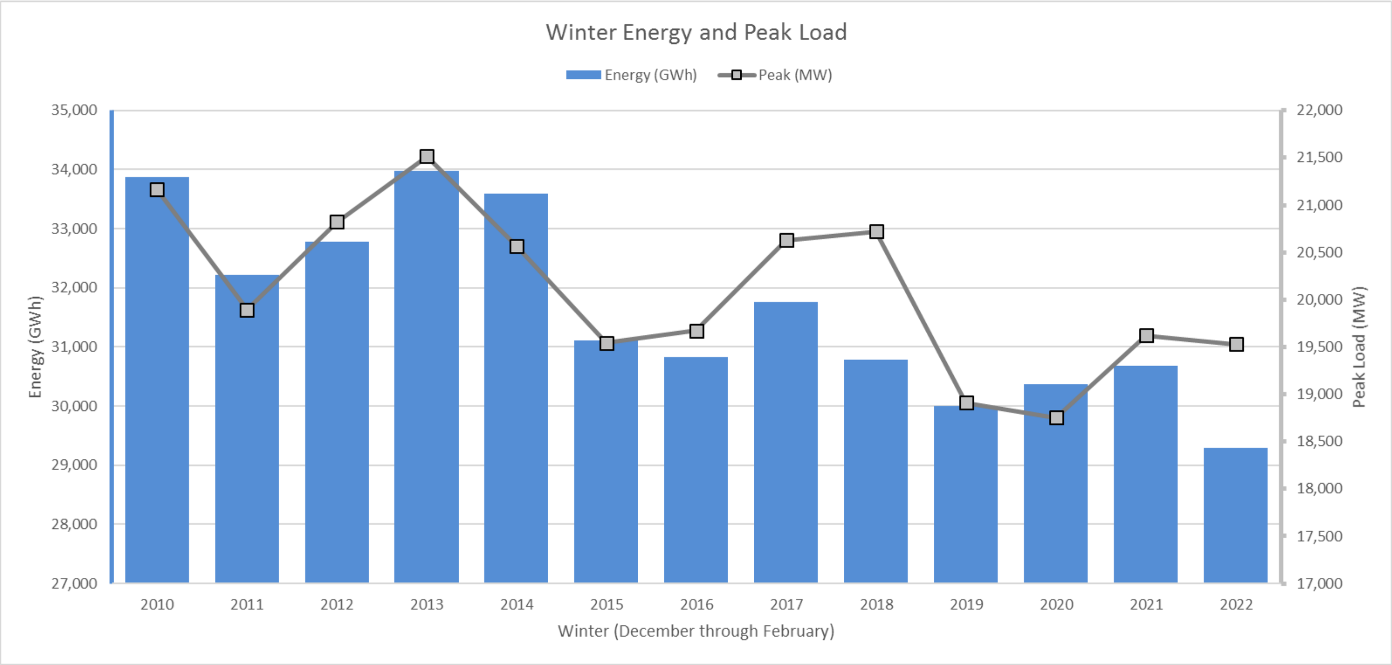

- Hartford
  - Total precipitation was 1.7” above normal
  - 14.0” of snowfall recorded; 25.1” below normal

Accumulated Precipitation – Hartford, CT



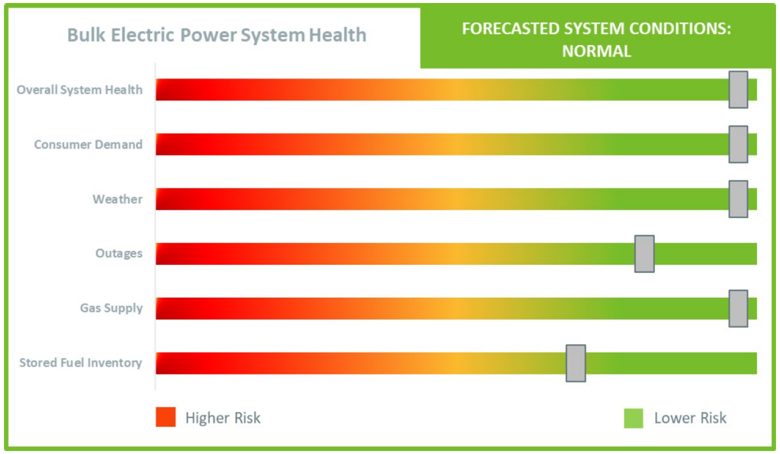
# Winter Peak Load and Total Energy Demand

- Total winter energy demand was ~29,300 GWh
  - Since 2010 winter energy demand has averaged ~31,600 GWh
- Actual winter peak load was 19,529 MW on February 3, 2023
  - Forecasted 50/50 peak load was 20,009 MW

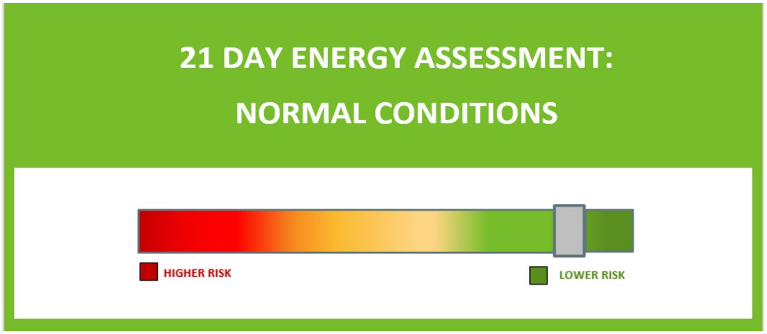


# ISO Published 21-Day Energy Assessments Weekly Throughout the Winter

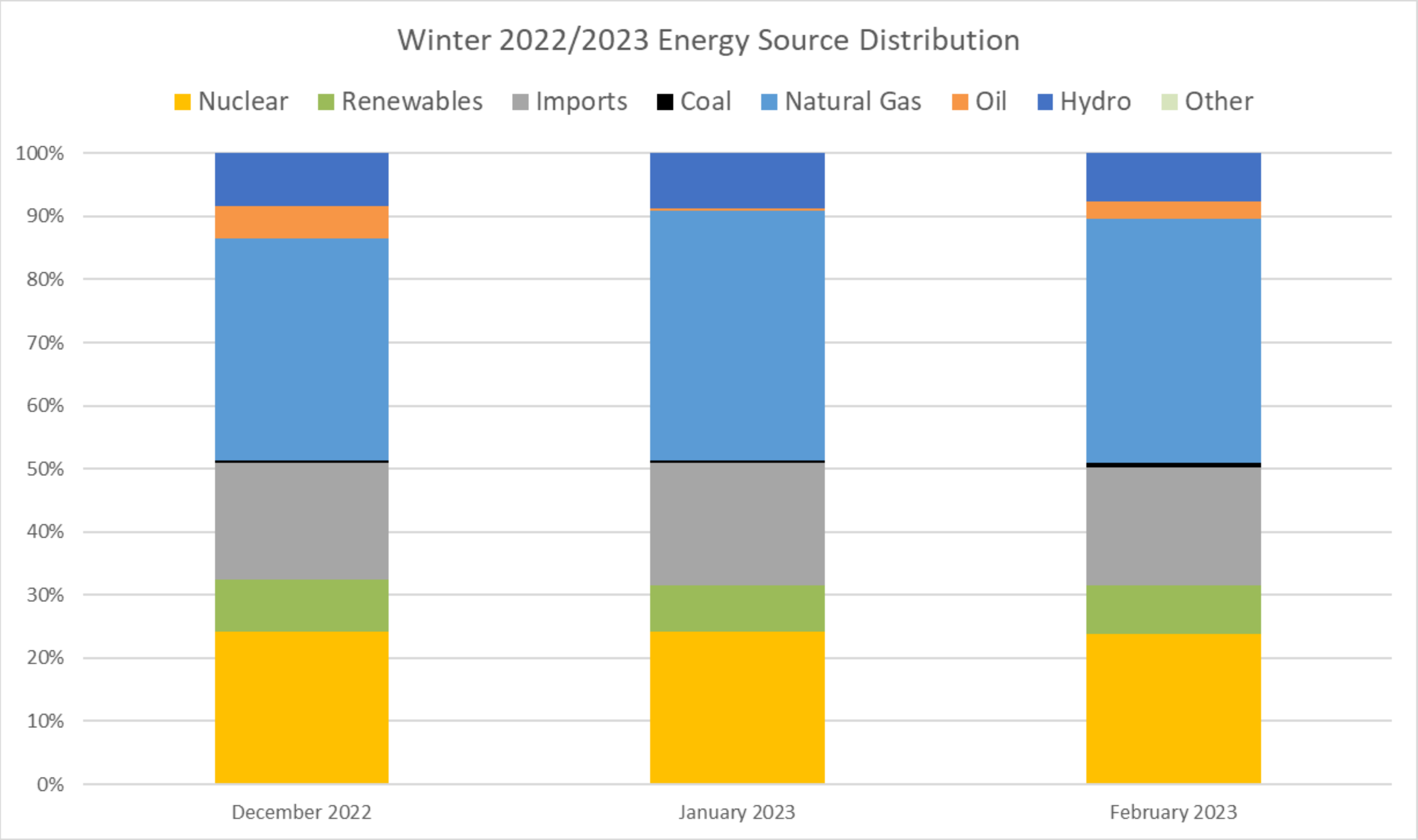
- Provide situational awareness of anticipated system conditions and identify potential energy shortfalls
- Several new visuals were added to the report this winter to more clearly indicate projected system conditions
- ISO's 21-Day Energy Assessment forecasted Normal System Conditions throughout the winter



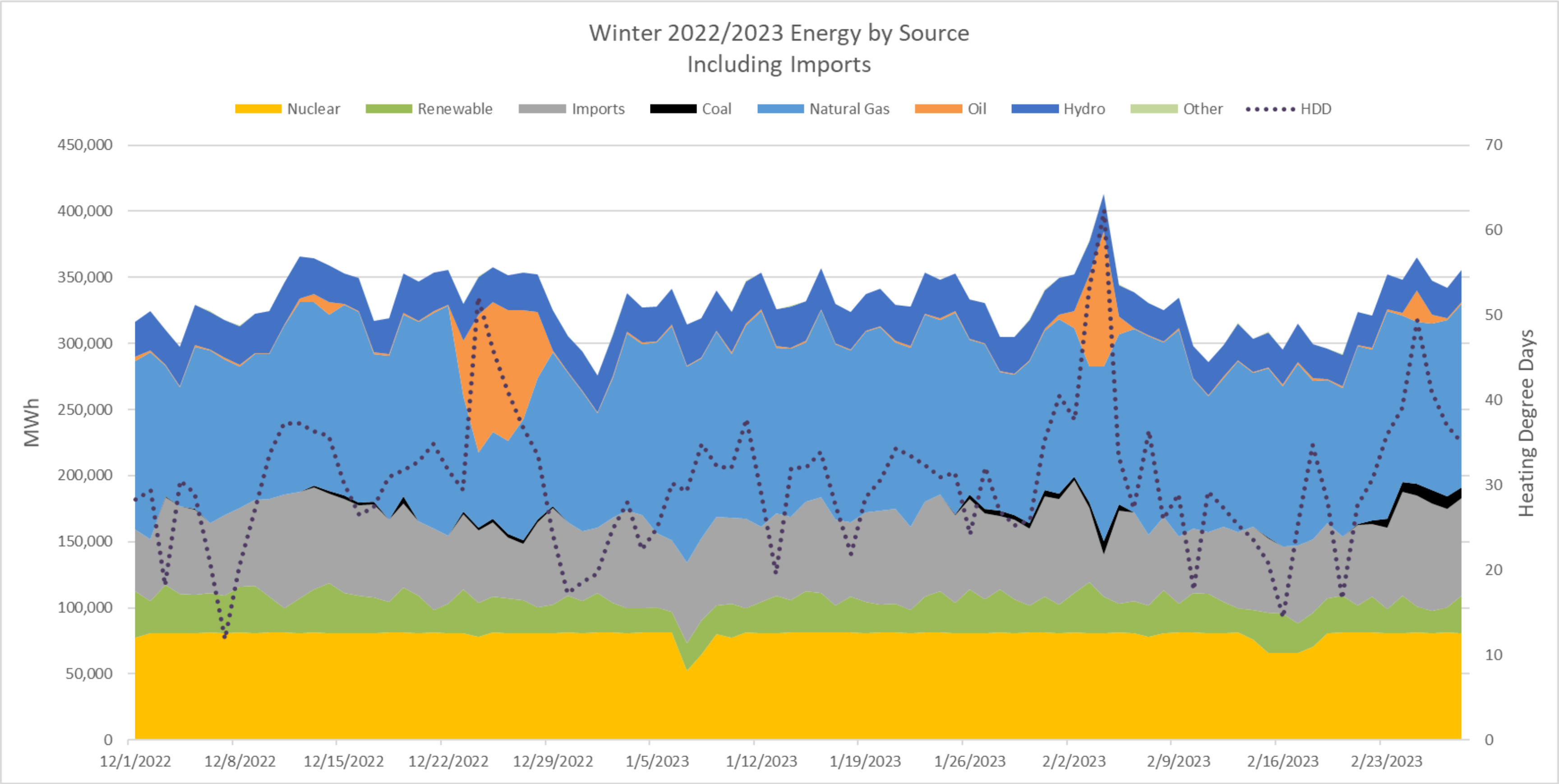




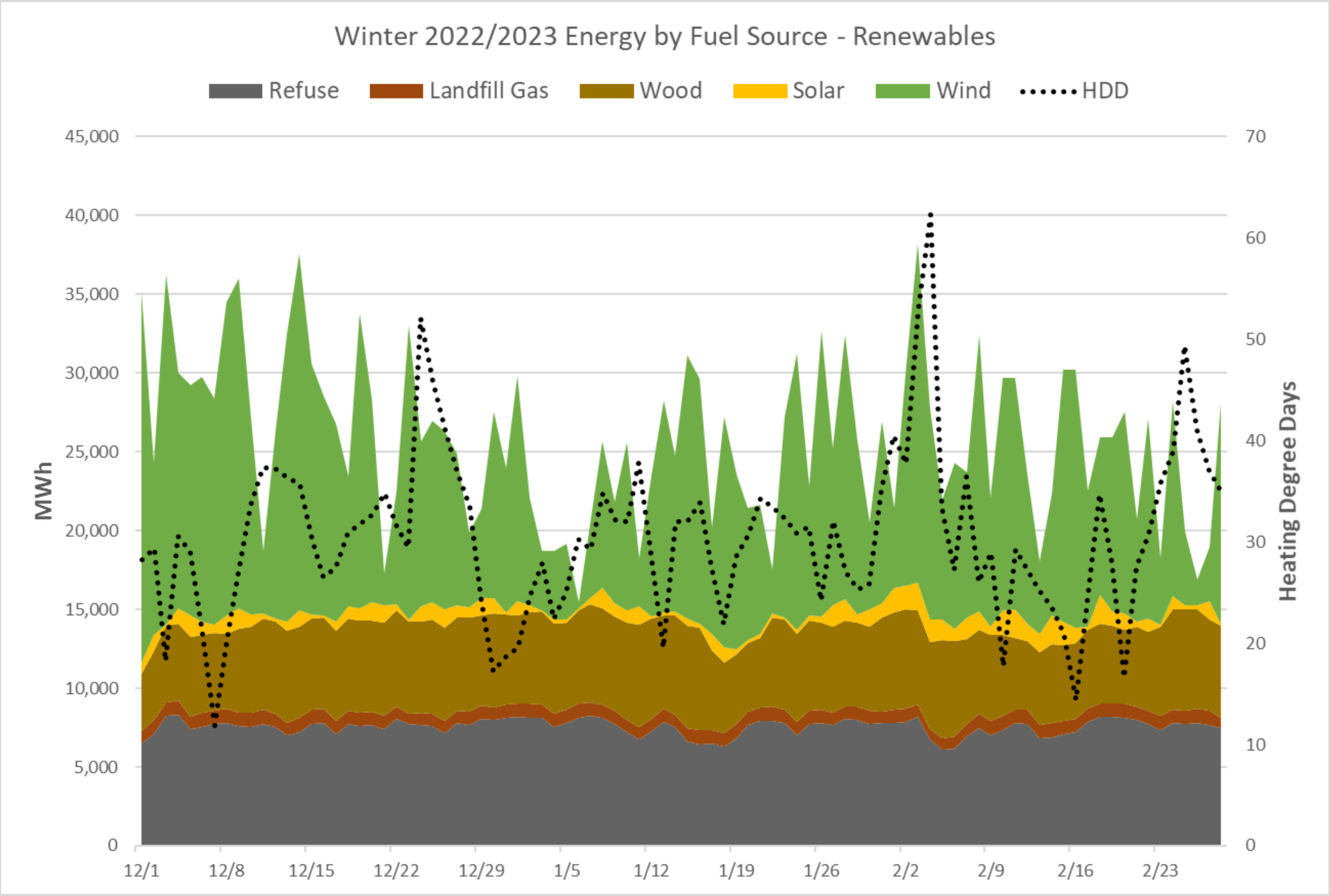
# Winter 2022/2023 Energy Sources



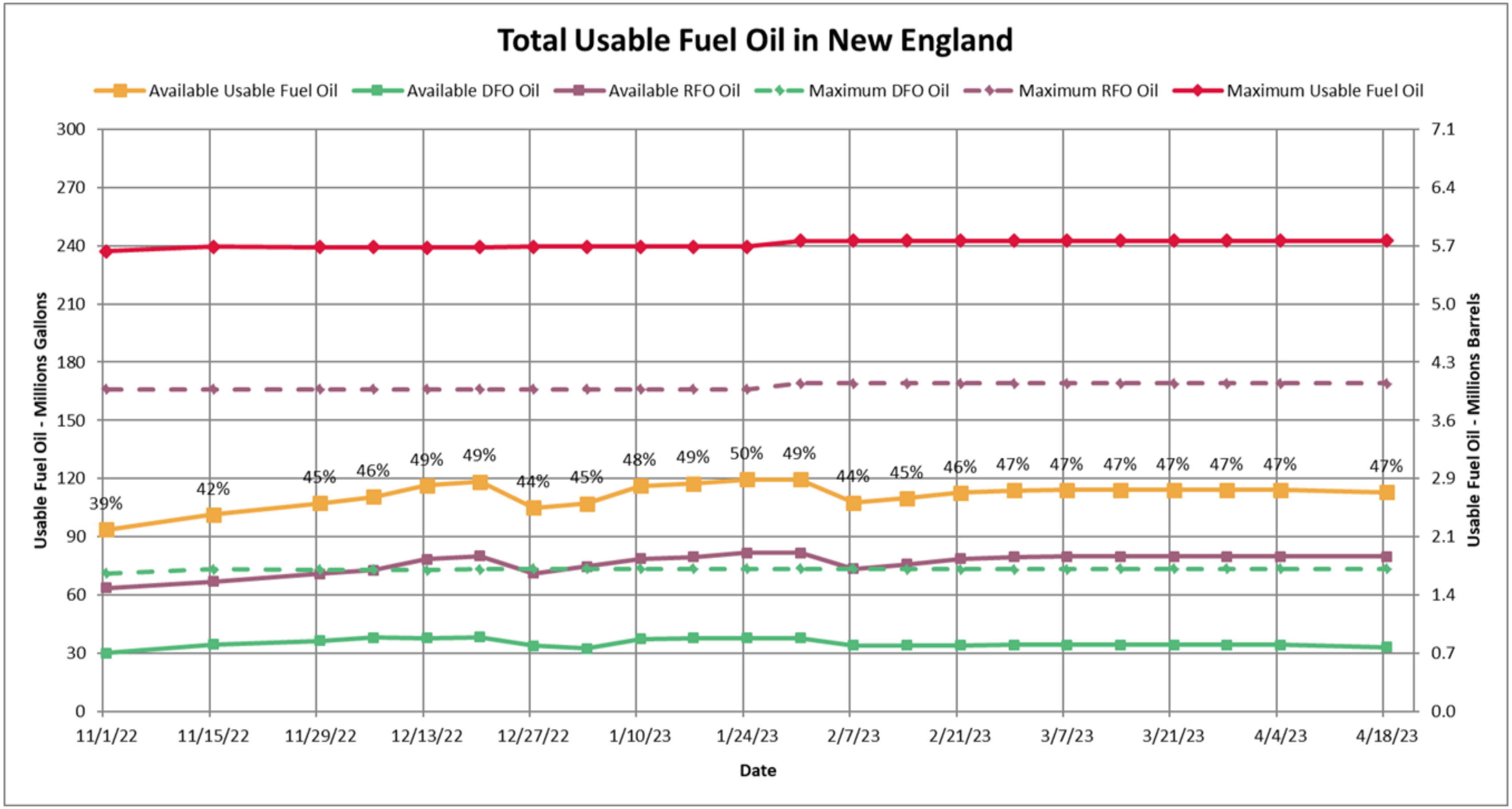
# On The Coldest Days in December and February Oil-Fired Generation Ramped Up Significantly



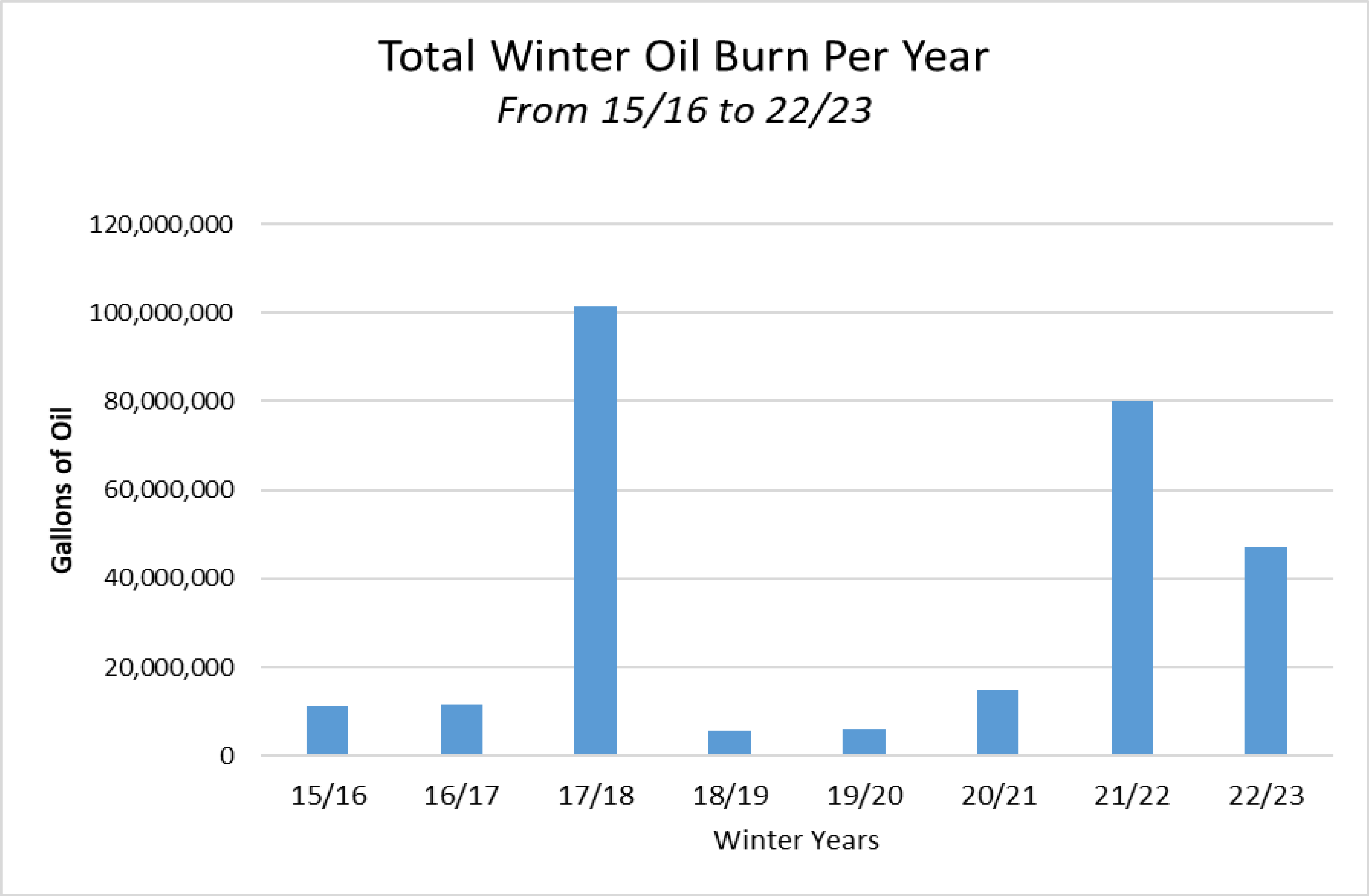
# Daily Energy by Fuel Source - Renewables Only



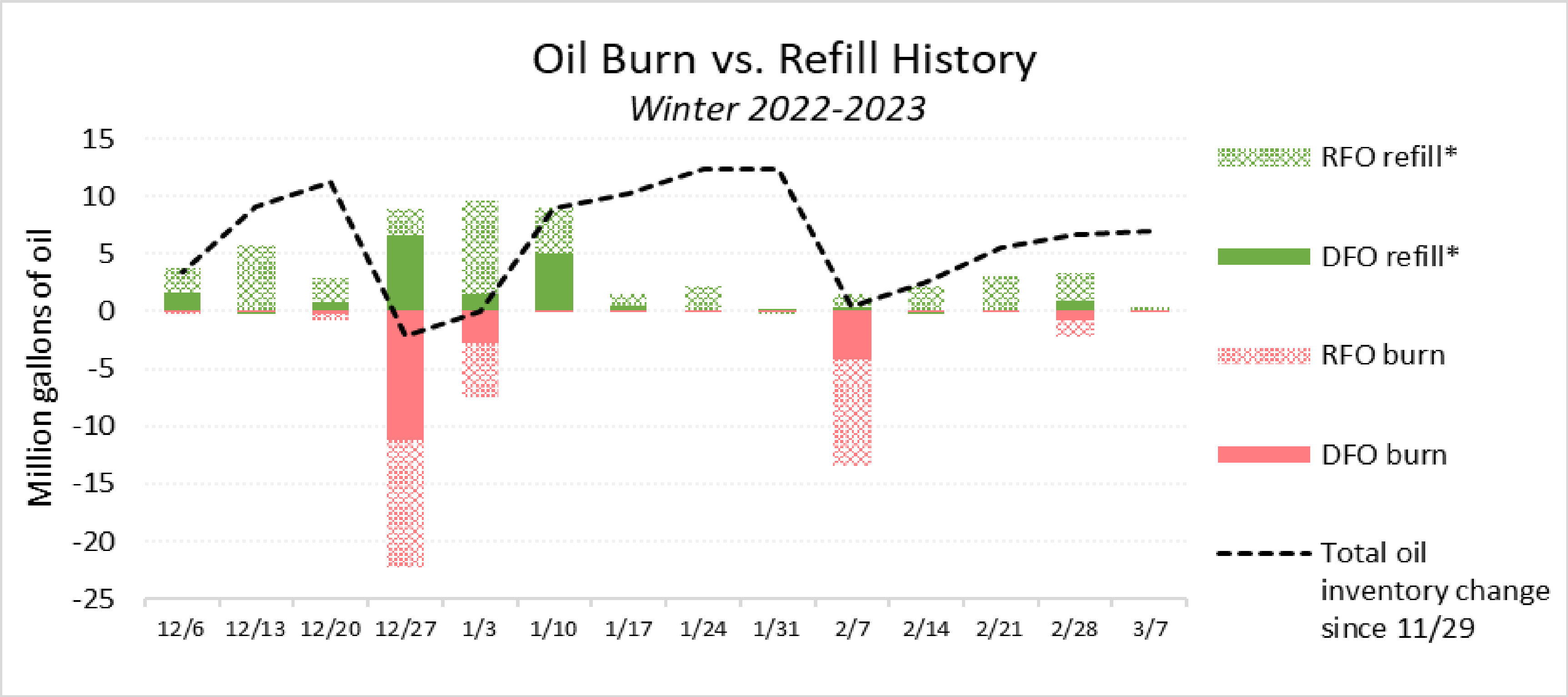
# Fuel Oil Inventories Increased Ahead of the Winter and Were Adequate Throughout



# Winter Fuel Oil Usage of ~47M Gallons Was ~41% Lower Than Last Winter



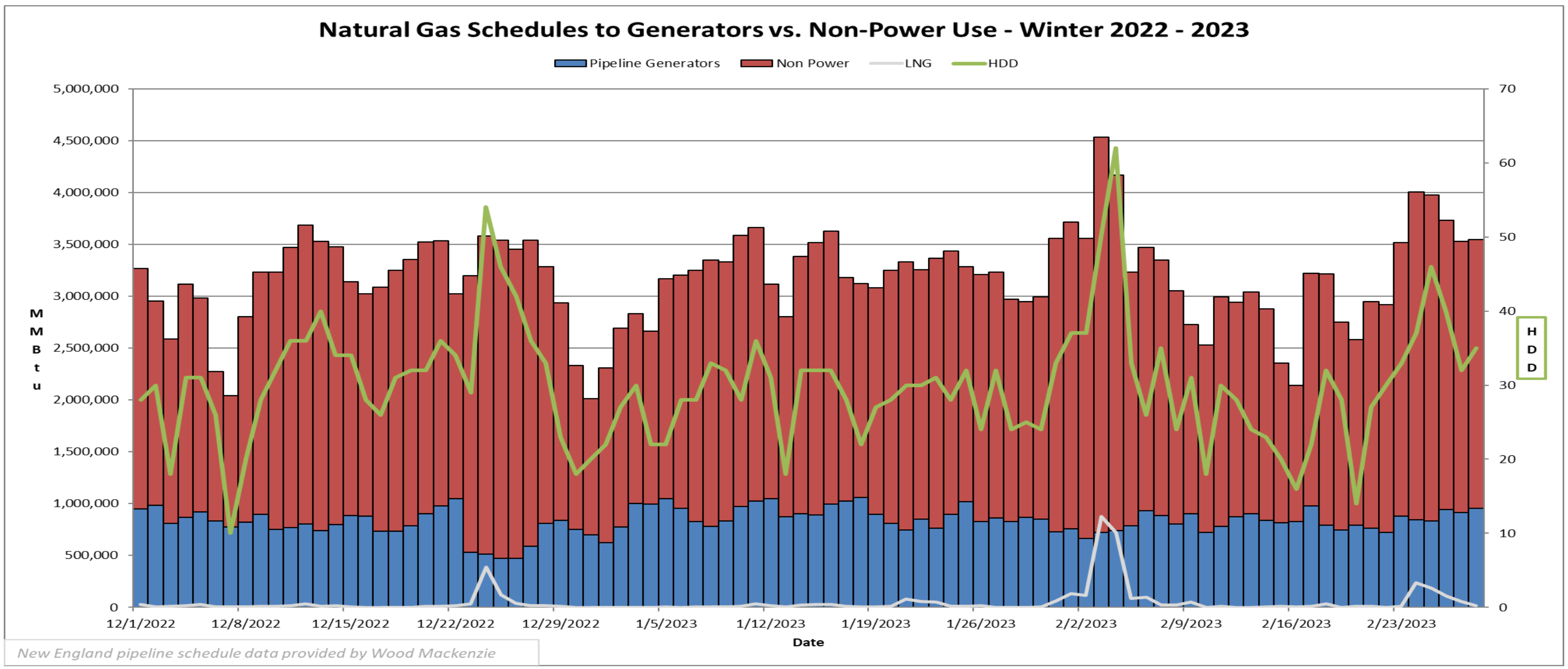
# Timely Fuel Oil Replenishment Occurred Prior To and Following Periods of Fuel Oil Burn




*Refill is estimated from fuel oil burns and inventories reported by participants on periodic OP-21 generator surveys

# Natural Gas Demand – Winter 2022/2023

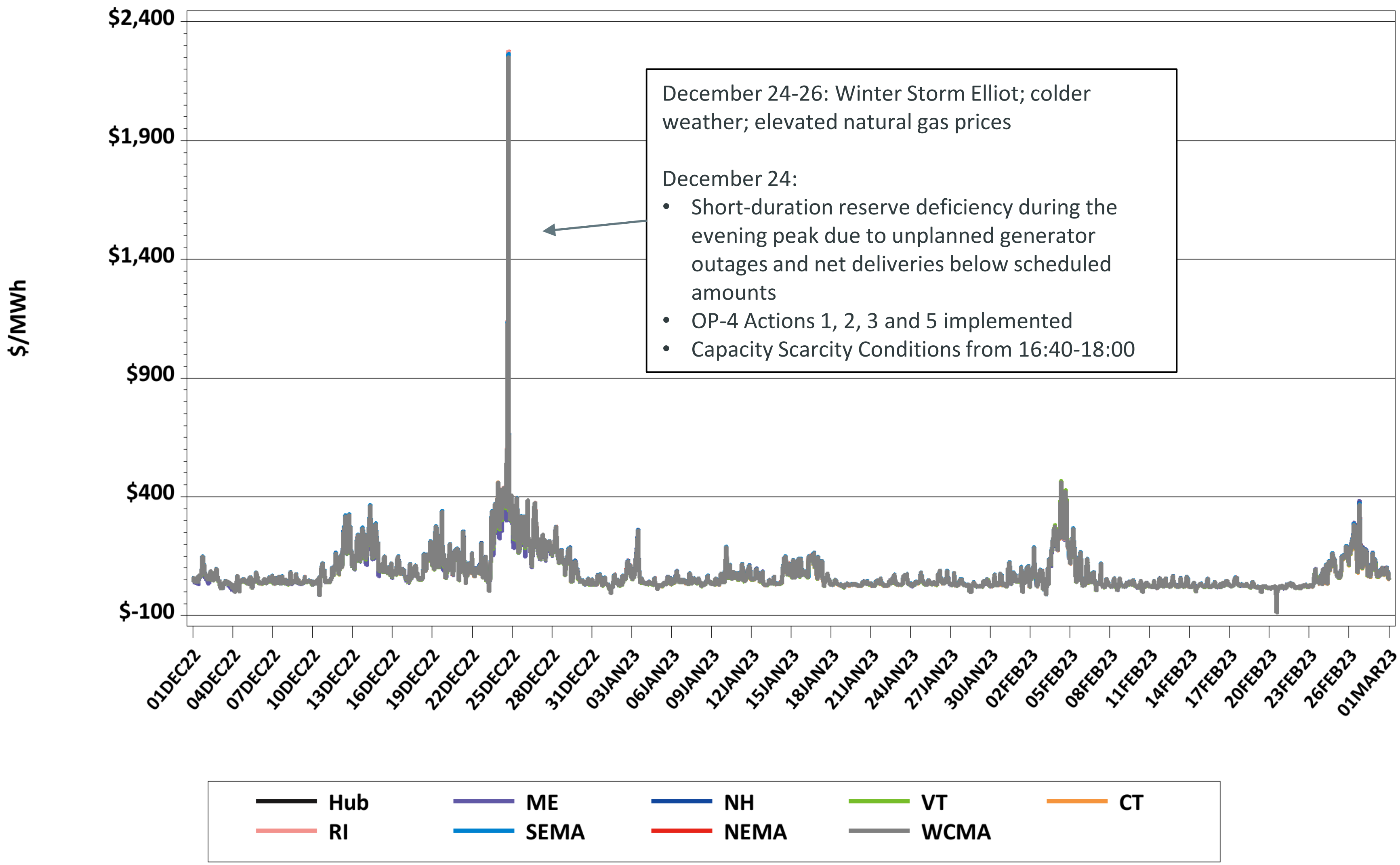
- Non-power demand for heating is higher than natural gas demand for generation
- On February 3, LNG scheduled to pipelines was higher than the natural gas scheduled to generators



# Winter 2022/2023 Wholesale Market Summary

- December
  - Average RT Hub LMP: **$121.47/MWh** (highest December value since SMD)
  - Average natural gas price: **$13.86/MMBtu** (up ~65% from prior December)
  - December natural gas prices were the highest in over 15 years
  - Capacity Scarcity Conditions on December 24 contributed to elevated RT pricing
- January
  - Average RT Hub LMP: **$50.51/MWh** (down ~66% from prior January)
  - Average natural gas price: **$4.73/MMBtu** (down ~77% from prior January)
  - Weather was ~7°F warmer than prior January and the warmest January in over 15 years; loads were the lowest for a January since SMD
- February
  - Average RT Hub LMP: **$65.21/MWh** (down ~40% from prior February)
  - Average natural gas price: **$8.13/MMBtu** (down ~44% from prior February)
  - Relative to the February 2022, average temperatures were ~2°F warmer and average loads were down 4%

# Hourly Real-Time LMPs, Winter 2022/2023



# Comparison of Recent Winter Wholesale Energy Market Revenues

- The table below shows a comparison of Energy Market Revenues for seven of the past 10 winters, in millions of dollars

| Winter | December | January | February | Total | Rank[1] |
|---|---|---|---|---|---|
| 2013/14 | $1,161 | $2,190 | $1,703 | $5,054 | 1 |
| 2014/15 | $498 | $871 | $1,400 | $2,769 | 6 |
| 2017/18 | $856 | $1,340 | $401 | $2,597 | 8 |
| 2019/20 | $468 | $297 | $233 | $998 | 20 |
| 2020/21 | $450 | $489 | $759 | $1,698 | 15 |
| 2021/22 | $720 | $1,792 | $1,216 | $3,728 | 2 |
| 2022/23 | $1,328* | $552 | $749 | $2,629 | 7 |

1 Since the beginning of Standard Market Design in March 2003
* December 2022 value ($1.33B) was highest for a December month since SMD primarily due to elevated natural gas prices

# 2023/24 Winter Outlook Scenarios

# Introduction – 2023/24 Winter Scenarios

- The ISO routinely performs scenario assessments to prepare for the winter
- The following slides illustrate the qualitative and quantitative aspects of three scenarios
  - Scenario 1 assumes a mild winter as represented by the 2021/22 winter
  - Scenario 2 assumes a moderate winter, but with a 13 day cold spell, as represented by the 2017/18 winter
  - Scenario 3 assumes a severe winter as represented by the 2013/14 winter
- The ISO's 21-day energy forecast tool will signal any potential energy emergencies, thereby alerting the market to procure necessary fuel replenishments, both to meet their obligation and to protect against scarcity

# 2023/24 Winter Assumptions

- Peak load for moderate winter is 19,600 MW
- Peak load for severe winter is 20,300 MW
- Behind the Meter PV is ~6400 MW
  - Loads and energy demand are reduced accordingly
- Incremental fuel of ~3Bcf LNG and ~10 million gallons of oil assumed from the Inventoried Energy Program*
  - As a reminder, the 2022/23 assumptions included that the oil inventory would be at ~50% and LNG volumes would be ~31 Bcf
- Imports held at 1500 MW when temperatures dip below 20° F, and vary from 3000 – 4000 MW when temperatures are above 20° F
- No significant, multiple, or long-duration generator or transmission contingencies

*This estimate is on the lower end of expected incremental fuel

# Scenario 1 – Mild Winter, Similar to 2021/22

- Winter 2021/22 overview:
  - Milder than normal winter with very few days staying below freezing
  - Average temperature departure from normal was +1.0°F (i.e., warmer than normal)
  - Winter peak load of 19,623 MW
  - Approximately 80M gallons of fuel oil was burned
- Under this scenario, the ISO anticipates that there would be sufficient capacity and energy available to meet the expected peak loads and energy

# Scenario 2 – Moderate Winter with a Deep and Prolonged Cold Spell; Similar to 2017/18

- Winter 2017/18 characteristics:
  - Milder than normal outside of a two-week span of significantly below normal temperatures
  - Average temperature departure from normal was +0.5°F degrees
  - The region was impacted by an extended stretch of cold weather between December 25 and January 9; all major cities in the region experienced temperatures below normal for at least 13 consecutive days, of which 10 days averaged more than 10°F below normal
  - Winter peak load of 20,631 MW

- Under this scenario, the ISO anticipates that there would be sufficient capacity and energy available to meet the expected peak loads and energy

# Scenario 3 – Cold Winter with Several Cold Stretches; Similar to 2013/14

- Winter 2013/14 characteristics:
  - Colder than normal overall highlighted by a polar vortex event which resulted in significant stretches of cold weather in New England and surrounding areas
  - Average temperature departure from normal was -2.3°F degrees
  - The region experienced six cold weather stretches of four or more consecutive days, including a stretch of ten consecutive days at or below freezing
  - Winter peak load of 21,514 MW
  - Significant energy usage caused high demand on both the electric and natural gas systems
- Under this scenario, the ISO expects that capacity deficiency actions under OP-4 may be necessary across a few days
  - OP-7 actions are unlikely to be needed

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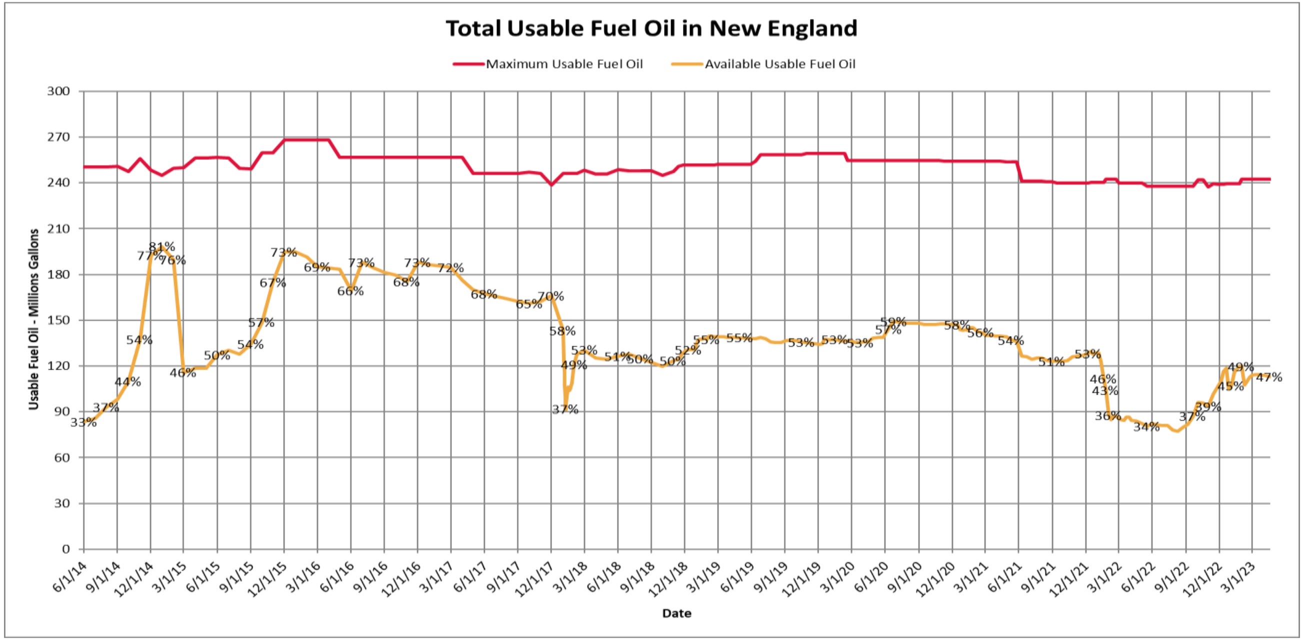
# Other Information

# Currently, aggregate Fuel Oil Inventories are close to pre-winter levels



# Looking Forward – World Gas Prices

- Current forward prices for European and Asian natural gas are ~$18 to $19
  - Prices below are from mid April

| Month | Dutch TTF USD/MMBtu | Asian JKM USD/MMBtu | AGT USD/MMBtu |
|---|---|---|---|
| November 2023 | 18.406 | 17.970 | 5.78 |
| December 2023 | 19.076 | 19.025 | 13.71 |
| January 2024 | 19.217 | 19.160 | 17.41 |
| February 2024 | 19.228 | 19.145 | 16.56 |
| March 2024 | 18.900 | 16.665 | 7.47 |

# Winter 2023-24 Preparations

- ISO will model 90-day forward looking energy analysis in advance of the winter and provide an update to stakeholders in October/November 2023
- Winter weather forecast will be an important factor
- ISO will continue its robust communication protocol with stakeholders, states, and federal agencies in advance of the winter
- Inventoried Energy Program will be in place for winter 2023/2024 and 2024/2025

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# Winter 2024-25 Analysis; With and Without Everett Marine Terminal

# Introduction

This analysis :

- Reviews 2024-25 winter operations with and without the Everett LNG facility
- Is intended to quantify the sensitivity of the loss of Everett to energy adequacy given that the reliability must run contract with Mystic/Everett terminates on June 1, 2024
- Uses the same (deterministic) model as prior winter analyses
- Is different from the probabilistic model that the ISO is collaborating on with EPRI

# 2024/25 Winter Analysis – Assumptions

- Loads are scaled to 2024-2025
  - Peak load modeled for moderate and severe winters is 19,900 MW and 20,600 MW, respectively
- Energy demand modeled for moderate and severe winters is 29,500 GWh and 31,500 GWh, respectively
- Behind-the-meter (BTM) PV nameplate capacity of ~7280 MW
  - Loads and energy demand are reduced accordingly
- Similar to the 2023/24 analysis, incremental fuel of ~3Bcf LNG and ~10 million gallons of oil assumed from the Inventoried Energy Program*
- Fuel oil is assumed to be distributed similar to winter 2022/23

*This estimate is on the lower end of expected incremental fuel

# 2024/25 Winter Analysis – Assumptions

- Assume maximum LNG injection capability of 1.2 Bcf/day with Everett
- Assume maximum LNG injection capability of 0.8 Bcf/day without Everett
- Imports range from 3000 – 4000 MW, but set at 1500 MW in hours when temperatures dip below 20° F
- Offshore wind ranges from 380 – 800 MW nameplate
- No significant, multiple or long-duration generator or transmission contingencies

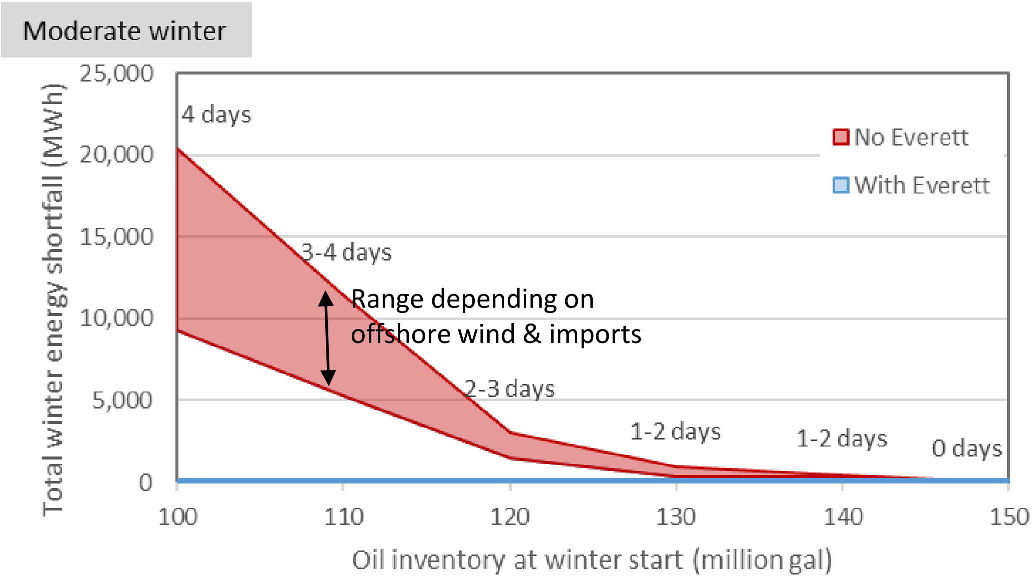
# Moderate Winter Sensitivity Analysis

With Everett:

- Assumed max available LNG injection capability is 1.2 Bcf/day
- No energy shortfall in any scenario studied

Without Everett:

- Assumed max available LNG injection capability is 0.8 Bcf/day
- Energy shortfall fully mitigated with increased fuel oil inventory
  - Assuming lower oil inventory (~100 million gallons), energy shortfall ranges from ~10,000 to ~20,000 MWh distributed over 4 days
    - Assume daily energy on a cold winter day is ~400,000 Mwh
    - This translates to roughly 0.6-1.2% of daily energy consumed across those four days



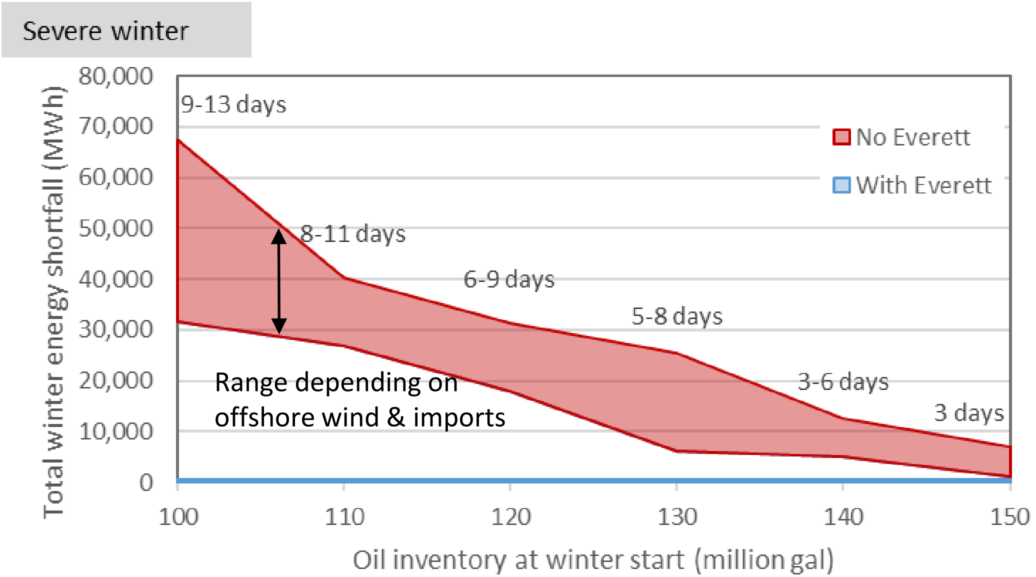
# Severe Winter Sensitivity Analysis

With Everett:

- Assumed max available LNG injection capability is 1.2 Bcf/day
- No energy shortfall in any scenario studied

Without Everett:

- Assumed max available LNG injection capability is 0.8 Bcf/day
- Energy shortfall mostly mitigated with increased fuel oil inventory
  - Assuming lower oil inventory (~100 million gallons), energy shortfall ranges from ~30,000 to ~67,000 MWh distributed over 9-13 days
    - Assume daily energy on a cold winter day is ~400,000 Mwh
    - This translates to roughly 0.6-1.8% of daily energy across those 9-13 days



# Everett Marine Terminal – Other Factors

- From a qualitative standpoint, the ISO has discussed its concerns about the retirement of existing infrastructure before new infrastructure is in-service
  - That concern extends to Everett
  - Given the uncertainty of the pace of future winter load growth from electrification, limited LNG import facilities, delays in new infrastructure being built, and other changes to the resource mix, including retirements, the ISO continues to believe that the region would be prudent to retain its limited gas infrastructure in the mid-term
- The ISO doesn't have the expertise to assess the operational capability of the regional pipeline system without Everett and will rely on the expertise of pipelines and the LDC's to identify any operational concerns

# Conclusion

- Data shows limited exposure to energy shortfalls in 2024/25 without Everett
- Factors leading to this result:
  - Acceleration of behind-the-meter (BTM) PV nameplate capacity
  - Limited load growth
  - Expectation that the Inventoried Energy Program will add incremental fuel
  - Additional off-shore wind in-service
  - Assumption that the ‘capacity’ of Everett will be picked up by the remaining LNG facilities and oil storage and that those facilities are available in the winter season
- This analysis doesn’t provide clear quantitative evidence of the need to retain Everett for electric system reliability
  - The ISO has previously stated the qualitative factors that may warrant the need for Everett in the mid-term
- As a consequence, the ISO sees its role as limited to providing any additional quantitative analysis that may be needed by the region to help inform its decision making on the need for Everett
  - The EPRI study results (released by May 12) will shed further information about the operational impacts to extreme weather events in 2027, with and without Everett

**M E M O R A N D U M**

**TO:** NEPOOL Participants Committee Members and Alternates

**FROM:** Rosendo Garza, NEPOOL Counsel

**DATE:** April 27, 2023

**RE:** Order No. 2222 – ISO-NE's Further Compliance Proposal

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At the May 4, 2023 Participants Committee meeting, you will be asked to support Tariff revisions proposed by the ISO to respond to certain additional compliance requirements set forth in the FERC's March 1, 2023 *Order 2222 Compliance Order*.[1] As detailed herein, these ISO-proposed Tariff changes were considered at, and supported by, the Markets Committee.

Background & Overview

By way of brief background, the FERC's March 1 *Compliance Order* accepted in part and rejected in part the region's joint *Order 2222* compliance proposal and set forth further compliance obligations to be filed within 30, 60 and 180 days. The FERC subsequently granted NEPOOL's motion requesting a brief extension of the original 60-day compliance deadline to permit the Participants Committee to consider any Tariff changes prior to the ISO's 60-day submission.[2]

The proposed set of compliance Tariff revisions to be considered at the May 4 meeting generally fall into two categories. The first set of changes are those that the FERC directed, namely, revisions to Tariff provisions related to the small utility opt-in requirement, dispute resolution requirement, and application of non-performance penalties that apply to a distributed energy resource aggregation. The other Tariff revisions concern the *Compliance Order* requirement that the ISO identify existing rules that a Market Participant providing wholesale energy withdrawal service must be a load-serving entity. To satisfy this directive, and as the ISO explained to the Markets Committee, the Tariff revisions add references to the Tariff sections of the existing Load Asset registration requirement for Continuous Storage Facilities and Binary Storage Facilities.

To review the proposed Tariff revisions, see the ISO's Tariff redlines included in Attachment A. Additional information concerning the ISO's 60-day compliance approach is included in Attachment B and Attachment C.

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[1] For a high-level summary of the order, see Memorandum from NEPOOL Couns. to the NEPOOL Participants Comm. Members and Alternates (Mar. 3, 2023), https://www.iso-ne.com/static-assets/documents/2023/03/a05_2023_03_07-09_order_2222_nepool_counsel_memo.pdf.

[2] The FERC extended the original deadline to file the 60-day further compliance from May 1, 2023 to May 9, 2023. Notice of Extension of Time, Docket Nos. ER22-983-000 and -001, at 2 (issued Apr. 11, 2023).

At its April 25, 2023 meeting, the Markets Committee considered and with a 78.64% Vote in favor, recommended that the Participants Committee support the ISO's proposed Tariff revisions to comply with the FERC's 60-day further compliance obligations.[3]

The following form of resolution may be used for Participants Committee action on this matter:

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

[3] The individual Sector votes at the Markets Committee were as follows: Generation (16.7% in favor, 0% opposed, 1 abstention), Transmission (16.7% in favor, 0% opposed, 0 abstentions), Supplier (14.61% in favor, 2.09% opposed, 1 abstention), Publicly Owned Entity (16.7% in favor, 0% opposed, 0 abstentions), Alternative Resources (9.75% in favor, 6.75% opposed, 1 abstention), and End User (4.18% in favor, 12.53% opposed, 3 abstentions).

## III.6 Distributed Energy Resource Aggregations

A Distributed Energy Resource Aggregation may participate in the New England Markets as described below. A Distributed Energy Resource Aggregation must comply with all applicable registration, metering, and accounting rules in this section.

### III.6.1 Participation Requirements

An aggregation of Distributed Energy Resources that satisfies the requirements of Section III.6 may participate in the New England Markets as a Distributed Energy Resource Aggregation. A Distributed Energy Resource Aggregation shall:

(a) comprise one or multiple facilities at one or more points of interconnection or Retail Delivery Points;

(b) have regulation capability, energy injection capability, or combined demand reduction capability and energy injection capability of at least 0.1 MW;

(c) be metered in accordance with Section III.6.4;

(d) be registered pursuant to Section III.6.7;

(e) participate in the wholesale markets as, and subject to all requirements applicable to a Generator Asset, Alternative Technology Regulation Resource, Continuous Storage Facility, Binary Storage Facility, Demand Response Resource, Settlement Only Distributed Energy Resource Aggregation, or Demand Response Distributed Energy Resource Aggregation;

   i. A Distributed Energy Resource Aggregation may participate as a Continuous Storage Facility or Binary Storage Facility to the extent the Distributed Energy Resource Aggregation as a whole is able to comply with all the requirements of a Continuous Storage Facility or Binary Storage Facility as stated in Sections III.1.10.6(b), ~~and~~ (c), ~~;~~ (d), and (e) respectively, regardless of whether any or all of the individual Distributed Energy Resources comprising the Distributed Energy Resource Aggregation meet the definition of Energy Storage Facility as defined in Section III.1.10.6.

(f) not be located in the metering domain of a Host Utility that distributed 4 million MWh or less in the previous fiscal year, unless the relevant electric retail regulatory authority that regulates such Host Utility has authorized customers of ~~permits~~ such Host Utility to ~~host~~ participate in Distributed Energy Resource Aggregations; and

(g) meet the locational rules specified Section III.6.2.

### III.6.2 Locational Requirements

A Distributed Energy Resource Aggregation must meet the following locational requirements.

(a) For a Distributed Energy Resource Aggregation participating as an Alternative Technology Regulation Resource or a Demand Response Resource, all associated Distributed Energy Resources shall be located in a single DRR Aggregation Zone.

(b) For a Distributed Energy Resource Aggregation participating as a Generator Asset, Binary Storage Facility, Continuous Storage Facility, Settlement Only Distributed Energy Resource Aggregation, or Demand Response Distributed Energy Resource Aggregation, all associated Distributed Energy Resources shall be located within both a single DRR Aggregation Zone and a single Host Utility metering domain.

(c) A Distributed Energy Resource Aggregation shall be settled at the DRR Aggregation Zone Node price, except where a single Distributed Energy Resource or a group of Distributed Energy Resources can inject greater than or equal to 5 MW at a single transmission Node, in which case, they are prohibited from aggregating with facilities at other Nodes, and will be settled at the single transmission Node price, not at the DRR Aggregation Zone Node price.

(d) The ISO shall determine that all of the Distributed Energy Resources in a Distributed Energy Resource Aggregation are located in the same DRR Aggregation Zone. For Distributed Energy Resources in a Distributed Energy Resource Aggregation with energy injection capability or demand reduction capability of 1 MW or greater, the ISO's determination shall be based on the Host Utility's evaluation of the transmission node that will serve the Distributed Energy Resource.

**III.6.3 Distributed Energy Resource Size Requirements**

Individual Distributed Energy Resources participating in a Distributed Energy Resource Aggregation must meet the following size requirements.

(a) A Distributed Energy Resource with overall injection capability of 5 MW or greater that participates in the New England Markets through a Distributed Energy Resource Aggregation must participate as a single facility Distributed Energy Resource Aggregation and be modeled and priced at a single transmission Node.

(b) If a group of Distributed Energy Resources can inject greater than or equal to 5 MW at a single transmission Node, this group of Distributed Energy Resources cannot aggregate with facilities at other Nodes. This group of Distributed Energy Resources may participate as a Distributed Energy Resource Aggregation that is modeled and priced at the single transmission Node.

(c) For a Distributed Energy Resource Aggregation with multiple Distributed Energy Resources participating as a Generator Asset, Binary Storage Facility, or Continuous Storage Facility, each participating Distributed Energy Resource in the aggregation must have injection capability of less than 5 MW.

(d) For a Distributed Energy Resource Aggregation participating as a Demand Response Resource, the size requirements in Section III.8 shall apply.

(e) For a Distributed Energy Resource Aggregation participating as a Demand Response Distributed Energy Resource Aggregation, the size requirements in III.6.5(b) shall apply.

(f) For a Distributed Energy Resource Aggregation participating as a Settlement Only Distributed Energy Resource Aggregation, the size requirements in III.6.6 shall apply.

(g) For a Distributed Energy Resource Aggregation participating as an ATRR, the size requirements in Section III.14 shall apply.

**III.6.4 Metering and Telemetry Requirements**

Distributed Energy Resource Aggregations must meet the following metering and telemetry requirements.

(a) Distributed Energy Resource Aggregations participating as a Generator Asset, Binary Storage Facility, or Continuous Storage Facility, must comply with the metering and telemetry requirements in Sections III.3.2.1 and III.3.2.2.

(b) Distributed Energy Resource Aggregations participating as an Alternative Technology Regulation Resource must comply with the metering and telemetry requirements in Section III.14.2.

(c) Distributed Energy Resource Aggregations participating as Demand Response Resources or Demand Response Distributed Energy Resource Aggregations must comply with the metering and telemetry requirements in Section III.3.2.2. The metering and communication equipment associated with each participating Distributed Energy Resource must meet the requirements in Section III.3.2.2 and ISO New England Operating Procedure No. 18, Metering and Telemetering.

(d) Metering for each Distributed Energy Resource participating in a Distributed Energy Resource Aggregation shall meet all applicable state and Host Utility requirements and be located at, a Retail Delivery Point, or point of interconnection as applicable. A Distributed Energy Resource's point of interconnection may be located behind a Retail Delivery Point to the extent that the pertinent Host Participant Assigned Meter Reader can accommodate such a configuration.

(e) If a Distributed Energy Resource's point of interconnection is located behind a Retail Delivery Point it shall be reported such that its output or load does not impact the load reported for the Retail Delivery Point. A Distributed Energy Resource Aggregator may only propose a metering location behind a Retail Delivery Point if the Host Utility confirms in writing to the Distributed Energy Resource Aggregator that the appropriate metering and associated system upgrades are in place to support load and generation reporting and any necessary reconstitution. Proof of such written confirmation from the Host Utility should be provided as part of the attestation as referenced in Section III.6.7(c)(i)2.

(f) The Distributed Energy Resource Aggregator shall retain metering data for each participating Distributed Energy Resource for a period of six years for purposes of auditing.

**III.6.5 Additional Requirements For Demand Response Distributed Energy Resource Aggregations**

In addition to the rules applicable to all Distributed Energy Resource Aggregations, the following rules apply to Demand Response Distributed Energy Resource Aggregations. A Demand Response Distributed Energy Resource Aggregation allows Distributed Energy Resources with demand reduction capability, Distributed Energy Resources with energy injection capability and Distributed Energy Resources with energy withdrawal capability to participate in the wholesale markets as a single resource.

(a) A Demand Response Distributed Energy Resource Aggregation must include Distributed Energy Resources with both demand reduction capability and energy injection capability and may include Distributed Energy Resources with energy withdrawal capability.

(b) Size Requirements. Individual Distributed Energy Resources participating in a Demand Response Distributed Energy Resource Aggregation must meet the following size requirements:

(i) An individual Distributed Energy Resource with a Maximum Deviation Capability or ability to inject greater than or equal to 5 MW may not be registered as a component of a Demand Response Distributed Energy Resource Aggregation if its maximum energy injection capability is greater than its Maximum Facility Load. Such a Distributed Energy Resource must be the only facility associated with a Demand Response Distributed Energy Resource Aggregation and shall be modeled and priced at the transmission Node.

(ii) An individual Distributed Energy Resource with a Maximum Deviation Capability and maximum energy injection capability less than 5 MW may participate in a Demand Response Distributed Energy Resource Aggregation with other facilities located within the same DRR Aggregation Zone and metering domain. Such a Demand Response Distributed Energy Resource Aggregation shall be modeled and priced at the DRR Aggregation Zone Node.

(iii) If a group of Distributed Energy Resources has a Maximum Deviation Capability of, or can inject greater than or equal to 5 MW at a single transmission Node, this group of Distributed Energy Resources cannot aggregate with facilities at another Node. This group of Distributed Energy Resources may participate as a Demand Response

Distributed Energy Resource Aggregation that is modeled and priced at the single transmission Node.

(c) Baseline, Offer Requirements and Related Threshold Requirements. For each Demand Response Distributed Energy Resource Aggregation:

(i) The ISO shall establish a baseline for each Distributed Energy Resource in the same manner as prescribed for a Demand Response Asset in Section III.8.2.

(ii) The Distributed Energy Resource Aggregator shall submit a Baseline Deviation Offer pursuant to Section III.1.10.1A(l) that reflects the aggregation's ability to deviate from its normal operational level.

(iii) Its Baseline Deviation Offer shall be subject to the Demand Reduction Threshold calculated pursuant to Section III.1.10.1A(f)

(iv) It may inject energy outside of dispatch intervals, which will be settled consistent with the rules for Settlement Only Resources.

(v) It may withdraw energy outside of dispatch intervals, which will be settled consistent with the rules for Load Assets.

(d) Performance Calculation. The ISO shall calculate a Demand Response Distributed Energy Resource Aggregation's performance when it is dispatched. Such performance shall be the sum of the performance of each constituent Distributed Energy Resource. The ISO shall calculate the performance of each Distributed Energy Resource in the same manner as prescribed for a Demand Response Asset in Section III.8.4.

### III.6.6 Additional Requirements For Settlement Only Distributed Energy Resource Aggregations

A Settlement Only Distributed Energy Resource Aggregation is a Distributed Energy Resource Aggregation that may include Distributed Energy Resources with non-dispatchable energy injection capability and/or non-dispatchable energy withdrawal capability. A Settlement Only Distributed Energy Resource Aggregation shall comply with all Market Rules applicable to Settlement Only Resources and the following additional rules.

(a) A Settlement Only Distributed Energy Resource Aggregation may submit a Supply Offer and/or Demand Bid in the Day-Ahead Energy Market in accordance with the requirements in Section III.1.10.1A(m).

(b) There is no maximum size limit for a Settlement Only Distributed Energy Resource Aggregation, provided each constituent Distributed Energy Resource would otherwise be eligible to register as a Settlement Only Resource pursuant to OP-14.

**III.6.7 Coordination of Registration and Modification**

The process of coordinating the registration and activation for participation in the New England Markets between the ISO, the Distributed Energy Resource Aggregator and the Host Utility, regardless of the participation model chosen, includes four stages: 1) Initial Notification of Intent to Register a Distributed Energy Resource Aggregation; 2) Eligibility Confirmation; 3) Registration and Activation; and 4) Updates to an Existing Distributed Energy Resource Aggregation Registration. Completion of the Distributed Energy Resource Aggregation registration process requires that the Distributed Energy Resource Aggregator, Host Utility (or its agent) and ISO meet the following requirements for each stage.

(a) Initial Notification

(i) Distributed Energy Resource Aggregator shall make an initial notification to both the ISO and the Host Utility (or the Host Utility's Agent) of its intent to register a Distributed Energy Resource Aggregation. Such notification shall include the information required by applicable ISO New England Manuals, including, but not limited to: the retail billing account(s) of the individual Distributed Energy Resource(s) participating in the aggregation, information regarding the location, anticipated size, technologies to be included, markets in which participation is planned, information required by the Host Utility Tariff and Terms and Conditions, and the participation model that the Distributed Energy Resource Aggregation intends to use for the Distributed Energy Resource Aggregation; interconnection agreement(s) for each participating Distributed Energy Resource, if required under state law; and an anticipated date to begin energy and/or ancillary service market participation.

(b) Eligibility Confirmation. The Host Utility (or its agent) shall review each Distributed Energy Resource's eligibility to participate in a Distributed Energy Resource Aggregation and confirm the Aggregator's eligibility to register the proposed Distributed Energy Resource Aggregation in the manner established in this subsection. The time period for such review shall begin when the Host Utility or its agent receives the initial notification from the Distributed Energy Resource Aggregator and shall not exceed 60 calendar days. The Host Utility (or its agent) shall provide written notice to the ISO and the Distributed Energy Resource Aggregator of the eligibility confirmation, in accordance with the eligibility criteria described in this subsection. The eligibility confirmation shall be provided by the Host Utility or its agent to the appropriate relevant electric retail regulatory authority upon request. If the ISO does not receive timely notification from the Host Utility or its agent, then the ISO will assume that the operation of the

Distributed Energy Resource will not have a material reliability and/or safety impact on the applicable distribution system and shall be eligible to register with the proposed Distributed Energy Resource Aggregation.

(c)

(i) In order to verify eligibility, the Host Utility or its agent shall, to the extent practicable based on the representations made by the Distributed Energy Resource Aggregator in the initial notification or through information otherwise in the Host Utility's (or its agent's) possession:

1. confirm that each Distributed Energy Resource's metered net consumption or injection of energy will not be included in another Load Asset (if the Distributed Energy Resource Aggregation includes load) or Generator Asset.
2. confirm, based on the representations made by the Distributed Energy Resource Aggregator that no individual Distributed Energy Resource (as identified by any retail billing account record of the Host Utility) is participating in a retail program that prohibits it from providing the requested service in New England Markets.
3. confirm based on the representations made by the Distributed Energy Resource Aggregator that the proposed operation of each Distributed Energy Resource as part of the proposed Distributed Energy Resource Aggregation has appropriate interconnection and/or operating agreements in place with the Host Utility applicable to its technology and size.
4. determine whether the Distributed Energy Resource Aggregation may pose significant risks, or may require further study to evaluate the potential significance of the risks, to the safe and reliable operation of the distribution system based on analysis of relevant risk factors, such as overloads, voltage, stability, short circuit interrupting capability, flicker, equipment operation frequency coordination, and contingency analysis.
5. consider whether the proposed operation of any Distributed Energy Resource participating in a proposed Distributed Energy Resource Aggregation, or the Distributed Energy Resource Aggregation as a whole, imposes a need for distribution system upgrades to avoid safety and reliability impacts and, if so, confirm that the Distributed Energy Resource Aggregator has self-certified that such upgrades have been completed or will be completed before the Distributed Energy Resource desired activation date.

6. confirm that all the Distributed Energy Resources are within the Host Utility's metering domain.

7. confirm that the net injection and consumption capability of the Distributed Energy Resources participating in the Distributed Energy Resource Aggregation do not exceed the capabilities as authorized by any associated interconnection agreements.

(ii) For a Distributed Energy Resource Aggregation connecting to a Host Utility that served less than or equal to 4 million MWh of load in the previous fiscal year, the Host Utility (or its agent) shall confirm that the relevant electric retail regulatory authority has authorized customers of the Host Utility ~~has been expressly authorized by the relevant electric retail regulatory authority opted~~ to participate in ~~allow~~ Distributed Energy Resource Aggregations ~~to participate in wholesale markets~~.

(iii) If the Host Utility (or its agent) confirms that the Distributed Energy Resource Aggregation is eligible in full or in part, the Distributed Energy Resource Aggregator shall provide a finalized list to the ISO and the Host Utility (or its agent) of the Distributed Energy Resources that have been found to be eligible for participation in the Distributed Energy Resource Aggregation, the participation model that the Distributed Energy Resource Aggregation intends to use, and the New England Markets in which the Distributed Energy Resource Aggregation plans to participate.

(iv) If the Host Utility (or its agent) confirms that the Distributed Energy Resource Aggregation is not eligible in full or in part, the Host Utility (or its agent) shall provide a written notice to the ISO and the Distributed Energy Resource Aggregator describing the eligibility criteria that were not met for any Distributed Energy Resource.

(v) In the event the Host Utility (or its agent) confirms that a Distributed Energy Resource Aggregation has not fulfilled the requirements of this subsection to be activated for participation in the New England Markets, and the Distributed Energy Resource Aggregator disputes this confirmation, the Distributed Energy Resource Aggregation may seek dispute resolution in accordance with Section I.6 of the Tariff if the dispute falls within ISO's authority or is subject to the Tariff or in a process established by the relevant electric retail regulatory authority if ~~, if available, if~~ the dispute falls within the relevant electric retail regulatory authority's purview and the relevant electric retail regulatory authority has established such a process. Where the relevant electric retail regulatory authority has not established such a process, the Distributed Energy Resource Aggregator may seek resolution under Section I.6 of the Tariff. ~~or if not available, in~~

~~accordance with Section I.6 of the Tariff~~. Notwithstanding the foregoing, ~~A~~any disputes regarding whether the Distributed Energy Resource Aggregator has appropriate contractual rights to offer a Distributed Energy Resource as part of a Distributed Energy Resource Aggregation in the New England Markets shall be resolved in the manner established in such contract, or otherwise by a court of competent jurisdiction as applicable.

(vi) In the event the ISO determines that a Distributed Energy Resource Aggregation is ineligible to participate in the New England Markets for reasons that are not related to the Host Utility (or its agent's) review, the Distributed Energy Resource Aggregator may seek resolution in accordance with Section I.6 of the Tariff.

(d) Registration/Activation

(i) In order to complete the registration and activation of a DERA the DER Aggregator shall:

1. Provide both the ISO and the Host Utility (or its agent) with a desired activation date, once eligibility has been confirmed.
2. Provide the information required by applicable ISO New England Manuals, as well as 1) an attestation, in a form prescribed by the ISO, stating that all participating Distributed Energy Resources are fully compliant with the tariffs and operating procedures of the distribution utilities and the rules and regulations of any relevant electric retail regulatory authority, including the terms of any state interconnection agreements, and that the Distributed Energy Resource Aggregator retains the rights to offer the individual Distributed Energy Resource in New England Markets; and 2) confirmation in writing to the ISO and Host Utility (or its agent) that all Distributed Energy Resources in the Distributed Energy Resource Aggregation have been deemed eligible under subsection (b) of this section; and that the required metering and telemetry is in place, to meet the ISO requirements for participation in the planned markets.

(ii) Prior to activation, the ISO must receive confirmation from the Host Utility (or its agent) that the Distributed Energy Resource Aggregator has met all applicable requirements with respect to metering and telemetry to enable the Host Utility or Assigned Meter Reader to include the Distributed Energy Resource Aggregation's metering in the appropriate Load Asset and metering domain.

(iii) Distributed Energy Resources participating in a Distributed Energy Resource Aggregation may provide both retail and wholesale services to the extent such dual participation is allowed under state law or regulation, the Distributed Energy Resource Aggregator retains the rights to such services from the owner of the Distributed Energy Resource, and so long as the Distributed Energy Resource Aggregation is able to comply with all requirements under the ISO Tariff.

(e) Updates/Modifications to Existing Distributed Energy Resource Aggregation

(i) When a Distributed Energy Resource is added to or removed from an existing Distributed Energy Resource Aggregation, the Distributed Energy Resource Aggregator shall update the Distributed Energy Resource Aggregation's registration information. Such updates shall include: the information required by applicable ISO New England Manuals, sufficient to confirm that any newly added Distributed Energy Resources are eligible for participation; notification to the ISO and the Host Utility (or its agent) by the Distributed Energy Resource Aggregator of any Distributed Energy Resource being removed from the aggregation; verification that any required metering is in place for the reconfigured Distributed Energy Resource Aggregation; and an updated list of participating Distributed Energy Resources and the updated performance capabilities of the aggregation to be reflected in the aggregation's registration information.

(ii) The Host Utility (or its agent) shall have up to 60 days to confirm eligibility and review any impacts associated with Distributed Energy Resources that the Distributed Energy Resource Aggregator is proposing to add to or remove from an existing Distributed Energy Resource Aggregation.

(iii) Changes to the Distributed Energy Resources participating in a Distributed Energy Resource Aggregation shall become effective in the manner stated in Manual M-RPA.

**III.6.8 Operational Coordination**

The responsibilities related to the coordination of operations of a Distributed Energy Resource Aggregation between the Distributed Energy Resource Aggregator, the ISO, and the Host Utility are as follows:

(a) The Distributed Energy Resource Aggregator shall: operate Distributed Energy Resources in a manner consistent with the limitations and operating orders established by the Host Utility; confer with the applicable Host Utility on a periodic basis to ensure available distribution service exists to operate its Distributed Energy Resources consistent with its New England Market obligations; submit outage requests for each Distributed Energy Resource Aggregation as necessary and to the extent required by ISO Operating Documents, in order to reflect known distribution system constraints or limitations that reduce the overall capability of the Distributed Energy Resource Aggregation; as required, account for any known limitations of the distribution system to which the Distributed Energy Resources are connected in its Offer Data for the Distributed Energy Resource Aggregation including restrictions that have been placed directly on the Distributed Energy Resource Aggregation by the Host Utility in the form of an override of an ISO Dispatch Instruction; determine a Distributed Energy Resource-level operating plan to be provided to the Host Utility for analysis, subject to the requirements of each Host Utility.

(b) The Distributed Energy Resource Aggregator shall have a Designated Entity or Demand Designated Entity, as applicable, for each of its Distributed Energy Resource Aggregations in accordance with the provisions set forth in ISO Operating Procedures. Designated Entities and Demand Designated Entities for Distributed Energy Resource Aggregations shall comply with the requirements of each Host Utility and/or relevant electric retail regulatory authority as applicable.

(c) In the event that the Host Utility identifies conditions on the distribution system that result in actual or anticipated limitations on the operation of individual Distributed Energy Resources or Distributed Energy Resource Aggregations, the Host Utility shall notify the relevant Distributed Energy Resource Aggregator as soon as practicable.

(d) The Host Utility may temporarily override the ISO's dispatch of a Distributed Energy Resource Aggregation. Such override shall only occur in circumstances where needed to maintain the reliable and safe operation of the distribution system. Failure of a Distributed Energy Resource Aggregation to follow an ISO Dispatch Instruction due to a Host Utility override does not excuse the Distributed Energy Resource Aggregator from any applicable charges (including any penalties) to which the Distributed Energy Resource Aggregator is subject under the terms of Sections III.3.2.1(g), III.3.2.1(h), III.3.2.6, III.9.7, III.13.7.2, III.F.3.1.2(i), and III.F.3.2 of the Tariff.

(e) The ISO shall coordinate with the applicable Host Utility to avoid conflicting operational directives, which may include but is not limited to sharing Day-Ahead Energy Market results and Real-Time Dispatch Instructions.

memo

**To:** NEPOOL Markets Committee (MC)

**From:** Henry Yoshimura, Director, Demand Resource Strategy

**Date:** April 20, 2023

**Subject:** Order No. 2222 – Further Compliance Due May 9, 2023 (WMPP ID: 155)

The ISO is requesting a vote on proposed Market Rule 1 revisions addressing the additional compliance obligations contained in the Commission's March 1, 2023 order[1] in the Distributed Energy Resource Aggregations (DERAs) proceeding that are due to be filed by May 9, 2023.[2]

By way of background, the Commission's March 1, 2023 order accepted in part and rejected in part the ISO's compliance filing associated with Order No. 2222 and included additional compliance obligations to be filed within 30, 60, and 180 days of the order. The additional compliance filing due by May 9, 2023 must address six discrete elements of the proposal. These elements include:

(1) The small utility opt-in requirement,
(2) Existing rules requiring a Market Participant providing energy withdrawal service to register a Load Asset,
(3) Dispute resolution requirements,
(4) Application of non-performance penalties to aggregations,
(5) Metering configurations, and
(6) The submission of metering data by DER Aggregators.

The proposed Market Rule 1 revisions address elements (1) and (3) by incorporating clarifications that the relevant electric retail regulatory authority authorizes customers of small utilities (distributing 4 million MWh or less in the previous year) to participate in a DERA and that the ISO will resolve disputes that are within its authority and subject to its Tariff. To address elements (2) and (4), references to existing Tariff sections on the Load Asset registration requirement for Continuous Storage Facilities and Binary Storage Facilities and the application of charges to DERAs not following the ISO's Dispatch Instructions have been incorporated.

With regard to element (5), the ISO's compliance filing will further explain why its present metering proposal minimizes DER barriers to entry and is just and reasonable.

[1] *See ISO New England Inc.,* 182 FERC ¶ 61,137 (2023) ("March 1, 2023 order").

[2] For the ISO's initial compliance filing in this proceeding, see *ISO New England Inc. and New England Power Pool,* Revisions to ISO New England Inc. Transmission Markets and Services Tariff to Allow for the Participation of Distributed Energy Resource Aggregations in New England Markets, Docket Nos. ER22-983-000 and ER22-983-001 (filed February 2, 2022).

Finally, with regard to element (6), on March 31, 2023, the ISO petitioned for rehearing on the compliance requirement to designate the DER Aggregator as the entity responsible for providing any required metering information to that ISO.[3] To the extent that the Commission denies the rehearing request, any alternative metering requirements would depend on the Commission's final orders concerning both acceptable metering configurations (element (5)) and the rehearing request related to the submission of metering data by DER Aggregators (element (6)). In its compliance filing, the ISO intends to ask the Commission to delay this further compliance requirement until these issues are resolved.

The specific proposal for the committee's consideration at its April 25, 2023 meeting has been presented previously to the Markets Committee at the April 11-13, 2023 meeting (link).

[3] On March 31, 2023, several New England Public Utilities filed a separate petition asking for clarification and rehearing on this requirement.

# Order No. 2222: Participation of Distributed Energy Resource Aggregations in Wholesale Markets

Approach to address FERC's 60-day compliance obligations

Henry Yoshimura

Director, Demand Resource Strategy

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# Participation of Distributed Energy Resource Aggregations in Wholesale Markets | WMPP ID: 155

- On September 17, 2020, FERC issued Order No. 2222 requiring that ISOs/RTOs allow distributed energy resources (DERs) to provide all wholesale services that they are technically capable of providing through an aggregation of resources
- On February 2, 2022, the ISO, joined by NEPOOL and the Participating Transmission Owners, filed a Compliance Proposal
- On March 1, 2023, FERC issued a Compliance Order accepting in part and rejecting in part, subject to further compliance, the Compliance Proposal
  - The Compliance Order directed further compliance filings within 30, 60 and 180 days of the order (see NEPOOL Counsel's Compliance Order summary)
  - On March 31, 2023, the ISO submitted a Compliance Filing to meet the 30-day compliance obligations
  - The ISO also submitted a request for rehearing regarding certain aspects of the Compliance Order

# This Presentation Focuses on the 60-Day Compliance Obligations

- The 60-day compliance obligations include six items
  - The ISO addressed five of these obligations at the April 11-13, 2023 Markets Committee meeting
- This presentation includes:
  - Discussion on the compliance approach for the submission of metering data by DER Aggregators (i.e., the Commission's $6^{th}$ obligation)
  - Additional information on the compliance approach for metering configurations (i.e., the Commission's $5^{th}$ obligation)
  - Review the modification to the Small Utility Opt-In Requirement (i.e., the Commission's $1^{st}$ obligation)
- The ISO will submit a compliance filing to meet the 60-day compliance obligations by May $9^{th}$
- The ISO will address the 180-day compliance obligation, related to implementation for FCA 19 and beyond, with the Markets Committee starting in Q3

# Proposed Compliance Approach Summary

| # | 60-Day Compliance Obligations | Proposed Compliance Approach |
|---|---|---|
| 1 | Small Utility Opt-In Requirement | Revise Tariff Language |
| 2 | Existing Rules Requiring a Market Participant Providing Energy Withdrawal Service to Register a Load Asset* | |
| 3 | Dispute Resolution Requirements* | |
| 4 | Application of Non-Performance Penalties to Aggregations* | |
| 5 | Metering Configuration | Further Explain the Compliance Proposal |
| 6 | Submission of Metering Data by DER Aggregators | Rehearing Pending – Any Alternative Proposal Depends on Commission rulings on #5 and #6 |

*Appendix A summarizes the proposed compliance approach discussed at the April 11-13, 2023 MC meeting

# DETAILED COMPLIANCE APPROACH

*Submission of Metering Data by DER Aggregators*

# 6. Submission of Metering Data by DER Aggregators

- The Compliance Order requires the ISO to make “a further compliance filing that revises its Tariff ***to designate the DER Aggregator as the entity responsible for providing any required metering information*** to ISO-NE” (*see* Compliance Order at P 169)
- On March 31, 2023, the ISO petitioned for rehearing on this compliance requirement
- On March 31, 2023, in a separate petition, several New England Public Utilities asked for clarification/rehearing on this compliance requirement

# 6. Submission of Metering Data by DER Aggregators – ISO Rehearing Petition

- The requirement contravenes state policies, institutional agreements, and metering infrastructure and processes in which Host Utilities are responsible for providing metering services to all Energy Market loads and resources in New England
- The requirement also contravenes the flexibility allowed by Order No. 2222
- Compliance would be costly to the region
  - Current agreements would need to be modified, and costly revisions to metering infrastructure and processes would be required
  - Additional design elements would be needed to avoid costly delays in Energy Market settlement from potential data transmission errors and energy balance reporting, and to prevent double-counting of services
- Compliance imposes unnecessary requirements and costs on DER Aggregators
  - DER Aggregators would need to install and operate costly and redundant metering and communications systems that no other Energy Market Participant is required to install and operate
- Using Host Utility metering infrastructure and processes, pursuant to the original Compliance Filing, is consistent with existing state policies and institutional agreements and is the least-cost approach that gives DER Aggregators greater market access

# 6. Submission of Metering Data by DER Aggregators – Compliance Approach

- The ISO believes that the requirement that Host Utilities or their Assigned Meter Reader submit metering data to the ISO is just and reasonable
- To the extent the Commission does not agree with the ISO and denies the rehearing request on this issue, any alternative metering requirements would depend on the Commission's final orders concerning both acceptable metering configurations (compliance requirement #5) and the rehearing request related to the submission of metering data by DER Aggregators (compliance requirement #6)
- The ISO cannot develop alternative metering requirements until the Commission issues final orders on these two outstanding issues
- The ISO intends to ask the Commission to delay this further compliance requirement until these issues have been resolved

# DETAILED COMPLIANCE APPROACH

*Additional Information on Metering Configurations*

# 5. Metering Configurations

- The Commission directed the ISO to file:

  [A] compliance filing that explains why its proposal to require measurement of behind-the-meter DERs not participating solely as demand response at the [Retail Delivery Point], unless the Assigned Meter Reader can accommodate submetering or parallel metering of the DER, is just and reasonable and does not pose an unnecessary and undue barrier to individual DERs joining an aggregation … or, alternatively, modifications to the proposal (*see* Compliance Order at P 168)

# 5. Metering Configurations - Compliance Approach

- The ISO intends to further explain why its present metering proposal minimizes DER barriers to entry and is just and reasonable
- The proposed metering configurations for behind-the-meter DERs are (1) metering at the Retail Delivery Point ("RDP"), (2) parallel metering, or (3) device-level metering with reconstitution if the Assigned Meter Reader can accommodate that configuration
- These metering configurations:
  - Allow DER Aggregators to use the existing RDP metering infrastructure to participate in wholesale markets
    - This is the least-cost approach to metering that minimizes barriers to entry
  - Were based on stakeholder feedback to allow for device-level DER metering, and
  - Were designed to prevent double counting of wholesale market services provided by BTM DERs as required by Order No. 2222
    - Double counting results in, for example, beneficiaries of BTM generation not paying wholesale power costs, and instead shifting those costs to other consumers who do not benefit from BTM generation

# 5. Metering Configuration - Compliance Approach (cont.)

- In the Compliance Order, the Commission noted that, if ISO-NE chooses to provide further explanation of its proposal, ISO-NE is required to include a discussion of whether the approaches already approved by the Commission for other RTOs/ISOs were considered

**Summary of Metering Proposals for Non-Demand Response BTM DERs**

| Metering Configuration | ISO-NE | PJM | NYISO | CAISO |
|---|---|---|---|---|
| Configuration #1: RDP Metering | Y | Y | Y/N* | N |
| Configuration #2: Parallel Metering | Y | N | Y | Y |
| Configuration #3: Sub-metering with Reconstitution | Y | N | Y | Y |

* NYISO allows RDP metering if the BTM DER is not an electric storage resource ("ESR"), or the BTM DER is an ESR with no capability to inject energy into the grid.  However, RDP metering is not allowed if the BTM DER is an ESR with the capability to inject energy into the grid.

# DETAILED COMPLIANCE APPROACH

*Modifications to the Small Utility Opt-In Requirement*

# 1. Small Utility Opt-In Requirement

- The Commission directed the ISO to revise the proposed Tariff rules so that they clearly provide for the RERRA to determine whether to allow customers of small utilities to participate in the ISO's markets through aggregation

# 1. Small Utility Opt-In Requirement – Compliance Approach

- The ISO proposes Tariff revisions in Section III.6.1 and III.6.7 to clearly state that the RERRA, not the Host Utility, determines whether to allow customers of small utilities to participate in the ISO's markets through a DERA

| Tariff Section | Description of Change | Reason for Change |
|---|---|---|
| III.6.1(f)<br>III.6.7(c)(ii) | Clarify RERRA determines DERA participation eligibility | FERC Compliance Order |

- *The ISO has slightly modified the wording of these Tariff changes from the version circulated for the 4/13/23 MC meeting*
  - *The modifications state that the RERRA authorizes the customers of small utilities to participate in a DERA rather than authorizing the Host Utility to host a DERA*
  - *The modified wording more precisely mirrors the language of the Commission's order*

# Conclusion

- The proposed compliance approach is a combination of revising the Tariff and further explaining the Compliance Proposal
- The ISO will submit a compliance filing to meet the 60-day compliance obligations by May 9$^{th}$

# Stakeholder Schedule

| Stakeholder Committee and Date | Scheduled Project Milestone |
|---|---|
| MC: April 11-13, 2023 | Discuss the proposed compliance approach and related Tariff changes |
| MC: April 25, 2023 | - Discuss the remaining compliance obligation and continue review of Tariff redlines focusing on what is new<br>- Vote on further compliance revisions including any proposed amendments* |
| PC: May 4, 2023 | Vote on further compliance revisions including any proposed amendments |

* NEPOOL members should provide their materials in advance so that they can be distributed by the posting date of the MC meeting and should work with NEPOOL Counsel in the drafting of any desired Tariff changes or amendments to the ISO proposal

# Q&A AND DISCUSSION

# APPENDIX A

*Compliance Items with no changes since April 11-13, 2023 MC meeting*

# 2. Existing Rules Requiring a Market Participant Providing Energy Withdrawal Service to Register a Load Asset

- The Commission directed the ISO to submit a compliance filing that:
  1. Identifies the existing rules that require a market participant that provides wholesale energy withdrawal service to be a load-serving entity ("LSE"), and
  2. Explains whether this requirement is applicable to all resources in ISO-NE in order to provide wholesale energy withdrawal service in the energy market
- In the stakeholder and regulatory processes, many referred to an entity purchasing energy from the wholesale market to serve an end-use load or an Electric Storage Facility load as a LSE
  - However, LSE is not a defined term in the Tariff
  - Rather, such an entity is referred to in the Tariff as a Market Participant registering a Load Asset.

# 2. Existing Rules Requiring a Market Participant Providing Energy Withdrawal Service to Register a Load Asset – Compliance Approach

- The ISO will explain in the filing that any Market Participant seeking to provide wholesale energy withdrawal service must register one or more wholesale Load Assets with the ISO
- The ISO proposes Tariff revisions in Section III.6.1 to add references pointing to the existing requirement that a Market Participant using CSF and BSF models to register a Load Asset with the ISO

| Tariff Section | Description of Change | Reason for Change |
|---|---|---|
| III.6.1(e)(i) | Add references to the Tariff sections of the existing Load Asset registration requirement for CSFs and BSFs | FERC Compliance Order |

- No changes have been made to the version circulated for the 4/13/23 MC meeting

# 3. Dispute Resolution Requirements

- The Commission directed the ISO to demonstrate on further compliance how it will resolve disputes that are within its authority and subject to its Tariff, regardless of whether there is an available dispute resolution process established by the RERRA, and propose any necessary Tariff revisions

Introduced
April 11-13 MC

# 3. Dispute Resolution Requirements – Compliance Approach

- The ISO proposes Tariff revisions to clearly provide that all disputes that fall within the ISO's purview are subject to the ISO's existing dispute resolution process

| Tariff Section | Description of Change | Reason for Change |
|---|---|---|
| III.6.7(c)(v) | Further clarify the dispute resolution requirements | FERC Compliance Order |

- No changes have been made to the version circulated for the 4/13/23 MC meeting

# 4. Application of Non-Performance Penalties to Aggregations

- The Commission directed further Tariff revisions that “specify the existing non-performance penalties that will apply to a DERA when the DERA does not perform because a Host Utility overrides ISO-NE’s dispatch”

Introduced
April 11-13 MC

# 4. Application of Non-Performance Penalties to Aggregations – Compliance Approach

- The ISO proposes Tariff revisions to add references pointing to the existing charges that apply to resources not following the ISO's Dispatch Instruction

| Tariff Section | Description of Change | Reason for Change |
|---|---|---|
| III.6.8(d) | Add references to the Tariff sections of the existing charges that apply to resources not following the ISO's Dispatch Instruction | FERC Compliance Order |

- No changes have been made to the version circulated for the 4/13/23 MC meeting

# M E M O R A N D U M

**TO:** NEPOOL Participants Committee Members and Alternates

**FROM:** Sebastian Lombardi and Rosendo Garza, NEPOOL Counsel

**DATE:** April 27, 2023

**RE:** LS Power's Repowering Proposal

At the May 4, 2023 Participants Committee[1] meeting, you will be asked to consider revisions to Market Rule 1, as proposed by LS Power, through its Lead Market Participant, Jericho Power, LLC, to permit a repowering resource that cleared as a New Generating Capacity Resource in the Forward Capacity Market (FCM) to commercialize a portion of its cleared MW capacity in instances where the resource does not complete the repowering (referred to herein as the "LS Power Proposal"). This memorandum provides a high-level summary of the LS Power Proposal and stakeholder consideration to date.

Included with this memorandum are the following materials:

- Attachment A: LS Power's proposed Market Rule 1 Tariff revisions
- Attachment B: LS Power's April 25, 2023 PowerPoint presentation
- Attachment C: The ISO's memorandum regarding the LS Power Proposal, dated April 24, 2023
- Attachment D: The Internal Market Monitor's memorandum regarding the LS Power Proposal, dated April 24, 2023

## BACKGROUND AND OVERVIEW OF THE LS POWER PROPOSAL

In the fifteenth Forward Capacity Auction, LS Power's Ocean State Power generating resource qualified as a repowering project[2] and cleared 334 MW (i.e., 270 MW of existing capacity plus 64 MW of repowering) as a New Generating Capacity Resource. In addition, this resource elected and obtained a seven-year price lock.

Recently, LS Power explored with the ISO whether its cleared repowering resource could, in effect, be "reverted back" to the original and currently operational 270 MW "existing" resource. The ISO indicated that, if a repowered resource did not complete the repowering as contemplated in its Show of Interest, the entire project was at risk of being terminated and removed from the FCM. In the case for LS Power, this would mean that a failure to deliver the 334 MW repowered resource would result in the termination of both 64 MW of incremental capacity as well as the termination of 270 MW of currently operational capacity.

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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.

[2] *See* Tariff § III.13.1.1.1.2.

***LS Power Proposal***

In light of the ISO's position at this time, LS Power is proposing Market Rule 1 revisions to permit a repowered resource that cleared an auction can "unwind" its incremental obligation and remain in the FCM.

To achieve its intent, LS Power proposes Tariff revisions that modify three relevant Market Rule 1 provisions. First, the proposal includes revisions to the FCM Commercial Operation provision (Tariff Section III.13.3.8) to clarify that a repowered resource (up to its current audited output level) that withdraws from critical path schedule (CPS) monitoring (or the ISO deems withdrawn) can partially commercialize, thereby explicitly permitting a partial termination of the repowered resource (i.e., the non-commercial MW portion). Second, the Tariff revisions to Section III.13.1.1.2.2.4 make clear that the ISO would be able to terminate the price lock of a repowered resource if it withdraws from CPS monitoring. Third, LS Power proposed Tariff redlines revising a CPS monitoring provision (Tariff Section III.13.3.6) to clarify that a resource withdrawing from CPS monitoring may first partially commercialize before being subject to termination.

The proposed Market Rule 1 revisions are included Attachment A, with additional background information on LS Power's proposal provided in Attachment B.

## STAKEHOLDER PROCESS TO DATE

The Markets Committee discussed and reviewed the LS Power Proposal at two meetings in April. In discussions at the Markets Committee, the ISO and the Internal Market Monitor expressed some concern with LS Power's proposed approach, which were articulated in respective memoranda (*see* Attachment C and Attachment D). At its April 25 meeting, the Markets Committee considered a motion to recommend Participants Committee support for LS Power's proposed Market Rule 1 changes. That motion passed at the Markets Committee with an 83.3% Vote in favor, with the all of the Publicly Owned Entity Sector in opposition and a number of abstentions noted across the other Sectors.[3]

## MAY 4 PARTICIPANTS COMMITTEE ACTION

A 60% Vote in favor is required for the Participants Committee to approve LS Power's proposed Market Rule 1 modifications. To be clear, the following form of resolution to be used for Participants Committee action is a motion for the Committee to provide affirmative support for the proposed changes (and not one to indicate any position as to just and reasonableness of any currently effective Tariff provision(s)):

[3] The individual Sector votes were as follows: Generation – 16.7% in favor, 0% opposed, 4 abstentions; Transmission – 16.7% in favor, 0% opposed, 4 abstentions; Supplier – 16.7% in favor, 0% opposed, 7 abstentions; Publicly Owned Entity – 0% in favor, 16.7% opposed, 0 abstentions; Alternative Resources – 16.5% in favor, 0% opposed, 4 abstentions; and End User – 16.7% in favor, 0% opposed, 4 abstention.

RESOLVED, that the Participants Committee supports the Market Rule 1 Tariff revisions, as proposed by LS Power and recommended by the Markets Committee at its April 25, 2023 meeting, 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.

**LS Power's Proposed Tariff Revisions**

**III.13.1.1.2.2.4. Capacity Commitment Period Election.**

Project Sponsors shall be required to specify whether they are making the election set forth in this Section III.13.1.1.2.2.4 for each Forward Capacity Auction up to and including the auction held in February 2021 for the June 1, 2024 through May 31, 2025 Capacity Commitment Period, and no election shall be permitted thereafter.

For each Forward Capacity Auction occurring up to and including the February 2021 auction, in the New Capacity Qualification Package, the Project Sponsor must specify whether, if its New Capacity Offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. For incremental capacity qualified pursuant to Section III.13.1.1.1.3.A, this election shall apply to both the incremental amount of capacity and the existing Qualified Capacity matched to the incremental capacity at the same generating resource. If no such election is made in the New Capacity Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Capacity Offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Capacity Offer clears. If a New Capacity Offer clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.1.2.2.4.

The ISO shall terminate the a multi-year rate election of an Existing Generating Capacity Resource or a New Generating Capacity Resource obtained pursuant to this Section III.13.1.1.2.2.4 if the resource (1) previously qualified and cleared in a Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (re-powering), and (2) is withdrawn by its Project Sponsor (or deemed withdrawn by the ISO) from critical path schedule monitoring pursuant to Section III.13.3.6. When the ISO terminates a multi-year rate election of a qualifying resource, then that resource shall be paid the Capacity Clearing Price of each Forward Capacity Auction in which the resource already obtained a Capacity Supply Obligation. Upon termination of the multi-year rate election, the Existing Generating Capacity Resource can participate in the Forward Capacity Auction pursuant to Section III.13.1.2.

**III.13.3.6. Withdrawal from Critical Path Schedule Monitoring.**

A Project Sponsor may withdraw its resource from critical path schedule monitoring by the ISO at any time by submitting a written request to the ISO. The ISO also may deem a resource withdrawn from critical path schedule monitoring if the Project Sponsor does not adhere to the requirements of this Section III.13.3. Any resource withdrawn from critical path schedule monitoring shall be subject to the provisions of Section III.13.3.4A. A resource that (1) previously qualified and cleared in a Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (re-powering) and (2) is withdrawn by its Project Sponsor (or deemed withdrawn by the ISO) from critical path schedule monitoring pursuant to this Section III.13.3.6 may achieve FCM Commercial Operation under Section III.13.3.8(d) prior to being subject to the provisions of Section III.13.3.4A.

**III.13.3.8 FCM Commercial Operation.**

A resource (or portion thereof) achieves FCM Commercial Operation when (1) the ISO has determined that the resource (or portion thereof) has achieved all its critical path schedule milestones, including completion of any transmission upgrades necessary for the resource to obtain the requisite interconnection service; and (2) the ISO verifies the resource's (or a portion of the resource's) summer capacity rating (or, for a resource with winter capacity only, its winter capacity rating).

(a) For a Generating Capacity Resource (or portion thereof) that has achieved all its critical path schedule milestones, the ISO shall confirm FCM Commercial Operation as soon as practicable following the ISO's verification of the resource's summer capacity rating (or, for a resource with winter capacity only, its winter capacity rating), which may take place in any month of the year. The ISO shall verify the summer capacity rating of a Generating Capacity Resource that is an Intermittent Power Resource

following no fewer than 30 consecutive calendar days of operation (for periods from October 1 through May 31, a Market Participant must request such verification).

(b) For a Demand Capacity Resource (or portion thereof) that has achieved all its critical path schedule milestones, the ISO shall confirm FCM Commercial Operation upon verifying that the Demand Capacity Resource described in the New Demand Capacity Resource Qualification Package has achieved its full demand reduction value, subject to the requirements of Section III.13.6.1.5.3(b).

(c) For an Import Capacity Resource (or portion thereof) that has achieved all its critical path schedule milestones, the ISO shall confirm FCM Commercial Operation upon demonstration that the Import Capacity Resource described in the New Capacity Qualification Package has achieved its full Qualified Capacity.

For a resource that (1) previously qualified and cleared in a Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (re-powering), (2) completed any transmission upgrade(s) necessary for the re-powered resource to obtain the requisite interconnection service, and (3) subsequently is withdrawn by its Project Sponsor (or deemed withdrawn by the ISO) from critical path schedule monitoring pursuant to Section III.13.3.6, the ISO shall confirm FCM Commercial Operation of the portion of the re-powered resource equal to the re-powered resource's summer capacity rating (or, for a resource with winter capacity only, its winter capacity rating). The summer capacity rating can be established using an Establish Claimed Capability Audit, which may take place in any month of the year.

# Proposed Tariff Changes to Clarify that FCM Repowering Projects are Able to Unwind their Incremental Obligations

April 25, 2023

# About LS Power

## LS Power is a development, investment and operating company focused on the North American power and energy infrastructure sector

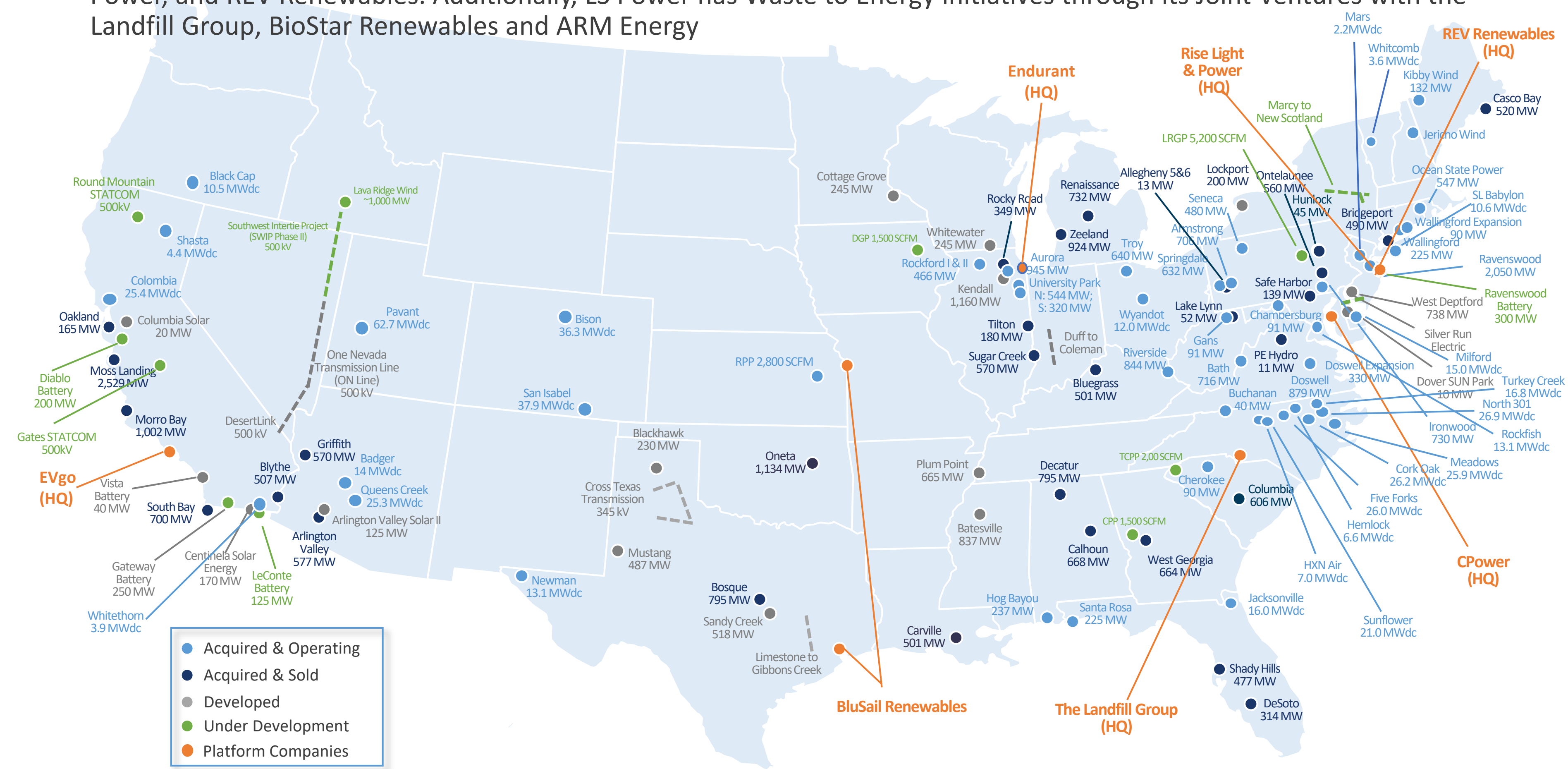
- Founded in 1990, LS Power has 280 employees across its principal and affiliate offices in New York, New Jersey, Missouri, Texas and California
- LS Power is at the leading edge of the industry's transition to low-carbon energy by commercializing new technologies and developing new markets.
  - **Utility-scale power projects across multiple fuel and technology types**, such as pumped storage hydro, wind, solar and natural gas-fired generation
  - **Battery energy storage**, market-leading utility-scale solutions that complement weather dependent renewables like wind and solar energy
  - **High voltage electric transmission infrastructure**, which is key to increasing grid reliability and efficiency, as well as carrying renewable energy from remote locations to population centers
  - **EVgo, the nation's largest public fast charging platform for electric vehicles** and first platform to be 100% powered by renewable energy
  - **CPower Energy Management**, the largest demand response provider in the country that is dedicated solely to the commercial and industrial sector
- Since inception, LS Power has developed, constructed, managed and acquired competitive power generation and transmission infrastructure, for which **we have raised over $47 billion in debt and equity financing.**
  - **Developed over 11,000 MW of power generation** (both conventional and renewable) across the United States
  - **Acquired over 34,000 MW of power generation assets** (both conventional and renewable)
  - **Developed over 660 miles of high voltage transmission**, with ~400 miles of additional transmission under development

**Utilize deep industry expertise as owner/operator**

# LS Power Project Portfolio

## Extensive development/operating experience across multiple markets and technologies

- With over $47 billion in equity and debt raised, LS Power has developed and acquired 120 Power Generation projects (renewable and conventional generation), 7 Transmission projects, and 5 Battery Energy Storage projects
- LS Power's Energy Transition Platforms includes CPower Energy Management, Endurant Energy, EVgo, Rise Light & Power, and REV Renewables. Additionally, LS Power has Waste to Energy initiatives through its Joint Ventures with the Landfill Group, BioStar Renewables and ARM Energy






LS POWER

# Issue Summary

**Under the ISO's interpretation of the tariff, there is no way for a "repowered" resource to unwind future FCM commitments, leading to an unexpected and nonsensical "bet-the-plant" situation**

- In FCA15, LS bid an expansion at its Ocean State Power (OSP) facility, cleared the auction, and secured a 7-year price lock
  - Because the expansion would increase summer capacity by more than 20%, it was technically a "repowering". As a repowering, the *whole facility* is treated as **new** for purposes of FA, CPS monitoring, etc.
- Since the start of the year, LS has been exploring whether it is possible to functionally "revert" back to the plant as it exists today. The ISO tells us that based on their interpretation of the tariff, there is **no mechanism to shed the incremental MWs of a repowering project**. Based on their reading, a repowering project must either be:
  - **(a)** completed as originally contemplated in its Show of Interest; or
  - **(b)** terminated in its ***totality,*** which would result in the loss of the **whole plant's** ability to participate in the FCM in perpetuity (forfeit of CNRC) and forfeit of FA associated with MWs which are currently operational
- If a repowered resource is not developed for any reason, **including failure to obtain permits**, then the ISO's interpretation means that the whole resource must exit the FCM, even if a significant amount of capacity could remain operational
- This is not how we understood tariff to work and conversation with various NEPOOL stakeholders confirms that this is not how they understood the tariff to work, either. The ISO's current interpretation is untested and never been applied to another resource
- To that end, **LS is proposing tariff changes that clarify that the treatment of repowered resources** align with the treatment of both greenfield new builds and smaller uprates at existing facilities
  - Treatment would allow a repowered resource to shed its *incremental* obligations and forfeit FA and price-lock while retaining FCM-eligibility of the currently operating resource
- Since the last MC, LS has made modest revisions to its proposed tariff changes based on the suggestions of NEPOOL stakeholders
  - One substantive change makes clear that a repowered resource can only partly commercialize if it withdraws from CPS monitoring
  - Various stylistic changes added to enhance clarity and precision



LS POWER

# Background on Ocean State Power & its Repowering

## A Reliable, 2-Block NGCC, Operating Since 1991

- OSP is an existing, operational facility with two NGCC power blocks (with dual fuel backup) located in Rhode Island
  - The facility is comprised of two different capacity resources of approximately 270 MWs with two different resource IDs (528, 529). Both resources are of the same vintage, same technology, and same configuration
- OSP has operated since 1991 and cleared in every FCA since the inception of the capacity market
- OSP offers valuable energy-security / fuel-security contributions to New England with connections to two interstate pipelines (TGP and Algonquin) as well as 2 million gallons of on-site oil storage (~3 days of supply at full output)
  - Today, both phases of OSP continue to operate in the real world and have various capacity and energy obligations
  - Both units had good performance during the most recent PfP event that occurred on December 24, 2022
- OSP offered both of its power blocks as repowering projects in FCA 15, at different prices
  - It did not offer any capacity as a sub-20% uprate.
- OSP cleared one of its two power blocks as a repowering with that block increasing its output from 270 MW to 334 MW
  - This is a 64 MW increase representing a ~24% increase in summer output
- The repowered resource *also* secured a 7-year price lock at $3.98/kW-month for FCAs 15-21 on the full 334 MW size
- The repowered resource was originally thought to necessitate modest network upgrades but subsequent analysis has shown that no upgrades are required
- OSP did not change its primary or secondary energy sources, still an NGCC with dual-fuel backup

# Repowered resources are treated worse than greenfield new or smaller uprates of existing capacity under ISO interpretation

- **Operational capacity is never at risk on either a new greenfield project or a minor uprate at an existing unit**. Failure to meet CPS milestones can only result in the termination of *incremental* MWs
- FA on currently operational capacity is never at risk, either. A repowered resource must post FA on MWs that are currently operational but which cannot be commercialized under the ISO's interpretation of the tariff. **Results in roughly five times more FA posted per non-operational MW for repowered resources**

| | Greenfield New | Minor Uprate (≤20%) | Repowerings (>20%) |
|---|---|---|---|
| **Project Description** | A new 64 MW gen separate from OSP | A 53 MW uprate at OSP (19% increase) | A 64 MW uprate at OSP (24% increase) |
| **FA at risk** | 64 MW | 53 MW | 334 MW |
| **CNRC at risk** | 64 MW | 53 MW | 334 MW |
| **Currently operational capacity at risk** | 0 MW | 0 MW | 270 MW |



LS POWER

# Preferred Outcome

- If OSP had cleared as greenfield new or as a minor uprate, we would not be here today: the tariff is unambiguous in the ability of these resources to shed incremental obligations
- OSP would like to clarify the tariff to make clear that it has the right to shed its 64 MW of incremental obligations while also maintaining the ability of its 270 MW of currently operational capacity to continue to participate in the FCM
- **The most reasonable outcome would have OSP face the same set of penalties that would occur if a minor uprate or a greenfield new project were terminated.** This would require OSP to:
  - **Forfeit FA on the 64 MW of non-operational capacity that OSP cleared in FCAs 15-17.** If these MWs do not get built, OSP should lose the FA posted to support them
  - **Forfeit the price lock on the full 334 MW resource**. OSP should not benefit from a price lock on new or existing capacity if it does not build an uprate
- Allowing OSP to shed its repowering benefits both load *and* generators
  - **Load** would receive three benefits:
    (1) ~**$2mm in Financial Assurance** forfeited by OSP and refunded to load
    (2) SENE customers would avoid having to pay $3.98/kWm for 334 MW of capacity in FCA 16-21. Based on the two most recent auctions, which cleared around $2.6/kwm, this would **save customers $15mm in just FCA 16 and FCA 17**
    (3) Allow a 270 MW firm-fuel, flexible resource continue to participate in FCM and provide winter energy security benefits
  - **Generators** would receive a benefit, too:
    (1) The elimination of 64 MW of capacity from the supply stack in future FCAs



LS POWER

# Repowerings, market prices, & market power

# Repowering provisions were designed for the purpose of allowing existing capacity to get a price-lock. Price-locks are now gone

- Repowering provisions have their origin in the FCM Settlement. At that time, a repowering's treatment as "new" had two important market impacts. Only new resources could:
  1. Obtain price locks (first five years, later seven, now none)
  2. Set the market clearing price (originally, existing resources were treated as price takers)
- The uprate and repowering rules were explicitly designed to enable existing resources to clear as "new" in order to secure a price-lock. Per the Settlement Order, they were "intended to provide predictable revenues and facilitate financing for new capacity" – including incremental capacity at repowered sites [1]
- No party opposed the concept of repowering provisions. The only dispute related to the threshold between an uprate (≤20% increase) and a repowering (>20% increase). The threshold question was about the tradeoff between:
  - Generator benefit in securing a price lock to enable the financing of incremental capacity
  - Load not being subject to price-locks on too much capacity [2]

1. FERC 16-June-2006 Order Accepting Proposed Settlement (ER03-563) at 16, 133. Settlement at 11.II.B.2.
2. 16-June-2006 Order at 139.

# Market power concerns were originally focused on "toggling capacity" which does not have the same market impact today

- Market power concerns, such as they were, were focused on the fact that under the Settlement, only new resources could set the clearing price.[1] Today, of course existing resources can set clearing prices so concerns about toggling between new/existing do not matter in same way
- On the quantity front, a repowering offer in the FCM should *increase* supply in the market, not remove it
  - Greenfield new and uprated resources can also offer new capacity into the market before that capacity is operational, leading to risk of "phantom MWs." This is not a unique phenomenon to repowerings; it is simply a fact of life in a forward market that allows non-commercial capacity to participate
  - Repowering resources offer as both new and existing in the FCM, so the clearing engine can select between the "existing" resource size or the "new" resource size. We see this with how both parts of OSP cleared in FCA 15: one repowering proposal cleared and the other unit cleared as existing because it was the least-cost outcome
- The 20% threshold for repowering is largely arbitrary for purposes of mitigation because it is percentage-based. Market impacts occur due to aggregate MW in the market
  - Our 64 MW "repowering" (reflecting a 23% increase in summer capacity) would have been considered an uprate if OSP had a starting capacity of 320 MW instead of 270 MW. That resource could have shed its incremental MWs without issue
  - LS could have proposed a 64 MW greenfield new build adjacent to OSP, which could have affected clearing price/quantity. That resource could have shed its incremental MWs without issue
- On the pricing front, repowerings do not circumvent offer review or mitigation
  - The existing resource offer is mitigated if priced above the DDBT and the "new resource" (repowering) offer is subject to review as well as part of resource qualification

1. ISO-NE Filing Letter in ER03-563 at 10.



LS POWER

# Repowering rules were designed, in part, to enhance reliability. ISO's interpretation runs contrary to that intent

- FERC found that the repowering rules would allow existing resources to quickly and cost-effectively increase their capacity. Given concerns about prospective capacity shortfalls at that time, FERC noted that these increments could "provide important reliability protection"

> "The Commission finds that the threshold provision […] provides incentives to attract more supply to New England because it will encourage existing suppliers to expand their facilities. We further find that the level of the 20 percent/40 megawatt threshold is sufficient to provide incentives for significant additions to capacity levels, while preventing existing capacity from being reclassified as new capacity by means of minor additions. **We note that both Load Supporters and Capacity Suppliers argue that investment in existing capacity may be more cost efficient than new construction as well as quicker to come online.** Results of recent ISO-NE analyses, presented in the 2005 Regional System Plan, show that "New England will likely face an increased risk of operating with less capacity than needed by 2008." The 2005 Regional System Plan further states that results indicate that the region "will not have sufficient capacity to meet the IC Requirement in the 2008 to 2010 timeframe, depending on load growth, weather conditions, generator performance and attrition, and the conditions in specific load pockets, such as Connecticut**." Given these projections and that new generation requires two to four years to be built, increased output from existing resources could provide important reliability protection**. The Commission thus accepts the 20 percent/40 megawatt threshold agreed to by settling parties as an appropriate means for attracting additional capacity." [1] (emphasis added)

- It is hard to fathom how the ISO's tariff interpretation, leading to termination of operational capacity, aligns with FERC's intent of enabling projects which enhance reliability in a fast/cost-effective manner

1. FERC 16-June-2006 Order Accepting Proposed Settlement (ER03-563) at 138.

# Modifications to the Proposed Tariff Changes

# Updated proposal ties ability to partially commercialize resource to withdrawal from CPS monitoring

- Our original proposal did not limit when, how, or how often a repowered resource could partially commercialize
- A stakeholder expressed concern that our original tariff proposal could provide a repowered resource with the ability to prematurely receive FA back by repeatedly commercializing a portion of the facility. The stakeholder thought that this would be a more fundamental change to FA treatment of repowered resources, rather than simply an off-ramp for non-viable projects
  - LS thinks broader changes to repowering rules are warranted after the termination of the price-lock provisions, but that these broader changes are outside the scope of our proposal.
- To accommodate this stakeholder concern, we have updated our tariff proposal to allow for partial commercialization of repowered resources only when they withdraw from CPS monitoring
  - Withdrawal from CPS monitoring can occur only once, which avoids the ability to repeatedly commercialize a portion of a facility
- Separately, we have made several stylistic changes to aid with clarity

**A separate word document provides tracked changes to our original 4/13/2023 tariff language.**



LS POWER

# Conceptual Tariff Language for Partial Commercialization

## Partial Commercialization allows for Partial Termination under existing provisions

- Changes to the FCM Commercial Operation provision (III.13.3.8) would clarify that a repowered resource can commercialize up to its current audited output level – irrespective of whether all CPS monitoring milestones are met
  - Language would limit this pathway to repowerings that withdraw from CPS monitoring
  - Language would be limited to resources where no network upgrades required or upgrades are complete
- Updated proposal eliminates the "like-for-like" technology requirement, because the CPS withdrawal modification obviates its need. A resource of any technology can be commercialized at its audit level when it withdraws from monitoring.
- Partial commercialization allows for partial termination of non-commercial MWs by the ISO (or by us) under current market rules (III.13.3.4A)
- **Allows OSP to commercialize (i.e. retain) its operational 270 MW unit and the ISO to terminate the incremental 64 MW**

**If a resource:**

1. qualified and cleared as a New Generating Capacity Resource pursuant to repowering provisions
2. ~~did not change its prime mover or primary energy source in its Show of Interest Form from the resource that was previously counted as a capacity resource, and~~ ← Proposed Elimination
3. completed any transmission upgrade(s) necessary for the resource to obtain the requisite interconnection service on the uprated facility, and,
4. Withdraws from CPS monitoring ← Proposed Addition

**Then,**

the ISO shall confirm FCM Commercial Operation of the portion of the re-powered resource equal to the repowered resource's Establish Claimed Capability audit value

# FCM Commercial Operation Changes (III.13.3.8)

## Proposed Additions in Red

A resource (or portion thereof) achieves FCM Commercial Operation when (1) the ISO has determined that the resource (or portion thereof) has achieved all its critical path schedule milestones, including completion of any transmission upgrades necessary for the resource to obtain the requisite interconnection service; and (2) the ISO verifies the resource's (or a portion of the resource's) summer capacity rating (or, for a resource with winter capacity only, its winter capacity rating).

(a) For a Generating Capacity Resource (or portion thereof) that has achieved all its critical path schedule milestones, the ISO shall confirm FCM Commercial Operation as soon as practicable following the ISO's verification of the resource's summer capacity rating (or, for a resource with winter capacity only, its winter capacity rating), which may take place in any month of the year. The ISO shall verify the summer capacity rating of a Generating Capacity Resource that is an Intermittent Power Resource following no fewer than 30 consecutive calendar days of operation (for periods from October 1 through May 31, a Market Participant must request such verification).

(b) For a Demand Capacity Resource (or portion thereof) …

(c) For an Import Capacity Resource (or portion thereof) …

For a resource that (1) previously qualified and cleared in a Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (re-powering), (2) completed any transmission upgrade(s) necessary for the re-powered resource to obtain the requisite interconnection service, and (3) subsequently is withdrawn by its Project Sponsor (or deemed withdrawn by the ISO) from critical path schedule monitoring pursuant to Section III.13.3.6, the ISO shall confirm FCM Commercial Operation of the portion of the re-powered resource equal to the re-powered resource's summer capacity rating (or, for a resource with winter capacity only, its winter capacity rating). The summer capacity rating can be established using an Establish Claimed Capability Audit, which may take place in any month of the year.



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# Conceptual Tariff Language for Price Lock Termination

**Allows for the ISO to terminate a price lock if certain provisions are met and clarifies pricing treatment for auctions in which a price-locked resource has already cleared.**

- Allows ISO to terminate a price lock on a repowered resource if the resource **withdraws from CPS monitoring**
  - Does **not** affect truly *new* resources with a price-lock obtained prior to FCA 15 (those do not clear as repowering)
  - Does **not** affect DR resources with a price-lock obtained prior to FCA 15 (those are not Generating Capacity Resources)
  - Does **not** affect generating capacity resources which cleared a minor uprate (<20%) under III.13.1.1.1.3
  - Does **not** affect repowered resources with active price-locks that are currently commercial
  - No new resources will fall into this category because resources can no longer obtain a price-lock
- Updated proposal allows ISO to terminate a price-lock on withdrawal from CPS monitoring – better aligning both provisions
- Based on our review, the repowered portion of OSP is the only resource that fits into this bucket
- It is reasonable to assume that the price-locked resource would have cleared the FCM as an existing resource for auctions already run. The portion of OSP which is an existing resource (with no price-lock) has cleared every FCA.

**The ISO ~~may~~ shall terminate a price-lock If a resource:**

1. qualified and cleared as a New Generating Capacity Resource pursuant to repowering provisions
2. ~~Has not commercialized~~ ← Proposed Elimination
3. Withdraws from CPS monitoring ← Proposed Addition

**When the ISO terminates a price-lock, then,**

- **For auctions already run:** the resource shall be paid the zonal FCM price of that CCP (not the price-locked rate)
- **For future auctions:** the resource participates like any other existing generating capacity resource (i.e., can delist, no guaranteed clear, paid prevailing market price)



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# Price Lock Changes (III.13.1.1.2.2.4)

**Proposed Additions in Red**

Project Sponsors shall be required to specify whether they are making the election set forth in this Section III.13.1.1.2.2.4 for each Forward Capacity Auction up to and including the auction held in February 2021 for the June 1, 2024 through May 31, 2025 Capacity Commitment Period, and no election shall be permitted thereafter.

For each Forward Capacity Auction occurring up to and including the February 2021 auction, in the New Capacity Qualification Package, the Project Sponsor must specify whether, if its New Capacity Offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to six additional and consecutive Capacity Commitment Periods, in whole Capacity Commitment Period increments only. For incremental capacity qualified pursuant to Section III.13.1.1.1.3.A, this election shall apply to both the incremental amount of capacity and the existing Qualified Capacity matched to the incremental capacity at the same generating resource. If no such election is made in the New Capacity Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Capacity Offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Capacity Offer clears. If a New Capacity Offer clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.1.2.2.4.

The ISO shall terminate the a multi-year rate election of an Existing Generating Capacity Resource or a New Generating Capacity Resource obtained pursuant to this Section III.13.1.1.2.2.4 if the resource (1) previously qualified and cleared in a Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (re-powering), and (2) is withdrawn by its Project Sponsor (or deemed withdrawn by the ISO) from critical path schedule monitoring pursuant to Section III.13.3.6. When the ISO terminates a multi-year rate election of a qualifying resource, then that resource shall be paid the Capacity Clearing Price of each Forward Capacity Auction in which the resource already obtained a Capacity Supply Obligation. Upon termination of the multi-year rate election, the Existing Generating Capacity Resource can participate in the Forward Capacity Auction pursuant to Section III.13.1.2.



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# Withdrawal from Critical Path Schedule Monitoring (III.13.3.6)

**Proposed Additions in Red**

**Rationale**

- With the new partial commercialization language in III.13.3.8(d) being tied to withdrawal from CPS monitoring, we clarify that a resource withdrawing from CPS monitoring may first partially commercialize before being subject to termination.
- Without this change, there could be ambiguity about sequencing and whether CSO termination occurs before partial commercialization can be achieved.

**III.13.3.6. Withdrawal from Critical Path Schedule Monitoring**.

A Project Sponsor may withdraw its resource from critical path schedule monitoring by the ISO at any time by submitting a written request to the ISO. The ISO also may deem a resource withdrawn from critical path schedule monitoring if the Project Sponsor does not adhere to the requirements of this Section III.13.3. Any resource withdrawn from critical path schedule monitoring shall be subject to the provisions of Section III.13.3.4A. A resource that (1) previously qualified and cleared in a Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (re-powering) and (2) is withdrawn by its Project Sponsor (or deemed withdrawn by the ISO) from critical path schedule monitoring pursuant to this Section III.13.3.6 may achieve FCM Commercial Operation under Section III.13.3.8 prior to being subject to the provisions of Section III.13.3.4A.

# Are other tariff changes required? No.

- **Do we need to make changes to Financial Assurance? No.** The tariff already has rules that make a distinction between Commercial and Non-Commercial Capacity. For example FAP VII.B.1-2 explain that FA is only required on non-commercial capacity (i.e., capacity which has not been commercialized under III.13.3.8). When capacity is commercialized, FA on the commercial MWs should be refunded per VII.B.3
  - Our proposal does not make any changes to the definition of Non-Commercial Capacity so does not require any changes to FA rules
- **Do we need to make changes to treatment of Interconnection Agreements? No.** III.13.3.5 provides the ISO with the right to terminate an Interconnection Agreement (“IA”) when the associated CSO has been terminated. This provision has been used previously to adjust downward an IA to match the CSO of a resource which was also adjusted downward (under III.13.3.4A)
  - Note that Section III.13.3.5 does not require termination. Instead, the Tariff leaves the termination decision to the ISO’s discretion. We understand that the ISO’s general practice is that the ISO will amend an IA or terminate the IA and replace it with a new IA to reflect the termination or partial termination of a CSO
- **What about changes to CNR Capability? No.** In ER18-704, the ISO stated that a resource may achieve partial Commercial Operation for purposes of CNRC when it can show that it can meet some of its CSO. Section II.48.3 notes that partial termination of a resource by the ISO (or by us) would reduce our capacity network rights down to our FCM qualified capacity

# Conclusions & Next Steps

- LS Power has uncovered confusion about tariff rules that lead to discriminatory treatment of repowered resources
  - The ISO's interpretation of these rules leads to an inadvertent "bet-the-plant" situation if a resource is not developed for any reason then it will be terminated in its ***totality,*** which would result in the loss of the **whole plant's** ability to participate in the FCM in perpetuity and forfeit FA associated with MWs which are currently operational
- LS proposes tariff changes that clarify the treatment of repowered resources
  - Proposed treatment aligns with outcome when a greenfield project or minor uprate is unwound
  - Not clear that this language is even needed, but codifies a reasonable outcome
- Proposed language would allow OSP to prospectively unwind its repowering without losing its existing facility, while still paying a reasonable penalty for non-delivery of cleared capacity and forfeiting its price-lock
- Allowing LS to unwind these obligations would:
  - save consumers tens-of-millions of dollars between FA refunds, price-lock termination, and continued FCM participation
  - enhance winter energy security by allowing a firm-fuel resource to remain a capacity resource and participate in the FCM and all other ISO markets
  - rationalize the supply stack
- **Schedule**: Because OSP remains under a CPS monitoring we request that the committee move expeditiously
  - **April 13:** Issue Discussion and Proposed Tariff Changes
  - **April 25 (Today):** Markets Committee Vote on Proposed Tariff Changes
  - **May 4:** Participants Committee Vote on Proposed Tariff Changes

# Contact Information

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# Appendix on Tariff & Tariff Interpretation

# Summary of Key Tariff Provisions

- **III.13.1.1.1.2 (a)** requires an *existing* capacity resource to clear as *new* if it increases its capacity by at least 20%
- **III.13.1.1.2.2.4** allowed *new* resources, through FCA 15, to secure a 7-year price lock
  - These provisions also forbid a price-locked resource from making any sort of "de-list or export bid" on the price-locked capacity meaning that a price-locked cannot terminate incremental capacity using a Retirement De-List bid or a Permanent De-List bid
- **III.13.2.3.2 (e)** is an accounting provision which notes that a resource which *clears* as new under III.13.1.1.1.2 will have its existing capacity "permanently de-listed". This provision makes sure that there is no duplicate capacity in the market (i.e., that the original MWs from the "existing" resource is netted out from the "new" expanded resource)
  - This provision *intentionally* relies on the undefined and ambiguous phrase "permanently de-listed." The ISO stated in the Filing Letter from ER08-199 that "the phrase 'permanently de-listed' was intentionally made lower-case so as to not implicate the formal requirements associated with clearing Permanent De-List Bids…"
- **III.13.3.4A** describes how the ISO can terminate or "adjust" downward the CSO of capacity resources
- **III.13.3.8** describes how a resource can demonstrate FCM Commercial Operation on its full output or a "portion thereof" if it completes CPS milestones, any transmission upgrades for network service, and does a commercialization audit.

# OSP's Predicament

- **III.13.1.1.1.2 (the repowering provision)** specifies that a resource shall clear as a new resource if investment will increase output by at least 20%. **III.13.2.3.2 (e)** notes that "If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed"
  - Reading these provisions together, ISO-NE has concluded that if an existing resource *clears* in an FCA as a New Capacity Resource then the Existing Capacity Resource must be "permanently delisted", **irrespective of whether the new resource is actually built**. This interpretation means that a resource must exit the FCM in perpetuity (unless it re-enters as a repowering), even if the a significant amount of capacity have been, and could remain operational and commercial
- **III.13.3.8** describes how a resource can demonstrate FCM Commercial Operation on its full output or a "portion thereof" if it completes CPS milestones, any transmission upgrades for network service, and does a commercialization audit
  - OSP's uprate has no required network upgrades and is willing to do a commercialization audit, but the ISO has concluded that it can not commercialize *any* of its 270 MW of currently operational capacity because it has not achieved all of the CPS milestones contemplated in its original Show of Interest
  - Although this provision nominally allows for partial commercialization, it is not clear if there is any mechanism, in practice, to partially commercialize a facility if it has not met *all aspects of it SOI or CPS milestones*
  - Uncertainty remains as to what would happen if OSP were to try to develop the uprate and it was unable to deliver a full 334 MW, as part of CPS monitoring includes MW thresholds (e.g. what happens if a project comes in 1 MW short?)
  - Additionally, the ISO has indicated that it still might not be willing to allow OSP to be commercialized because if it comes up with less than a 20% uprate because it should not have been able to clear under III.13.1.1.1.2 in the first place
- OSP cannot partially terminate, retire, or delist the 64 incremental MWs under **III.13.3.4A** because they are not currently FCM operational and because the price lock, **III.13.1.1.2.2.4**, does not allow OSP to make any "de-list or export bid" on the price-locked capacity

# III.13.1.1.1.2. Resources Previously Counted as Capacity

A resource that has previously been counted as a capacity resource, including a deactivated or retired capacity resource, may elect to participate in the Forward Capacity Auction as a New Generating Capacity Resource, as described in this Section III.13.1.1.1.2. The incremental expenditure required to reactivate a resource that previously has been deactivated or retired pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff (or its predecessor provisions) may be included in the calculation of the dollar per kilowatt thresholds in this Section III.13.1.1.1.2. **A resource accepted for participation in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to this Section III.13.1.1.1.2 shall participate in the Forward Capacity Auction pursuant to Section III.13.2.3.2(e).** A Market Participant that elects to have a resource that has previously been counted as a capacity resource participate in the Forward Capacity Auction as a New Generating Capacity Resource, must notify the ISO when the existing resource ceases to operate and the New Generating Capacity Resource commences operation. If a Market Participant with a resource that has previously been counted as a capacity resource elects, pursuant to Section III.13.3.4(a)(iii), to have the resource that has previously been counted as a capacity resource cover the Capacity Supply Obligation of a New Generating Capacity Resource and the resource that has previously been counted as a capacity resource must take an outage in order for the New Generating Capacity Resource to commence Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff), then the Market Participant must notify the ISO that the outage is for the purpose of the New Generating Capacity Resource commencing Commercial Operation (as defined in Schedule 22, 23, or 25 of Section II of the Transmission, Markets and Services Tariff). **A resource shall be accepted for participation as a new resource if it complies with one of the following three subsections:**

**(a) Where investment in the resource will result, by the commencement of the Capacity Commitment Period, in an increase in output by an amount exceeding the greater of: (i) 20 percent of the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction**; or (ii) 40 MW above the summer Qualified Capacity of the resource at the time of the qualification process for the Forward Capacity Auction, the whole resource shall participate in the Forward Capacity Auction as a New Generating Capacity Resource…

# III.13.2.3.2 (e) Step 2: Compilation of Offers and Bids – Repowering

Offers and bids associated with a resource participating in the Forward Capacity Auction as a New Generating Capacity Resource pursuant to Section III.13.1.1.1.2 (resources previously counted as capacity resources) shall be addressed in the Forward Capacity Auction in accordance with the provisions of this Section III.13.2.3.2(e). The Project Sponsor shall offer such a New Generating Capacity Resource into the Forward Capacity Auction in the same manner and pursuant to the same rules as other New Generating Capacity Resources, as described in Section III.13.2.3.2(a). As long as any capacity is offered from the New Generating Capacity Resource, the amount of capacity offered is the amount that the auctioneer shall include in the aggregate supply curve at the relevant prices, and the quantity of capacity offered from the associated Existing Generating Capacity Resource shall not be included in the aggregate supply curve. **If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period.** If at any price, no capacity is offered from the New Generating Capacity Resource, then the auctioneer shall include capacity from the associated Existing Generating Capacity Resource at that price, subject to any bids submitted and accepted in the qualification process for that Existing Generating Capacity Resource pursuant to Section III.13.1.2.5. Bids submitted and accepted in the qualification process for an Existing Generating Capacity Resource pursuant to Section III.13.1.2.5 shall only be entered into the Forward Capacity Auction after the associated New Generating Capacity Resource is fully withdrawn (that is, the Forward Capacity Auction reaches a price at which the resource's New Capacity Offer is zero capacity), and shall only then be subject to the reliability review described in Section III.13.2.5.2.5.

LS views this provision as an accounting exercise. Permanently de-listing an existing resource's capacity when it receives a CSO as a new resource simply removes capacity from an existing resource and transfers the same capacity to a new resource.

This provision *intentionally* relies on the undefined and ambiguous phrase "permanently de-listed." The ISO stated in the Filing Letter from ER08-199 that "the phrase 'permanently de-listed' was intentionally made lower-case so as to not implicate the formal requirements associated with clearing Permanent De-List Bids…"

# III.13.3.4A Termination of Capacity Supply Obligations

If a Project Sponsor fails to comply with the requirements of Sections III.13.3.2 or III.13.3.3, or if a Project Sponsor covers a Capacity Supply Obligation for two Capacity Commitment Periods, or if, as a result of milestone date revisions, the date by which a resource will have achieved all its critical path schedule milestones is more than two years after the beginning of the Capacity Commitment Period for which the resource first received a Capacity Supply Obligation, then **the ISO, after consultation with the Project Sponsor, shall have the right, through a filing with the Commission, to terminate the resource's Capacity Supply Obligation for any future Capacity Commitment Periods and the resource's right to any payments associated with that Capacity Supply Obligation in the Capacity Commitment Period, and to adjust the resource's qualified capacity for participation in the Forward Capacity Market; provided that, where a Project Sponsor voluntarily withdraws its resource from critical path schedule monitoring in accordance with Section III.13.3.6, no filing with the Commission shall be necessary to terminate the resource's Capacity Supply Obligation.** Upon Commission ruling, the Project Sponsor shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation. If in these circumstances, however, the ISO does not take steps to terminate the resource's Capacity Supply Obligation and instead permits the Project Sponsor to continue to cover its Capacity Supply Obligation, such continuation shall be subject to the ISO's right to revoke that permission and to file with the Commission to terminate the resource's Capacity Supply Obligation, and subject to continued reporting by the Project Sponsor as described in this Section III.13.3….

LS views this provision as allowing the ISO to "adjust" downward the CSO at OSP from 334 MW to the currently operational 270.18 MW. Nothing in this provision requires ISO-NE to terminate the entire facility should it not complete its uprate.

# III.13.1.1.2.2.4. Capacity Commitment Period Election

Project Sponsors shall be required to specify whether they are making the election set forth in this Section III.13.1.1.2.2.4 for each Forward Capacity Auction up to and including the auction held in February 2021 for the June 1, 2024 through May 31, 2025 Capacity Commitment Period, and no election shall be permitted thereafter.

For each Forward Capacity Auction occurring up to and including the February 2021 auction, in the New Capacity Qualification Package, **the Project Sponsor must specify whether, if its New Capacity Offer clears in the Forward Capacity Auction, the associated Capacity Supply Obligation and Capacity Clearing Price (indexed for inflation) shall continue to apply after the Capacity Commitment Period associated with the Forward Capacity Auction in which the offer clears, for up to six additional and consecutive Capacity Commitment** Periods, in whole Capacity Commitment Period increments only. For incremental capacity qualified pursuant to Section III.13.1.1.1.3.A, this election shall apply to both the incremental amount of capacity and the existing Qualified Capacity matched to the incremental capacity at the same generating resource. If no such election is made in the New Capacity Qualification Package, the Capacity Supply Obligation and Capacity Clearing Price associated with the New Capacity Offer shall apply only for the Capacity Commitment Period associated with the Forward Capacity Auction in which the New Capacity Offer clears. **If a New Capacity Offer clears in the Forward Capacity Auction, the capacity associated with the resulting Capacity Supply Obligation may not be subject to any type of de-list or export bid in subsequent Forward Capacity Auctions for Capacity Commitment Periods for which the Project Sponsor elected to have the Capacity Supply Obligation and Capacity Clearing Price continue to apply pursuant to this Section III.13.1.1.2.2.4.**

OSP secured a 7-year price lock in FCA 15. The price lock provisions forbid OSP from making any sort of “de-list or export bid”, meaning that we cannot retire the 64 MW of incremental capacity using a Retirement De-List bid or a Permanent De-List bid. The only method for MW reductions is via a “partial termination” under III.13.3.4A.



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# III.13.3.8 FCM Commercial Operation

A resource (**or portion thereof**) achieves FCM Commercial Operation when (1) the ISO has determined that the resource (or portion thereof) has achieved all its critical path schedule milestones, including completion of any transmission upgrades necessary for the resource to obtain the requisite interconnection service; and (2) the ISO verifies the resource's (or a portion of the resource's) summer capacity rating (or, for a resource with winter capacity only, its winter capacity rating).

(a) **For a Generating Capacity Resource (or portion thereof**) that has achieved all its critical path schedule milestones, the ISO shall confirm FCM Commercial Operation as soon as practicable following the ISO's verification of the resource's summer capacity rating (or, for a resource with winter capacity only, its winter capacity rating), which may take place in any month of the year. The ISO shall verify the summer capacity rating of a Generating Capacity Resource that is an Intermittent Power Resource following no fewer than 30 consecutive calendar days of operation (for periods from October 1 through May 31, a Market Participant must request such verification). …



LS POWER

ISO new england

memo

**To:** NEPOOL Markets Committee

**From:** Andrew Gillespie – Director, Market Development

**Date:** April 24, 2023

**Subject:** Concerns with LS Power's Mechanism for Repowered Resources to Unwind Forward Capacity Market Obligations Proposal

While the ISO understands that LS Power finds itself in a challenging position with regards to its Capacity Supply Obligation (CSO), we have concerns with the remedy that it proposes which would 'revert' its CSO associated with this resource from the new repowered resource cleared in the Forward Capacity Auction (FCA) to the existing resource it 'replaced.' This memo articulates ISO's primary concern only. Due to the fast-track nature of LS Power's proposal, the ISO has not conducted a thorough assessment of the proposal and, therefore, takes no position on the efficacy of the proposal beyond the concern discussed in this memo.

The remainder of this memo is organized in three sections. The first section is a generalized description of the mechanics regarding the treatment of a repowering offer in the FCA. The second section demonstrates how clearing a new repowering offer in the FCA could yield different auction outcomes relative to the case where the underlying existing resource might have participated as a priced existing capacity segment. The final section summarizes the ISO's primary concern with the LS Power proposal; namely the incentive and appropriate compensation problems created if existing capacity effectively participates in the FCA as new capacity and sets the FCA clearing price.

## Repowering 'Mechanics' in the FCA

In this section we generally describe, through an example, how repowering offers function within the FCA. Consider an example where a participant has submitted and qualified a new (repower) offer for an (underlying) existing capacity resource, and also submitted a de-list bid for the underlying existing capacity resource.[1] For this example, assume an existing 200 MW resource is participating as a new 250 MW repowered resource.

At the start of the auction and as it proceeds through its descending rounds, only the new (repower) offer supply segment (250 MW) is included in the auctioneer's aggregate supply stack. Of particular note is the additional capacity, 50 MW in this example, is not offered separately; it is part of the (singular) new offer for 250 MW. It is also worth recalling that new capacity offers (segments) are eligible to set the clearing price, and are only subject to buyer-side mitigation (*i.e.,* there is no 'downward' mitigation of new offers).

[1] It is not a requirement that a de-list bid for the underlying existing resource also be submitted with a repowering offer.

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During the auction, only when the new (repower) offer supply segment becomes extra-marginal (*i.e.,* when it is not the marginal offer, or infra-marginal) is the underlying existing capacity segment then included in the auctioneer's aggregate supply stack. In the example, if the auction price goes below the 250 MW new (repower) offer price and hence would not get a CSO, only then is the 200 MW existing capacity segment included in the auctioneer's aggregate supply stack. As the auction then proceeds through subsequent descending rounds, only the (lower priced) existing capacity segment is included in the auctioneer's aggregate supply stack.

In the next section, we provide an example that contrasts a resource participating and clearing as a new (repower) offer with the same resource participating as an existing resource.

## Different Potential Auction Outcomes

In this section we contrast two different scenarios.

The first scenario (Figure 1) shows the effects on the FCA outcome if a marginal new (repower) offer clears and sets the zonal clearing price (the 250 MW segment in the previous example).[2]

The second scenario (Figure 2) shows the effects on the FCA outcome if the existing capacity had instead participated with a de-list bid (the 200 MW segment in the prior example). In this scenario, the existing capacity is awarded a Capacity Supply Obligation (CSO) as the de-list bid price was infra-marginal.

In the next section, we use these figures to demonstrate one possible, unintended, outcome the LS Power proposal might create.

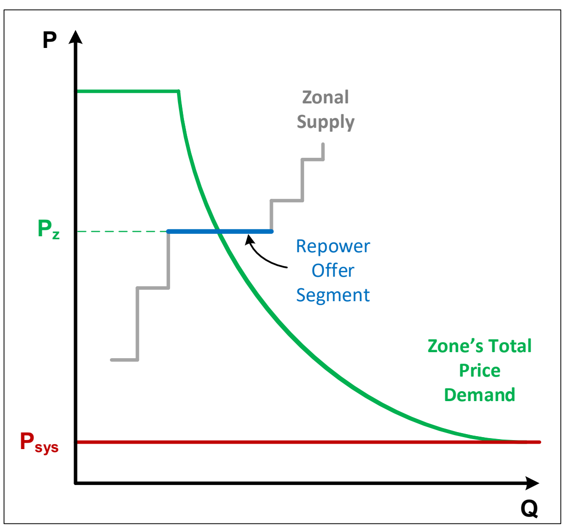


**Figure 1. Marginal New (repower) Offer Segment**

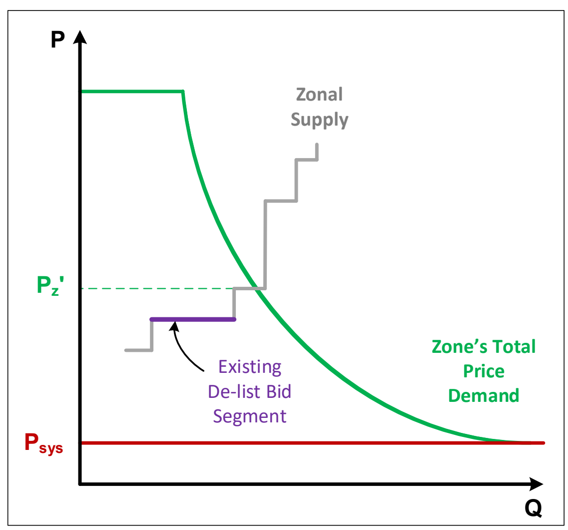


**Figure 2. Infra-marginal Existing Bid Segment**

[2] While the effect is shown in the context of an import-constrained capacity zone, the same would apply at the system level (*i.e.,* for the 'Rest of Pool' zone).

## Implications of LS Power's Proposal

The main concern regarding repowering is the ability of an existing resource to participate as a new resource in the FCA.[3] For this reason the thresholds for qualifying an existing resource as a "new" repowered resource were established and the rules were developed to "assure that capacity from these re-powerings will be unable to exercise market power."[4] As the FCM Settlement Agreement Order stated "We further find that the level of the 20 percent/40 megawatt threshold is sufficient to provide incentives for significant additions to capacity levels, *while preventing existing capacity from being reclassified as new capacity by means of minor additions*" [emphasis added].[5]

Putting all this together, the ISO's primary concern with LS Power's proposal is that it could, going forward, produce an outcome where existing capacity, in effect, has participated in the FCA as new capacity *and set the clearing price*, with very little or perhaps no capacity addition. This is a problem from both an incentive standpoint and an appropriate compensation (ex post) standpoint.

This unintended outcome of LS Power's proposal can be seen using the figures shown above.

- Figure 1 shows the FCA clearing price is set by the new (repower) offer, which would include the additional capacity necessary to meet the threshold requirements.
- After the auction, this new (repower) offer is then 'unwound' and reverts back to the underlying existing resource. However, the auction results are not altered or modified after the fact to account for how the auction might have cleared had the resource instead participated in the FCA as an existing resource (Figure 2).
- Instead, the now 'reverted' existing resource, like all other resources with a CSO, would be paid the clearing price; in this case the higher clearing price set by the 'unwound' new (repower) offer. Unlike a terminated 'greenfield' new resource which does not have a CSO and is therefore not paid the auction clearing price, here the 'unwound' resource is paid the auction clearing price.

This possible outcome was of concern for stakeholders and from a market power perspective when the repowering rules were created. To prevent this outcome the rules are constructed such that if the new (repower) offer clears, the underlying existing resource is wholly replaced in all instances by the cleared new (repower) resource. Consequently, there is no ability in the current rules to 'unwind' a cleared new (repower) offer, and this omission was by design.

In summary, based on its initial review, the ISO's primary concern with the LS Power proposal is the problem it could create; namely that it could, in its effect, produce an outcome where existing capacity, whether occurring prospectively or retrospectively, has participated in the FCA as new capacity *and set the FCA clearing price*.

Again, the ISO understands the challenging position LS Power finds itself in. However, the ISO finds LS Power's proposed Tariff changes problematic.

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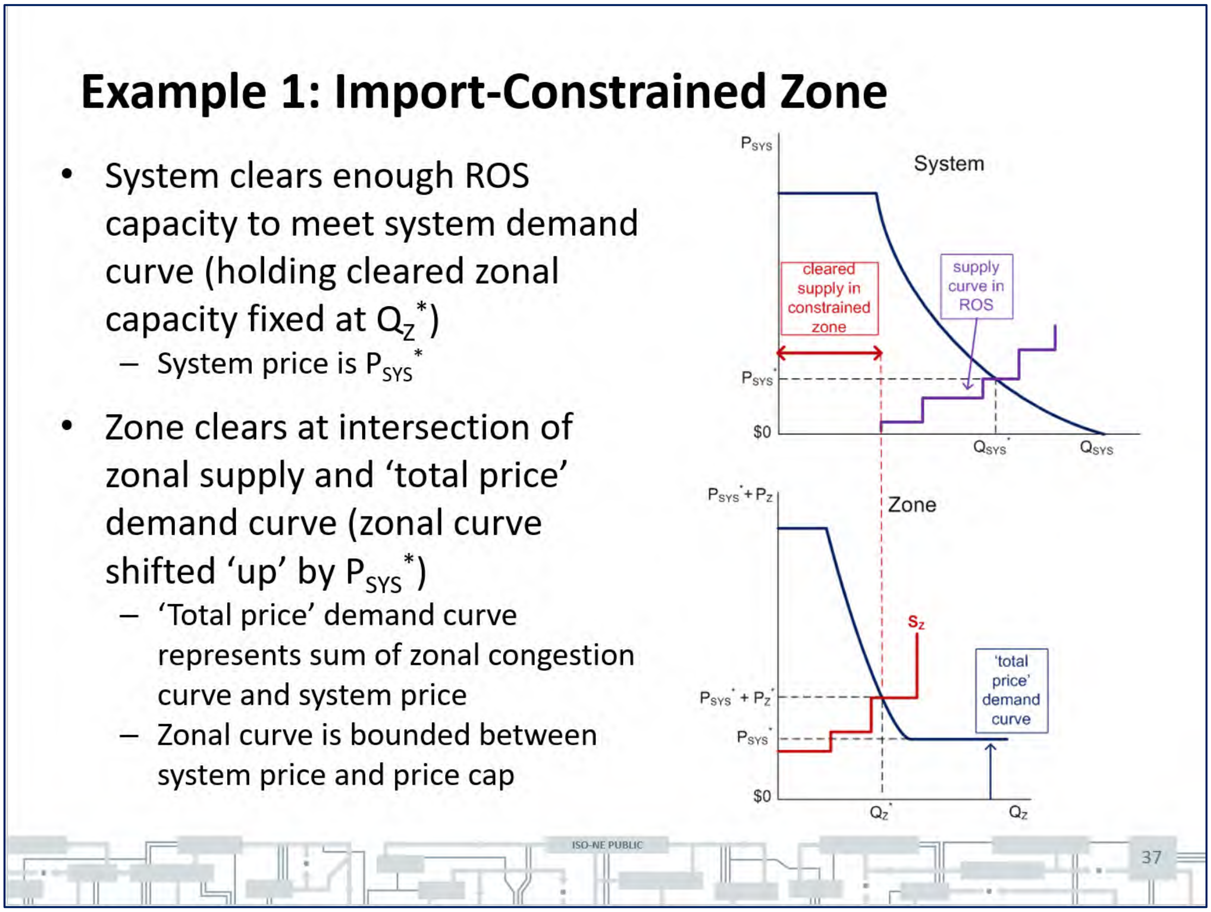
[3] 115 FERC ¶ 61,340, pp134 "Objecting Parties argue that because existing suppliers have both the incentive and ability to withhold capacity, it is important that only "new" resources be allowed to set the auction clearing price."

[4] *Ibid* pp136.

[5] *Ibid* pp138

**Appendix – Import-Constrained Zone pricing example**

FCM Zonal Demand Curves presentation to December 2015 Markets Committee.



ISO new england

memo

**To:** NEPOOL Markets Committee

**From:** Internal Market Monitor (IMM)

**Date:** April 24, 2023

**Subject:** LS Power's Repowering Proposal

In this memo, the IMM offers its initial assessment of LS Power's proposed rules to allow a repowering resource to revert to its original existing resource status. While we understand the time constraints faced by LS Power that have resulted in an expedited stakeholder review process, such a proposed rule change requires a thorough assessment of all the associated issues, which is simply not practical in this timeframe. However, we offer these initial thoughts to assist stakeholders with their review of the proposal and will be available to discuss this memo at the upcoming NEPOOL Markets Committee meeting.

## Background

LS Power is proposing changes to Section 13 of Market Rule 1 of the ISO New England Tariff ("Tariff") as a way to remove its obligation to repower the Ocean State Power 2 Resource ("OSP2"), a 270 MW facility that cleared as part of a New Generating Capacity Resource in Forward Capacity Auction 15 ("FCA 15").

In FCA 15, LS Power proposed repowering OSP2 with an additional 64 MW, or more than a 20% incremental output. Under Tariff Section III.13.1.1.1.2(a), the repowering proposal allowed the 270 MW Resource that was previously counted as capacity to participate in FCA 15 as a New Generating Capacity Resource, which cleared a total of 334 MW (270 MW plus 64 MW of repowering) of capacity at the clearing price of $3.98 kW/mo for the associated Capacity Commitment Period (i.e., June 2024 to May 2025).[1] In turn, under Tariff Section III.13.2.3.2(e), because a portion of the New Generating Capacity Resource (in fact, all 334 MW) cleared in the FCA, the former "associated Existing Generating Capacity Resource" must be "permanently de-listed as of the start of associated Capacity Commitment Period" to avoid double counting of capacity.[2] In addition, LS Power elected the 7-year rate lock that was available under the Tariff at the time, whereby the New Generating Capacity Resource would receive the fixed

[1] Tariff Section III.13.1.1.1.2(a) provides in relevant part: "When investment in the resource will result, by the commencement of the Capacity Commitment Period, in an increase in output by an amount exceeding . . . 20% of the summer Qualified Capacity" … "<u>the whole resource</u> shall participate in the Forward Capacity Auction as a New Generating Capacity Resource." (emphasis added)

[2] Tariff Section III.13.2.3.2.(e) provides in relevant part: "If any portion of the New Generating Capacity Resource clears in the Forward Capacity Auction, the associated Existing Generating Capacity Resource shall be permanently de-listed as of the start of the associated Capacity Commitment Period." This provision ensures that the previously counted as capacity that clears as "new" is not double counted.

capacity payment of $3.98 kW/mo for the next six FCAs (regardless of clearing price) for the associated Capacity Commitment Periods.

LS Power has announced that it would like not to invest in the repowering of the cleared New Generating Capacity Resource and to "revert back" to the original 270 MW Resource. LS Power asserts that the ISO has responded that a repowering project must either be: (a) completed as originally contemplated in its Show of Interest; or (b) terminated in its totality, which would result in the loss of the whole plant's ability to participate in the Forward Capacity Market (FCM) in perpetuity (forfeit of Capacity Network Resource Capability) and forfeit of Financial Assurance (FA), including that associated with MWs which are currently operational. In response, LS Power has proposed Tariff revisions that would allow them not to go forward with the repowering obligation while retaining FCM-eligibility on the currently operating facility, ranging from revisions to commercialization rules to a partial forfeiture of FA and partial forfeiture of its 7-year rate lock. LS Power has also asked for expedited vote on this issue as it is in the process of determining if they are going to move forward with this project or not.

**IMM Assessment of Current Tariff Provisions**

The IMM's view is that once the combined repowered resource (334 MW) cleared FCA 15 as a "New Generating Capacity Resource," its entire capacity then became subject to the critical path schedule (CPS) monitoring and termination provisions that apply to a new resource. This includes the possibility of the ISO exercising its right to seek termination in the event of LS Power's non-performance of the repowering obligation, which is ultimately subject to the Commission's approval and determination.[3] The Tariff also provides, "upon Commission ruling, the Project Sponsor shall forfeit any financial assurance provided with respect to that Capacity Supply Obligation."[4]

**IMM Initial Assessment of Design Proposal**

The IMM is sympathetic to the situation LS Power is in and to the fact that circumstances can change and impact a Participant's business decisions. We do think taking a fresh look at the repowering rules in the Tariff is a good idea, but we have a number of concerns with the proposed rule changes and the short evaluation timeframe. In summary, the evaluation will need to assess incentives to limit the exercise of market power and gaming, and provide a clear and commensurate remedy if a participant is unable to perform on its repowering obligation.

[3] *See* Tariff Sections III.13.2.3.2(e) and III.13.3.4A. Under Tariff Section III.13.3.4A, if a Project Sponsor fails to comply with CPS monitoring Tariff provisions, then the ISO "shall have the right, through filing with the Commission, to terminate the resource's [CSO] for any future Capacity Commitment Periods and the resource's right to any payments associated with that [CSO] in the Capacity Commitment Period, and to adjust the resource's qualified capacity for participation in the Forward Capacity Market."

[4] Tariff Section III.13.3.4A. In practice, a range of remedies could be available in the event that LS Power does not perform on its repowering obligation — from being compelled to strictly perform, to paying monetary damages and a penalty, to an outright termination of eligibility to participate in the capacity market — all of which remain subject to the approval and determination of the Commission.

First, this design change is being brought through the stakeholder process in an expedited way, which does not allow for a comprehensive review of the impacts of the change. Design changes need to be vetted to ensure they do not create other issues down the road (unintended consequences). Under the IMM business process, we review rule changes for how they enhance the function of the market as well as ensuring market power concerns are appropriately addressed. This review is an iterative process and not something that can be sufficiently completed in this expedited time frame.

Second, an assessment of market power or gaming issues needs to be completed. A fundamental design intent of the repowering provisions was to provide a means of securing capacity revenue certainty, for the *entire* capacity of the resource for a multi-year period, in order to underpin significant investment to maintain operation or to increase the capability of the resource. Once cleared as a new capacity resource, there is no Tariff means of reverting to the original resource. While this, on the face of it, is very restrictive, it was intended to act as a strong deterrent to potentially setting a higher clearing price and securing a multi-year revenue stream, and subsequently toggling back to the original status.

In the context of this proposal, the elimination of the multi-year price lock helps attenuate market power concerns by limiting the payoff of a successful withholding strategy. There are also market power mitigation protections already in the Tariff that apply to the existing resource, namely the review of a Static De-List Bid. However, while existing resources are reviewed for seller-side market power (inflated bids are subject to downward IMM adjustment), there is no such review of new supply offers, which are subject to buyer-side market power review (upward adjustment) only. This allows the new resource to be offered as high as the auction starting price down to its offer floor price. Therefore, there is still an open question of whether this proposal increases the opportunity for exercising market power or gaming, which tends to be a greater concern when capacity conditions are tighter (for example, than conditions in FCA 15).

Third, the IMM is concerned that the proposed changes create an ability for a participant to “unwind” its repowering obligation (and rate lock election) retroactively, with limited consequences for essentially breaching that obligation. This proposal does not factor in the potential market harm caused by the clearing of the repowering resource in the FCA, and may not adequately incentivize Market Participants to deliver on obligations obtained in the auction.

In short, the capacity market, and all of the rules around CPS monitoring, Financial Assurance and commercialization need careful monitoring to ensure participants that take on obligations in the FCM will face strong incentives to deliver on those obligations.

**EXECUTIVE SUMMARY**
**Status Report of Current Regulatory and Legal Proceedings**
**as of May 3, 2023**

The following activity, as more fully described in the attached litigation report, has occurred since the report dated April 5, 2023 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

## I. Complaints/Section 206 Proceedings

| | | | | |
|---|---|---|---|---|
| | 4 | NextEra/Avangrid/NECEC Seabrook Complaint (EL21-6) and Seabrook Declaratory Order (EL21-3) | Apr 3<br>Apr 4 | FERC issues *Seabrook Dispute Allegheny Order*<br>NextEra petitions DC Circuit for review of *Seabrook Dispute Order* |

## II. Rate, ICR, FCA, Cost Recovery Filings

| | | | | |
|---|---|---|---|---|
| * | 8 | BHD Regulatory Asset-Establishment & Recovery Through Rates (ER23-1598) | Apr 7<br><br>May 3 | Versant request approval for establishment and recovery through the ISO-NE Tariff of a $15 million regulatory asset<br>MPUC moves to intervene out-of-time and protest |
| | 8 | FCA17 Results Filing (ER23-1435) | Apr 7<br>Apr 21-May 3<br><br>May 3 | National Grid intervenes<br>Over 70 individual citizens file anti-fossil fuel comments; comment deadline ***May 5, 2023***<br>No Coal No Gas submits comments |
| | 9 | Add'l Cost Recovery Due to Dec 24 General Threshold Energy Mitigation: Dynegy (ER23-1261) | Apr 14 | Dynegy answers Apr 4 ME OPA and joint MA AG/CT OCC protests |
| | 10 | **Mystic 8/9 COSA (ER18-1639)** | | |
| * | 10 | (-024) Mystic Request for Rehearing of Mystic I Order on Remand | Apr 27 | Mystic requests rehearing of *Mystic I Order on Remand* |
| * | 10 | (-023) Revised COSA | Apr 27 | Mystic submits 30-day compliance filing; comment deadline ***May 18, 2023*** |
| | 10 | (-021) First CapEx Info. Filing Settlement Agreement | Apr 14 | Mystic and State Settling Parties submit reply comments |
| * | 12 | 30-Day Compliance Filing per *Order on ENECOS Mystic COSA Complaint* (ER23-1735) | Apr 27 | Mystic submits 30-day compliance filing; comment deadline ***May 18, 2023*** |
| | 12 | Trans. Rate Annual (2022/23) Update/Info Filing (ER09-1532) | Apr 14 | Eversource answers Mar 31 RENEW answer |

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

| | | | | |
|---|---|---|---|---|
| * | 13 | IEP Parameter Updates (ER23-1588) | Apr 7<br>Apr 10-27<br><br>Apr 28 | ISO-NE and NEPOOL file Updates<br>Calpine, Constellation, Eversource, National Grid, Public Systems, MA DPU file doc-less motions to intervene only<br>Indicated Suppliers support Updates; Consumer Advocates, Sierra Club/CLF/UCS protest Updates |
| | 16 | IEP Remand (ER19-1428-006) | Apr 24 | FERC accepts ISO-NE's proposed Tariff Revisions (but not the alternative changes proposed by Brookfield), eff. May 30, 2019 |

| | | | | |
|---|---|---|---|---|
| | 14 | New England's *Order 2222* Compliance Filing (ER22-983) | Apr 11 | FERC accepts NEPOOL request to extend 60-day compliance filing deadline to ***May 9, 2023*** |
| | | | Apr 14 | MA AG answers Mar 31 New England Public Utils. request for reh'g |
| | | | Apr 17 | Advanced Energy United answers Mar 31 ISO-NE rehearing request |
| | | | May 1 | FERC issues *Order 2222 Compliance Allegheny Order* |
| | | | May 2 | ISO-NE answers AEU Apr 17 answer |

## IV. OATT Amendments / TOAs / Coordination Agreements

| | | | | |
|---|---|---|---|---|
| * | 16 | *Order 676-J* Compliance Filings Part II (ER23-1771; ER23-1774; ER23-1782; ER23-1785) | May 1 | Revisions filed to incorporate the remainder of the NAESB WEQ v. 003.3 standards into Tariff Schedule 24 (by ISO-NE/NEPOOL-ER23-1771); Schedule 18-Attachment Z (by ISO-NE/CSC-ER23-1774); MPD OATT (by Versant Power-ER23-1782); and Schedules 20A-Common and 21-Common (by the PTOs/Schedule 20A Service Providers-ER23-1785); comment deadline ***May 22, 2022*** |
| * | 16 | CNRIS Time-Out Rules Removal (ER23-1581) | Apr 11-27 | Constellation, RI Energy, National Grid, Glenvale intervene |
| | | | Apr 27 | AEU and RENEW filed comments supporting Rules removal |

## V. Financial Assurance/Billing Policy Amendments

*No Activities to Report*

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

| | | | | |
|---|---|---|---|---|
| | 17 | Schedule 21-NEP: NEP/Dichotomy Collins Hydro SGIA (ER23-888) | Apr 14 | NEP submits deficiency letter response; comment deadline ***May 5, 2023*** |
| | 18 | Schedule 21-VP: Revised 2021 Annual Update Settlement Agreement (ER20-2119-002) | May 1 | FERC approves Revised 2021 Annual Update Settlement Agreement |
| | 18 | Schedule 21-VP: Revised 2020 Annual Update Settlement Agreement (ER15-1434-006) | May 1 | FERC approves Revised 2020 Annual Update Settlement Agreement |
| * | 18 | Schedule 21-VEC and 20-VEC: Annual Informational Filing (ER10-1181) | Apr 28 | VEC submits its annual update to its Schedule 21-VEC and 20-VEC formula rates covering the Jul 1, 2023 – Jun 30, 2024 period |

## VII. NEPOOL Agreement/Participants Agreement Amendments

*No Activities to Report*

## VIII. Regional Reports

| | | | | |
|---|---|---|---|---|
| * | 18 | RTO/ISO Common Performance Metrics (AD19-16) | Apr 24 | ISO-NE files FERC Form 922 for 2019-2022 |
| * | 19 | LFTR Implementation Quarterly Status Reports (ER07-476) | Apr 14 | ISO-NE files its 58th quarterly report |
| * | 19 | ISO-NE 2022 FERC Form 582 (not docketed) | Apr 20 | ISO-NE submits 2022 annual report of total MWh of transmission service (approx. 1.25 million MWhs) (roughly 1.1 million MWh more than 2021) |
| * | 19 | ISO-NE 2022 Q4 FERC Form 3Q (not docketed) | Apr 14 | ISO-NE submits its 2022 Q4 FERC Form 3Q |

## IX. Membership Filings

| | | | | |
|---|---|---|---|---|
| * | 19 | May 2023 Membership Filing (ER23-1768) | Apr 28 | ***New Members***: Carbon Solutions Group, PPL TransLink, Second Foundation US Trading<br>***Terminations***: EnPowered, Invenia, Uniper, WATTIFI;<br>***Name Changes***: RWE Clean Energy Wholesale Services; RWE Clean Energy Asset Holdings; RWE Clean Energy Solutions; and SYSO Inc.; comment deadline ***May 19, 2023*** |
| * | 19 | Membership - NTE CT Involuntary Termination (ER23-1689) | Apr 21 | NEPOOL and ISO-NE request the involuntary termination of the Participant status of NTE Connecticut, LLC, effective Jun 22, 2023; comments due by May 12, 2023 |
| | 19 | Mar 2023 Membership Filing (ER23-1197) | Apr 27 | FERC accepts (i) ***the membership*** of Calpine Community Energy; (ii) ***the termination of the Participant status*** of Clean Choice Energy; InBalance; and Stored Solar J&WE; and (iii) ***the name change*** of Interstate Gas Supply, LLC (f/k/a Interstate Gas Supply, Inc.) |
| * | 20 | Suspension Notice – Rivercrest Power-SOUTH (not docketed) | Apr 14 | ISO-NE files notice of Apr 12 suspension of Rivercrest Power-SOUTH from the New England Markets |

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

| | | | | |
|---|---|---|---|---|
| | 20 | Revised Reliability Standard: PRC-002-4 (RD23-4) | Apr 14 | FERC approves PRC-002-4 (Disturbance Monitoring and Reporting Requirements) |
| | 20 | NERC Report on Evaluation of Physical Reliability Standard (CIP-014) (RD23-3) | Apr 14 | NERC files evaluation report; comment deadline ***May 15, 2023*** |
| | 21 | Revised Rel. Standards: EOP-011-3 and EOP-012-1 (RD23-1) | Apr 20 | FERC issues *Cold Weather Standards Allegheny Order* |

## XI. Misc. - of Regional Interest

| | | | | |
|---|---|---|---|---|
| * | 24 | 203 Application: Energy Harbor / Vistra (EC23-74) | Apr 17<br><br>Apr 18-24 | Energy Harbor and Vistra seek FERC authorization to become indirect subsidiaries of Vistra Vision; comment deadline ***June 16, 2023***<br>PJM IMM, NOPEC, Public Citizen intervene |
| | 24 | 203 Application: Saddleback / CPV (EC23-52) | Apr 6 | CPV acquires Saddleback, with Spruce Mountain Wind becoming a Related Person to CPV Towantic |
| | 25 | 203 Application: Salem Harbor / Castleton Commodities (EC23-50) | Apr 25 | Castleton Commodities acquires 88.4% of the units of Salem Harbor Holdco, making CCI and Salem Harbor Related Persons |
| | 25 | 203 Application: Agilitas Companies / AB CarVal Funds (EC23-30) | Apr 6 | AB Carval Funds notifies FERC that the transaction authorized by the FERC was consummated on Mar 29, 2023 |
| * | 25 | D&E Agreement: NSTAR / Vineyard Wind (ER23-1665) | Apr 20 | NSTAR files amended D&E Agreement;<br>comment deadline ***May 11, 2023*** |
| * | 25 | NSTAR / Commonwealth Wind D&E Agreement (ER23-1607) | Apr 11 | NSTAR files D&E Agreement with Commonwealth Wind |
| * | 26 | NSTAR / Ocean State Power RFA Termination (ER23-1606) | Apr 11 | NSTAR files to terminate, as unnecessary, the RFA between itself and Ocean State Power |
| * | 26 | LGIA: RIE / ISO-NE / Various Entities (ER23-1748, ER23-1741, ER23-1767) | Apr 28 | RIE and ISO-NE file three revised LGIAs to reflect RIE as the new Interconnecting Transmission Owner; comment deadline ***May 19, 2023*** |
| | 27 | National Grid/ GRH SGIA (ER23-1152) | Apr 20 | FERC accepts SGIA, eff. Jan 30, 2023 |

| | | | |
|---|---|---|---|
| 27 | LSAs: RI Energy/ISO-NE/BIPCO (ER23-1000; ER23-1003) | May 1 | ISO-NE and RI Energy file (i) response to Mar 31, 2023 deficiency letter issued in ER23-1003 and (ii) compliance filing directed in order accepting LSA in ER23-1003; comment deadline ***May 22, 2023*** |

## XII. Misc. - Administrative & Rulemaking Proceedings

| | | | |
|---|---|---|---|
| 29 | Second New England Winter Gas-Electric Forum (AD22-9) | Apr 13 | FERC issues supplement notice of a 2nd New England Winter Gas-Electric Forum to be held ***June 20, 2023*** in Portland, Maine; panelist self-nominations due ***May 19, 2023*** |
| 29 | Transmission Planning & Cost Management Tech. Conf. (AD22-8) | Apr 18, 24 | PJM IMM and the ITC Companies file reply comments |
| 30 | Joint Federal-State Task Force on Electric Transmission (AD21-15) | Apr 18<br>Apr 24<br>Apr 19 | PJM IMM files comments<br>ITC Companies file reply comments<br>FERC issues notice that 7th JFSTF meeting will be held ***Sunday, Jul 16, 2023*** in Austin, TX |
| 32 | *Order 893*: Incentives for Advanced Cybersecurity Investment (RM22-19) | Apr 21 | FERC issues *Order 893*, eff. Jul 3, 2023 |
| 32 | NOPR: Interconnection Reforms (RM22-14) | Apr 26 | Senator J. Barrasso, a ranking member of the Senate's Committee on Energy and Natural Resources, asks for FERC responses to a series of questions |
| 35 | NOPR: Transmission Siting (RM22-7) | Apr 17-18 | Comments filed by American Chemistry Council, Arizona Game and Fish Department, ELCON, Land Trust Alliance, and Nansemond Indian Nation; comment deadline ***May 17, 2023*** |

## XIII. FERC Enforcement Proceedings

*No Activity to Report*

## XIV. Natural Gas Proceedings

*No Activity to Report*

## XV. State Proceedings & Federal Legislative Proceedings

| | | | |
|---|---|---|---|
| 40 | Maine - NECEC Transmission LLC et al. v. Bureau of Parks and Lands et al. (BCD-21-416) | Apr 20 | Jury rules 9-0 that developers had completed enough work in good faith before the passage of the ballot question to have a constitutional right to proceed with construction of the NECEC Project |

## XVI. Federal Courts

| | | | |
|---|---|---|---|
| * 40 | Seabrook Dispute Order (23-1094) | Apr 4<br>Apr 6<br>Apr 17 | NextEra files Petition for Review<br>Clerk issues order directing filing of initial submissions<br>Avangrid and NECEC Transmission file motion to intervene |
| 41 | Mystic II (ROE & True-Up) (21-1198 et al.) (consol.) | Apr 24 | Constellation proposes continued abeyance for an additional 90 days |
| 44 | Algonquin Atlantic Bridge Project Orders (22-1146, 22-1147) (consol.) | Apr 20 | Oral argument held before Judges Srinivasan, Millett and Tatel |

**M E M O R A N D U M**

**TO:** NEPOOL Participants Committee Members and Alternates

**FROM:** Patrick M. Gerity, NEPOOL Counsel

**DATE:** May 3, 2023

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

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"),[1] state regulatory commissions, and the Federal Courts and legislatures through May 3, 2023. If you have questions, please contact us.

## I. Complaints/Section 206 Proceedings

- **RENEW Network Upgrades O&M Cost Allocation Complaint (EL23-16)**

The December 13, 2022 complaint by RENEW Northeast, Inc. ("RENEW") against ISO-NE and the Participating Transmission Owners ("PTOs"), which seeks changes to the ISO-NE Tariff (Schedules 11 and 21) that would eliminate the direct assignment of Network Upgrade Operations and Maintenance ("O&M") costs to Interconnection Customers,[2] is pending before the FERC. As previously reported, the proposed revisions to Schedule 11 of the Tariff were voted by the Transmission Committee at its October 26, 2021 meeting, and were discussed at the Participants Committee November 3, 2021 meeting. RENEW asked the FERC to issue an order granting the Complaint by April 14, 2023 (approximately 60 days prior to the June 15, 2023 deadline for the NE PTOs to publish a draft of the Annual Update to the data used in the transmission formula rate).

Following a request by the PTO AC for a 20-day extension of time to submit comments, supported by NEPOOL, the Massachusetts Attorney General's Office ("MA AG") and NESCOE, and granted by the FERC on December 22, 2022, comments were due on or before January 23, 2023. On January 19, 2023, ISO-NE moved to dismiss itself as a party or, in the alternative, answer the Complaint ("ISO-NE Jan 19 Motion"). On January 23, responses, comments and protests were filed by the PTO AC, NEPOOL, AEU/Clean Energy Council, CPV Towantic, Glenvale, MA AG, NECOS, NEPGA, and NESCOE. Doc-less interventions only were filed by Calpine, CMMEC, EMI, Eversource, Narragansett ("RI Energy"), National Grid, New Leaf Energy, NextEra, NRG, Versant, CT DEEP, MA DPU, the American Clean Power Association ("ACPA"), Solar Energy Industries Association ("SEIA"), and Public Citizen.

Since the last Report, RENEW answered ISO-NE's Jan 19 Motion. On February 7, 2023, RENEW, the PTO AC, and National Grid filed answers to the January 23 protests/comments. On February 16, 2023, ISO-NE answered RENEW's February 7 answer. On February 22, 2023, CPV Towantic, Glenvale, and the MA AG filed answers to the February 7 answers. This matter is pending before the FERC. If you have questions on this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

[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] RENEW also requested (i) that it be considered an Interested Party or afforded adequate opportunity to participate and access transmission rate information under the PTOs' Formula Rate Protocols and (ii) the PTOs be directed to provide greater transparency regarding O&M costs in the interconnection process.

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

On July 28, 2022, the FERC instituted a Section 206 proceeding finding that the existing tariffs of certain ISO/RTOs, including the ISO-NE Tariff, appear to be unjust and unreasonable.[3] The FERC found that ISO-NE's Tariff appears to be unjust and unreasonable in the absence of volumetric minimum collateral requirements for FTR Market Participants ("volumetric FTR collateral requirements"). Accordingly, ISO-NE was directed, on or before October 26, 2022, to either: (1) show cause as to why the Tariff remains just and reasonable and not unduly discriminatory or preferential; or (2) explain what changes to the Tariff it believes would remedy the identified concerns if the FERC were to determine that the Tariff has in fact become unjust and unreasonable or unduly discriminatory or preferential.[4] As noted below, ISO-NE answered by explaining why it believes its existing Tariff provisions to be just and reasonable and changes not necessary.

By way of background, the *FTR Collateral Show Cause Order* follows PJM's *Green Hat* experience,[5] a 2019 request by the Energy Trading Institute requesting a FERC-convened technical conference to consider a potential rulemaking to improve ISO/RTO credit practices,[6] and a two-day technical conference in February 2021 that discussed principles and best practices for credit risk management in organized wholesale electric markets.[7] In the *FTR Collateral Show Cause Order*, the FERC stated that, although the record developed through the technical conference highlighted numerous different approaches to managing credit risk, "we believe that two specific practices may be particularly critical to effectively managing credit risk for FTRs: the use of a mark-to-auction mechanism and a volumetric minimum collateral requirement for FTRs."[8] ISO-NE currently employs a mark-to-auction mechanism but not volumetric FTR collateral requirements.

The FERC issued on July 28, 2022, a notice of this proceeding and of the refund effective date, August 3, 2022.[9] Those interested in participating in this proceeding were required to intervene on or before August 18, 2022. Doc-less interventions were filed by NEPOOL, Calpine, DC Energy, NRG, the Maine Public Utilities Commission ("MPUC"), Electric Power Supply Association ("EPSA"), PJM, SPP, Public Citizen, and Financial Marketers Coalition[10] (out-of-time).

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

[4] *Id.* at P 31.

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

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

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

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

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

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

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

If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

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

Still pending before the FERC is the FERC-instituted FPA Section 206 proceeding under which the FERC is considering whether Schedule 25 and Tariff § I.3.10 may be unjust and unreasonable.[11] As previously reported, this proceeding arises out of issues raised in the NECEC Transmission LLC ("NECEC")/Avangrid Complaint Against NextEra/Seabrook (related to the interconnection of the New England Clean Energy Connect transmission project ("NECEC Project")) summarized below (EL21-6). Specifically, the FERC identified a concern that "Schedule 25's definition of Affected Party and Tariff section I.3.10 may be unjust and unreasonable to the extent they may allow generating facilities and their components to be identified as facilities on which adverse impacts must be remedied before an elective transmission upgrade can interconnect to the ISO-NE transmission system, even though generators are not subject to the [FERC]'s open access transmission principles," and could result in upgrades identified on an Affected Party's system without any obligation for the Affected Party to construct the identified upgrades.[12]

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

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

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

[11] *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*").

[12] *Id.* at P 20.

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

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

- **NextEra / Avangrid/NECEC Dispute - ("Seabrook Complaint") (EL21-6)[14] and ("Seabrook Declaratory Order Petition") (EL21-3)[15]**

As previously reported, the FERC issued, on February 1, 2023, a single order addressing these two proceedings.[16] In the *Seabrook Dispute Order*, the FERC (i) both denied and granted in part the Seabrook Complaint; (ii) dismissed the Seabrook Declaratory Order Petition; and (iii) directed Seabrook to replace the Seabrook Station breaker pursuant to its obligations under the Seabrook LGIA and Good Utility Practice. Specifically, the FERC denied the Seabrook Complaint in part because it found that Avangrid had "not shown that Seabrook is obligated to replace the breaker due to Seabrook failing to meet certain open access obligations or because Seabrook has failed to comply with Schedule 25 of the ISO-NE Tariff".[17] However, the FERC found that, "under Seabrook's LGIA, Seabrook may not refuse to replace the breaker because it is needed for reliable operation of Seabrook Station and required by Good Utility Practice" and thus, given the specific facts and circumstances in the record, granted the Seabrook Complaint in part.[18] With respect to cost issues, the FERC agreed with Avangrid that, in this case, Seabrook should not recover opportunity costs (e.g. lost profits, lost revenues, and foregone Pay for Performance ("PFP") bonuses) or legal costs.[19] In dismissing the Declaratory Order Petition, the FERC noted that the issues raised in the Petition were addressed in the *Seabrook Dispute Order*, that additional findings were unnecessary, and thus exercised its discretion to not take action on, and to dismiss, the Petition.[20] The breaker replacement is currently expected to take place during the Fall 2024 refueling outage and the commercial operation date for the NECEC Project is December 2024.[21] Seabrook plans to file an agreement governing installation at the earlier of 30 days prior to delivery of the breaker or 120 days prior to the start of the Fall 2024 outage.[22] The FERC noted its expectation that such an agreement would resolve whatever remaining issues exist between the parties to allow replacement of the breaker to move forward during the 2024 outage, or if not, an unexecuted agreement would be filed.[23]

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[14] On Oct. 13, 2020, NECEC and Avangrid Inc. (together, "Avangrid") filed a complaint 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 and direct NextEra to immediately commence engineering, design, planning and procurement activities that are necessary for NextEra to construct the generator owned transmission upgrades during Seabrook Station's Planned 2021 Outage (the "Seabrook Complaint").

[15] On Oct. 5, 2020, NextEra Energy Seabrook, LLC ("Seabrook") filed a Petition for a Declaratory Order seeking clarity on the scope of Seabrook's "FERC-jurisdictional regulatory obligations with respect to the project ("NECEC Elective Upgrade"), and to resolve its dispute with NECEC" (the "Seabrook Declaratory Order Petition" or "Petition"). Please see prior Reports for additional procedural details related to these proceedings.

[16] *NextEra Energy Seabrook, LLC and NECEC Transmission LLC and Avangrid, Inc. v. NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC*, 182 FERC ¶ 61,044 (Feb. 1, 2023) *("Seabrook Dispute Order*"), *reh'g denied by operation of law*, *NextEra Energy Seabrook, LLC et al.*, 183 FERC ¶ 62,001 (Apr. 3, 2023) ("*Seabrook Dispute Allegheny Order*").

[17] *Id*. at P 74.

[18] *Id*.

[19] *Id.* at P 100. The FERC noted that Avangrid has agreed to pay for the direct costs of the engineering, procurement and construction of the Seabrook breaker replacement. The FERC further noted that it did not address arguments over consequential damages in light of the fact that both Seabrook and Avangrid both asserted that consequential damages were no longer a live issue.

[20] *Id.* at P 112.

[21] A&R E&P Agreement Between NextEra Energy Seabrook and NECEC Transmission at 2, NextEra Energy Seabrook, LLC, Docket No. ER22-2807-000 (filed Sep. 7, 2022).

[22] Amended E&P Agreement, Art. VI, Docket No. ER22-2807-000 (filed Sept. 7, 2022).

[23] *Id.* at P 88.

***Denied By Operation of Law: NextEra Request for Rehearing, Avangrid Request for Clarification.*** As previously reported, NextEra requested rehearing of the *Seabrook Dispute Order* on the basis that, among other things, the FERC lacked authority to require Seabrook to replace its generation breaker and to rule that Seabrook cannot recover all its costs; Avangrid similarly sought clarification of the basis for FERC's jurisdiction. On April 3, 2023, the FERC issued a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration".[24] That Notice confirmed that the 60-day period during which a petition for review of the *Seabrook Dispute Order* can be filed with an appropriate federal court was triggered when the FERC did not act on NextEra's request for rehearing of the *Seabrook Dispute Order*. The Notice also indicated that the FERC would address, as is its right, the rehearing request in a future order, and may modify or set aside its order, in whole or in part, "in such manner as it shall deem proper." The FERC also did not act on Avangrid's request for clarification which, like NextEra's request for rehearing, can be deemed denied by operation of law. The *Seabrook Dispute Order* has been appealed to the DC Circuit (*see* Section XVI below), with further developments to be reported in that Section.

If you have any questions concerning these matters, 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,[25] set the TOs' Base ROE at 10.57% (reduced from 11.14%), capped the TOs' total ROE (Base ROE *plus* transmission incentive adders) at 11.74%, and required implementation effective as of October 16, 2014 (the date of *Opinion 531-A*).[26] However, the FERC's orders were challenged, and in *Emera Maine,*[27] 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)[28] and third (EL14-86)[29] ROE complaint proceedings were consolidated for purposes of hearing and

[24] *NextEra Energy Seabrook, LLC et al.*, 183 FERC ¶ 62,001 (Apr. 3, 2023) ("*Seabrook Dispute Allegheny Order*").

[25] 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*")).

[26] *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*").

[27] *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).

[28] 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%.

[29] 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.

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.[30] 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[31] also went to hearing before an Administrative Law Judge ("ALJ"), Judge Glazer, who issued his initial decision on March 27, 2017.[32] 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.[33] Parties in this proceeding filed briefs on exception to the FERC, which has not yet issued an opinion on the *Base ROE IV Initial Decision*.

***October 16, 2018 Order Proposing Methodology for Addressing ROE Issues Remanded in Emera Maine and Directing Briefs***. On October 16, 2018, the FERC, addressing the issues that were remanded in *Emera Maine,* proposed a new methodology for determining whether an existing ROE remains just and reasonable.[34] 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*[35] (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.[36]

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

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[30] *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*").

[31] 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.

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

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

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

[35] *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*.

[36] *Id.* at P 19.

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

The FERC directed participants in the four proceedings to submit briefs regarding the proposed approaches to the FPA section 206 inquiry and how to apply them to the complaints (separate briefs for each proceeding). Additional financial data or evidence concerning economic conditions in any proceeding must relate to periods before the conclusion of the hearings in the relevant complaint proceeding. Following a FERC notice granting a request by the TOs and Customers[38] 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*[39] 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).

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[37] *Id.* at P 59.

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

[39] *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).

## II. Rate, ICR, FCA, Cost Recovery Filings

- **BHD Regulatory Asset - Establishment & Recovery Through Rates (ER23-1598)**

On April 7, 2023, Versant Power requested authorization to (i) establish a regulatory asset for the Bangor Hydro District ("BHD") totaling $15,622,081 in capitalized regulatory overhead costs (identified in a recent FERC audit as incorrectly allocated as construction costs) as of January 1, 2024, and amortize this asset over a period of 16 years on a straight-line basis beginning January 1, 2024, subject to FERC approval; and (ii) recover as an expense in transmission rates under the ISO-NE OATT a return of the unamortized balance of the regulatory asset effective January 1, 2026 and continuing for 16 years. Comments on Versant's request were due on or before April 28, 2023. On May 3, the Maine Public Utilities Commission ("MPUC") moved to intervene out-of-time and protest. In its protest, the MPUC and requests that Versant be required to refund retail customers for the improper collection of "Allocation of Overhead Costs to Construction Work in Progress" and to provide additional detail regarding the amounts included. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

On March 21, 2023, ISO-NE filed the results of the seventeenth FCA ("FCA17") held March 6, 2023 for the June 1, 2026 - May 31, 2027 Capacity Commitment Period ("CCP"). ISO-NE reported the following highlights:

- FCA17 Capacity Zones were 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 Southeastern Massachusetts, Rhode Island, Northeastern Massachusetts/Boston, Connecticut and Western/Central Massachusetts Load Zones). NNE was modeled as an export-constrained Capacity Zone. The Maine Load Zone was modeled as a separate nested export-constrained Capacity Zone within NNE.
- FCA17 commenced with a starting price of $12.76/kW-mo. and concluded for all Capacity Zones after four rounds.
- Capacity Clearing Prices were as follows (prices expressed per kw-mo.): All Capacity Zones - $2.59; imports over the NY AC Ties (390 MW); and imports over the New Brunswick external interface (177 MW) - $2.55.[40]
- 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.

ISO-NE asked the FERC to accept the FCA17 rates and results, effective July 19, 2023. Comments on this filing are due on or before ***May 5, 2023***. Thus far, NEPOOL, Calpine, Constellation, Dominion, National Grid, NESCOE, EPSA, No Coal No Gas, and Public Citizen have filed doc-less interventions. No Coal No Gas submitted comments on May 3. Individual comments have been filed by more than 70 citizens (generally critical of process that permits continued assignment of Capacity Supply Obligations to fossil-fueled resources). 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).

[40] The HQ Highgate external interface and Phase I/II HQ Excess external interface were priced at $2.59, with no imports receiving a Capacity Supply Obligation over either interface.

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

As previously reported, Dynegy Marketing and Trade, LLC ("Dynegy") requested in a March 6, 2023 filing, and pursuant to § 15 of Appendix A to Market Rule 1, that the FERC authorize the recovery of $903,400 in unrecovered costs incurred by Dynegy because its Resources were subject to General Threshold Energy Mitigation on December 24, 2022. Specifically, Dynegy requested (i) $903,400 in under-recovered fuel and variable operating and maintenance costs consistent with calculations set forth in ISO-NE IMMU's Report and (ii) reasonable, related regulatory costs ($62,000 plus any further regulatory costs to be identified in a compliance filing).

Comments on this filing were due, after an extension of time requested by Public Citizen, Maine Office of the Public Advocate ("ME OPA"), and MA AG, and subsequently granted by the FERC, on or before April 4, 2023. That day, NEPGA filed comments supporting Dynegy's request; ME OPA and MA AG and the Connecticut Office of Consumer Counsel ("CT OCC") jointly protested Dynegy's request. The protests generally asserted that Dynegy did not demonstrate that its request for recovery associated with Upward Mitigation was consistent with or required by the Market Rules (recovery, which they assert, is limited to fuel and variable operating and maintenance costs of a Resource for the hours during which a supply offer was capped). Should the FERC grant Dynegy's cost recovery request, however, they suggested that the FERC utilize the Day-Ahead Real-Time approach described in the proceeding as the basis to calculate any cost recovery. Dynegy answered the ME OPA and MA AG/CT OCC protests on April 21, 2023. Doc-less interventions only were filed by NEPOOL, ISO-NE, National Grid, CT AG, CT PURA, EPSA, and Public Citizen.

This matter is now pending before the FERC. If you have any questions concerning this matter, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Mystic COS Agreement Updates to Reflect Constellation Spin Transaction[41] (ER22-1192)**

As previously reported, on May 2, 2022, the FERC accepted and suspended in part Constellation Mystic Power, LLC's ("Mystic's") changes to its Amended and Restated Cost-of-Service Agreement ("COSA") to reflect Mystic's current upstream ownership.[42] The changes were accepted effective as of June 1, 2022, but subject to refund and to the outcome of paper hearing (or settlement procedures) on the issues of capital structure and cost of debt raises issues. Mystic filed an offer of settlement on September 8, 2022 to resolve all issues set for hearing and settlement proceedings and the FERC accepted that offer of settlement on November 2, 2022,[43] directing Mystic to make a compliance filing with revised tariff records in eTariff format reflecting the FERC's action in the November 2 order. Mystic submitted that compliance filing on December 2, 2022 (ER22-1192-003). No comments were received by the December 23, 2022 comment date, and there was no activity in this proceeding since the last Report. This compliance filing remains pending before the FERC. FERC action on the compliance filing will conclude this proceeding. If you have questions on any aspect of this proceeding, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **VTransco Deferral of Retiree Lump Sum Payment Cost Recovery (ER21-2627)**

On March 17, 2023, Vermont Transco LLC ("VTransco") submitted an informational filing for lump sum payment elections taken in 2022. As previously reported, the FERC authorized VTransco to defer for future recovery costs associated with lump sum payments to employees who retire in 2021 and 2022.[44] VTransco

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

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

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

[44] *Vermont Transco LLC*, Docket No. ER21-2627 (Sep. 22, 2021) (unpublished letter order).

reported that 24 plan participants elected lump sum payments in 2022, with the lump sum payments totaling approximately $14.38 million. As a result, $2.15 million was recorded as a regulatory asset on VTransco's balance sheet and will be amortized pursuant to the FERC-approved methodology and recovered from Vermont distribution utilities under the 1991 Vermont Transmission Agreement. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

***Mystic I Remand***. As previously reported, the DC Circuit issued a decision on August 23, 2022[45] that, among other things: (i) granted State Petitioners' petitions for review on the cost allocation issue; (ii) vacated the clawback portions excluding Everett costs and the challenged delay provision of the orders under review; and (iii) remanded the cases to the FERC to address NESCOE's request for clarification about revenue credits and for clarification of the apparent contradictions in the FERC's *December 2020 Rehearing Order*.

***(-024) Mystic Request for Rehearing of Mystic I Order on Remand.*** On April 27, 2023, Mystic requested rehearing and/or clarification of the March 28, 2023 *Mystic I Order on Remand*.[46] Mystic asserted that (a) the FERC should have considered and rejected NESCOE's arguments about "truing up" and challenging the Revenue Credit; (b) the Tank Congestion Charge and the calculation of the Forward Sales Margin credited to Mystic and its ratepayers should not be included in the true-up process; and (c) if the FERC does not grant rehearing on (a) or (b), in the alternative, it should clarify that the scope of review during the true-up for Revenue Credits and the Forward Sale Margin Shared with Mystic is not a prudence review and does not require disclosure of granular, unmasked transaction data. Mystic's request for rehearing is still pending, with FERC action required on or before ***May 26, 2023***, or Mystic's request will be deemed denied by operation of law.

***(-023) 30-Day Compliance Filing (Revised COSA).*** As directed in the *Mystic I Order on Remand*, Mystic filed, on April 27, 2023, an amended COSA to reinstate the previous revenue sharing mechanism. An effective date of June 1, 2022 was requested. Comments on the 30-Day Compliance Filing are due on or before ***May 18, 2023.***

***(-022) First CapEx Info. Filing Settlement Agreement Interim Rate Implementation***. As previously reported, on March 27, 2023, Acting Chief ALJ Satten granted Mystic's request to implement the settlement rates on an interim basis, effective as of June 1, 2022. The interim rates will remain in effect pending FERC action on the First CapEx Settlement Agreement (-021).[47]

***(-021) First CapEx Info. Filing Settlement Agreement***. On March 15, 2023, Mystic filed a Settlement Agreement to resolve all issues raised by the formal challenges to its First CapEx Info. Filing[48] and set for hearing in

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

[46] *Constellation Mystic Power, LLC*, 182 FERC ¶ 61,200 (Mar. 28, 2023) ("*Mystic I Order on Remand*"), *reh'g requested*. In the *Mystic I Order on Remand*, the FERC (1) found the initial allocation of 91% of Everett's fixed operating costs to Mystic remains just and reasonable and required that the revenue sharing mechanism be reinstated in the COSA; (2) held its ruling on the clawback issue in abeyance pending resolution in the settlement proceeding; (3) found that the existing language of the COSA mitigates the incentive to unduly delay capital projects; and (4) clarified that all interested parties can review and challenge Mystic's revenue credits and tank congestion charges during a subsequent true-up process. The FERC directed Mystic to submit a 30-day compliance filing, on or before April 27, 2023, revising the COSA to reinstate the revenue sharing mechanism (*see* -023).

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

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

the April 28, 2023 Mystic *First CapEx Info. Filing Order* ("Settlement Agreement").[49] The Settling Parties asked that the FERC act on the Settlement Agreement as soon as possible, but no later than September 1, 2023. Initial comments on the Settlement Agreement were due by April 4, 2023 and filed by ENECOS, CT PURA, FERC Trial Staff, MA AG, NESCOE, and National Grid. Reply comments were filed on April 14, 2023 by Mystic and State Settling Parties.[50] The Settlement Agreement is pending before the FERC.

***(-018) Second CapEx Info Filing***. Still pending is Mystic's September 15, 2022 "Second CapEx Info Filing" to provide support for the capital expenditures and related costs that Mystic projects will be collected as an expense between January 1, 2023 to December 31, 2023 ("2023 CapEx Projects"). Formal challenges to the Second CapEx Info Filing were submitted by NESCOE and ENECOS. Comments on NESCOE's and ENECOS' challenges were due on or before November 16, 2022 and November 17, 2022, respectively. Mystic responded separately to NESCOE's and ENECOS' challenges. MMWEC/NHEC filed comments supporting ENECOS' formal challenge, emphasizing its support for formal challenge to the pass through of charges incurred by Everett for pipeline transportation reservations. On December 6, 2022, ENECOS answered Mystic's November 17, 2022 answer. Later, on December 22, 2022, Mystic filed a response to ENECOS' December 6 answer, and requested that the FERC reject the Formal Challenges, and accept the Second Filing as expeditiously as possible.

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

***(-014) Revised ROE (Sixth) Compliance Filing****.* Also still pending is Mystic's December 20, 2021 filing in response to the requirements of the *Mystic ROE Allegheny Order*.[51] The sixth compliance filing revised (i) the Cost of Common Equity figures from 9.33% to 9.19%, for both Mystic 8&9 and Everett Marine Terminal ("Everett"), and (ii) the stated Annual Fixed Revenue Requirements for both the 2022/23 and 2023/24 Capacity Commitment Periods. Comments on the sixth compliance filing were due on or before January 10, 2022; none were filed. The Sixth Compliance Filing remains pending before the FERC.

***Limited Waiver of Certain Mystic COSA True-Up Deadlines (ER23-1159)***. On March 20, 2023, the FERC granted Mystic's request for waiver of certain deadlines required by Schedule 3A of the Mystic COSA.[52] to provide Settling Parties sufficient time to implement the terms of the Settlement Agreement as part of the Mystic COSA annual true-up process.

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

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

[51] An "Allegheny Order" is a merits rehearing order issued on or after the 31st day after receipt of a rehearing request, reflecting the FERC's authority to "modify or set aside, in whole or in part," its order until it files the record on appeal with a reviewing federal court. An Allegheny Order will use "modifying the discussion" if the FERC is providing a further explanation, but is not changing the outcome, of the underlying order; or "set aside" if the FERC is changing the outcome of the underlying order. Aggrieved parties have 60 days after a deemed denial to file a review petition, even if FERC has announced its intention to issue a further merits order.

[52] *Constellation Mystic Power, LLC*, 182 FERC ¶ 61,181 (Mar. 20, 2023).

***30-Day Compliance Filing per Order on ENECOS Mystic COSA Complaint (ER23-1735)***. On April 27, 2023, Mystic filed, as directed by the FERC's March 28, 2023 *Order on ENECOS Mystic COSA Complaint*,[53] changes to the Mystic COSA to include pipeline-related crediting as an explicit provision in the COSA. Mystic also provided additional information/COSA changes to (i) describe the crediting process; (ii) differentiate, through both an explanation in its compliance filing and creation of two new line items in Schedule 3A, the credits and charges included as part of the Fixed Pipeline Costs; (iii) address how and whether the pipeline-related crediting procedure interacts or should interact with the true-up procedure already included in the COSA and revise the true-up as necessary; and (iv) differentiate in the COSA the Pipeline Transportation Costs as Fixed O&M/Return on Investment Costs from the Pipeline Transportation Agreement Costs. Comments on the 30-day compliance filing are due on or before ***May 18, 2023***.

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

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

On July 29, 2022, the PTO AC submitted its 2023 annual filing identifying adjustments to Regional Transmission Service charges, Local Service charges, and Schedule 12C Costs under Section II of the Tariff. The filing reflected the charges to be assessed under annual transmission and settlement formula rates, reflecting actual 2021 cost data, plus forecasted revenue requirements associated with projected PTF, Local Service and Schedule 12C capital additions for 2022 and 2023, as well as the Annual True-up including associated interest. As prescribed in the Interim Protocols,[54] the formula rates that will be in effect for 2023 include a billing true up of seven months of 2021 (June-December). The PTO AC stated that the annual updates result in a Pool "postage stamp" RNS Rate of $140.94 /kW-year effective January 1, 2023, a decrease of $1.84 /kW-year from the charges that went into effect on January 1, 2022. In addition, the filing included updates to the revenue requirements for Scheduling, System Control and Dispatch Services (the Schedule 1 formula rate), which result in a Schedule 1 charge of $1.75 kW-year (effective June 1, 2022 through May 31, 2023), a $0.12/kW-year decrease from the Schedule 1 charge that last went into effect on June 1, 2022. This filing was not noticed for public comment.

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

***RENEW Formal Challenge.*** On January 31, 2023, RENEW filed a formal challenge ("Challenge"). RENEW asserted that (i) the TOs failed to provide adequate rate input information in the Annual Informational Filing and in the Information Exchange Period under the Interim Formula Rate Protocols regarding inclusion or exclusion of "O&M costs" on Network Upgrades that the TOs directly assign to Interconnection Customers (and thereby failing to demonstrate that such O&M costs are not being double counted in transmission rates);

[53] *Belmont Municipal Light Dept., et al. v. Constellation Mystic Power, LLC and ISO New England, Inc.*, 182 FERC ¶ 61,199 (Mar. 28, 2023) ("*Order on ENECOS Mystic COSA Complaint*", which denied in part, and accepted in part, ENECOS' Complaint against Mystic and ISO-NE challenging the pass-through of firm pipeline transportation costs under the 2nd Amended and Restated Mystic COSA).

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

and (ii) the TO's Interpretation of "Interested Party" to exclude RENEW violated the Interim Formula Rate Protocols. RENEW thus asked that the FERC (a) require the TOs to show the calculation of the annual O&M charges with sources of data inputs and show how such O&M charges are not being double recovered in transmission rates, and (b) determine that an entity such as RENEW is an Interested Party under the Interim Formula Rate Protocols and that its Information Requests seeking rate inputs and support for the O&M charges on Network Upgrades are within the scope of the Interim Formula Rate Protocols process. Comments on RENEW's Challenge were due on or before March 16, 2023. Comments and protests were filed by: Avangrid, Eversource, National Grid, Public Systems, RI Energy, Unitil, Versant Power, VTransco/GMP. On March 31, RENEW answered the comments and protests to its Challenge. Subsequently, on April 14, Eversource answered RENEW's March 31 answer. This matter is pending before the FERC.

If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

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

On April 7, 2023, ISO-NE and NEPOOL filed proposed revisions to Appendix K to Market Rule 1 to update certain parameters within the Inventoried Energy Program ("IEP Parameter Updates"). Specifically, the IEP Parameter Updates (i) move from a fixed rate to an indexed rate, which provides for automatic adjustments to account for changes in gas markets prior to each winter period, (ii) include modifications to natural gas contracting requirements to align the IEP more closely with common industry and commercial practices and the nature of firm pipeline service available in New England; and (iii) included changes to provide clarity and improve the administration of the IEP. A June 6, 2023 effective date was requested. The IEP Parameter Updates were supported by the Participants Committee at its April 6, 2023 meeting. Comments on the IEP Parameter Updates were due by April 28, 2023. Comments supporting the Updates were filed by Indicated Suppliers.[55] Consumer Advocates[56] and Sierra Club/CLF/UCS protested the Updates (challenging the costs and basis for the IEP as updated). Doc-less motions to intervene only were filed by Calpine, Constellation, Eversource, National Grid, Public Systems,[57] and the MA DPU. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

On December 29, 2022, ISO-NE, NEPOOL and the PTO AC filed revisions to the Tariff and the TOA, in two parts, to enable electric storage facilities to be planned and operated as transmission-only assets ("SATOA") to address system needs identified in the OATT's regional system planning process ("SATOA Revisions"). The SATOA Revisions were supported by the Participants Committee at its October 6, 2022 meeting (Agenda Item #7). ISO-NE requested a FERC order by March 29, 2023 and indicated that it intends to implement the SATOA Revisions effective July 1, 2024. ISO-NE committed to submit a filing specifying the precise effective date prior to implementation. For eTariff reasons, Part I included the ISO-NE Tariff revisions (ER23-739); Part II, the TOA revisions (ER23-743). Comments on the SATOA Revisions were due on or before January 19, 2023.

On January 19, 2023, comments and protests were filed by: AEU, FirstLight, National Grid, NEPGA, NESCOE, UCS, and VELCO. Doc-less interventions only were filed by Avangrid, Vistra, MA DPU, LSP Transmission Holdings, RENEW, RI Energy, ACPA, and EPSA. On February 3, 2023, NEPOOL answered VELCO's comments and

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

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

[57] "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").

ISO-NE answered VELCO's comments and National Grid's limited protest. NEPGA answered VELCO's comments and National Grid's limited protest on February 7. In turn, on February 16, National Grid answered NEPGA's and ISO-NE's answers. ISO-NE answered National Grid's February 16 answer. This matter is pending before the FERC.

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

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

In a lengthy compliance Order[58] issued March 1, 2023, the FERC approved in part, and rejected in part, ISO-NE, NEPOOL and the PTO AC's ("Filing Parties") *Order 2222* compliance filing[59] ("*Order 2222 Compliance Order*").[60]

In the *Order 2222 Compliance Order*, the FERC directed a number of revisions and additional compliance and informational filings to be filed within 30, 60 or 180 days of the *Order 2222 Compliance Order*:

- ***30-Day Compliance Requirements (-003)***. ISO-NE was directed to submit two filings by March 31, 2023. The first, a compliance filing to explain how current Tariff capacity market mitigation rules would apply to Distributed Energy Capacity Resources ("DECR") participating in FCA18. The second, an informational filing that provides an update on implementation timeline milestones associated with DECR participation in FCA18 and the other markets. Those compliance filings were submitted on March 31, 2023. Comments on the DECR compliance filing (ER22-983-003) were due on or before April 21, 2023; none were filed. The March 31 informational filing was not noticed for public comment. The DECR compliance filing is pending before the FERC.

- ***60-Day Compliance Filing***. On or before ***May 9, 2023*** (the FERC granted NEPOOL's March 23 request to extend the 60-day compliance deadline by 8 days, to May 9)), the FERC ordered ISO-NE:
    - ♦ to revise the Tariff to: (1) have RERRA make the determination of whether to allow customers of small utilities to participate in ISO-NE's markets through aggregation; (2) require that each DER Aggregator maintain and submit aggregate settlement data for the DERA; (3) designate the DER Aggregator as the entity responsible for providing any required metering information to ISO-NE, and if necessary, establish protocols for sharing meter data that minimize costs and other burdens and address concerns raised with respect to privacy and cybersecurity; (4) designate the DER Aggregator as the entity responsible for providing any required metering information to ISO-NE; and (5) add specificity regarding existing resource non-performance penalties that would apply to a DERA when a Host Utility overrides ISO-NE dispatch instructions.

[58] Commissioners Danly and Clements each provided separate concurrences with, and Commissioner Christie provided a separate dissent from, the Compliance Order. Commissioners Danly and Christie, despite their opposing positions on the Compliance Order, both reiterated their reasons for dissenting from *Order 2222* and concern for FERC overreach and difficulty with complying with *Order 2222*. In her separate concurrence, Commissioner Clements urged the ISO on compliance to "modify its proposal to address undue barriers and make participation more workable" and "to pursue steps that genuinely open [the New England Markets] to DERs like behind-the-meter resources."

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

[60] *ISO New England Inc. and New England Power Pool Participants Comm.*, 182 FERC ¶ 61,137 (March 1, 2023).

- ♦ ISO-NE was also directed to: (1) identify the existing rules requiring a Market Participant that provides energy withdrawal service to be a load serving entity that is billed for energy withdrawal ("LSE Requirement") and explain whether the LSE Requirement is required of all resources seeking to provide wholesale energy withdrawal service in the energy market; (2) explain why its proposed metering and telemetry requirements were just and reasonable and did not pose an unnecessary and undue barrier to individual DERs joining a DERA; (3) establish protocols for sharing metering data that minimize costs and other burdens and address privacy and cybersecurity concerns; and (4) address how ISO-NE will resolve disputes that are within its authority and subject to its Tariff, regardless of whether there is an available dispute resolution process established by the RERRA.

The 60-day compliance changes, as recommended by the Markets Committee, will be considered by the Participants Committee at its May 4 meeting (Agenda Item #6).

- ***180-Day Compliance Filing***. On or before **August 28, 2023**, the FERC directed ISO-NE to file a further compliance filing explaining how the current Tariff capacity market mitigation rules would apply to DECRs participating in FCA19 and beyond.

***Requests for Rehearing and/or Clarification (-002).*** As reported in the Last Report, on March 31, 2023, ISO-NE and New England Public Utilities[61] requested rehearing and/or clarification of the *Order 2222 Compliance Order*. ***ISO-NE*** urged the FERC to reconsider allowing DECRs to participate in FCA18 and designating the DER Aggregator as the entity responsible for transmitting DERA metering data. ***New England Public Utilities*** urged the FERC to adopt the DER metering and settlement approach proposed by the Filing Parties (*Order 2222* Changes) and clarify (1) that PTOs and distribution utilities are not prohibited from requiring metering and settlement data from DERs to satisfy their obligations to perform wholesale settlement and retail customer billing and (2) that it would not be unjust and unreasonable for utilities to recover costs related to investment and expenses incurred to modify its metering, billing, settlement, cyber security and other systems, to accommodate submetering of Behind-the-Meter DER participating in the wholesale market as part of a DERA. On April 14, 2023, ***MA AG*** answered New England Public Utilities' request for rehearing and clarification and requested that the FERC address the recovery of costs necessary to implement Behind-the-Meter DER submetering and the allocation of costs to DER aggregators and program participants. On April 17, ***Advanced Energy United*** ("AEU") answered ISO-NE's request for rehearing and urged the FERC to not reconsider its decision designating the DER Aggregator as the entity responsible for transmitting DERA metering data. ISO-NE answered the AEU answer on May 2, 2023.

***Order 2222 Compliance Allegheny Order***. On May 1, 2023, the FERC issued a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration".[62] That Notice confirmed that the 60-day period during which a petition for review of the *Order 2222 Compliance Order* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing and/or clarification of the *Order 2222 Compliance Order*. The Notice also indicated that the FERC would address, as is its right, the rehearing request in a future order, and may modify or set aside its order, in whole or in part, "in such manner as it shall deem proper."

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[61] "New England Public Utilities" are: National Grid USA on behalf of Massachusetts Electric Co., Nantucket Electric Co., and New England Power Co. ("NGUSA"); Avangrid Networks, Inc. on behalf of CMP and UI ("Avangrid Networks"); and Eversource on behalf of The Connecticut Light and Power Co. ("CL&P"), Public Service Co. of New Hampshire ("PSNH"), and NSTAR Electric Co. ("NSTAR").

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

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).

- **IEP Remand (ER19-1428-006)**

On April 24, 2023, the FERC accepted ISO-NE's Tariff provisions, effective May 28, 2019,[63] governing the Inventoried Energy Program ("IEP") consistent with the D.C. Circuit's *IEP Decision*.[64] ISO-NE's proposed Tariff changes removed nuclear, biomass, coal, and hydroelectric generators from the IEP. Alternative Tariff changes proposed by Brookfield that would have explicitly allowed pumped hydro resources to participate in the IEP as Electric Storage Facilities were rejected on procedural grounds.[65] Challenges, if any, to the *IEP Remand Compliance Filing Order* are due on or before ***May 24, 2023***. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

## IV. OATT Amendments / TOAs / Coordination Agreements

- ***Order 676-J* Compliance Filings Part II (ER23-1771; ER23-1774; ER23-1782; ER23-1785)**

On May 1, 2023, in accordance with Order 676-J,[66] the following second *Order 676-J* compliance filings to incorporate, or seek waiver of, the remainder of the WEQ Version 003.3 Standards were submitted:

- Order 676-J Compliance Filing Part II (ISO-NE and NEPOOL-Tariff Schedule 24) (ER23-1771);
- Order 676-J Compliance Filing Part II (CSC-Schedule 18-Attachment Z) (ER23-1774);
- Order 676-J Compliance Filing Part II (Versant-MPD OATT) (ER23-1782); and
- Order 676-J Compliance Filing Part II (TOs'-Schedules 20A-Common and 21-Common) (ER23-1785).

Comments on the compliance filings are due on or before ***May 22, 2023***. If there are questions on any of these compliance filings, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **CNRIS Time-out Rules Removal (ER23-1581)**

On April 6, 2023, ISO-NE, NEPOOL and PTO AC (the "Filing Parties") filed revisions to the OATT to remove the Capacity Network Resource Interconnection Service ("CNRIS") time-out rules from Section 4.4 of Schedules 22 and 25 and from Section 1.5.5 of Schedule 23 for Queue Positions that have not timed-out (in whole or part) by FCA 17. Under the proposed revisions, the time-out rules will not apply to Interconnection Requests for CNRIS deemed valid after May 31, 2020 (because these resources have not yet timed out). Resources that did not acquire a CSO in FCA 17 (or in earlier FCAs) timed-out and will need to submit a new Interconnection Request to re-establish CNRIS, but, going forward for FCAs 18 and after, Interconnection Requests for CNRIS will no longer time-out if they do not acquire a CSO in the FCA. The Filing Parties requested a June 5, 2023 effective date.

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[63] *ISO New England Inc.*, 183 FERC ¶ 61,059 (Apr. 24, 2022) ("*IEP Remand Compliance Filing Order*");

[64] *Belmont Mun. Light Dept., et al., v. FERC*, 2022 WL 2182810 (June 17, 2022) (the "*IEP Decision*"). The *IEP Decision* left intact the FERC's *June 2020 IEP Remand Order* (*ISO New England Inc.*, 171 FERC ¶ 61,235 (June 18, 2020)) except for the inclusion of nuclear, biomass, coal, and hydroelectric generators in ISO-NE's IEP, the inclusion of which the Court found arbitrary and capricious (because those resources were unlikely to change their behavior in response to the IEP payments). Because the Court believed "there is not substantial doubt that FERC would have adopted IEP if it had not included these resources in the first place [and] IEP can function sensibly without them", the Court found that it had the authority to sever this portion from the overall program and therefore vacated that portion of IEP from the remainder of the IEP. The Court upheld the remainder of the IEP and remanded the matter to the FERC for further proceedings consistent with its opinion.

[65] In the *IEP Remand Compliance Filing Order*, the FERC stated that "The only question before the Commission in this proceeding is whether ISO-NE's filing complies with the directives of the September 2022 Order."

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

Comments were due by April 27, 2023 and comments in support were filed by AEU and RENEW. Constellation, National Grid, RI Energy, and Glenvale intervened doc-lessly only. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

On July 22, 2022, following a requested 10-day extension of time granted by the FERC, a Phase I/II HVDC-TF *Order 881* compliance filing was submitted in two parts ((i) changes to the HVDC TOA and (ii) changes to Schedule 20-Common Attachment M) by: ISO-NE, the Asset Owners,[67] and the Schedule 20A Service Providers.[68] Specifically, the Filing proposed changes to the ***HVDC TOA*** (ER22-2467) to address the Order 881 requirements related to transmission ratings and rating procedures and to ***Schedule 20A-Common*** (ER22-2468) to ensure compliance with Order 881 with respect to transmission rating transparency and transmission service (together, the "Phase I/II HVDC-TF *Order 881* Compliance Filing"). Comments on the Phase I/II HVDC-TF *Order 881* Compliance Filing were due on or before August 12, 2022; none were filed. The IRH Management Committee submitted a doc-less intervention. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

As previously reported, ISO-NE, NEPOOL, the PTO AC, and CSC (the "Filing Parties") filed, on July 12, 2022, proposed revisions to the OATT in response to the requirements of *Order 881*[69] ("*Order 881* Compliance Changes"). Specifically, the Filing Parties proposed the addition of a new Attachment Q to the OATT, and to revise OATT Schedules 18 (MTF; MTF Service) and 21 (Local Service - Common). The *Order 881* Compliance Changes (the Attachment Q and Schedule 18 changes) were supported by the Participants Committee at its June 21-23 Summer Meeting (Consent Agenda Item No. 2). An effective date of September 10, 2022 was requested, with changes to Attachment Q and Schedule 21 to become applicable by their own terms in July 2025. Comments on the *Order 881* Compliance Changes were due on or before August 2, 2022; none were filed. Eversource, Narragansett Electric Company ("RI Energy") and National Grid filed 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).

## V. Financial Assurance/Billing Policy Amendments

**No Activities to Report**

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

- **Schedule 21-NEP: NEP/Dichotomy Collins Hydro SGIA (ER23-888)**

As previously reported, on January 18, 2023, NEP filed a non-conforming Small Generation Interconnection Agreement ("SGIA") with Dichotomy Collins Hydro LLC ("Dichotomy") to cover the continued interconnection of Dichotomy's 1.3 MW hydroelectric (run-of-river) generating facility in Wilbraham, Massachusetts. National Grid requested a December 19, 2022 effective date for the SGIA. Initial comments

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

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

[69] *Managing Transmission Line Ratings*, Order No. 881, 177 FERC ¶ 61,179 (Dec. 16, 2021); *Managing Transmission Line Ratings*, Order No. 881-A, 179 FERC ¶ 61,125 (May 19, 2022) (together, "*Order 881*").

on this filing were due on or before February 8, 2023; none were filed. On March 17, 2023, the FERC issued a deficiency letter requesting additional information related to the QF status of the Dichotomy facility. NEP filed its deficiency letter response on April 14, 2023. Comments, if any, on the deficiency letter response are due on or before ***May 5, 2023***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-VP: Revised 2021 Annual Update Settlement Agreement (ER20-2119-002)**

On May 1, 2023, the FERC approved a revised, uncontested Joint Offer of Settlement ("Revised 2021 Annual Update Settlement") between Versant Power and the MPUC.[70] The Revised 2021 Annual Update Settlement resolves all issues regarding Versant Power's Bangor Hydro District 2021 annual update under Schedule 21-VP. Unless the May 1 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-VP: Revised 2020 Annual Update Settlement Agreement (ER15-1434-006)**

Also on May 1, 2023, the FERC approved a revised, uncontested Joint Offer of Settlement ("Revised 2020 Annual Update Settlement") between Versant and the MPUC.[71] The Revised 2020 Annual Update Settlement resolves all issues regarding Versant Power's Bangor Hydro District 2020 annual update under Schedule 21-VP. Unless this May 1 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-VEC and 20-VEC Annual Informational Filing (ER10-1181)**

On April 28, 2023, VEC submitted its 20th annual update to the formula rates contained in Schedules 21-VEC and 20-VEC covering the July 1, 2023 – June 30, 2024 period. The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

## VII. NEPOOL Agreement/Participants Agreement Amendments

*No Activities to Report*

## VIII. Regional Reports

- **RTO/ISO Common Performance Metrics (AD19-16)**

On April 24, 2023, ISO-NE submitted its FERC Form-922 (RTO/ISO Common Performance Metrics) for 2019-2022. Form 922 helps the FERC track the performance of the RTO/ISOs that it regulates via information responses related to 29 metrics organized into 3 groups: (1) Administrative and Descriptive Metrics; (2) Energy Market Metrics; and, where applicable, (3) Capacity Market Metrics. ISO-NE's submittal will not be noticed for public comment.

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

The following refund reports filed in response to *Opinions No. 531-A*[72] *and 531-B*[73] remain pending:

  - The TOs' November 2, 2015 regional refund report;

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[70] *ISO New England Inc. and Versant Power*, 183 FERC ¶ 61,080 (May 1, 2023) (approving Revised 2021 Annual Update Settlement).

[71] *ISO New England Inc. and Versant Power*, 183 FERC ¶ 61,077 (May 1, 2023) (approving Revised 2020 Annual Update Settlement).

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

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

- The TOs'[74] local refund reports; and
- Fitchburg Gas & Electric's ("FG&E") June 29, 2015 local refund report.

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

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

On April 14, 2023, ISO-NE filed its 58th quarterly status report regarding LFTR implementation. ISO-NE reported that it implemented monthly reconfiguration auctions (accepted in ER12-2122) beginning with the month of October 2019. ISO-NE further reported that, while it will continue to evaluate its as-filed LFTR design and financial assurance issues, including an ongoing evaluation of the FTR market and risk associated with FTRs and LFTRs, it is currently focused on higher priority market-design initiatives. ISO-NE concluded its report by describing the 18-month implementation that would be required once the LFTR financial assurance issues are resolved. These status reports are not noticed for public comment.

- **ISO-NE 2022 FERC Form 582 (not docketed)**

On April 20, 2023, ISO-NE submitted a report of its total MWh of transmission service during 2022. ISO-NE reported that 125,007,501 MWh of transmission service in interstate commerce was provided during 2022 (roughly 1,099,0000 MWh more than 2021 (123,908,497 MWh)). These filings are not noticed for comment.

- **ISO-NE 2022 Q4 FERC Form 3Q (not docketed)**

On April 14, 2023, ISO-NE submitted its 2022/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 public comment.

## IX. Membership Filings

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

On April 28, 2023, NEPOOL requested that the FERC accept: (i) the memberships of Carbon Solutions Group (GIS-Only Participant); PPL TransLink Inc. [Related Person to RI Energy (Transmission Sector)]; and Second Foundation US Trading, LLC (Supplier Sector); (ii) the termination of the Participant status of EnPowered USA LLC; Invenia Technical Computing Corp.; Uniper Global Commodities NA LLC; and WATTIFI INC.; and (iii) the name changes of RWE Clean Energy Wholesale Services, Inc. (f/k/a Consolidated Edison Energy, Inc.); RWE Clean Energy Asset Holdings, Inc. (f/k/a Consolidated Edison Development, Inc.); RWE Clean Energy Solutions, Inc. (f/k/a Consolidated Edison Solutions, Inc.); and SYSO Inc. (f/k/a SYSO LLC). Comments on the May membership filing are due on or before ***May 19, 2023***.

- **Involuntary Termination of Membership of NTE Connecticut, LLC (ER23-1689)**

On April 21, 2023, NEPOOL and ISO-NE jointly requested that the FERC terminate (i) the NEPOOL Participant status of NTE Connecticut, LLC ("NTE CT") and (ii) the Market Participant Service Agreement between ISO-NE and NTE CT, each as a result of the failure by NTE CT to pay when and as due the amounts invoiced to it under the Billing Policy. NEPOOL and ISO-NE requested that the termination of NTE CT's NEPOOL and Market Participant status become effective as of June 22, 2023. Comments on this filing are due on or before ***May 12, 2023***.

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

- **March 2023 Membership Filing (ER23-1197)**

On April 27, 2023, the FERC accepted[75] (i) the membership of Calpine Community Energy [Related Person to Calpine Energy Services et al. (Generation Sector)]; (ii) the termination of the Participant status of Clean Choice Energy (Supplier Sector); InBalance, Inc. (Supplier Sector); and Stored Solar J&WE, LLC (AR Sector, RG Sub-Sector); and (iii) the name change of Interstate Gas Supply, LLC (f/k/a Interstate Gas Supply, Inc.).

- **Suspension Notice (not docketed)**

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

| ***Date of Suspension/ FERC Notice*** | ***Participant Name*** | ***Default Type*** | ***Date Reinstated*** |
|---|---|---|---|
| Apr 12/14 | Rivercrest Power-SOUTH, LLC | Payment | -- |

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

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

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

- **Revised Reliability Standard: PRC-002-4 (RD23-4)**

On April 14, 2023, the FERC approved proposed changes to Reliability Standard PRC-002-4 (Disturbance Monitoring and Reporting Requirements), the associated Violation Risk Factors and Violation Severity Levels, and the proposed implementation plan, including the retirement of the currently effective Reliability Standard PRC-002-3.[76] NERC's proposed revisions: (1) clarify requirements for notifications under the Standard, including when generator owners and transmission owners must have data for an applicable transformer or transmission line; (2) clarify and make consistent terminology used in the Standard; (3) incorporate the implementation timeframe for newly-identified facilities; and (4) add a criterion defining substantial changes in fault current levels requiring changing the locations for which certain data is recorded. Challenges, if any, to the April 14 order are due on or before ***May 14, 2023***.

- **NERC Report on Evaluation of Physical Reliability Standard (CIP-014) (RD23-3)**

As directed by the FERC's December 15, 2022 order,[77] NERC, on April 14, 2023, provided an updated evaluation of CIP-014 (its "Physical Security Reliability Standard"). NERC concluded that CIP-014 applicability criteria is meeting its objective to "appropriately focus[] limited industry resources on risks to the reliable operation of the BPS associated with physical security incidents at the most critical facilities" and the objective is broad enough to capture the subset of applicable facilities that TOs should identify as "critical" pursuant to the risks assessment mandated by Requirement R1. NERC did not find evidence that an expansion of the applicability criteria would identify additional substations that would qualify as "critical" substations under the CIP-014 Requirement R1 risk assessment, declined to recommend expansion of the CIP-014 applicability criteria, but committed to continued evaluation of the adequacy of the applicability criteria in meeting the objective of CIP-014. Comments on NERC's report are due on or before ***May 15, 2023***.

[75] *New England Power Pool Participants Comm.,* Docket No. ER23-1197-000 (Apr. 27, 2023).

[76] *N. Amer. Elec. Rel. Corp.*, Docket No. RD23-4-000 (Apr. 14, 2023) (unpublished letter order).

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

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

On February 16, 2023, the FERC approved NERC's changes to Reliability Standards EOP-011-3 (Emergency Operations) and EOP-012-1 (Extreme Cold Weather Preparedness and Operations) (the "*Cold Weather Standards*").[78] As previously reported, the changes to the *Cold Weather Standards*, which address certain key recommendations from the *Feb 2021 Cold Weather Outages Joint Report,*[79] establish a more comprehensive framework of requirements addressing generator preparedness for cold weather operations. The *Cold Weather Standards* also address the use of manual load shed during Emergency conditions, requiring Transmission Operators to take steps to minimize the use of manual load shed that could further exacerbate Emergency conditions and threaten system reliability.

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

♦ to ensure that it captures all bulk electric system generation resources needed for reliable operation and excludes only those generation resources not relied upon during freezing conditions by clarifying "the language of the applicability section to align with NERC's explanation of the entities that should already be preparing to comply with the Standard, and should not need additional implementation time";[80]

♦ Requirements R1 and R7, to address concerns related to the ambiguity of generator-defined declarations of technical, commercial, or operational constraints that exempt a generator owner from implementing the appropriate freeze protection measures by including "objective criteria on permissible technical, commercial, and operational constraints, to identify the appropriate entity that would receive the generator owners' constraint declarations under [] Requirements R1 and R7, to describe how that entity would confirm that the generator owners comply with the objective criteria, and to describe the consequences of providing a constraint declaration," ensuring that "declarations cannot be used to opt out of mandatory compliance with the Standard or obligations set forth in a corrective action plan";[81]

♦ to clarify R1 to ensure that generators that are technically incapable of operating for 12 continuous hours (e.g., solar facilities during winter months with less than 12 hours of sunlight) are not excluded from complying with the Standard;[82]

♦ to increase the length of R2's continuous operations requirement (one hour being too short);[83]

♦ to include in R7 deadlines for implementation completion of corrective action plans, as recommended in the *November 2021 Report*;[84]

♦ to shorten the implementation plan for existing generating units, staggering the implementation for existing unit(s) in a generator owner's fleet;[85] and

♦ to work with FERC staff to submit a plan no later than February 16, 2024 explaining how it will collect and assess data prior to and after the implementation of the following elements of EOP-012-1: (1) generator owner declared constraints and explanations thereof; and (2) the adequacy of the Extreme Cold Weather Temperature definition.[86]

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

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

[80] *Id.* at P 4.

[81] *Id.* at P 6.

[82] *Id.* at P 7.

[83] *Id.* at P 8.

[84] *Id.* at P 9.

[85] *Id.* at P 10.

[86] *Id.* at P 11.

The FERC deferred its decision on whether to approve or modify NERC's proposed implementation date for EOP-011-3 (and proposed retirement of EOP-011-2) until NERC submits its revised applicability section for EOP-012. The FERC stated that "allowing EOP-011-2 requirements to remain mandatory and enforceable until such time as the revised applicability is effective for EOP-012 will ensure all bulk electric system generating units are required to maintain cold weather preparedness plans."[87]

***Request for Rehearing Denied by Operation of Law***. On March 20, 2023, EPSA, NEPGA and the PJM Power Providers Group ("P3") filed a joint request for rehearing. The petitioners allege that, by approving the *Cold Weather Standards* without addressing how generators can recover the costs associated with complying with EOP-012-1, the FERC "breached its duty to ensure that proposed reliability standards are 'just' and 'reasonable' … and failed to engage in reasoned decision-making." On April 20, 2023, the FERC issued a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration".[88] That Notice confirmed that the 60-day period during which a petition for review of the *Cold Weather Standards Order* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing and/or clarification of the *Cold Weather Standards Order*. The Notice also indicated that the FERC would address, as is its right, the rehearing request in a future order, and may modify or set aside its order, in whole or in part, "in such manner as it shall deem proper."

- **Inverter-Based Resource Registration (RD22-4)**

On November 17, 2022, to address FERC concerns regarding the reliability impacts of inverter-based resources ("IBRs")[89] on the Bulk-Power System ("BPS"), the FERC issued an order[90] directing NERC to submit a work plan on or before February 15, 2023 describing how it plans to identify and register owners and operators of IBRs that are connected to the BPS, but that are not currently required to register with NERC under the bulk electric system ("BES") definition ("unregistered IBRs"), and that "have an aggregate, material impact on the reliable operation of the [BPS]". FERC stated that the work plan should explain how NERC will modify its processes to address unregistered IBRs within 12 months of approval of the work plan. The work plan must also include implementation milestones ensuring that owners and operators meeting the new registration criteria are identified within 24 months of the approval date of the work plan, and that they are registered and required to comply with applicable Reliability Standards within 36 months of the approval date of the work plan. The FERC will notice the work plan for public comment. Once approved, NERC must file progress reports every 90 days thereafter detailing the progress towards identifying and registering owners and operators of unregistered IBRs.

On February 16, 2023, NERC filed its IBR Work plan, which outlined NERC's proposed approach to identify and register owners and operators of IBRs within 36 months of FERC approval of the Work Plan. Comments on the IBR Work Plan were due on or before March 20, 2023. Comments were filed by ACPA, APPA, NRECA, Arizona Public Service Co., and Pine Gate Renewables. 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. NERC submitted its most recent informational filing regarding one active CIP standard

87 *Id.* at P 5.

88 *N. Am. Elec. Rel. Corp.*, 183 FERC ¶ 62,034 (Apr. 20, 2023) ("*Cold Weather Standards Allegheny Order*").

89 IBRs include all generating facilities that connect to the BPS using power electronic devices that change direct current ("DC") power produced by a resource to alternating current ("AC") power compatible with distribution and transmission systems. IBRs connected to the distribution system are not addressed in the *IBR Registration Order*.

90 *Registration of Inverter-based Resources*, 181 FERC 61,124 (Nov. 17, 2022) ("*IBR Registration Order*").

development project (Project 2016-02 – Modifications to CIP Standards ("Project 2016-02"))[91] on March 15, 2023. Project 2016-02 focuses on modifications to the CIP Reliability Standards to incorporate applicable protections for virtualized environments. In the March 15 report, NERC reported that, because ballot body approval was again not achieved for two related Reliability Standards, the schedule for Project 2016-02 has been further revised and now calls for final balloting of revised standards in May 2023, NERC Board of Trustees Adoption in August 2023 and filing of the revised standards with the FERC in September 2023.

- **NOPR: IBR Reliability Standards (RM22-12)**

On November 17, 2022, the FERC issued a notice[92] proposing to direct NERC (i) to develop new or modified Reliability Standards that address the following reliability gaps related to inverter-based resources ("IBR"): data sharing; model validation; planning and operational studies; and performance requirements; and (ii) to submit a 90-day compliance filing that includes a detailed, comprehensive standards development and implementation plan to ensure all new or modified Reliability Standards necessary to address the IBR-related reliability gaps identified in the final rule are submitted to the FERC within 36 months of FERC approval of the plan. Initial comments were due February 6, 2023[93] and were filed by nearly 20 parties, including, among others, ISO-NE, the IRC, SPP, CAISO, Advanced Energy United, ACPA/SEIA, EEI, and EPRI. Reply comments were due on March 6, 2023 and were filed by ISO-NE, APPA, and CA DWP. This matter is pending before the FERC.

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

On June 16, 2022, the FERC issued a notice[94] proposing to require that NERC modify Reliability Standard TPL-001-5.1 (Transmission System Planning Performance Requirements) within one year of the effective date of a final rule in this proceeding to address reliability concerns pertaining to transmission system planning for extreme heat and cold weather events that impact the reliable operations of the Bulk-Power System. Specifically, the FERC proposed modifications to TPL-001-5.1 to require: (i) development of benchmark planning cases; (ii) planning for extreme heat and cold events using steady state and transient stability analyses expanded to cover a range of extreme weather scenarios; and (iii) corrective action plans that include mitigation for any instances where performance requirements for extreme heat and cold events are not met. Initial comments were due August 26, 2022[95] and were filed by over 37 parties, including, among others, ISO-NE, Eversource, NESCOE, NRDC, UCS, NERC, ERCOT, MISO, NYISO, PJM, ACPA, EPRI, EPSA, NARUC, and Trade Associations. This matter is pending before the FERC.

- ***Order 887*: Internal Network Security Monitoring for High and Medium Impact BES Cyber Systems (RM22-3)**

One year after the FERC issued its *Internal Network Security Monitoring NOPR,*[96] the FERC issued *Order 887*.[97] *Order 887* directs NERC to develop and submit, on or before July 10, 2024[98] for FERC approval, new or

[91] 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.

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

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

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

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

[96] *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*").

[97] *Internal Network Security Monitoring for High and Medium Impact Bulk Electric System Cyber Systems*, Order No. 887, 182 FERC ¶ 61,021 (Jan. 19, 2023) ("*Order 887*").

[98] *Order 887* was published in the *Fed. Reg.* on Feb. 9, 2023 (Vol. 88, No. 27) pp. 8,354-8,368.

modified Reliability Standards that require internal network security monitoring ("INSM")[99] within a trusted Critical Infrastructure Protection ("CIP") networked environment for all high impact bulk electric system ("BES") Cyber Systems with and without external routable connectivity and medium impact BES Cyber Systems with external routable connectivity. In addition, the FERC directed NERC to perform a study of all low impact BES Cyber Systems with and without external routable connectivity and medium impact BES Cyber Systems without external routable connectivity, and to submit its study report to the FERC on or before January 19, 2024. *Order 887* will become effective April 10, 2023.

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

As previously reported, the FERC accepted, subject to a 60-day compliance filing, NERC's proposed Business Plan and Budget, as well as the Business Plans and Budgets for the Regional Entities, including NPCC, for 2023.[100] In accepting NERC's Business Plan/Budget Filing, the FERC agreed with EEI that additional transparency into certain Electricity Information Sharing and Analysis Center ("E-ISAC") costs would better allow the FERC to fulfill its oversight duties, and thus directed NERC to submit a compliance filing providing additional information related to E-ISAC costs, the E-ISAC vendor affiliate program, and the E-ISAC and natural gas stakeholder partnership. That compliance filing was due, and was filed, on January 3, 2023. Comments on the January 3 compliance filing were due on or before January 24, 2023; none were filed. The 60-day compliance filing remains pending before the FERC.

## XI. Misc. - of Regional Interest

- **203 Application: Energy Harbor / Vistra (EC23-74)**

On April 17, 2023, Energy Harbor Corp., on behalf of Energy Harbor, LLC and Energy Harbor Nuclear Generation LLC (collectively, the "Energy Harbor Public Utilities"), and Vistra Corp. ("Vistra"), requested FERC authorization for a proposed transaction pursuant to which the Energy Harbor Public Utilities and certain Vistra subsidiaries that are public utilities will become indirectly owned by a newly-formed subsidiary holding company of Vistra – Vistra Vision. Comments on this 203 application are due on or before ***June 16, 2023***. Thus far, the following parties have filed doc-less interventions: Monitoring Analytics, LLC (the PJM Independent Market Monitor), Northeast Ohio Public Energy Council ("NOPEC") and Public Citizen. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Weaver Wind / Greenbacker (EC23-68)**

On March 27, 2023, Weaver Wind, LLC and Weaver Wind Maine Master Tenant, LLC ("Weaver Wind") requested FERC authorization for a proposed transaction pursuant to which Jade Energy LLC, a wholly-owned subsidiary of Greenbacker Renewable Energy Company, will acquire all the membership interests in Weaver Wind (upon consummation, making Weaver Wind a Related Person to Howard Wind and Hecate Energy). Comments on this 203 application were due April 17, 2023; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Saddleback / CPV (EC23-52)**

On March 23, 2023, the FERC authorized CPV Mountain Wind Holdings, LLC's ("Buyer") acquisition of all of the membership interests in Saddleback Ridge Wind, LLC ("Saddleback").[101] The transaction closed on April 6, 2023 and with the closing, Spruce Mountain Wind and CPV Towantic became Related Persons. Pursuant to the March 23 order, Saddleback must file a notice within 10 days of consummation of the transaction, which as of the

[99] 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.

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

[101] *Saddleback Ridge Wind, LLC*, 182 FERC ¶ 62,168 (Mar. 23, 2023).

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: Salem Harbor / Castleton Commodities (EC23-50)**

On April 4, 2023, the FERC authorized a proposed transaction pursuant to which CCI U.S. Asset Holdings LLC ("Castleton Commodities") will acquire at least 67%, and up to 100%, of the issued and outstanding Series A-1 Common Units and/or Series A-2 Common Units of Salem Harbor Power Holdco LLC ("Salem Harbor").[102] Pursuant to the April 4 order, Salem Harbor 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: Talen Energy Supply Reorganization (EC23-42)**

On March 30, 2023, the FERC issued an order authorizing a change in control transaction whereby 10% or more of the voting securities of a new parent of Talen Energy Supply, LLC ("TES") and its affiliated debtors will be distributed to some or all of Indicated Noteholders pursuant to a joint plan of reorganization of the TES Debtors subject to confirmation by the Bankruptcy Court.[103] If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Agilitas Companies / AB CarVal Funds (EC23-30)**

On January 24, 2023, the FERC authorized[104] a transaction pursuant to which the AB CarVal Funds[105] will convert their existing passive, non-voting ownership interest in Agilitas Energy, Inc., which indirectly owns all of the membership interests in the Agilitas Companies,[106] into 21.3% of the voting interests in Agilitas Energy. On April 6, 2023, AB CarVal Funds filed a notice informing the FERC that the transaction was consummated on March 29, 2023. Reporting on this matter has concluded. If you have any remaining questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **NSTAR / Vineyard Wind D&E Agreement (ER23-1665)**

On April 20, 2023, NSTAR Electric Company ("NSTAR") filed an amendment to the previously-approved D&E Agreement between NSTAR and Vineyard Wind LLC for civil and below-grade and above-grade electrical substation work at NSTAR's Bourne 345 kV substation.[107] The amendment seeks to extend the term of the Agreement for additional work and changes the scope of work of the D&E Agreement (i) to address the risks and impacts to milestone revisions; (ii) to address the impact of higher rating of certain Direct Assigned Facilities; and (iii) to conduct harmonic study and data collection. An April 21, 2023 effective date was requested. Comments on this filing are due on or before ***May 11, 2023***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **NSTAR / Commonwealth Wind D&E Agreement (ER23-1607)**

On April 11, 2023, NSTAR filed a Design & Engineering Agreement setting forth the terms and conditions under which NSTAR will perform necessary engineering and design services for the interconnection of Commonwealth Wind, LLC's large generating facility to the Administered Transmission System. An effective date of April 12, 2023 was requested. Comments on this filing were due on May 2, 2023; none were filed. This matter

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[102] *Salem Harbor Power Development LP*, 183 FERC ¶ 62,005 (Apr. 4, 2023).

[103] *Talen Energy Supply, LLC*, 182 FERC ¶ 62,183 (Mar. 30, 2023).

[104] *Madison BTM, LLC et al.*, 182 FERC ¶ 62,048 (Jan. 24, 2023).

[105] The "AB CarVal Funds" are CEF Master Fund IV LP, CVI CEF II Pooling Fund IV LP, and CVI CSF Master Fund II LP.

[106] For purposes of this proceeding, "Agilitas Companies" are: Madison BTM LLC; Madison ESS, LLC; Rumford ESS, LLC; South Portland ESS, LLC; Sanford ESS, LLC; Ocean State BTM, LLC; and AE-ESS NWS 1, LLC. Madison BTM, Madison ESS, Rumford EES, and Ocean State BTM are each NEPOOL Participants. This transaction will not impact Agilitas' membership in the AR Sector.

[107] *NSTAR Electric Co.*, Docket No. ER21-1285 (Apr. 16, 2021).

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

- **NSTAR / Ocean State Power RFA Termination (ER23-1606)**

On April 11, 2023, NSTAR filed to terminate the Related Facilities Agreement ("RFA") between Eversource Energy, on behalf of NSTAR, and Ocean State Wind following a determination by NSTAR that, pursuant to capital project upgrades on its own system for its own purposes, the Related Facilities were no longer necessary. Both parties agree to terminate the Agreement. No further work is being done under the Agreement and all applicable billing and refunds have been finalized. An effective date of April 11, 2023 was requested. Comments on this filing were due on May 2, 2023; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Study Work Agreement Cancellation: CL&P / NYISO (ER23-1483)**

On March 28, 2023, CL&P submitted a Notice of Termination of the Study Work Agreement with NYISO that was accepted by FERC in Docket No. ER21-2946. All work contemplated by the Agreement was completed in February 2023 and all billing and invoices have been finalized. An effective date of March 29, 2023 was requested. Comments on this filing were due on April 18, 2023; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **PSNH / National Grid D&E Agreement (ER23-1481)**

On March 28, 2023, Eversource Energy, on behalf of Public Service Company of New Hampshire ("PSNH"), filed a Design & Engineering ("D&E") Agreement that sets forth the terms and conditions under which PSNH will perform necessary engineering, procurement and design services in connection with National Grid's asset separation project with Great River Hydro. An effective date of March 29, 2023 was requested. Comments on this filing were due on April 18, 2023; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA: RIE / ISO-NE / Various Entities (ER23-1767, ER23-1748, ER23-1741)**

On April 28, 2023, ISO-NE and Rhode Island Energy ("RIE") filed three revised LGIAs to reflect RIE as the new Interconnecting Transmission Owner pursuant to a FERC-approved transaction. A January 1, 2023 effective date was requested for each of the following LGIAs:

  - **ER23-1767**: First Revised LGIA that governs the interconnection of Manchester Street, LLC's 516 MW facility located in Providence, RI.
  - **ER23-1748:** First Revised LGIA that governs the interconnection of Ocean State Power LLC's 656.157 MW facility located in Burrillville, RI.
  - **ER23-1741:** Second Revised LGIA that governs the interconnection of Rhode Island LFG Genco, LLC's 38 MW facility located in Johnston, RI.

Comments on these filings are due on or before ***May 19, 2023***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA: CL&P/Generate NB Fuel Cells/ISO-NE (ER23-1479)**

On March 27, 2023, as supplemented on March 28 and April 4, CL&P and ISO-NE filed a revised non-conforming Large Generation Interconnection Agreement ("LGIA") with Generate NB Fuel Cells, LLC ("Generate NB") to govern the interconnection of Generate NB's 20 MW fuel cell project in New Britain, Connecticut (Stanley Black & Decker campus). The original non-conforming LGIA was accepted by FERC on July 11, 2022.[108] The revised LGIA includes, among others, changes reflecting the sale of the fuel cell project by EIP Investment to Generate NB.

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

A February 23, 2023 effective date was requested. Comments on this filing were due on April 17, 2023; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **National Grid/ GRH SGIA (ER23-1152)**

On April 20, 2023, the FERC accepted National Grid's non-conforming SGIA with Great River Hydro to cover the continued interconnection of GRH's 13 MW hydro facility in the towns of Barnet, VT and Monroe, NH.[109] The SGIA is effective January 30, 2023. Unless the April 20 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).

- **LSAs: RI Energy/ISO-NE/BIPCO (ER23-1003; ER23-1000)**

On January 31, 2023, ISO-NE and RI Energy filed two Local Service Agreements ("LSAs"), as replacements to two current New England Power TSAs (TSA-NEP-83 and TSA-NEP-86), to allow RI Energy to fully recover the Block Island Transmission System ("BITS") surcharge now that it is both Transmission Owner and Customer under these arrangements. On March 31, 2023, the FERC conditionally accepted the LSA replacing TSA-NEP-86 (ER23-1003), effective January 1, 2023, [110] and directed RI Energy, on or before May 1, 2023, to add language to the LSA to make explicit that the BITS Surcharge shall be subject to the Protocols for Schedule 21-RIE. That compliance filing was submitted on May 1, 2023 as directed. Also on March 31, 2023, FERC also issued a deficiency letter asking for additional information regarding whether the LSA replacing TSA-NEP-83 (ER23-1000) is subject to the Schedule 21-RIE Protocols. The response to the deficiency letter was also filed, as directed, on May 1, 2023. Comments on both May 1 filings are due on or before ***May 22, 2023***. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

On July 12, 2022, in response to the requirements of *Order 881*, Versant Power filed a proposed new Attachment T to the Versant Power Open Access Transmission Tariff for the Maine Public District ("MPD OATT"). Attachment T, Versant reported, incorporates all the contents of the *pro forma* OATT's new Attachment M. An effective date of July 12, 2025 was requested in an errata filing submitted on August 1, 2022. On August 2, 2022, MPUC submitted comments asserting that Versant's Compliance Filing, without further detail, is insufficient to meet the requirements of *Order 881* and should either (i) be rejected outright, ordering Versant to re-file with sufficient detail, or (ii) subject to a deficiency letter requiring further information with respect to the Compliance Filing. MPUC withdrew those comments on August 31, 2022 in exchange for certain understandings with Versant Power (including MPUC's attendance, as a non-voting participant, at any NMISA working group discussions on *Order 881* implementation planning and Versant Power's submission of informational compliance filings to keep the FERC apprised of versant's progress in developing its AAR implementation plan). On September 6, 2022, Versant Power supplemented its compliance filing to confirm the MPUC's understandings, as delineated in its Notice of Withdrawal. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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[109] *New England Power Co.*, Docket No. ER23-1152-000 (Apr. 20, 2023) (unpublished letter order).

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

## XII. Misc. - Administrative & Rulemaking Proceedings[111]

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

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

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

- **Joint FERC-DOE Supply Chain Risk Management Technical Conference (Dec 7, 2022) (AD22-12)**

On December 12, 2022, the FERC and the DOE convened a joint technical conference held its annual Commissioner-led technical conference to discuss supply chain security challenges related to the BPS, ongoing supply chain-related activities, and potential measures to secure the supply chain for the grid's hardware, software, computer, and networking equipment. Speaker materials are posted in eLibrary and a recording of the conference will be available on the FERC website for roughly one more month. On December 19, 2022, the FERC invited all those interested to file, by February 17, 2023, post-technical conference comments addressing issues raised during the technical conference. Comments were filed by AEP, APPA, EEI, the North American Transmission Forum. In addition, on February 13, 2023, the FERC posted a transcript of the December 12 technical conference in eLibrary. This matter is pending before the FERC.

- **Reliability Technical Conference (Nov 10, 2022) (AD22-10)**

On November 10, 2022, the FERC held its annual Commissioner-led technical conference to discuss policy issues related to the reliability of the BPS. The conference's two panels were: (I) "Managing the Electric Grid to Advance Reliability" (to explore the current state of grid reliability and efforts that can be undertaken to improve it); and (II) "Managing Cyber Security Threats, the CIP Reliability Standards, and Best Practices for the Bulk-Power System" (to discuss how cyber security governance encompasses the CIP Reliability Standards and compliance as well as best practices; the challenges of implementing appropriate oversight; and ways in which industry can address these challenges to improve its response to evolving vulnerabilities and threats to reduce the risk to the BPS). On November 22, 2022, the FERC invited all those interested to file post-technical conference comments to address issues raised during the technical conference identified in the Supplemental Notice of Technical Conference issued on November 3, 2022. Comments were due on or before January 23, 2023 and were filed by

[111] Reporting on the following Administrative proceeding has been suspended since the last Report and will be continued if and when there is new activity to report: NOI: Dynamic Line Ratings (AD22-5).

EPSA and Public Power Associations.[112] A transcript of the technical conference was posted in the FERC's eLibrary on January 17, 2023. This matter is pending before the FERC.

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

***The Second New England Gas-Electric Forum (June 20, 2023 in Portland, ME)***. On April 13, 2023, the FERC issued a supplemental notice of a Second New England Winter Gas-Electric Forum containing the preliminary agenda for the Forum, further registration details, and details regarding the panelist nomination process. The event (with address corrected) will be held at the DoubleTree by Hilton Portland, 363 Maine Mall Rd, Portland, ME, 04106.

Registration for in-person attendance is required and there will be no fee for attendance. Link to attendee registration is available on the New England Winter Gas-Electric Forum event page. Due to space constraints, seating for this event is limited. Members who wish to attend in-person should register as soon as possible. The forum will also be available on webcast. Individuals interested in participating as panelists should submit a self-nomination email by Friday, ***May 19, 2023***, to Panelist_NewEnglandForum@ferc.gov. For more information, technical or logistical questions about this forum, please contact NewEnglandForum@ferc.gov.

***The First New England Gas-Electric Forum (September 8, 2022 in Burlington, VT)***. The purpose of the Forum was to discuss and achieve a greater understanding among stakeholders in defining the electric and natural gas system challenges in the New England Region. Topics discussed included the historical context of New England winter gas-electric challenges, concerns and considerations for upcoming winters such as reliability of gas and electric systems and fuel procurement issues, and whether additional information or modeling exercises are needed to inform the development of solutions to these challenges. On September 21, 2022, the FERC invited parties wishing to submit comments regarding the topics discussed at the Forum to do so on or before November 7, 2022. Post-Forum Comments were submitted by: ISO-NE, Acadia, AEU, AIM, Calpine, Constellation, Excelerate, FirstLight, LS Power, NECOS, NEPGA, NESCOE, Public Systems, Repsol, TOs, VELCO, Vistra, Potomac Economics, CT DEEP, AEMA, APGA, EPSA, INGA, NE LDCs, NGSA, New England Council, NEPPA, NH BIA, PIOs, RENEW/ACPA, Berkshire Action Team, Greater Concord Chamber of Comm., Mass. Alliance for Econ. Dev., Mass. Business Roundtable, Mass. Coalition for Sustainable Energy, Mass. United Assoc. of Journeymen, Middlesex County Chamber of Commerce, Public Citizen, Western Mass. Economic Dev. Council, and Individual Citizens (M. Axner, E. Blank, S. Botkin, D. Heimann, J. Krieger, B. Little, I. McDonald, J. Neville, W. Persons, R. Spector). On November 22, National Grid filed reply comments.

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

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

[112] "Public Power Associations" are American Public Power Association ("APPA"), the Large Public Power Council ("LPPC"), and Transmission Access Policy Study Group ("TAPS").

Agency, Northwest & Intermountain Power Producers Coalition, OH Consumers' Counsel, OH PUC, Old Dominion Elec. Coop., PJM, G. Poulus, SPP, Potomac Economics, Southern California Edison, Southern Environmental Law Center, and TAPS/FMPA and WIRES.

On September 30 and October 4, the FERC issued supplemental notices that included a final agenda, including further details regarding the agenda and speakers, for this technical conference. On November 1, 2022, a transcript of the technical conference was posted in the FERC's eLibrary. On December 23, 2022, the FERC issued a notice inviting post-technical conference comments on questions listed in that notice. Those comments were due by March 23, 2023 and were filed by: ISO-NE, AEU, Avangrid, Cypress Creek Renewables, Eversource, LS Power, MA AG, NE Public Systems, NESCOE, NextEra, NRDC, NRG, Maine PUC, American Council on Renewable Energy ("ACRE"), APPA, EEI, Harvard Elec. Law Inst., LPPC, NASUCA, NRECA, and R Street Institute. Since the last Report, reply comments were filed by the PJM IMM and the ITC Companies. This matter is pending before the FERC.

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

A seventh meeting of the FERC-established Joint Federal-State Task Force on Electric Transmission ("Transmission Task Force" or "JFSTF")[113] will be held Sunday, July 18, 2023 in Austin, TX. s held February 15, 2023 in Washington, DC.[114] An agenda for the February 15 meeting was posted on February 1, 2023. The one topic noticed was "Physical Security of the Transmission System", with Jim Robb, NERC President and CEO, and Puesh Kumar, Director of DOE's Office of Cybersecurity, Energy Security, and Emergency Response, as the principal speakers. A transcript of the February 15 meeting was posted to eLibrary on March 6, 2023.

Comments on the topics/questions related to the FERC's October 6, 2022 technical conference on Transmission Planning and Cost Management, also posted in this docket, were due on or before March 23, 2023. *See* AD22-8 above for a more information.

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

***ISO/RTO Reports***. On April 21, 2022, the FERC issued an order[115] directing each independent system operator ("ISO") and regional transmission organization ("RTO"), including ISO-NE, to submit on or before October 18, 2022 a report that describes: (1) current system needs given changing resource mixes and load profiles; (2) how it expects its system needs to change over the next five and 10 years; (3) whether and how it plans to reform its energy and ancillary services ("EAS") markets to meet expected system needs over the next five and 10 years; and (4) information about any other reforms, including capacity market reforms and any other resource adequacy reforms that would help it meet changes in system needs. The *Order Directing Reports* followed a series of staff-

[113] *Joint Federal-State Task Force on Electric Transmission*, 175 FERC ¶ 61,224 (June 18, 2021). The Transmission Task Force is comprised of all FERC Commissioners as well as representatives from 10 state commissions (two from each NARUC region). State commission representatives will serve one-year terms from the date of appointment by FERC and in no event will serve on the Task Force for more than three consecutive terms. The Transmission Task Force will convene multiple formal meetings annually, with FERC issuing orders fixing the time and place and agenda for each meeting, and the meetings will be open to the public for listening and observing and on the record. The Transmission Task Force will focus on "topics related to efficiently and fairly planning and paying for transmission, including transmission to facilitate generator interconnection, that provides benefits from a federal and state perspective." New England is represented by Commissioners Riley Allen (VT PUC) and Marissa Gillett (Chair, CT PURA). *See* Order on Nominations, *Joint Federal-State Task Force on Elec. Trans.*, 180 FERC ¶ 61,030 (July 15, 2022).

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

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

led technical conferences, convened in 2021 and summarized in previous Reports, addressing ISO/RTO resource adequacy[116] and energy and ancillary services markets.[117]

***ISO-NE Report***. On October 18, 2022, ISO-NE (as well as the other ISO/RTOs) filed its report in response to the *Order Directing Reports.* Comments in response to the RTO/ISO reports were due, following an EEI request, on or before January 18, 2023. Comments were filed by, among others: Advanced Energy United, API, Constellation, New England Public Systems,[118] Shell, Clean Energy Assocs, Clean Energy Buyers Association, EEI, EPSA, Public Interest Orgs, R Street Institute.

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

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

On July 28, 2022, the FERC issued a NOPR[119] proposing to add a new section to its regulations to require that any entity communicating with the FERC or other specified organizations (e.g. ISO/RTOs, FERC-approved market monitors, NERC and its Regional Entities, or transmission providers) related to a matter subject to FERC jurisdiction submit accurate and factual information and not submit false or misleading information, or omit material information ("Duty of Candor Requirements"). An entity would be shielded from violation of the new regulation if it has exercised due diligence to prevent such occurrences. The FERC's current regulations prohibit, in defined circumstances, inaccurate communications to the FERC and other organizations upon which the FERC relies to carry out its statutory obligations. However, because those requirements cover only certain communications and impose a patchwork of different standards of care for such communications, the FERC believes that a broadly applicable duty of candor will improve its ability to effectively oversee jurisdictional markets. It further indicated that its proposed due 'diligence standard' and other limitations are intended to minimize the additional burdens to industry that come with the new Duty of Candor Requirements.

On September 1, 2022, Joint Associations[120] requested an additional month to submit comments.[121] On September 14, 2022, the FERC granted that request. Accordingly, initial comments were due November 11, 2022 and over 30 sets of comments were filed, including by: ISO-NE, ISO-NE IMM, ISO-NE EMM, PJM IMM, ABA, AGA,

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

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

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

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

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

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

APGA, APPA, EEI, Energy Trade Associations, INGA, NGSA, Nodal Exchange, NRECA, State Agencies, US Chamber of Commerce, DE Riverkeeper Network, New Civil Liberties Alliance, and Nodal Exchange. The US Chamber of Commerce filed reply comments on December 12, 2022. There was no activity in the proceeding since the last Report. This matter is pending before the FERC.

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

On April 21, 2023, the FERC issued *Order 893*,[122] which revises the FERC's regulations to encourage investments by utilities in Advanced Cybersecurity Technology and participation by utilities in cybersecurity threat information sharing programs, as directed by the Infrastructure Investment and Jobs Act of 2021. *Order 893* (1) identifies the utilities permitted to request incentive-based rate treatment for cybersecurity investments; (2) establishes the criteria that the FERC will use to determine whether a cybersecurity investment is eligible to receive an incentive-based rate treatment; (3) discusses the approaches that a utility may use to demonstrate that a cybersecurity investment satisfies the eligibility criteria; (4) explains the type of incentive-based rate treatment available for qualifying cybersecurity investments; (5) sets limits on the duration of the incentive-based rate treatment; (6) describes what utilities must include in their applications for incentive-based rate treatment for cybersecurity investments; and (7) establishes the annual reporting requirements for utilities that receive incentive-based rate treatment for their cybersecurity investments. *Order 893* will become effective July 3, 2023.[123]

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

On June 16, 2022, as corrected on July 12, 2022, the FERC issued a notice[124] proposing to require transmission providers to submit one-time informational reports describing their current or planned policies and processes for conducting extreme weather vulnerability assessments[125] (how they establish a scope for their extreme weather vulnerability assessments, develop inputs, identify vulnerabilities and determine exposure to extreme weather hazards, estimate the costs of impacts, and develop mitigation measures to address extreme weather risks). Initial comments were due August 30, 2022[126] and were filed by over 13 parties, including among others, Eversource, NRDC, NERC, MISO, PJM, and EPSA. This matter is pending before the FERC.

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

On June 16, 2022, the FERC issued a notice of proposed rulemaking ("NOPR"),[127] more than 400 pages long, that proposed reforms to the *pro forma* Large Generator Interconnection Procedures ("LGIP"), *pro forma* Small Generator Interconnection Procedures ("SGIP"), *pro forma* Large Generator Interconnection Agreement ("LGIA"), and *pro forma* SGIA to address interconnection queue backlogs, improve certainty, and prevent undue discrimination for new technologies.

As previously reported, the proposed reforms fall into three main categories: (1) reforms to implement a first-ready, first-served cluster study process;[128] (2) reforms to increase the speed of interconnection queue

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122 *Incentives for Advanced Cybersecurity Investment*, Order No. 893, 183 FERC ¶ 61,033 (Apr. 21, 2023) ("*Order 893*").

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

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

125 "Extreme weather vulnerability assessments" are proposed to be defined as "analyses that identify where and under what conditions jurisdictional transmission assets and operations are at risk from the impacts of extreme weather events, how those risks will manifest themselves, and what the consequences will be for system operations".

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

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

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

processing;[129] and (3) reforms to incorporate technological advancements to the interconnection process.[130] Within each of these categories, the FERC proposes a wide array of reforms, and requested comment.

***Initial Comments***. Initial comments were due October 13, 2022[131] and over 130 sets of comments were filed, including: NEPOOL, ISO-NE, NESCOE, AEU, Anbaric, Avangrid, Cypress Creek Renewables, Dominion, EDF Renewables, ENGIE, Envir. Defense Fund, Longroad, National Grid, NextEra, PPL, RWE, Shell, VELCO, Vistra, ACPA, ACRE, APPA, US DOE, EEI, ELCON, EPRI, EPSA, IRC, NARUC, NERC, NRECA, PIOs, R Street Institute, SEIA, State Agencies, and WIRES.

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- Require transmission providers offer an alternative option for an informational interconnection study that would not require a project enter the interconnection queue;
- Make cluster studies the required interconnection study method under the *pro forma* LGIP;
- Allocate the shared costs of the cluster studies so that 90% of the applicable study costs are allocated to interconnection customers on a pro rate basis based on the requested MWs included in the applicable cluster, and 10% of the applicable study costs are allocated to interconnection customers on a per capita basis based on the number of interconnection requests in the applicable cluster;
- Require transmission providers to allocate network upgrade costs to interconnection customers within a cluster using a proportional impact method, in which the transmission provider will determine the degree to which each generating facility in the cluster contributes to the need for a specific network upgrade;
- Allow interconnection customers in an earlier-in-time cluster to share the costs of network upgrades with interconnection customers who will significantly benefit from those upgrades but would not share the cost of the network upgrades solely by virtue of being in a later cluster;
- Increase study deposits based on the size of the generating facility from $35,000 to $250,000;
- Require more stringent site control requirements, and proposes to require an interconnection customer to demonstrate 100% site control for a proposed generating facility when they submit the interconnection request;[128]
- Implement a commercial readiness framework whereby interconnection customers must show demonstrable milestones towards commercial readiness in order to enter the cluster, such as an executed term sheet, reasonable evidence the project was selected in a resource plan, or a provisional LGIA; and
- Impose withdrawal penalties when the interconnection customer withdraws from the interconnection queue.

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

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

[130] As **technological advances to the interconnection process**, the FERC proposes to:

- Require transmission providers to allow more than one resource to co-locate on a shared site behind a single point of interconnection and share a single interconnection request;
- Change the way in which transmission providers assess an addition of a generating facility to an interconnection request, requiring that transmission providers evaluate a proposed addition as long as the addition does not change the requested interconnection service level;
- Enable customers with unused interconnection capacity share that surplus capacity with other resources as long as the original interconnection customer executes an LGIA or requests filing of an unexecuted LGIA;
- Require transmission providers, at the request of the interconnection customer to use operating assumptions for interconnection studies that reflect the proposed operation of an electric storage resource or co-located storage resource; and
- Require transmission providers to evaluate grid-enhancing solutions and file an annual informational report on their use of grid-enhancing technologies.

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

***Reply Comments***. Following a request by EEI for a 30-day extension of time to submit reply comments, supported by AEU, ACPA, ACRE, and SEI, and granted by the FERC on October 28, 2022, reply comments were due December 14, 2022. More than 50 sets of reply comments were filed, including by ACPA, ACORE, AEU, APPA/LPPC, Avangrid, Dominion, EDF, EEI, Elevate Renewables F7, Enel, ENGIE, Invenergy, the IRC, Longroad Energy, NERC, NESCOE, NextEra, Orsted, SEIA, Shell, Sierra Club, UCS, WIRES. Since the last Report, US Senator John Barrasso, M.D., a ranking member of the Senate's Committee on Energy and Natural Resources, asked the FERC to respond to a series of questions.

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

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

On July 28, 2022, the FERC issued a NOPR[132] proposing to revise its regulations to permit ISO/RTOs to share among themselves[133] credit-related information regarding market participants.[134] The FERC believes that the proposed credit information sharing could improve ISO/RTOs' ability to accurately assess market participants' credit exposure and risks and enable ISO/RTOs to respond to credit events more quickly and effectively (minimizing the overall credit-related risks, including risks of unexpected defaults by market participants, in organized wholesale electric markets). The FERC proposal would not permit the information sharing to be conditioned on the specific consent of the market participant, would permit the receiving ISO/RTO to use market participant credit-related information received from another ISO/RTO to the same extent and for the same purposes that the receiving ISO/RTO may use credit-related information collected from its own market participants, and would not change the existing discretion an ISO/RTO has to act on credit-related information, regardless of the source of that information. The FERC sought comment on whether ISO/RTOs' credit-related information sharing discretion should be limited in any specific ways or to any specific circumstances.

***Initial Comments***. Initial comments were due October 7, 2022[135] and were filed by, among others: NEPOOL, Dominion, EEI, Energy Trading Institute, EPSA, and the IRC.

***Reply Comments***. Reply comments were due November 7, 2022 and were filed by the IRC and a couple of persons from Augusta University.

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

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

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

[135] The *ISO/RTO Credit-Related Info Sharing NOPR* was published in the *Fed. Reg.* on Aug. 8, 2022 (Vol. 87, No. 151) pp. 48,118-48,125.

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

On December 15, 2022, the FERC issued a NOPR[136] proposing to revise its regulations governing applications for permits to site electric transmission facilities under section 216 of the FPA, as amended by the Infrastructure and Jobs Act. The *Transmission Siting NOPR* is intended to ensure consistency with the Infrastructure and Jobs Act's amendments to FPA section 216, to modernize certain regulatory requirements, and to incorporate other updates and clarifications to provide for the efficient and timely review of permit applications. Following a NARUC request for an extension of time, granted by the FERC on March 3, 2023, comments on the *Transmission Siting NOPR* are due on or before ***May 17, 2023***.

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

Following its ANOPR process,[137] the FERC issued on April 21, 2022 a NOPR[138] 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

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

[137] *See Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 176 FERC ¶ 61,024 (July 15, 2021) ("*Transmission Planning & Allocation/Generation Interconnection ANOPR*"). The FERC convened a tech. conf. on Nov. 15, 2021, to examine in detail the issues and potential reforms described in the *ANOPR*. Speaker materials and a transcript of the tech. conf. are posted in FERC's eLibrary. Pre-technical conference comments were submitted by over 175 parties, including by: NEPOOL, ISO-NE, AEU, Anbaric, Avangrid, BP, CPV, Dominion, EDF, EDP, Enel, EPSA, Eversource, Exelon, LS Power, MA AG, MMWEC, National Grid, NECOS, NESCOE, NextEra, NRDC, Orsted, Shell, UCS, VELCO, Vistra, Potomac Economics, ACORE, ACPA/ESA, APPA, EEI, ELCON, Industrial Customer Orgs, LPPC, MA DOER, NARUC, NASUCA, NASEO, NERC, NRECA, SEIA, State Agencies, TAPS, WIRES, Harvard Electric Law Initiative; NYU Institute for Policy Integrity, New England for Offshore Wind Coalition, and the R Street Institute. *ANOPR* reply comments and post-technical conference comments were filed by over 100 parties, including: by: CT AG, Acadia Center/CLF, CT AG, Dominion, Enel, Eversource, LS Power, MA AG, MMWEC, NESCOE, NextEra, Shell, UCS, Vistra, ACPA/ESA, AEU, APPA, EEI, ELCON, Environmental and Renewable Energy Advocates, EPSA, Harvard ELI, NRECA, Potomac Economics, and SEIA. Supplemental reply comments were filed by WIRES, a group of former military leaders and former Department of Defense officials, and ACPA/AEU/SEIA.

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

and costs, the *Transmission NOPR* does not propose broad or comprehensive reforms directly related to these topics. The FERC indicated that it would continue to review the record developed to date and expects to address possible inadequacies through subsequent proceedings that propose reforms, as warranted, related to these topics.

A number of the elements of the *Transmission NOPR*, if adopted as part of a final rule, would result in some significant changes to how the region's transmission needs are identified, solutions are evaluated and selected, and costs recovered and allocated. A more fulsome high-level summary from NEPOOL Counsel of the *Transmission NOPR* was distributed to, and was reviewed with, the Transmission Committee.

***Comments***. Following a number of requests for extensions of time, comments on the *Transmission NOPR* were due August 17, 2022.[139] Nearly 200 sets of comments were filed, including comments by NEPOOL , ISO-NE, Acadia/CLF, Anbaric, AEU, Avangrid, BP, Dominion, Enel, Engie, Eversource, Invenergy, LSP Power, MOPA, MMWEC/CMEEC/NHEC/VPPSA, National Grid, NECOES, NESCOE, NextEra, NRG, Onward Energy, Orsted, PPL, Shell, Transource, VELCO, Vistra, ISO/RTO Council, NERC, US DOJ/FTC, MA AG, State Agencies, VT PUC/DPS, Potomac Economics, ACPA, ACRE, APPA, EEI, EPSA, Industrial Customer Organizations, LPPC, NASUCA, NRECA, Public Interest Organizations, SEIA, TAPS, WIRES, Harvard Electricity Law Initiative, New England for Offshore Wind, and the R Street Institute.

***Reply Comments***. Reply comments were due September 19, 2022. Nearly 100 sets of reply comments were filed, including by: ISO-NE, AEU, Anbaric, Avangrid, CT DEEP, Cypress Creek, Dominion, ENGIE, Eversource, Invenergy, LS Power, MA AG, NECOS, NESCOE, NextEra, Shell, Transource, UCS, ACPA, ACRE, APPA, EEI, Industrial Customer Organizations, LPPA, NRECA, Public Interest Organizations, R Street, and SEIA. On November 28, 2022, the New Jersey BPU moved to lodge its recently issued Board Order selecting transmission projects to be built pursuant to PJM's State Agreement Approach ("SAA") for the purpose of supporting New Jersey's offshore wind ("OSW") goals, the Brattle Group's SAA Evaluation Report, and PJM's SAA Economic Analysis Report, which it stated demonstrates that competitive transmission solicitations can provide significant value to consumers. In December 2022, the Harvard Electricity Law Initiative, and P. Alaama submitted further comments.

LS Power and NRG filed comments in this proceeding, as well as in (Transmission Planning and Cost Management Joint Federal-State Task Force on Electric Transmission) (AD22-8) and JFSTF proceeding (AD21-15). They asserted that the FERC "cannot sufficiently address the transmission planning issues raised in its Transmission NOPR without addressing the intertwined cost management issues raised in AD22-8-000 and during the October 6, 2022 Technical Conference in AD22-8.

This matter remains pending before the FERC. If you have any questions concerning the *Transmission NOPR*, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

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

On July 28, 2022, the FERC issued a NOPR[140] proposing reforms to the accounting and reporting treatment of certain renewable energy assets. Specifically, the FERC proposes changes to the Uniform System of Accounts ("USofA") and relevant FERC forms to: (i) include new accounts for wind, solar, and other non-hydro renewable assets; (ii) create a new functional class for energy storage accounts; (iii) codify the accounting treatment of renewable energy credits; and (iv) create new accounts within existing functions for hardware, software, and communication equipment. The FERC also seeks comment on whether the Chief Accountant should issue guidance on the accounting for hydrogen. Comments on the *Renewable Energy Assets USofA and Reporting NOPR*

[139] A July 27, 2022, request by the Georgia Public Service Commission ("GA PUC") for an additional 30 days of time to submit comments and reply comments was denied on Aug. 9, 2022.

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

were due November 17, 2022.[141] Comments were filed by: Dominion, ACPA/SEIA, EEI, Liquid Energy Pipeline Assoc., RESA, PG&E/SDG&E, C. Pechman. There was no activity in this proceeding since the last Report. This matter remains pending before the FERC.

## XIII. FERC Enforcement Proceedings

**Electric-Related Enforcement Actions**

- **No activity to report**

**Natural Gas-Related Enforcement Actions**

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

***Procedural Schedule Suspended***. As previously reported, on May 24, 2022, the Honorable Judge Karen Gren Scholer of the U.S. District Court for the Northern District of Texas issued an order staying this proceeding. Consistent with that order and out of an abundance of caution, ALJ Joel DeJesus, who will be the presiding judge for hearings in this matter,[142] suspended the procedural schedule until such time as the Court's stay is lifted and the parties provide jointly a proposed amended procedural schedule.

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

On December 16, 2021, the FERC issued a show cause order[143] in which it directed Rover and ETP (together, "Respondents") to show cause why they should not be found to have violated NGA section 7(e), FERC Regulations (18 C.F.R. § 157.20); and the FERC's Certificate Order,[144] by: (i) intentionally including diesel fuel and other toxic substances and unapproved additives in the drilling mud during its horizontal directional drilling ("HDD") operations under the Tuscarawas River in Stark County, Ohio, in connection with the Rover Pipeline Project;[145] (ii) failing to adequately monitor the right-of-way at the site of the Tuscarawas River HDD operation; and (iii) improperly disposing of inadvertently released drilling mud that was contaminated with diesel fuel and hydraulic oil. The FERC directed Respondents to show why they should not be assessed civil penalties in the amount of ***$40 million***.

On March 21, 2022, Respondents answered and denied the allegations in the *Rover/ETP CPCN Show Cause Order*. On April 20, 2022, OE Staff answered Respondents' March 21 answer. On May 13, Respondents submitted a surreply, reinforcing their position that "there is no factual or legal basis to hold either [Respondent] liable for

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141 The *Renewable Energy Assets USofA and Reporting NOPR* was published in the *Fed. Reg.* on Oct. 3, 2022 (Vol. 87, No. 190) pp. 59,870-59,963.

142 See *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.*, 178 FERC ¶ 61,028 (Jan. 20, 2022) ("*Rover/ETP Hearings Order*"). The hearings will be to determine whether Rover Pipeline, LLC ("Rover") and its parent company Energy Transfer Partners, L.P. ("ETP" and collectively with Rover, "Respondents") violated section 157.5 of the FERC's regulations and to ascertain certain facts relevant for any application of the FERC's Penalty Guidelines.

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

144 *Rover Pipeline LLC,* 158 FERC ¶ 61,109 (2017), *order on clarification & reh'g*, 161 FERC ¶ 61,244 (2017), *Petition for Rev.*, *Rover Pipeline LLC v. FERC*, No. 18-1032 (D.C. Cir. Jan. 29, 2018) ("Certificate or Certificate Order").

145 The Rover Pipeline Project is an approximately 711 mile long interstate natural gas pipeline designed to transport gas from the Marcellus and Utica shale supply areas through West Virginia, Pennsylvania, Ohio, and Michigan to outlets in the Midwest and elsewhere.

the intentional wrongdoing of others that is alleged in the Staff Report." The FERC denied Respondents' request for rehearing of the FERC's January 21, 2022 designation notice.[146] This matter is pending before the FERC.

- **BP (IN13-15)**

On December 17, 2020, the FERC issued *Opinion 549-A*,[147] a 159-page decision addressing arguments raised on rehearing requested of *Opinion 549.*[148] *Opinion 549-A* modifies the discussion in *Opinion 549*, but reaches the same the result (ultimately requiring BP to pay a ***$20.16 million civil penalty (roughly $24.4 million with accrued interest) and disgorge $207,169***). Of note, *Opinion 549-A* denied BP's motion to dismiss this enforcement action as time barred (by the five-year statute of limitations set forth in 28 U.S.C. § 2462), finding BP waived any statute of limitations defense by failing to raise it earlier in this proceeding.[149] 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.[150]

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[151] 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.[152]

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

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[146] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 179 FERC ¶ 61,090 (May 11, 2022) ("*Designation Notice Rehearing Order*"). The "Designation Notice" provided updated notice of designation of the staff of the FERC's Office of Enforcement ("OE") as non-decisional in deliberations by the FERC in this docket, with the exception of certain staff named in that notice.

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

[148] *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*")).

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

[150] *Id*. at P 319.

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

[152] 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.

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.[153] On July 27, 2021, Chief Judge Cintron designated Judge Suzanne Krolikowski as the Presiding ALJ and established an extended Track III Schedule for the proceeding.

Discovery in this case closed on December 2, 2022. On December 16, 2022, Respondents filed for a preliminary injunction in the US District Court for the Southern District of Texas. In order to allow for briefing and a decision on that motion, the FERC placed this proceeding in abeyance for 90 days, and directed that the hearing scheduled to begin on January 23, 2023, commence no earlier than ***April 24, 2023***.[154]

## XIV. Natural Gas Proceedings

For further information on any of the natural gas proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com).

**New England Pipeline Proceedings**
The following New England pipeline projects are currently under construction or before the FERC:

- **Iroquois ExC Project (CP20-48)**
  - 125,000 Dth/d of incremental firm transportation service to ConEd and KeySpan by building and operating new natural gas compression and cooling facilities at the sites of four existing Iroquois compressor stations in Connecticut (Brookfield and Milford) and New York (Athens and Dover).
  - Three-year construction project; service request by November 1, 2023.
  - On March 25, 2022, after procedural developments summarized in previous Reports, the FERC issued to Iroquois a certificate of public convenience and necessity, authorizing it to construct and operate the proposed facilities.[155] The certificate was conditioned on: (i) Iroquois' completion of construction of the proposed facilities and making them available for service within ***three years*** of the date of the; (ii) Iroquois' compliance with all applicable FERC regulations under the NGA; (iii) Iroquois' compliance with the environmental conditions listed in the appendix to the order; and (iv) Iroquois' filing written statements affirming that it has executed firm service agreements for volumes and service terms equivalent to those in its precedent agreements, prior to commencing construction. The March 25, 2022 order also approved, as modified, Iroquois' proposed incremental recourse rate and incremental fuel retention percentages as the initial rates for transportation on the Enhancement by Compression Project.
  - On April 18, 2022, Iroquois accepted the certificate issued in the *Iroquois Certificate Order*.
  - On June 17, 2022, in accordance with the *Iroquois Certificate Order,* Iroquois submitted its Implementation Plan, documenting how it will comply with the FERC's Certificate conditions.
  - The Project is targeted for a 4th quarter 2023 in-service date.

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

[154] *Total Gas & Power North America, Inc., Total, S.A., Total Gas & Power, Ltd., Aaron Hall, and Therese Tran f/k/a Nguyen*, 181 FERC ¶ 61,252 (Dec. 21, 2022).

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

## XV. State Proceedings & Federal Legislative Proceedings

- **Maine - NECEC Transmission LLC et al. v. Bureau of Parks and Lands et al. (BCD-21-416)**

On August 30, 2022, the Maine Supreme Judicial Court concluded that the legislation enacted as a result of the passage of Maine's November 2, 2021 ballot question,[156] and that effectively halted construction of the NECEC Project,[157] was unconstitutional to the extent it required the legislation to be applied retroactively to the certificate of public convenience and necessity ("CPCN") issued for the Project if NECEC had acquired vested rights to proceed with Project construction (by undertaking substantial construction consistent with and in good-faith reliance on the CPCN before the Initiative was enacted). The Court remanded to the Business and Consumer Docket the factual question of whether NECEC performed substantial construction in good faith according to a schedule that was not created or expedited for the purpose of generating a vested rights claim (which it suggested appeared to be the case from the limited record developed in connection with the request for preliminary injunctive relief in this matter).

On April 20, 2023, after a week-long trial, a jury ruled 9-0 that developers had completed enough work in good faith before the passage of the ballot question to have a constitutional right to proceed with construction. Based on that verdict, a state judge is expected to conclude that the referendum was unconstitutional. The decision will almost certainly be appealed to the Maine Supreme Judicial Court for a final say.

## XVI. Federal Courts

The following are matters of interest, including petitions for review of FERC decisions in NEPOOL-related proceedings, that are currently pending before the federal courts (unless otherwise noted, the cases are before the U.S. Court of Appeals for the District of Columbia Circuit ("DC Circuit")). An "**" following the Case No. indicates that NEPOOL has intervened or is a litigant in the appeal. The remaining matters are appeals as to which 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).

- **Seabrook Dispute Order (23-1094)**
  **Underlying FERC Proceeding: EL21-6, EL 23-3**
  **Petitioner: NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC**
  **Status: Filing of Initial Submissions Underway**

On April 4, 2023, NextEra Energy Resources, LLC and NextEra Energy Seabrook, LLC (collectively, "NextEra") petitioned the DC Circuit Court of Appeals for review of the FERC's orders. The Court ordered NextEra to file, by May 8, 2023, a Docketing Statement, a Statement of Intent to Utilize Deferred Joint Appendix, a Statement of Issues, and the Underlying Decision from which the appeal arose. Appearances and other procedural motions, if any, are also due on or before May 8. A Certified Index to the Record and Dispositive Motions, if any, are due on or before May 22, 2023. On April 14, 2023, NECEC Transmission LLC and Avangrid, Inc. (collectively, "Avangrid") filed a motion for leave to intervene in support of the FERC.

[156] The ballot question, approved by 59% of Maine voters, which summarized the citizen's initiative pursued under Maine's constitutional provision for direct initiative of legislation (ME. Const. Art. IV, pt. 3, § 18), read: "Do you want to ban the construction of high-impact electric transmission lines in the Upper Kennebec Region and to require the Legislature to approve all other such projects anywhere in Maine, both retroactively to 2020, and to require the Legislature, retroactively to 2014, to approve by a two-thirds vote such projects using public land?"

[157] The New England Clean Energy Connect ("NECEC") project (the "NECEC Project") is designed to transmit power generated in Québec through Maine and into Massachusetts. The Project includes a new 145.3-mile, high-voltage direct current ("HVDC") transmission line, proposed to run from the Maine-Québec border in Beattie Township, ME to a new converter station in Lewiston, ME and from there to an existing substation by a new 1.2-mile, high-voltage alternating current transmission line.

- ***2nd Revised Narragansett LSA Orders* (22-1161, 22-1108) (consolidated)**
  **Underlying FERC Proceeding: ER22-707**[158]
  **Petitioner: Green Development**
  **Status: Briefing Completed; Oral Argument Held March 20, 2023; Decision Pending**

Oral argument in this case was held before Judges Henderson, Pillard and Katsas on March 20, 2023. This matter, which as previously reported was initiated on June 15, 2022 by a Green Development petition challenging the FERC's *2nd Revised Narragansett LSA Orders,*[159] is pending before the Court.

- **Mystic II (ROE & *True*-Up)**
  **(21-1198; 21-1222, 21-1223, 21-1224, 22-1001, 22-1008, 22-1026) (consolidated)**
  **Underlying FERC Proceeding: EL18-1639-010, -011,**[160] **-013**[161] **-017**[162]
  **Petitioners: Mystic, CT Parties,**[163] **MA AG, ENECOS**
  **Status: Being Held in Abeyance; Motion for further abeyance pending**

As previously reported, this case was initiated when, on October 8, 2021, Mystic petitioned the DC Circuit Court of Appeals for review of the FERC's orders setting the base ROE for the Mystic COS Agreement at 9.33%. The *Mystic ROE Order* and subsequent FERC orders addressing the Mystic ROE issues have all also been appealed by various parties and consolidated under 21-1198. Docketing Statements and Statements of Issues to be Raised, and the Underlying Decision from which the various appeals arise have been filed as new dockets have been opened and then consolidated with 21-1198. As previously reported, the Certified Index to the Record was due, and filed by the FERC, on February 22, 2022. On March 10, 2022, MMWEC and NHEC filed a notice of intent to participate in support of FERC in Case Nos. 21-1198, 22-1008, and 22-1026 and in support of Petitioners in the remaining consolidated cases, and filed a statement of issues. On March 17, 2022, CT Parties moved to intervene, and those interventions were granted on May 4, 2022.

As previously reported, on July 8, 2022, Connecticut Parties and ENECOS jointly moved to hold these proceedings in abeyance until 30 days after the DC Circuit issued an opinion in *MISO Transmission Owners v. FERC*, 16-1325 ("*MISO TOs"*). They requested abeyance on the basis that the consolidated petitions in this proceeding and *MISO TOs* both involve challenges to the FERC's ROE methodology (the FERC set the ROE used in calculating Constellation's rates using the methodology challenged in *MISO TOs*). Although Constellation opposed the

158 *ISO New England Inc. and New England Power Co. d/b/a National Grid*, 178 FERC ¶ 61,115 (Feb. 18, 2022) ("*2nd Rev Narragansett LSA Order*"). *ISO New England Inc. and New England Power Co. d/b/a National Grid*, 179 FERC ¶ 62,035 (Apr. 18, 2022) (notice of denial of rehearing by operation of law and providing for further consideration). Together, these orders referred to as the "*2nd Revised Narragansett LSA Orders*".

159 The 2nd Revised Narragansett LSA is a Local Service Agreement ("LSA") among New England Power, Narragansett and ISO-NE. The LSA reflects the construction of the new Iron Mine Hill Road Substation and related transmission modifications, and the assessment to Narragansett of a Direct Assignment Facilities Charge ("DAF Charge") associated with the facilities. The Iron Mine Hill Road Substation, a new 115 kV/34.5 kV substation (including modifications necessary to loop Narragansett's existing 115 kV H17 transmission line through the new substation) will connect to a new 34.5 kV distribution feeder, which will serve as the point of interconnection for several distributed generation projects being developed by Green Development, LLC ("Green Development"), located in North Smithfield, Rhode Island.

160 *Constellation Mystic Power, LLC,* 176 FERC ¶ 61,019 (July 15, 2021) ("*Mystic ROE Order*")*; Constellation Mystic Power, LLC*, 176 FERC ¶ 62,127 (Sep. 13, 2021) ("*September 13 Notice*") (Notice of Denial By Operation of Law of Rehearings of Mystic ROE Order).

161 *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).

162 *Constellation Mystic Power, LLC*, 179 FERC ¶ 61,011 (Apr. 28, 2022) ("*Mystic First CapEx Info. Filing Order*"); *Constellation Mystic Power, LLC*, 179 FERC ¶ 62,179 (June 27, 2022) ("*June 27 Notice*") (Notice of Denial By Operation of Law of Rehearings of *Mystic First CapEx Info. Filing Order*).

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

abeyance request, the Court granted the abeyance request on July 27, 2022, directing the Parties to file motions to govern future proceedings within 30 days of the court's disposition of *MISO TOs*.

As previously reported, the Court has since decided *MISO TOs*. However, the parties continue to agree that this case should remain in abeyance pending further proceedings related to MISO TOs, now on remand at the FERC. Accordingly, on January 24, 2023, Mystic, without opposition, asked the Court for an order keeping these proceedings in abeyance and directing that motions to govern future proceedings be filed in late April, 2023. On February 3, 2023, the Court issued an order that these cases remain in abeyance and that the parties file motions to govern future proceedings by April 24, 2023. On April 24, Constellation reported that all parties agree and asked the Court that this case should remain in abeyance for an additional 90 days pending FERC action on remand in the MISO TOs case. Constellation's motion is pending before the Court.

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  **Underlying FERC Proceeding: ER18-619**[164]
  **Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF**
  **Status: Being Held in Abeyance (until March 1, 2024)**

As previously reported, the Sierra Club, NRDC, RENEW Northeast, and CLF petitioned the DC Circuit Court of Appeals on August 31, 2020 for review of the FERC's order accepting ISO-NE's CASPR revisions and the FERC's subsequent *CASPR Allegheny Order*. Appearances, docketing statements, a statement of issues to be raised, and a statement of intent to utilize deferred joint appendix were filed. A motion by the FERC to dismiss the case was dismissed as moot by the Court, referred to the merits panel (Judges Pillard, Katsas and Walker), and is to be addressed by the parties in their briefs.

Petitioners have moved to hold this matter in abeyance three times. The Court has granted each request. The most recent request was submitted on July 22, 2022 (third abeyance request) and the Court granted a few days later the request to hold this matter in abeyance until March 1, 2024, the date on which the elimination of MOPR is to be implemented, with motions to govern due 30 days thereafter.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  **Underlying FERC Proceeding: ER15-414**[165]
  **Petitioners: TOs' (CMP et al.)**
  **Status: Being Held in Abeyance**

On August 28, 2020, the TOs[166] 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*[167] 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

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

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

[166] 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.

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

requested abeyance. On February 11, 2021, the Court issued an order that that this case remain in abeyance pending further order of the court. On April 21, 2021, the FERC filed an unopposed motion for continued abeyance of this case *because* the Commission intends to issue a future order on Petitioners' request for rehearing of the challenged Order Rejecting Compliance Filing, and because the remand proceeding in which the challenged order was issued remains ongoing.

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

### Other Federal Court Activity of Interest

- ***Northern* Access *Project (22-1233)***
  **Underlying FERC Proceeding: *CP15-115*[168]**
  **Petitioners: Sierra Club**
  **Status: Briefing Complete; Oral Argument Not Yet Scheduled**

On September 6, 2022, the Sierra Club petitioned the DC Circuit for review of *Northern Access Project Add'l Extension Order*. On October 11, 2022, Sierra Club filed a Docketing Statement, a Statement of Issues, and the underlying decision from which the appeal arises. Also on October 11, the FERC moved to hold this proceeding in abeyance. Sierra Club opposed that motion on October 21, 2022. Having issued its further order on rehearing on October 14, 2022,[169] the FERC, on November 4, 2022, withdrew its 's motion to hold this proceeding in abeyance and asked the Court to issue a scheduling order in this proceeding. The Court issued that schedule on November 9, 2022. The Certified Index to the Record was submitted on November 16, 2022 and Petitioner's (Sierra Club's) Brief on December 16, 2022. Respondent's (FERC's) Brief was filed on February 14, 2023); Brief for Respondent-Intervenors and an amicus brief by the Natural Gas Association of America were filed on February 21, 2023. Since the last Report, briefing in this case was completed, with Petitioner's (Sierra Club's) Reply Brief filed on March 14, 2023; a Joint Deferred Appendix filed on March 21, 2023; and Final Briefs filed on April 4, 2023 by Sierra Club, the FERC, INGA (Amicus for FERC) and Empire Pipeline and National Fuel Gas Supply (Intervenor for Respondent FERC). The date of oral argument and the composition of the merits panel will be provided at a later date.

- ***Order 872* (20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
  **Underlying FERC Proceeding: RM19-15[170]**
  **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*.[171] Briefing was completed and oral argument held March 8, 2022 before Judges Nguyen, Miller and Bumatay. This matter remains pending before the Court.

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

[169] *Corpus Christi Liquefaction Stage III, LLC*, 181 FERC ¶ 61,033 (Oct. 14, 2022).

[170] *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).

[171] *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.

- **Algonquin Atlantic Bridge Project Orders (21-1115*, 21-1138, 21-1153, 21-1155 consol.) and (22-1146, 22-1147 consol.)**
  **Underlying FERC Proceeding: CP16-9-012[172]**
  **Petitioners: LS Power, Algonquin, INGA**
  **Status: Cases 22-1146/47 Deconsolidated, Briefing Completed and Oral Held Apr 20, 2023; Remaining Cases (21-1115 et al.) Being Held in Abeyance Pending Disposition of 22-1146/47**

On May 3, 2021, Algonquin petitioned the DC Circuit Court of Appeals for review of the *Briefing Order* and the *April 19 Notice of Denial of Rehearings by Operation of Law*. Appearances, docketing statements and a statement of issues were due and filed June 4, 2021. Also on June 4, 2021, the FERC filed an unopposed motion to hold this proceeding in temporary abeyance, until August 2, 2021, including the fling of the certified index to the record, because "the May 3 petition for review no longer reflects the [FERC]'s latest determination in this matter." The Court granted the first abeyance motion. On November 15, 2021, the Court granted a third abeyance motion by the FERC, directing the parties to file motions to govern future proceedings by January 31, 2022. On January 31, 2022, Algonquin and INGA asked the Court to extend the abeyance by an additional 120 days (to May 31, 2022). On February 15, 2022, the Court issued an order extending the abeyance and directing the Petitioners to file motions to govern future proceedings by May 31, 2022. On May 31, 2022, Petitioners asked the Court to continue to hold this proceeding in abeyance pending the First Circuit's disposition of Algonquin's pending motions to transfer that Court's cases 20-1458 and 22-1201 (which also challenge the FERC's authorization of the "Atlantic Bridge Project").

On June 30, the First Circuit transferred cases 20-1458 and 22-1201 to the DC Circuit. The DC Circuit docketed those cases as 22-1146 and 22-1147, consolidated them with its cases challenging the Atlantic Bridge Project orders (with 21-1115 remaining the lead case), and directed the parties to file a proposed briefing schedule. On July 19, the parties filed a proposal that cases 22-1146 and 22-1147 be severed, proposed a revised briefing format and schedule for those cases, and asked the Court to continue to hold the remaining cases in abeyance (asserting that abeyance may avoid the need for briefing and adjudication of the issues that Algonquin and INGAA would press).

On August 16, 2022, the Court deconsolidated 22-1146 and 22-1147 from 21-1115 et al., which is to remain in abeyance pending a further order of the Court. The Court consolidated Cases 22-1146 and 22-1147 together and directed briefing in the consolidated cases. As previously reported, the FERC filed its Respondent Brief on January 12, 2023 and Algonquin and INGA filed a Joint Brief of Intervenors on January 26, 2023. Petitioners filed their Joint Reply Brief on February 16, 2023. Since the last Report, the Deferred Joint Appendix was filed on March 2, 2023 and Final Briefs were filed on March 9, 2023. Briefing in 22-1146/47 was completed and oral argument held April 20, 2023 before Judges Srinivasan, Millett and Tatel. This matter is pending before the Court.

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

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