Sebastian M. Lombardi
Secretary

February 23, 2023

VIA E-MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of March 2, 2023 Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the March 2023 meeting of the Participants Committee will be held **in person on Thursday, March 2, 2023, at the Seaport Boston Hotel, 1 Seaport Lane, Boston, MA in the Seaport Ballroom** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/.

For your information, the March 2 meeting will be recorded. NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, consumer advocates that are not members, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those participating in the meeting are required to identify themselves and their affiliation during the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.

For those who otherwise attend NEPOOL meetings but plan to participate in the March 2 meeting virtually, please use the following dial-in information: **866-803-2146; Passcode: 7169224.** To join WebEx, click this link and enter the event password **nepool**.

Looking ahead, please mark your calendars for the 2023 Participants Committee Summer Meeting, which will be held in person at The Equinox, Manchester Village, VT, on June 27-29, 2023 (https://www.equinoxresort.com/). As the date draws nearer, we will provide via future notices detailed information regarding that Summer Meeting, including a link to the registration page and the reservations block, once the block is open.

Respectfully yours,

/s/

Sebastian M. Lombardi, Secretary

NEPOOL
NEW ENGLAND POWER POOL

FINAL AGENDA

1. To receive an update on activities of the Joint Nominating Committee and information from and about ISO Board members Brook Colangelo and Mark Vannoy, each of whom is eligible and being considered for re-election to the Board. For your reference if and as needed, we have included with this supplemental notice ISO website bios for Messrs. Colangelo and Vannoy.

2. To approve the draft minutes of the February 2, 2023 Participants Committee teleconference meeting. The draft February 2 minutes have been marked to show the changes since the draft minutes were circulated with the initial notice.

3. [There is no Consent Agenda for this meeting.]

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

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

6. To consider and take action, as appropriate, on Market Rule 1 revisions recommended by the Markets Committee to update certain Inventoried Energy Program (IEP) program parameters. Background materials and a draft resolution are included and posted with this supplemental notice.

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

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

9. Administrative matters

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

Brook M. Colangelo

Brook Colangelo, now in his second term, is Vice President and Chief Information Officer for Waters Corporation, the world's leading specialty measurement company serving the life, materials, and food sciences industries for more than 60 years. Colangelo is responsible for driving global IT and digital business transformation. He previously served as Executive Vice President and first-ever Chief Technology Officer for Houghton Mifflin Harcourt (HMH), one of world's leading education companies. There, he led the transformation of the company's new online teaching and learning platform. Before HMH, he served as Chief Information Officer of the White House under President Barack Obama, responsible for modernizing, securing, and managing all aspects of the technology platforms and infrastructure supporting the first-ever digitally connected president of the United States. Earlier in his career, he led technology for the American Red Cross' Hurricane Recovery Program. Colangelo is a founding member of the Boston Chief Information Officer Council and is a graduate of The George Washington University.

Mark Vannoy

Mark Vannoy is President of Maine Water, having joined that company in 2019 as Vice President after serving on the Maine Public Utilities Commission (PUC) for seven years. During his tenure at the Maine PUC, which included serving four years as Chairman, Vannoy adjudicated more than 2,200 cases involving electric, gas, and water utilities. He also served as a board member of the National Association of Regulatory Utility Commissioners, a member of the Critical Infrastructure and Water Committees, and board chair of the New England Utility Cybersecurity Information Collaborative. Vannoy proudly served in the US military for 20 years and is a retired US Navy officer. He is a graduate of the United States Naval Academy and holds a master's degree in civil and environmental engineering from Cornell University.

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held via teleconference on Thursday, February 2, 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 JANUARY 5, 2023 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the January 5, 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.

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 January 5, 2023 Participants Committee meeting, which had been circulated and posted with the materials for the meeting. He highlighted that the Board had adopted a new mission statement regarding diversity, equity and inclusion (DEI), which would be used going forward to help inform the search process for new Board member candidates.

Responding to questions, Mr. van Welie explained that the Board's System Planning and Reliability Committee's discussion on the digital modeling of the New England electrical grid was focused on potential refinements and technological investments to its current modeling and simulations to further improve the effectiveness of its presentations to non-technical stakeholders on the implications of the clean energy transition and various risks to the system, including energy adequacy. Then, addressing a member's inquiry on the status of the ISO's consideration of the recommendation by the External Market Monitor to replace the Forward Capacity Market with a prompt capacity market, Mr. van Welie stated the ISO planned to undertake the necessary internal evaluations during the second half of 2023, including, if the approach wa~~i~~s to be considered further, the complexities associated with potential design and implementation of an annual versus seasonal prompt capacity market. He committed the ISO, following the completion of those internal discussions, to promptly bring the matter for stakeholder consideration thereafter.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by referring the Committee to his February operations report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through January 25, 2023, unless otherwise noted. The report highlighted: (i) Energy Market value for January 2023 was $455 million, down $873 million from the updated December 2022 value and down $1.3 billion from January 2022; (ii) January 2023 average natural gas prices were 66% lower than December average prices; (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for January ($52.89/MWh) were 56% lower than December averages; (iv) average January 2023 natural gas prices and Real-Time Hub LMPs over the period were down 77% and 64%, respectively, from January 2022 average prices; (v) average Day-Ahead cleared physical energy during the peak hours as percent of forecasted load was 98.9% during January (up from 97.5% reported for

December), with the minimum value for the month of 92.1% on Tuesday, January 3; (vi) Daily Net Commitment Period Compensation (NCPC) payments for January totaled $2.1 million, which was down $4.5 million from December 2022 and down $2.3 million from January 2022. January NCPC payments, which were 0.5% of total Energy Market value, were compromised of (a) $2 million in first contingency payments (down $4.5 million from December 2022); and (b) $75,000 in second contingency payments (down $3,000 from December 2022) (there were no voltage or distribution payments in January).

Commenting on the operational highlights, Dr. Chadalavada noted that temperatures recorded in New England for January 2023 were the warmest January temperatures since 2003 (with average temperatures between 37°F and 39°F). Average January load levels (13,600 MWh through January 25) were also the lowest January recorded values. Those lows were correspondingly reflected in January's overall Energy Market value.

Turning to transmission outages, he reported that a transmission outage, requested by the New York ISO, was scheduled February 7-8 on the Cricket Valley-to-Long Mountain Line (Line 398). He added that, if necessary, the line could be placed quickly back in service, given its short recall time, but if not, was expected to reduce transfer capabilities across ties (by approximately 500 MW New England-to-New York and by 800 MW New York-to-New England).

Dr. Chadalavada then summarized additional information related to the December 24, 2022 Capacity Scarcity Condition Event (Scarcity Event) included in his Report in response to members' requests at the January meeting. He noted that, as previously discussed, the causes for the Scarcity Event varied, but a majority of generation capacity reductions were due to mechanical problems. He also reviewed the timing of the outages and reductions, the energy sources behind the resources producing energy during the Scarcity Event's peak hour, and the estimated fuel-oil burn and replenishment between December 20 and January 3.

Before responding to questions, Dr. Chadalavada summarized preparations for the extreme cold weather expected to follow the day after and into the weekend following the meeting. He reported that the ISO was in regular discussions with pipeline operators, had operational flow orders in place, and did not foresee any fuel supply concerns. The ISO would evaluate the Day-Ahead Energy M~~m~~arket results available later that day to formulate the weekend's operating plan. Unlike the Scarcity Event, the ISO did not expect any uncertainty related to imports from Quebec (particularly given projections for a near-all-time peak in Quebec, which in turn would reduce projected imports). He added that the ISO did not plan to implement any material changes based on the experience of the Scarcity Event, including with respect to its load forecasting models (though the ISO remained committed to exploring and implementing improvements to the forecasting models and processes). Further, he noted that the ISO would consider additional commitments to maintain ~~o~~Operating ~~r~~Reserves if it foresaw a higher risk of non-delivery, but otherwise would continue its practice of balancing reliability and the efficiency/performance of the market. In response to questions, he confirmed that the ISO had the information and situational awareness it believed necessary to rely on reserves from fast-start resources without Day-Ahead commitments, including availability of fuel to operate, and to a lesser extent from some of the other off-line reserves.

Responding to requests for additional information on the Quebec transmission outages and curtailment of exports during the Scarcity Event, Dr. Chadalavada explained generally that Quebec had transmission outages caused by extensive icing during the days leading up to the Scarcity Event. On December 23, Quebec had three major circuits out of service; however, Quebec had expected one of those circuits to return to service on December 24. As time passed, Quebec became less confident that the circuit would be restored in time, prompting conversations on potential curtailments. In response, the ISO made assumptions concerning potential curtailments, and made adjustments (as reflected by the delta between the earlier and the later Morning Report). Further curtailment transpired throughout the operating day, which contributed to the Scarcity Event, but not singularly responsible for it. As to requests for specifics related to the impacted transmission lines and generation stations, Dr. Chadalavada stated he did not have information that could be shared during the meeting, but would provide further specifics if and to the extent permitted under the Information Policy, and internal ISO and Hydro-Quebec policies.

Responding to additional questions on the Scarcity Event, Dr. Chadalavada opined that 10 to 15% of the mechanical problems that led to generating capacity reduction were caused by the cold weather experienced on December 24, with the majority of the outages more readily attributable to the vintage and characteristics of the generation units that were online. He clarified that the gas scheduling issues referred to in the Report related to the delay in, rather than the availability of, the injection of liquefied natural gas (LNG) into the pipeline systems. A member questioned whether, moving forward, additional information could be made available to the public in real-time as conditions shift throughout the day. Dr. Chadalavada shared that the ISO was considering that possibility specifically, balancing what it presumed was the usefulness of providing up-to-date information to which the market could respond against the practicality and limitations of preparing and publishing such information (e.g., in an additional morning report). With those caveats, he committed to report back once the ISO had completed that consideration.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the February 1 Litigation Report that had been circulated and posted before the meeting. The following developments were highlighted:

(i) *RENEW Network Upgrades O&M Cost Allocation Complaint (EL23-16).* Numerous parties had intervened and many had filed responses, comments and protests;

(ii) *Participants Agreement Amendment No. 12 (ISO Board Member Age Limit Increase) (ER23-980)*. The ISO and NEPOOL had jointly filed for approval changes to the Participants Agreement (§ 9.2.3(a)) that raise the age limitation prohibiting the election or re-election of any candidate to the ISO Board of Directors from 70 to 75. Comments were due on or before February 21, 2023; ~~and~~

(iii) *Joint Federal-State Task Force on Electric Transmission (AD21-15).* At NARUC's recommendation, the FERC had appointed Connecticut Public Utilities Regulatory Authority (CT PURA) Chairman Marissa Gillett to the Joint Federal-State Task Force on Electric Transmission (Task Force) to replace former Massachusetts Department of Public Utilities Chairman Matt Nelson. Chairman Gillett and Commissioner Riley Allen from the Vermont Public Utility Commission would serve as the New England state commission representatives through the end of the 2022-2023 term. The next Task Force meeting was scheduled for February 15~~.~~; and

(iv) *Seabrook Complaint (EL21-6) and Seabrook Declaratory Order Petition (EL21-3).* In an order issued the evening before the meeting (and after nearly two and one-half years of litigation), the FERC had directed Seabrook to replace the Seabrook station breaker. Replacement was scheduled to occur during the Fall of 2024 refueling outage. Further details on other points addressed in the complaint proceedings were summarized and could be found in the Litigation Report.

COMMITTEE REPORTS

Markets Committee (MC). Mr. William Fowler, the MC Vice-Chair, reported that the next MC meeting was scheduled for three days (February 7-9, 2023) at the AC Hotel in Worcester, MA. He highlighted that the MC's action on proposed Inventoried Energy Program (IEP) amendments was scheduled for Wednesday, February 8.

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that the RC had two meetings scheduled in February, one on February 14 and the other following the TC meeting, on February 22, in Westborough, MA. The Valentine's Day meeting would include a discussion on ~~r~~Resource ~~c~~Capacity A~~a~~ccreditation; the February 22 meeting would cover tie-benefits, coordination agreements with neighboring Control Areas, and other routine business.

Transmission Committee (TC). Mr. David Burnham, TC Vice-Chair, reported that the next TC meeting was scheduled for the morning of February 22 in Westborough, MA and would focus on the potential elimination of the timeout rules in the Forward Capacity Market.

Budget and Finance Subcommittee (B&F). Mr. Tom Kaslow, the B&F Subcommittee Chair, reported that the next B&F Subcommittee meeting was scheduled for February 10.

Membership Subcommittee. Mr. Gerity, on behalf of Ms. Sarah Bresolin, Membership Subcommittee Chair, reported that the next Membership Subcommittee meeting was scheduled by Zoom for February 13. All those interested were encouraged to participate.

Joint Nominating Committee (JNC). Mr. Cavanaugh noted that the JNC's next meeting was scheduled to be held via teleconference on March 3. The JNC planned to review the list of candidates for the presumptively one open Board position. He confirmed that Messrs. Mark

Vannoy and Brook Colangelo would be joining the March Participants Committee meeting (to be held at the Seaport Hotel Boston) to discuss their experiences serving on the ISO Board.

There being no other business, the meeting adjourned at 11:25 a.m.

Respectfully submitted,

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Sebastian Lombardi, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN FEBRUARY 2, 2023 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Advanced Energy United	Associate Non-Voting	Caitlin Marquis		
American PowerNet Management	Supplier			Joyceline Chow
Ampersand Energy Partners LLC	Supplier			Julia Frayer
AR Large Renewable Gen. (RG) Group Member	AR-RG	Abby Krich		
AR Small Distributed Gen (DG) Group Member	AR-DG	Andrew Karetsky		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell		
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	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
Pawtucket Power Holding Company	Generation	Dan Allegretti		
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	Bill Dornbos
Conservation Law Foundation (CLF)	End User	Phelps Turner		
Constellation Energy Generation	Supplier		Bill Fowler	
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
DC Energy	Supplier	Bruce Bleiweis		
Deepwater Wind Block Island	Generation	Eric Wilkerson		
DTE Energy Trading, Inc.	Supplier			José Rotger
Durgin and Crowell Lumber Co., Inc.	End User			Bill Short
Dynegy Marketing and Trade, Inc.	Supplier			Bill Fowler
ECP Companies Calpine Energy Services, LP New Leaf Energy	Generation	Brett Kruse Liz Delaney		Bill Fowler, John Flumerfelt
Elektrisola, Inc.	End User			Bill Short
Emera Energy Services	Supplier			Bill Fowler
Enel X North America, Inc.	AR-LR	Alex Worsley		
Environmental Defense Fund	End User	Jolette Westbrook		
Eversource Energy	Transmission	James Daly	Dave Burnham	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
First Point Power, LLC	Supplier	Peter Schlieffelin		
Galt Power, Inc.	Supplier	José Rotger		
Garland Manufacturing Company	End User			Bill Short

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN FEBRUARY 2, 2023 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Generation Group Member	Generation		Abby Krich	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Granite Shore Power Companies	Generation			Bob Stein
Great River Hydro	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned Entity		Matt Ide	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	Louis Guilbault	Bob Stein	
Hammond Lumber Company	End User			Bill Short
Hanover, NH (Town of)	End User			Bill Short
Harvard Dedicated Energy Limited	End User	Joyceline Chow		
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Matt Ide	
Holyoke Gas & Electric Department	Publicly Owned Entity		Matt Ide	
Hull Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
Icetec Energy Services, Inc.	AR-LR	Doug Hurley		
Industrial Energy Consumer Group	End User	Dan Collins		
Ipswich Municipal Light Department	Publicly Owned Entity		Matt Ide	
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths	Nancy Chafetz	
Jupiter Power	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
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide	
Mass. Attorney General’s Office (MA AG)	End User	Ashley Gagnon	Jaimie Donovan	Tina Belew
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Dept. Capital Asset Management	End User			Nancy Chafetz
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
Nautilus Power, LLC	Generation	Dan Pierpont	Bill Fowler	
New England Power (d/b/a National Grid)	Transmission	Tim Brennan	Tim Martin	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson		
New Hampshire Electric Cooperative	Publicly Owned Entity		Brian Callnan	Brian Forshaw
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	

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PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN FEBRUARY 2, 2023 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Power Marketing LLC	Supplier		Pete Fuller	
Nylon Corporation of America	End User			Bill Short
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		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		
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	
Sunrun Inc.	AR-DG			Peter Fuller
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	Karin Stamy	
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw
Versant Power	Transmission	Lisa Martin		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide	
Walden Renewables Development LLC	Generation			Abby Krich
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	
ZTECH, LLC	End User			Bill Short

Summary of ISO New England Board and Committee Meetings

March 2, 2023 Participants Committee Meeting

Since the last update, the Compensation and Human Resources Committee met virtually on February 3. The Information Technology and Cyber Security Committee met on February 15; and the Audit and Finance Committee, the Nominating and Governance Committee, and the Board of Directors met on February 16. The February 15-16 meetings were held in Holyoke, Massachusetts.

The Compensation and Human Resources Committee discussed the Company's corporate performance for 2022, and the feedback from the various committees of the Board on specific projects completed in 2022, and officer compensation for 2023. The Committee agreed to spend additional time at a future meeting on an in-depth discussion of the work of Mercer, the Company's compensation consultant, to benchmark various critical jobs.

The Information Technology and Cyber Security Committee was provided with an update on the Company's cyber security plan, and discussed completed projects and the plan's major areas of emphasis going forward. The Committee was also provided a status report on GE's Next Generation Electricity Market (nGEM) project. The Committee discussed the schedule for completion, and costs, of various phases of the project, which culminates with implementation in 2025. The Committee then reviewed a summary of the Company's 2023 cyber security insurance program. The Committee also considered the Board's oversight of multi-year IT/cyber security capital projects.

The Audit and Finance Committee met with the Company's Investment Manager and the Internal ERISA 3(38) Committee for a review of the Company's benefits plan assets and 401(k) plan, and an analysis of investment options and details regarding the mix, cost, and performance of plan investments. The Committee approved significant accounting estimates used in the Company's budgeting and financial statements, including earnings and discount rates, health care trends, and depreciation. The Committee reviewed the annual vendor report, which showed the top fifteen vendors and a comparison to the previous period; the Committee noted that this exercise helps identify risks related to dependence on individual vendors. The Committee approved the use of an external audit firm to perform audit services related to the Mystic cost-of-service agreement. The Committee then met in executive session and reviewed Internal Audit Department results for 2022 and considered the performance and 2023 compensation for the Director of Internal Audit.

The Nominating and Governance Committee received an update on Joint Nominating Committee (JNC) activities and formally nominated the incumbent directors who are eligible for re-election in 2023 (Brook Colangelo and Mark Vannoy). The Committee reviewed a second draft of the Company's annual communications plan. The Committee also discussed interactions with, and activities of, the New England states, and considered topics for discussion at the Board's meeting with the states in March. Finally, the Committee agreed to launch the process for facilitated Board and committee evaluations later in the month.

The Board of Directors received a report from the CEO and COO on recent cold weather operations, and discussed the regional importance of the Everett LNG terminal and the potential consequences of its retirement. The Board considered the respective roles and authorities of the various stakeholders with interest in Everett. The Board also discussed the second New England Energy Adequacy Forum being planned by the Federal Energy Regulatory Commission, and the potential to discuss the results of the EPRI study on extreme weather, as well as potential energy adequacy solutions for further study. In executive session, the Board considered and approved the corporate performance results for 2022 and officer compensation for 2023.

NEPOOL PARTICIPANTS COMMITTEE | 3/2/23
Meeting Agenda item #5

NEPOOL Participants Committee Report

March 2023

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Highlights

Data is through February 22nd unless otherwise noted.

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: January 2022 Energy Market value totaled $552M
  - February 2023 Energy market value was $512M, down $40M from January 2023 and down $704M from February 2022
    - February 2023 natural gas prices over the period were 58% higher than January average values
    - Average RT Hub Locational Marginal Prices ($52.84/MWh) over the period were 4.6% higher than January averages
      - DA Hub: $59.30/MWh
    - Average February 2023 natural gas prices and RT Hub LMPs over the period were down 49% and 51%, respectively, from February 2022 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 99.7% during February, up from 98.9% during January*
    - The minimum value for the month was 92.1% on Sunday, February 5th

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

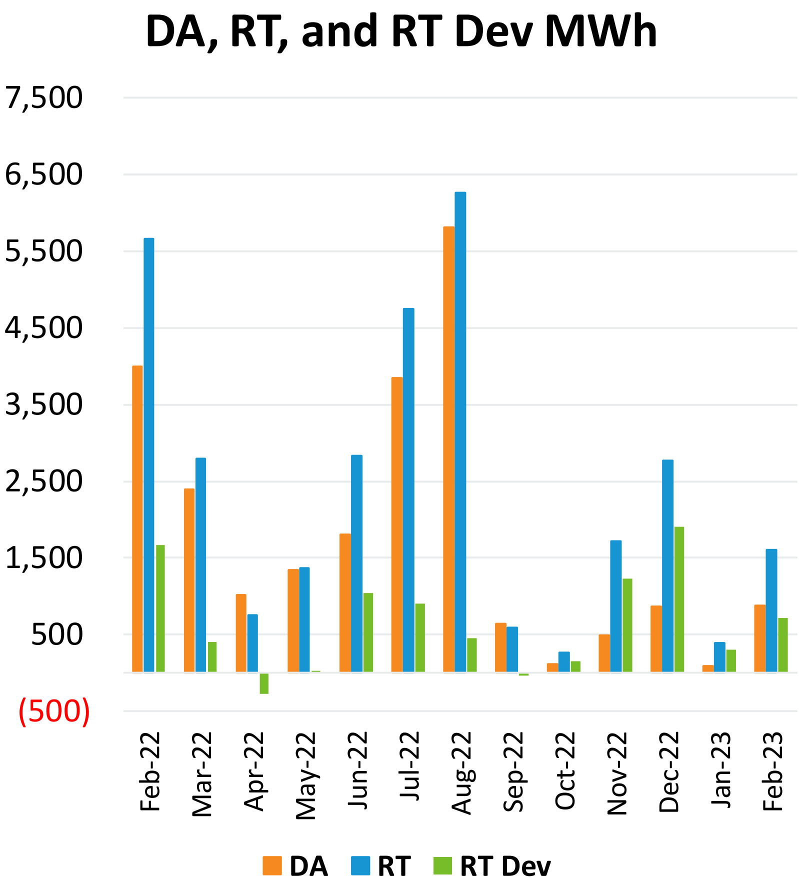
*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

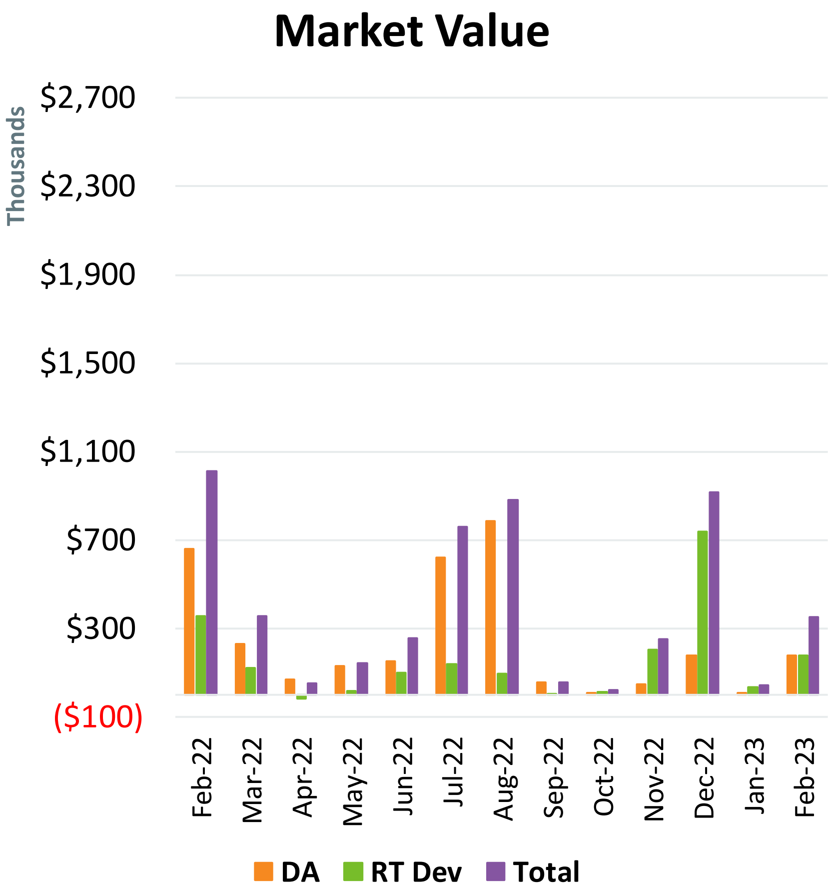
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - February 2023 NCPC payments totaled $2.4M over the period, down $46K from January 2023 and down $1.6M from February 2022
    - First Contingency payments totaled $2.3M, down $49K from January
      - $2.2M paid to internal resources, down $46K from January
        - » $206K charged to DALO, $1.4M to RT Deviations, $606K to RTLO*
      - $59K paid to resources at external locations, up $22K from January
        - » $17K charged to DALO at external locations, $42K to RT Deviations
    - Second Contingency payments totaled $58K, down $50K from January
    - Distribution payments totaled $27K, up $27K from January
    - Voltage payments were 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) - $345K; Rapid Response Pricing (RRP) Opportunity Cost - $261K; 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

- The Economic Study Process Improvement project to update Attachment K of the OATT was filed with FERC on January 27
- Preparations are ongoing for FCA 17, which will commence on March 6
  - Mock Auction conducted on Feb 27
- Public Meeting date for the 2023-24 RSP is set for November 1 and will be held concurrently with the ISO Open Board Meeting
- The Load Forecast Committee discussed the electrification forecasts and draft energy and demand forecasts on February 24

Highlights

- The lowest 50/50 and 90/10 Winter Operable Capacity Margins are projected for week beginning February 11, 2023.
- The lowest 50/50 and 90/10 Preliminary Spring Operable Capacity Margins are projected for week beginning May 13, 2023.

Forward Capacity Market (FCM) Highlights

- CCP 14 (2023-2024)
  - Third and final annual reconfiguration auction (ARA3) will be held on March 1-3, and results will be posted no later than March 31
- 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 – Capacity Commitment Period

FCM Highlights, cont.

- CCP 17 (2026-2027)
  - FCA 17 will model the following zones:
    - Export-constrained zones: Northern New England and Maine nested inside Northern New England
    - Rest-of-Pool
  - FCA 17 Installed Capacity Requirement and related values were filed with FERC on November 8, 2022 and accepted on December 20, 2022
  - ISO submitted the FCA 17 informational filing to FERC on December 21, 2022 and errata filing on January 12; both were accepted on February 17
  - Preparations are ongoing for the auction, which will commence on March 6

FCM Highlights, cont.

- CCP 18 (2027-2028)
  - The qualification process has started, and training materials are under development
  - Topology certifications were sent to the TOs on October 11, 2022
    - TOs identified in-service dates for new transmission projects and revisions to previously certified projects
    - Approved projects were shared with the RC at their January meeting
  - Capacity zone development discussions began at the December 13, 2022 PAC meeting
    - All subsequent reconfiguration auctions model the same zones as the FCA
  - ISO to calculate and post the FCA 18 dynamic delist bid threshold price in March

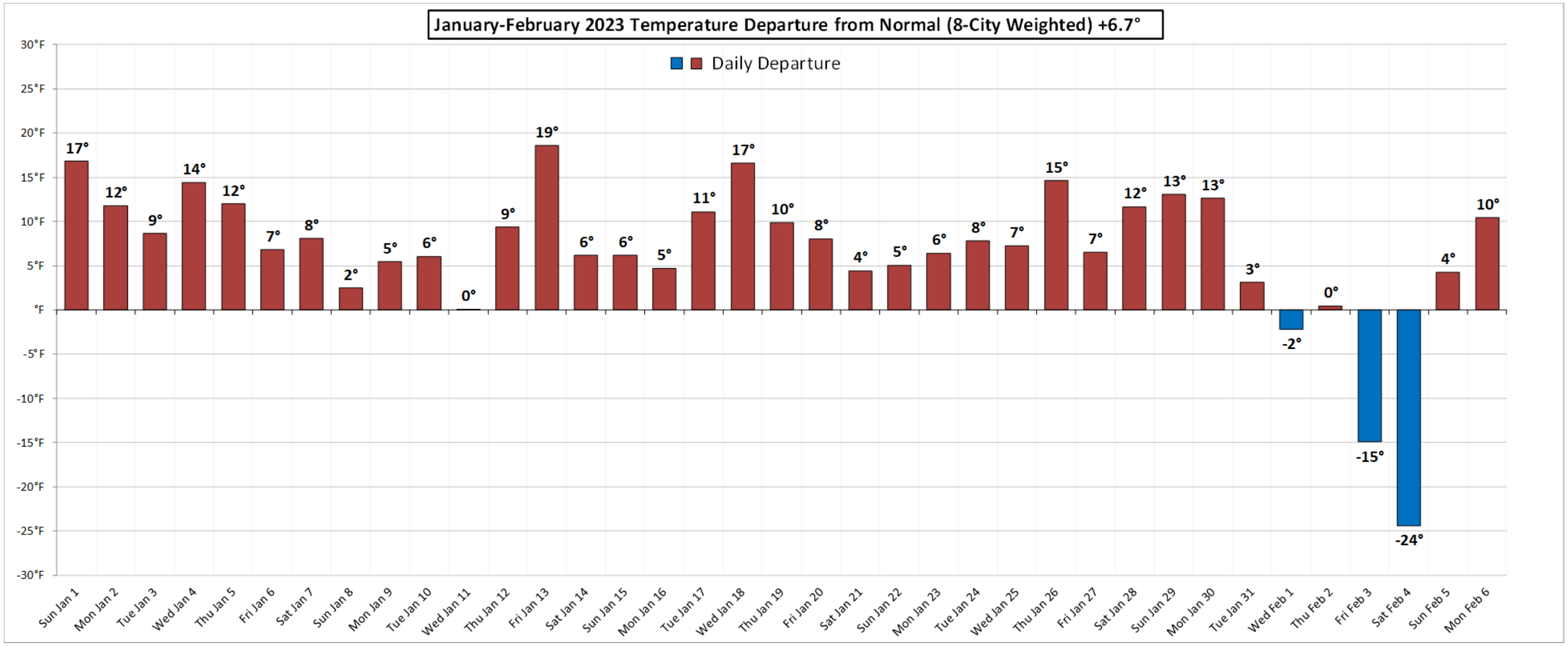
Summary of Operations, February 3rd – 4th, 2023

Short-Duration, Bitterly Cold Air Mass Affected The Region on February 3 and 4

- Bitterly cold air entered the region on the afternoon of Friday, February 3; the entire region experienced below zero temperatures on the morning of Saturday, February 4
  - High winds also accompanied the bitter cold temperatures, resulting in most areas reporting wind chill values of 30° to 50° below zero
  - Southern New England locations including Boston (-10°F), Providence (-9°F), and Bridgeport (-4°F), experienced top-10 coldest temperatures since 1950
- For the February 3 operating day, ISO forecasted a peak load of 19,300 MW (HE19) and a capacity surplus of ~4,200 MW
  - Actual peak load was 19,529 (HE19) with a capacity surplus of ~2,900 MW
- For the February 4 operating day, ISO initially forecasted a peak load of 18,320 MW (HE19) and a capacity surplus of ~3,000 MW
  - Based on lower than expected temperatures across the region, ISO revised the February 4 load forecast twice, first to 18,900 MW (in the early morning) and then to 19,600 MW (at approx. 1530)
  - Actual peak load was 19,349 (HE18) with a capacity surplus of ~1,800 MW

The Region Experienced The Coldest Temperature Departure From Normal Since 2016

- Prior to this cold snap, New England had experienced above normal temperatures for the entire month of January
- Average temperatures were 15°F below normal on February 3, but readings were even colder on February 4, dropping to 24°F below normal



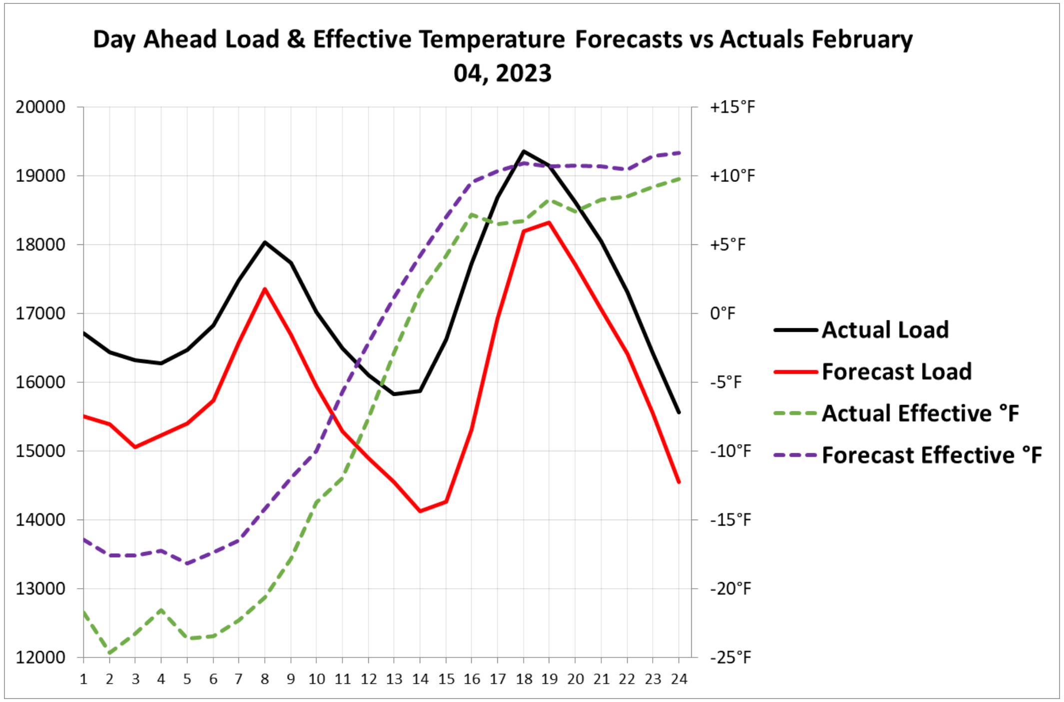
Load Forecast Error Was Significant on Saturday, February 4

- Load forecast for February 3 was highly accurate; 1.17% error during the peak hour

- Following the February 3 peak, system load began to diverge significantly from the forecast

- The February 4 load forecast was inaccurate throughout the day; forecast error was ~6% during the peak hour

- Primary factors contributing to the forecast error were actual temperatures considerably colder than forecast and a lack of historical load forecast data corresponding to the extreme cold

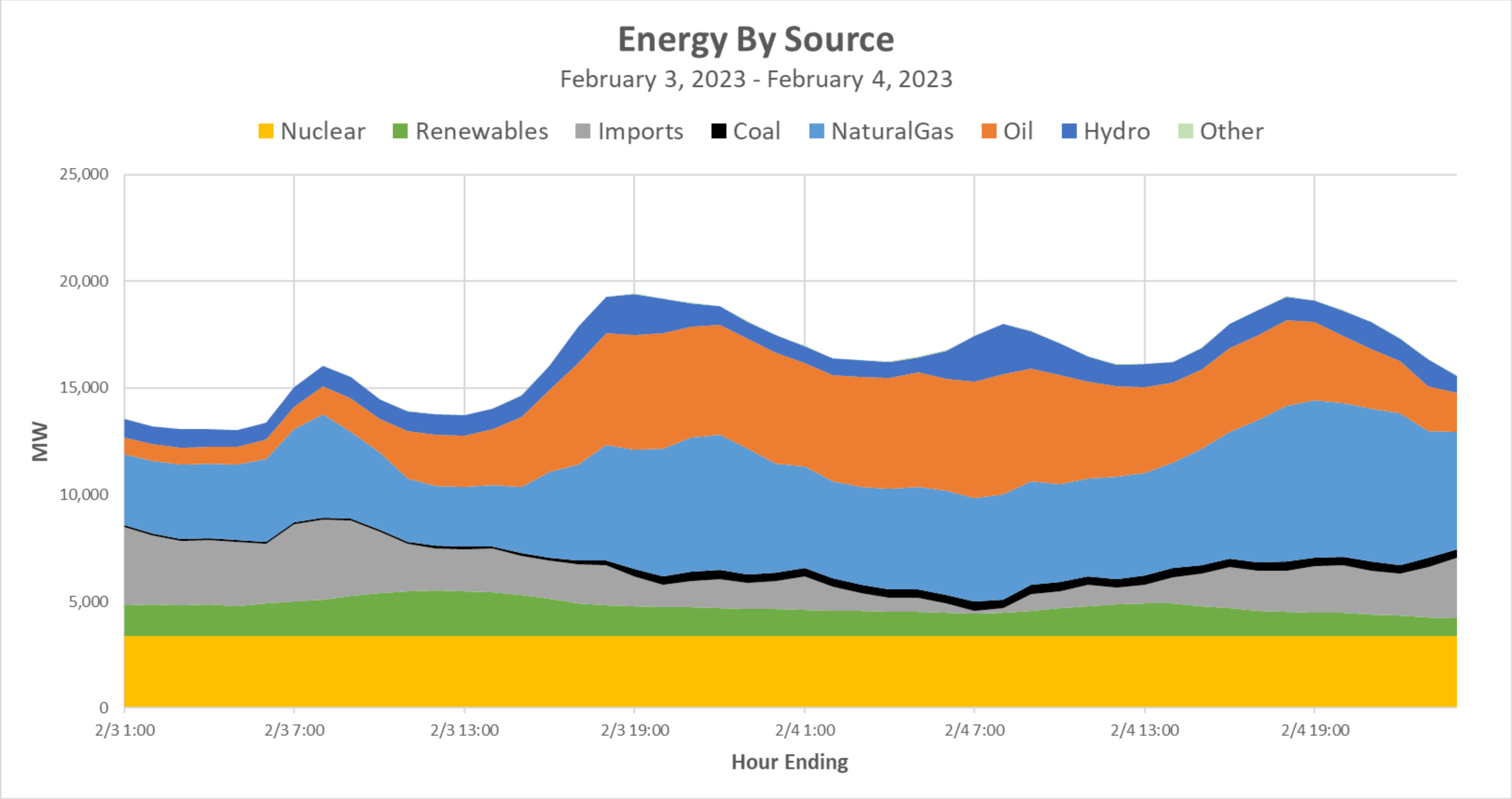


Use of Actual Weather in Forecast Models Generates Improved Results

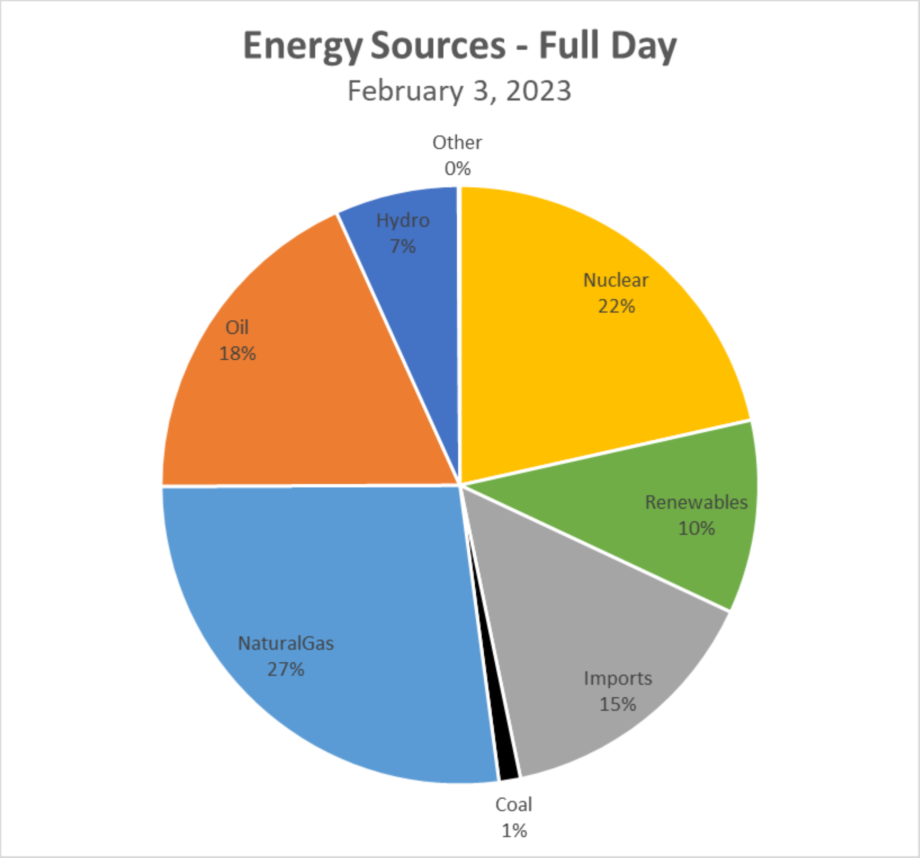
- In order to assess factors contributing to the large forecast error, ISO's Forecasting team utilized the actual weather conditions from February 3 to model the expected loads (i.e. backcast)
- Using actual weather conditions to model loads, error was reduced, ranging from ~2-3% across the various models
- ISO's Forecasting team continues to pursue enhancement of load forecasting tools and methods with several initiatives included as part of the Annual Work Plan

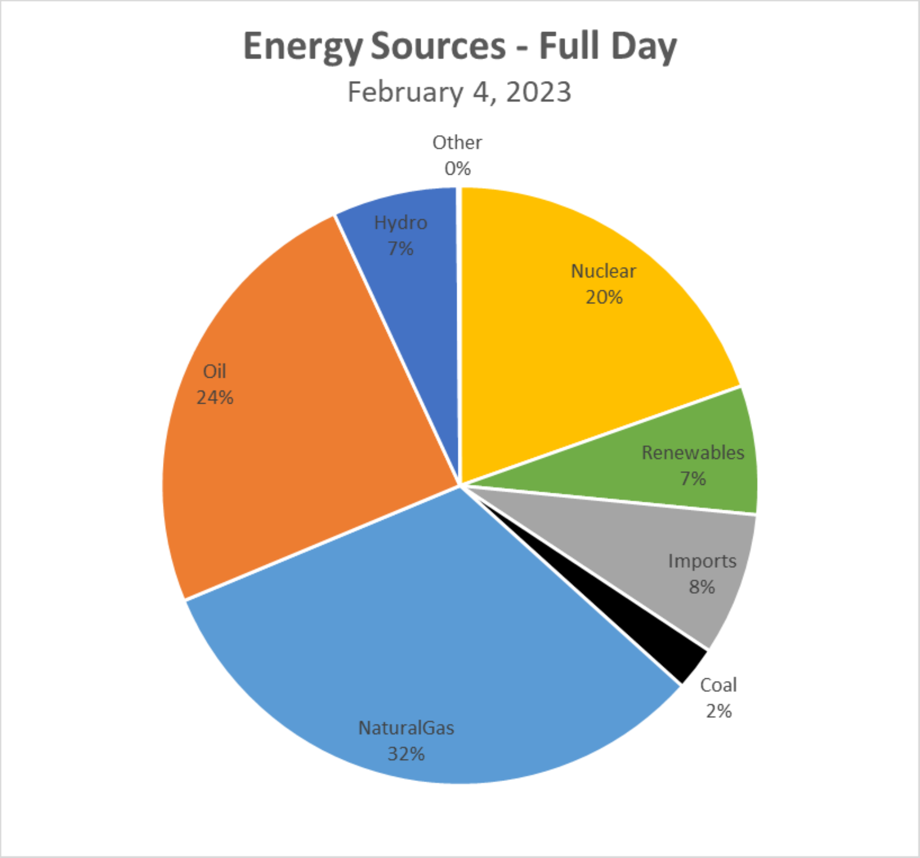
Energy By Source, February 3 – 4

- Natural gas, fuel-oil, and nuclear were the largest sources of energy during the cold snap; following the February 3 peak hour, energy contributions from imports decreased as flows to Quebec increased



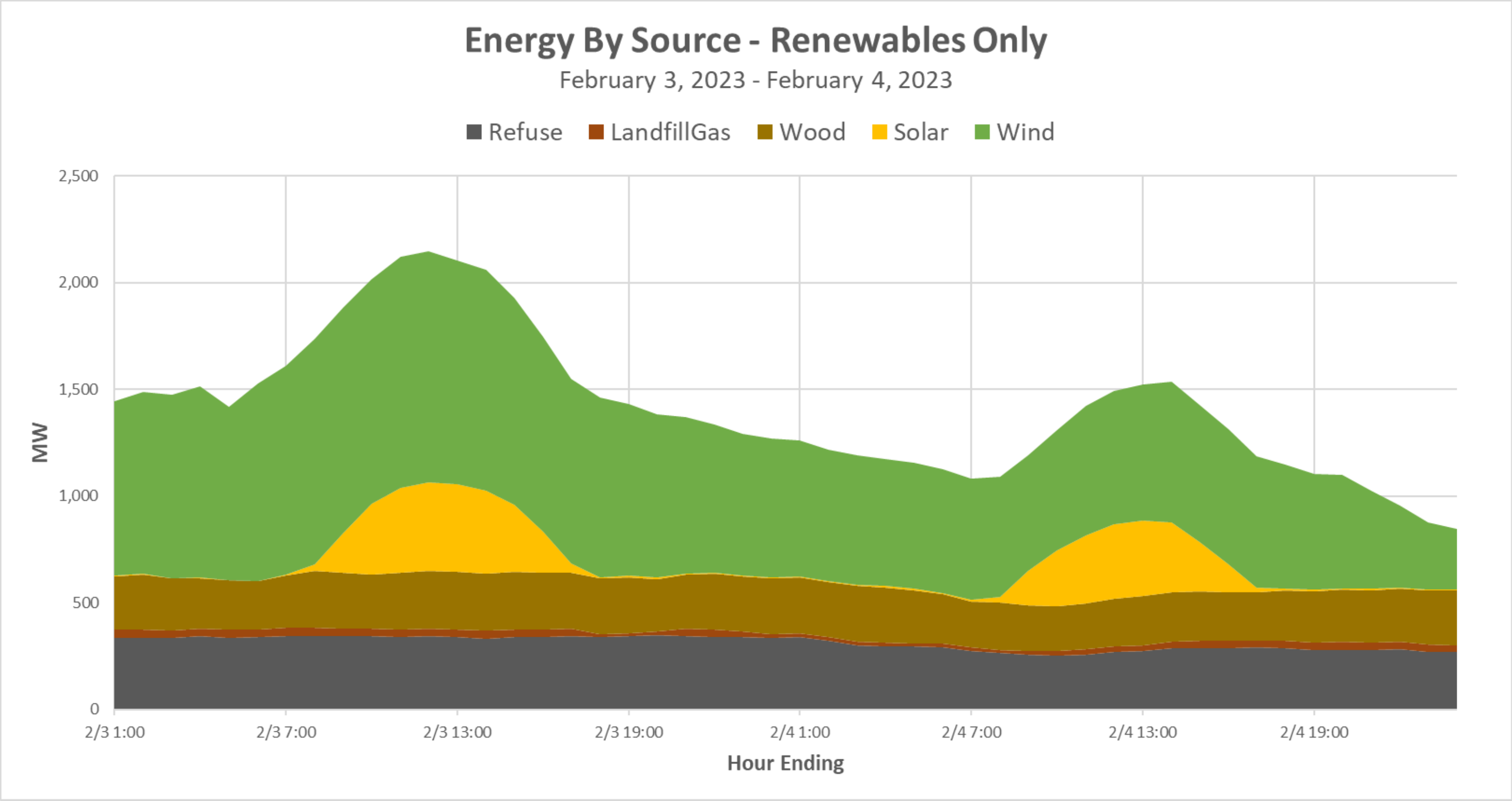
Energy By Source, February 3 – 4 , cont.





Energy Sources - Renewables

- Contributions from wind peaked at ~1,100 MW around noon on February 3 and averaged ~725 MW during the two-day cold snap



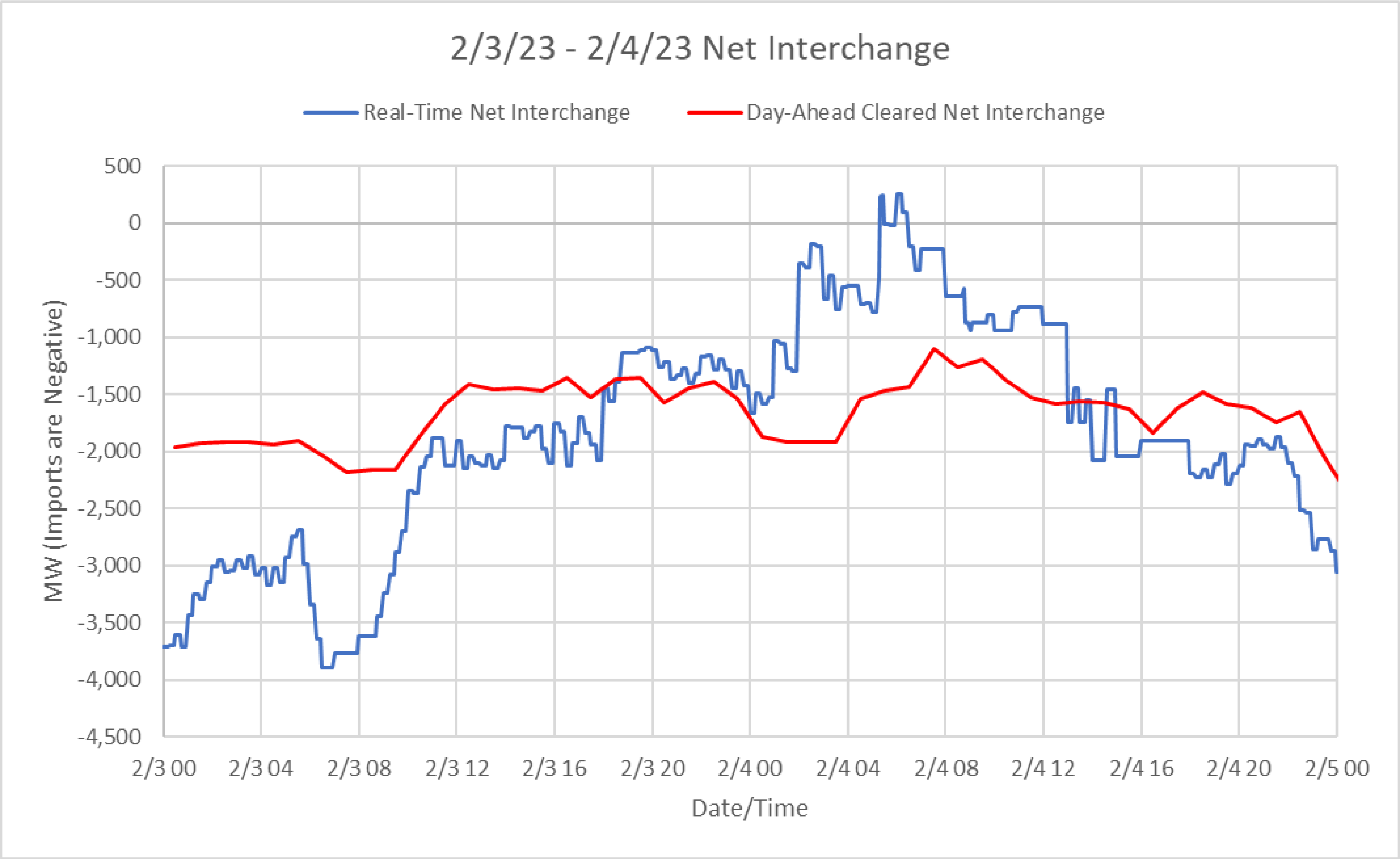
LNG and Fuel Oil Usage During the Cold Snap

- Over the two day period, St. John LNG scheduled ~1.2 Bcf into the pipeline; this is approximately the same volume scheduled for the entire winter period prior to the cold snap
- Prior to the cold weather, fuel-oil levels were at their highest of the winter season (~50%); aggregate usable fuel-oil level is now ~113M gallons (46%)
- Approx. 13.5M gallons of fuel-oil was burned during the cold snap
  - ~69% of fuel-oil burn was by residual fuel oil (RFO) generators, ~31% by distillate fuel oil (DFO) generators

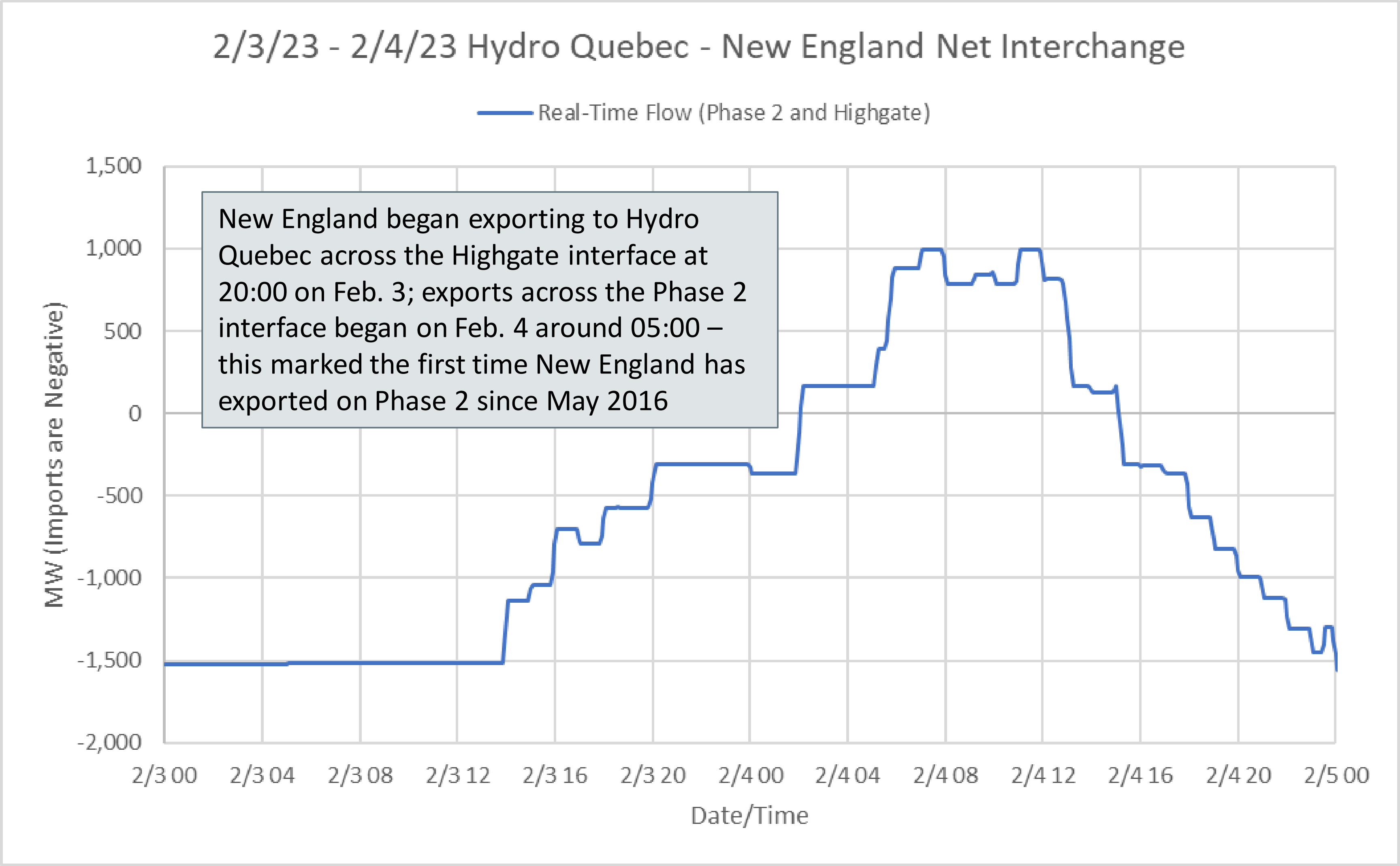
Generator Outages and Reductions

- Generators experienced outages and reductions at times throughout the cold snap
- In total, across the February 3-4 operating days, ~2,400 MW of generating capacity was unavailable during peak hours due to unexpected outages or reductions
- Outage and reduction causes varied; the primary reason was mechanical failures (vibrations, fan problems, other equipment issues etc.)
  - No generator outages or reductions were caused by natural gas pipeline issues or scheduling problems

Beginning on February 4, Interchange Schedules Deviated Significantly From Day-Ahead Schedules



Energy From Hydro-Quebec Was Impacted by Extreme Cold Weather Conditions

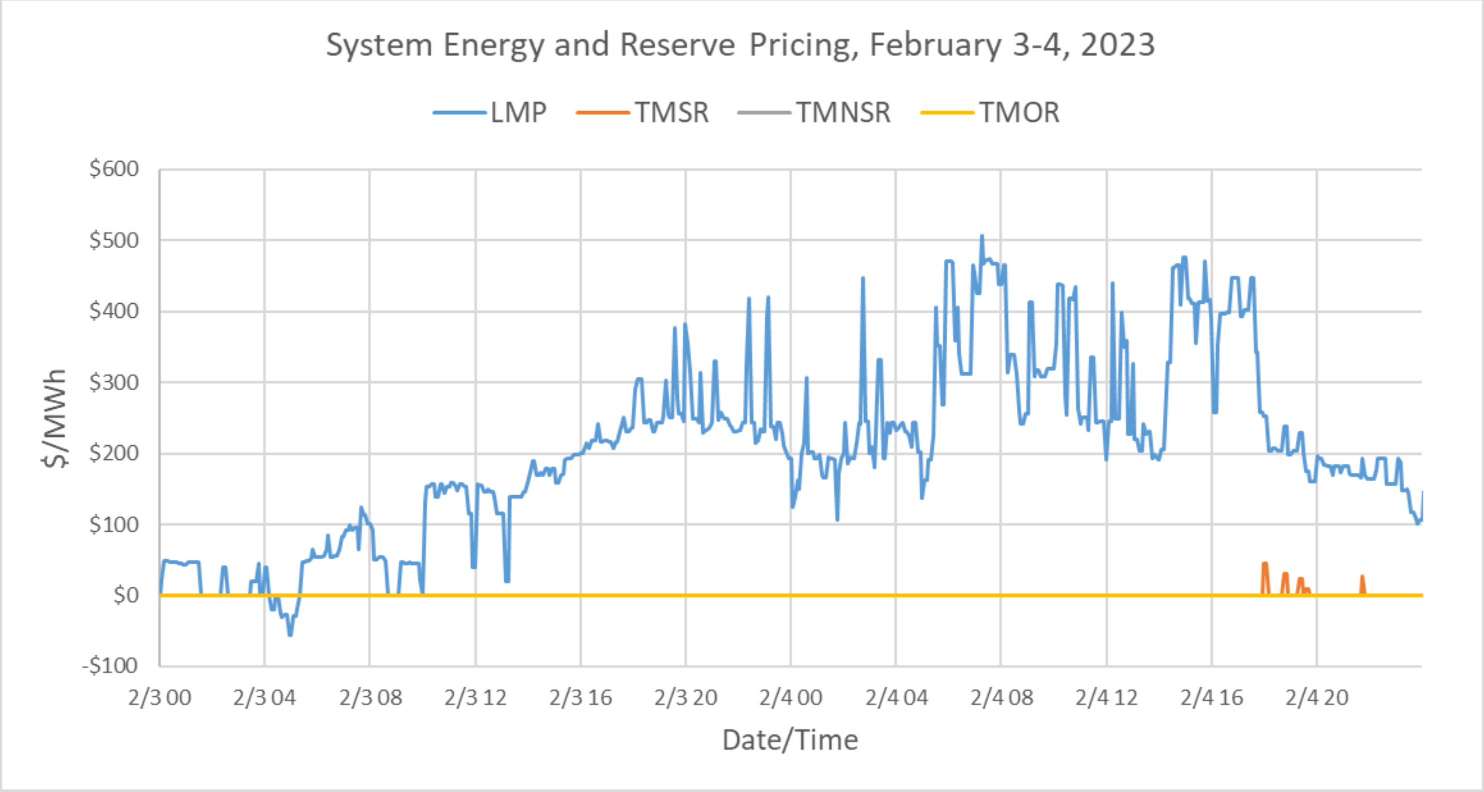


System Conditions in Hydro-Quebec

- Hydro Quebec set an all-time peak load of 42,790 MW on February 3 (HE18)
- During the February 3 peak hour, Hydro Quebec experienced forced outages of some generation plants and utilized demand response
- During the February 4 morning peak (HE08), Hydro Quebec was importing from neighboring areas including ~1000 MW from New England

System Energy and Reserve Pricing

- System LMPs averaged ~ $204/MWh during the two-day cold snap; non-zero system ten-minute spinning reserve prices occurred infrequently and there were no instances of TMOR or TMNSR pricing



SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (3.7°F) Max: 62°F, Min: -10°F Precipitation: 1.08" –Below Normal Normal: 2.96" Snow: 2.80"	Hartford	Temperature: Above Normal (4.5°F) Max: 63°F, Min: -9°F Precipitation: 1.11" - Below Normal Normal: 2.89" Snow: 1.00"

Peak Load:	19,529 MW	February, 03, 2023	19:00 (ending)

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

Procedure	Declared	Cancelled	Note
None			

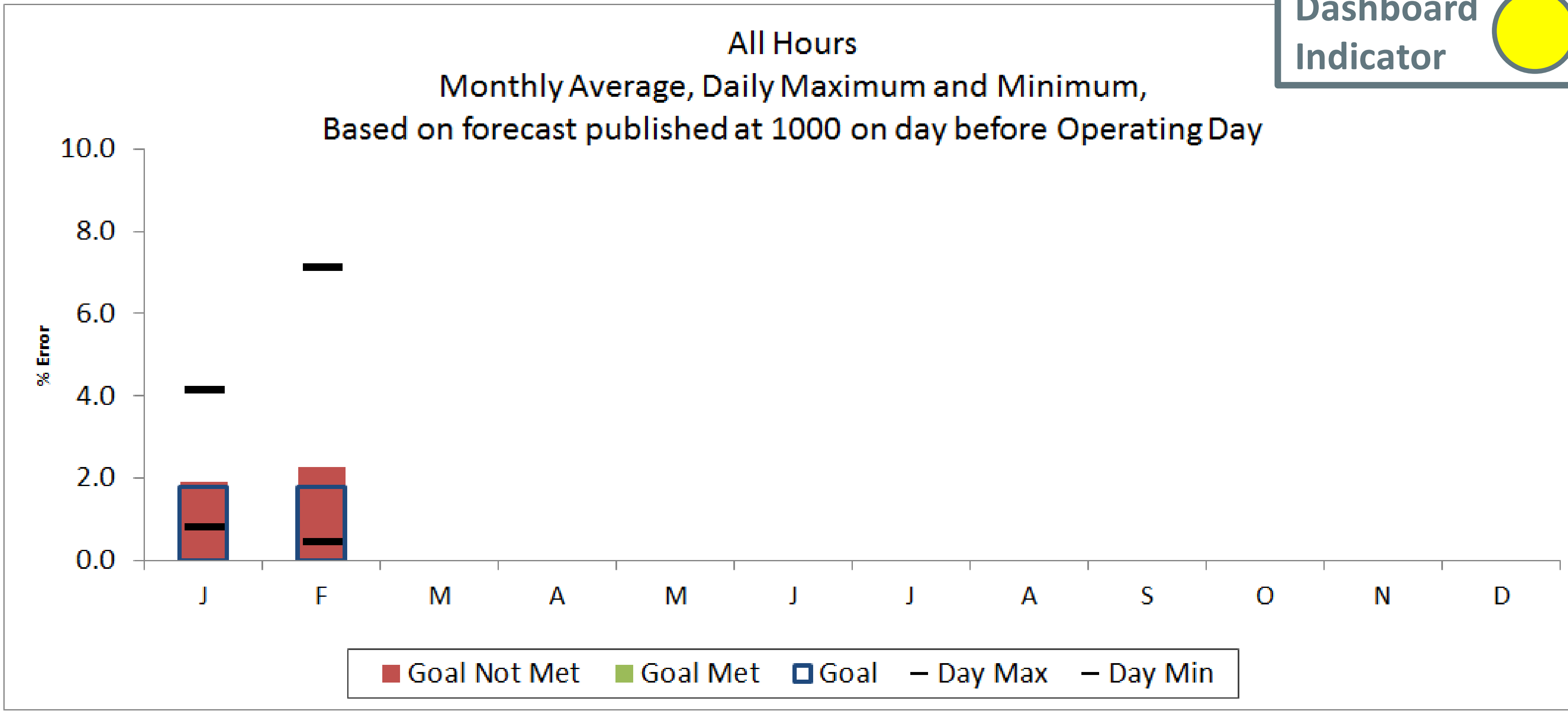
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
2/02/2023	NBP	312
2/03/2023	NYISO	600
2/03/2023	NYSIO	526
2/03/2023	NBP	165
2/04/2023	IESO	1700
02/11/2023	IESO	900

2023 System Operations - Load Forecast Accuracy

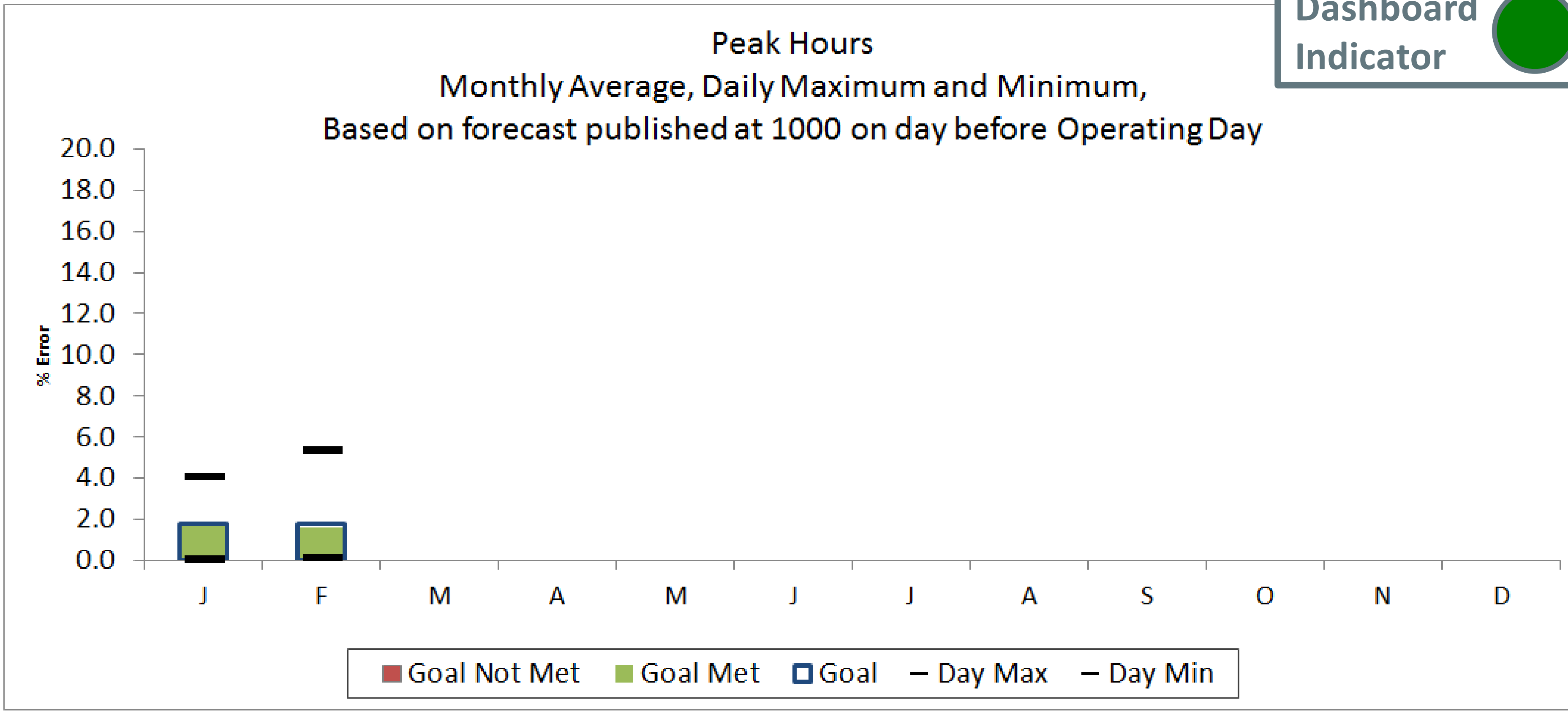
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.14	7.12											7.12
Day Min	0.80	0.46											0.46
MAPE	1.91	2.28											2.09
Goal	1.80	1.80											

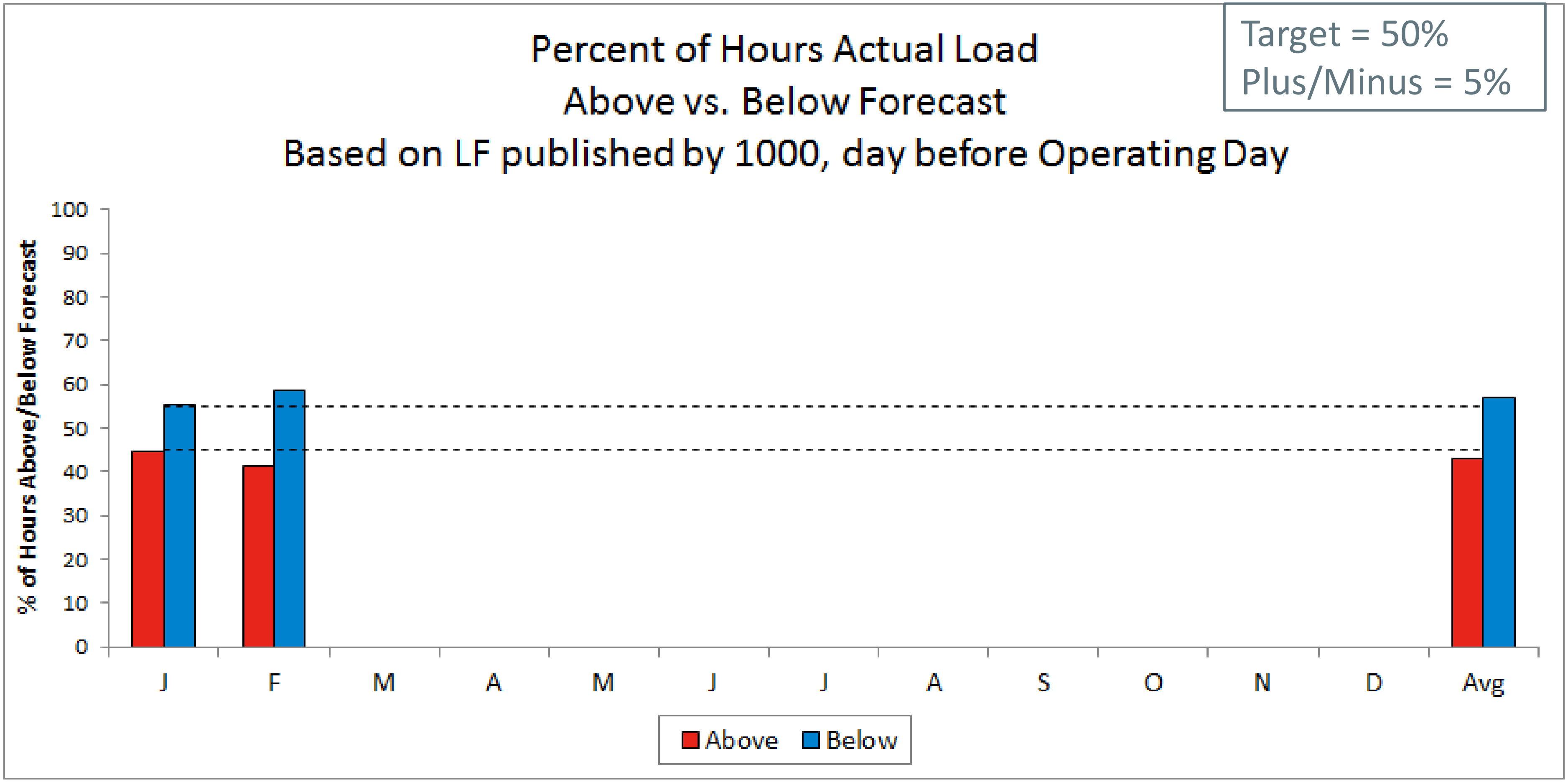
2023 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



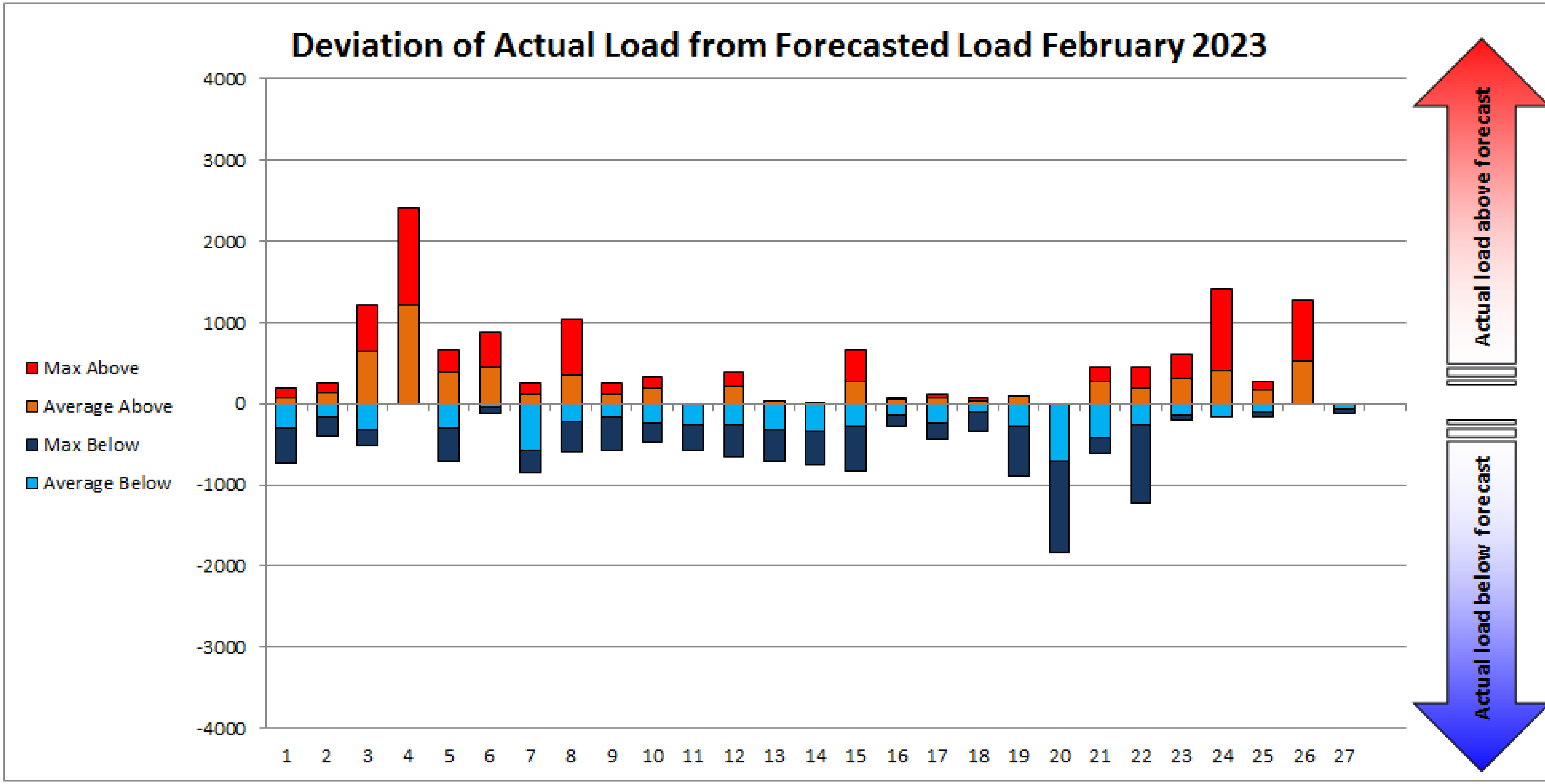
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.05	5.32											5.32
Day Min	0.01	0.08											0.01
MAPE	1.70	1.59											1.65
Goal	1.80	1.80											

2023 System Operations - Load Forecast Accuracy cont.

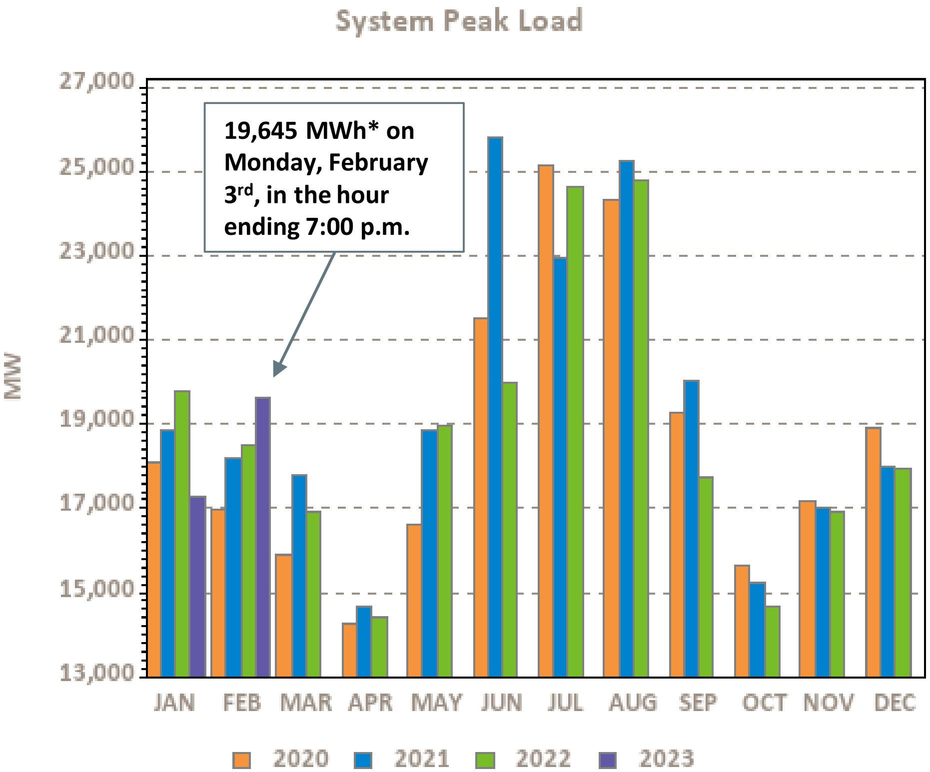


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	44.6	41.3											43
Below %	55.4	58.7											57
Avg Above	471.4	448.4											471
Avg Below	-394.6	-459.5											-460
Avg All	-10	-12											-11

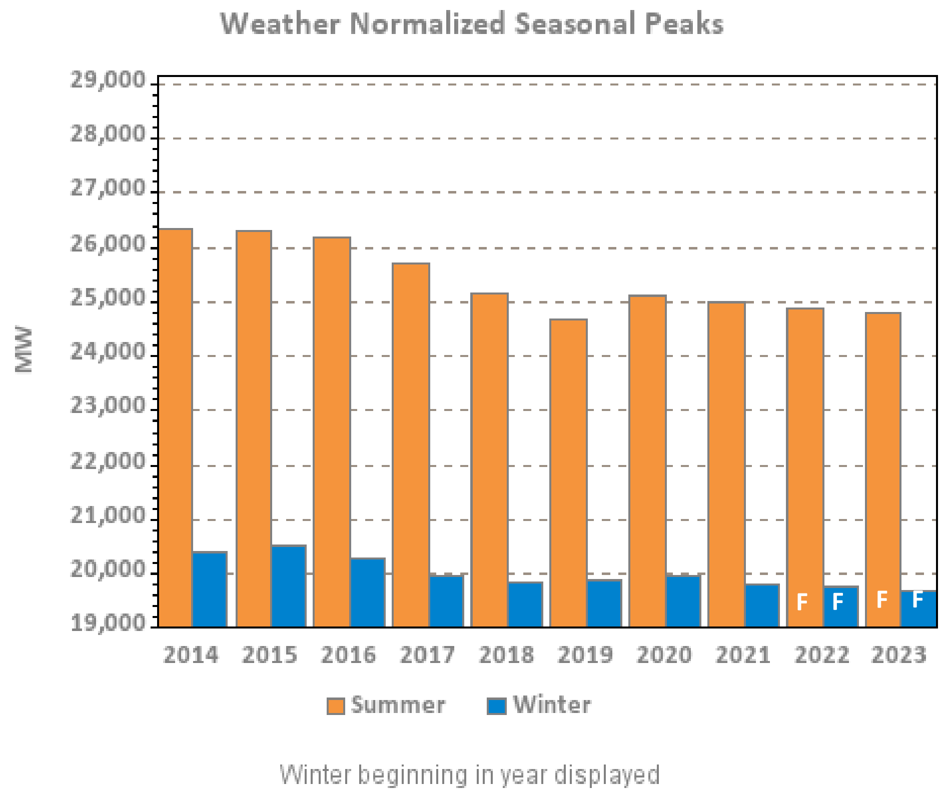
2023 System Operations - Load Forecast Accuracy cont.



Monthly Peak Loads and Weather Normalized Seasonal Peak History

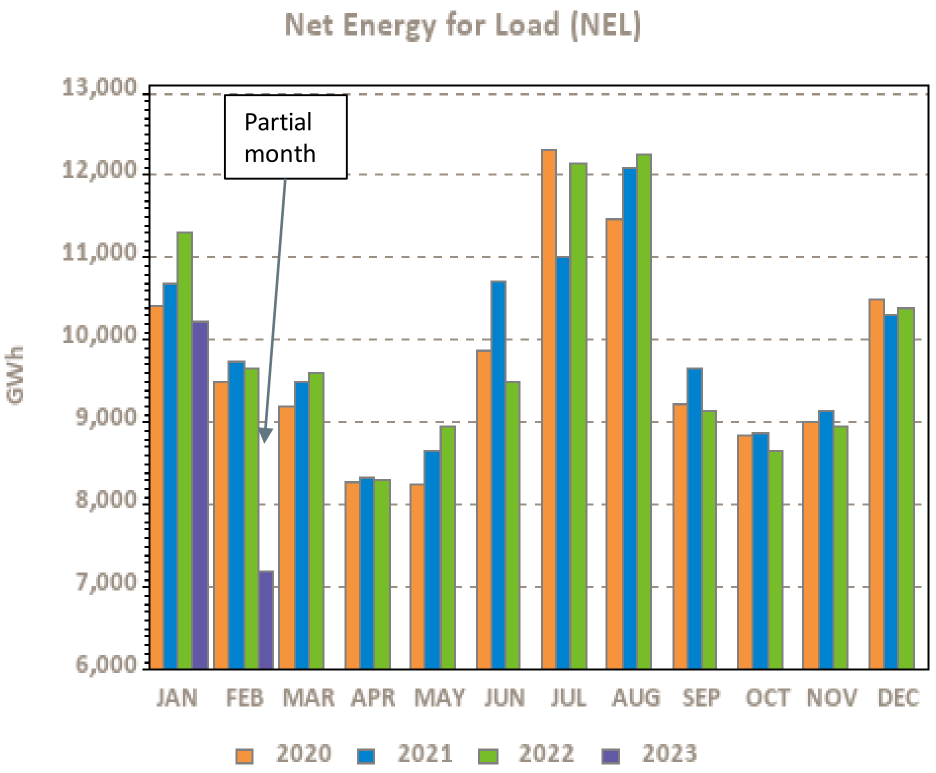


*Revenue quality metered value

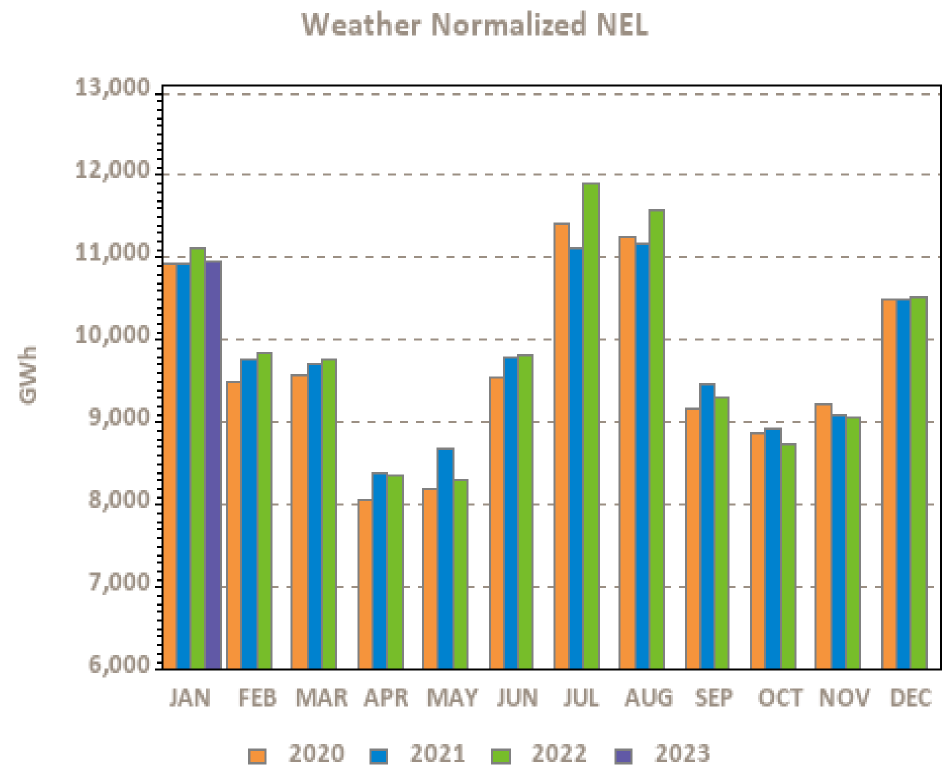


F – designates forecasted values, which are typically updated in April/May of the following year; represents "net forecast" (i.e., the gross forecast net of passive demand response and behind-the-meter solar demand)

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



Ann Tot (TWh): 116.9 118.8 118.9 17.4

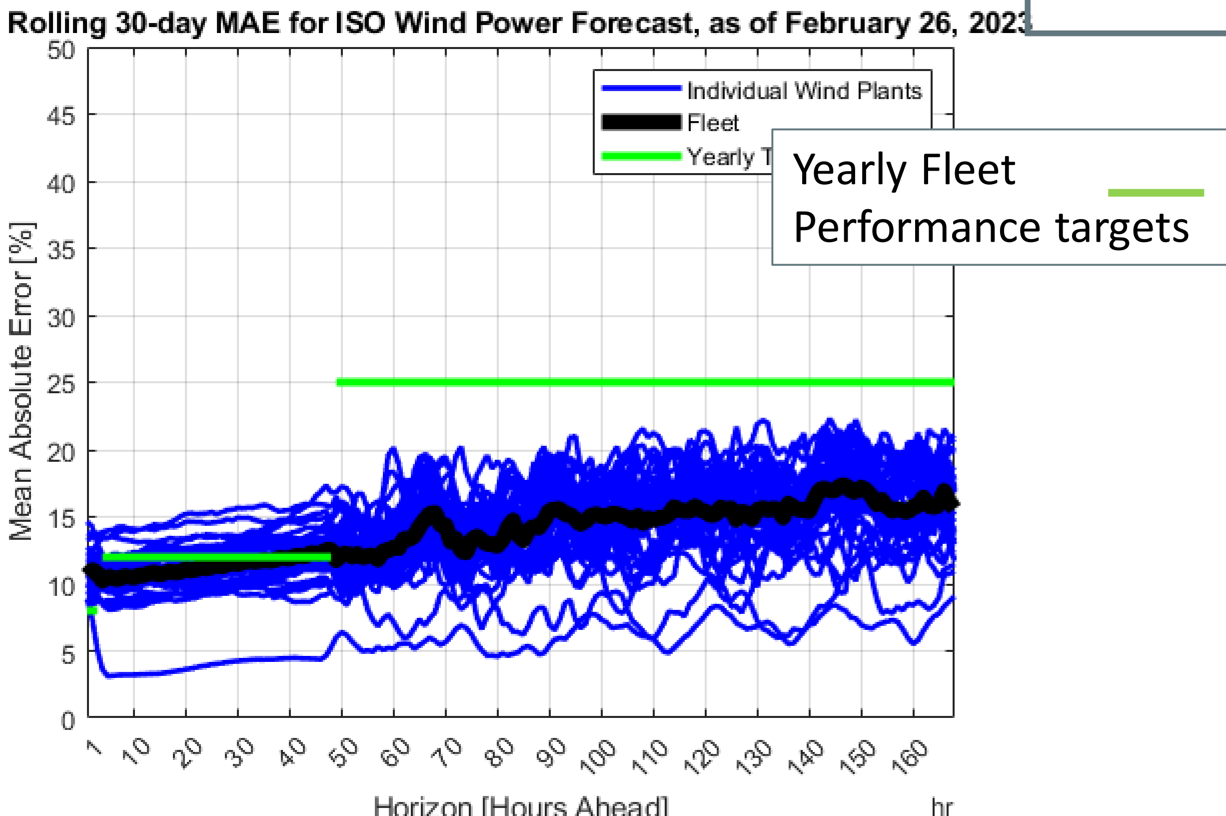


Ann Tot (TWh): 116.3 117.3 118.3 10.9

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

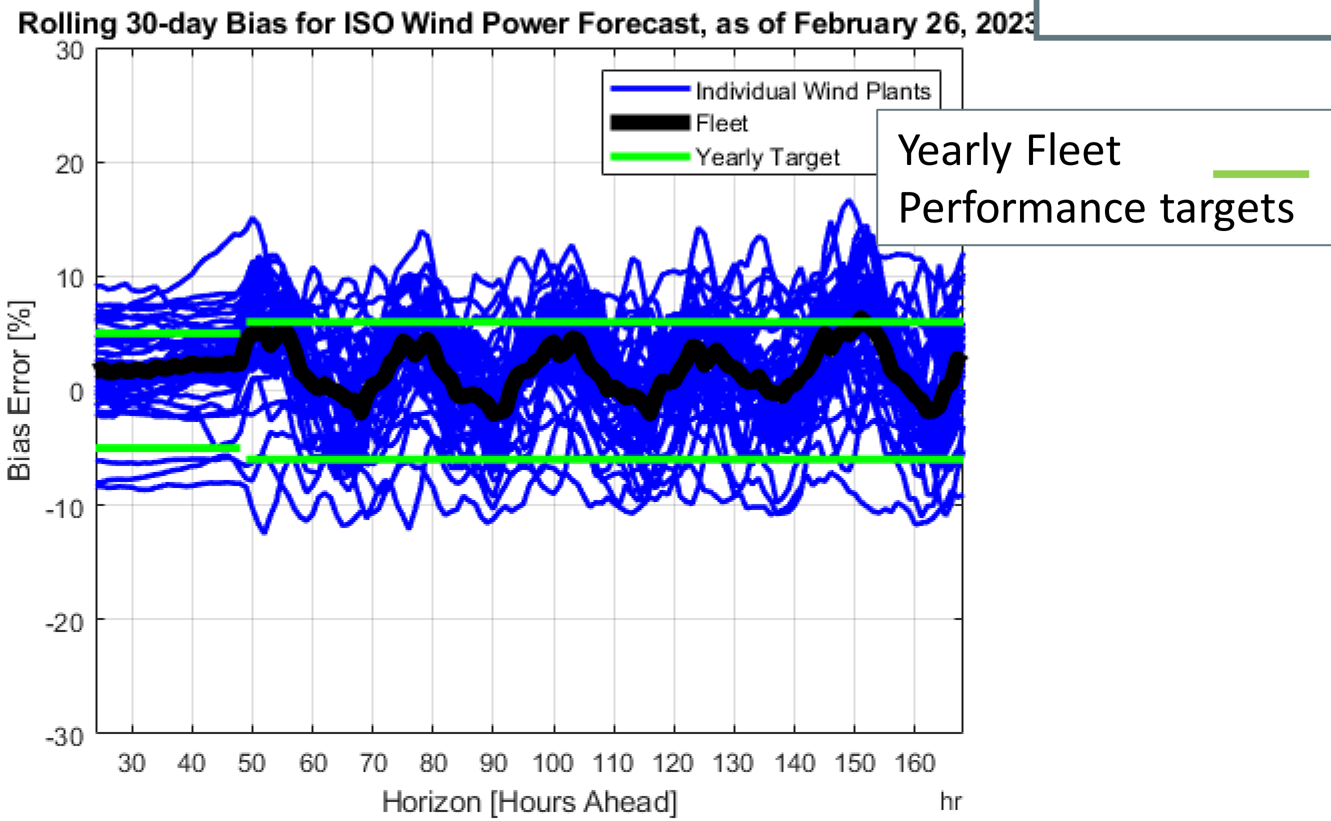
Dashboard Indicator



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

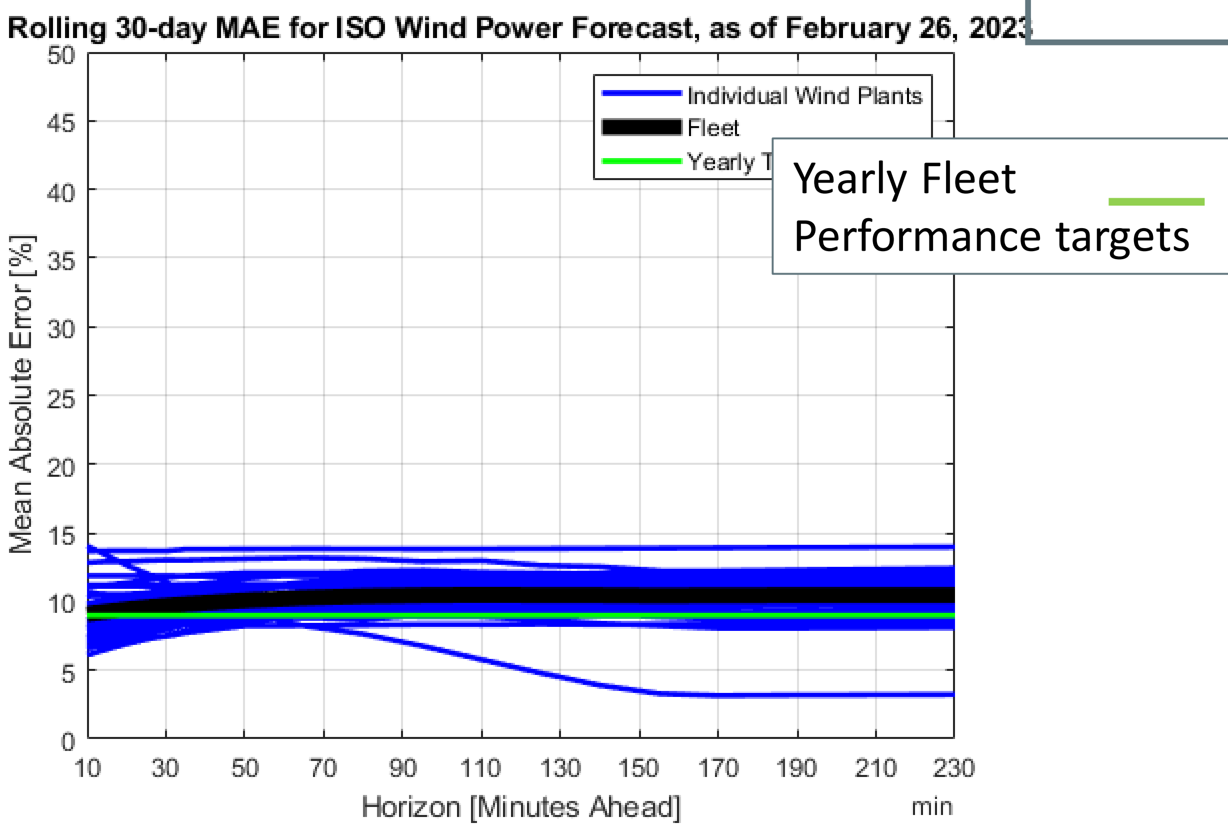
Dashboard Indicator



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

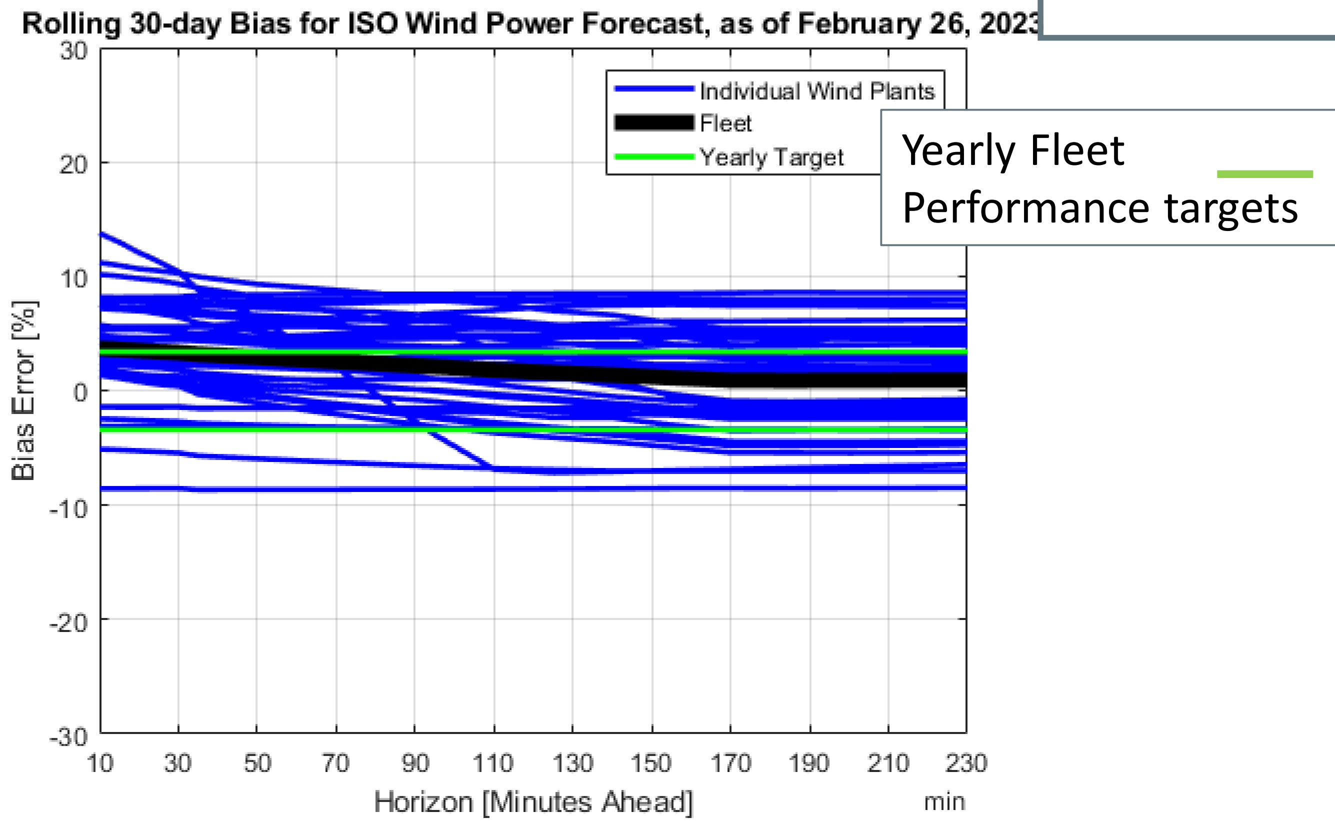
Dashboard Indicator



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. The error seems related to the quality of the input data – ISO is working with wind plants to correct.

Wind Power Forecast Error Statistics: Short Term Forecast Bias

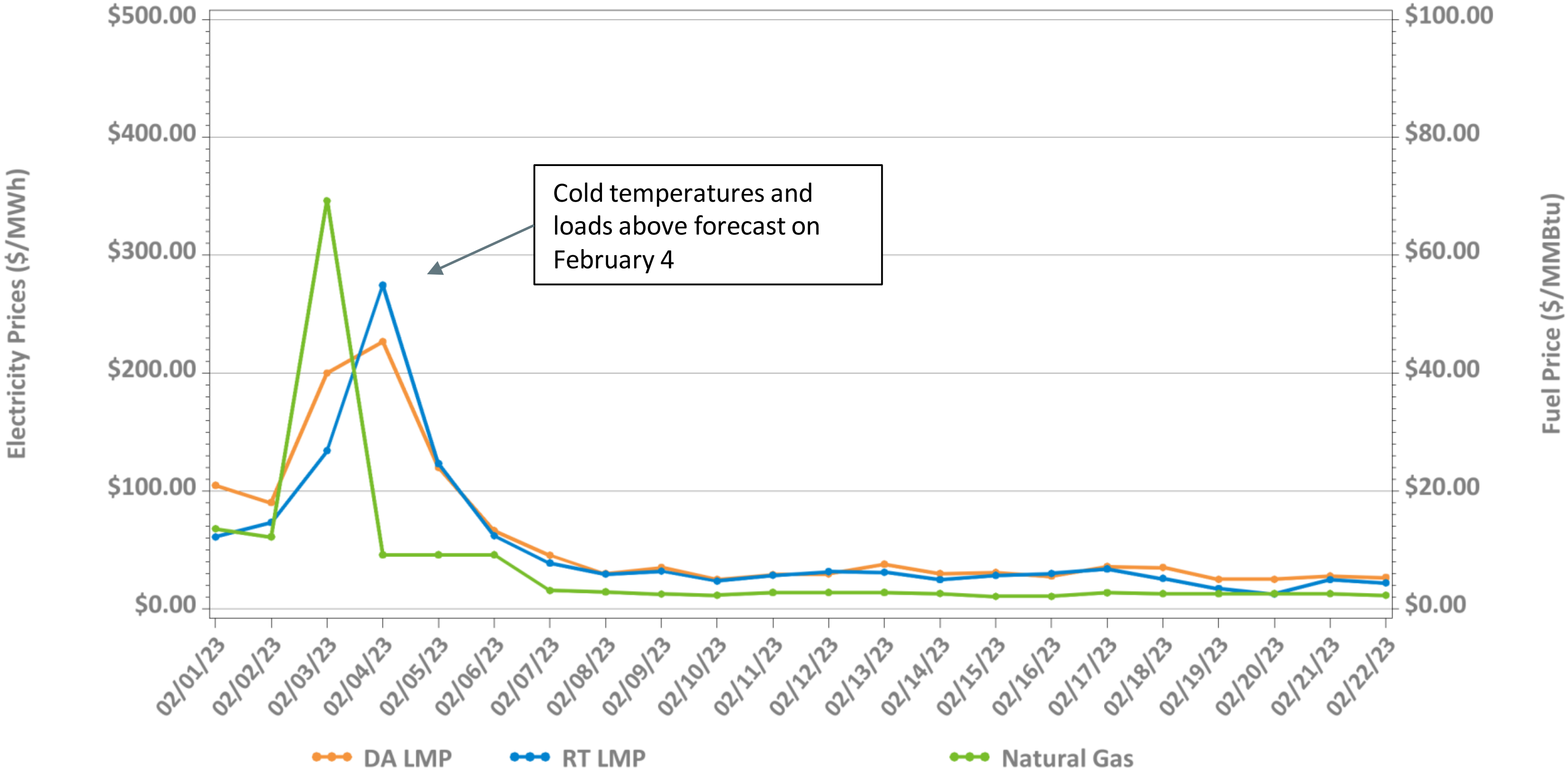
Dashboard Indicator



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

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: February 1-22, 2023

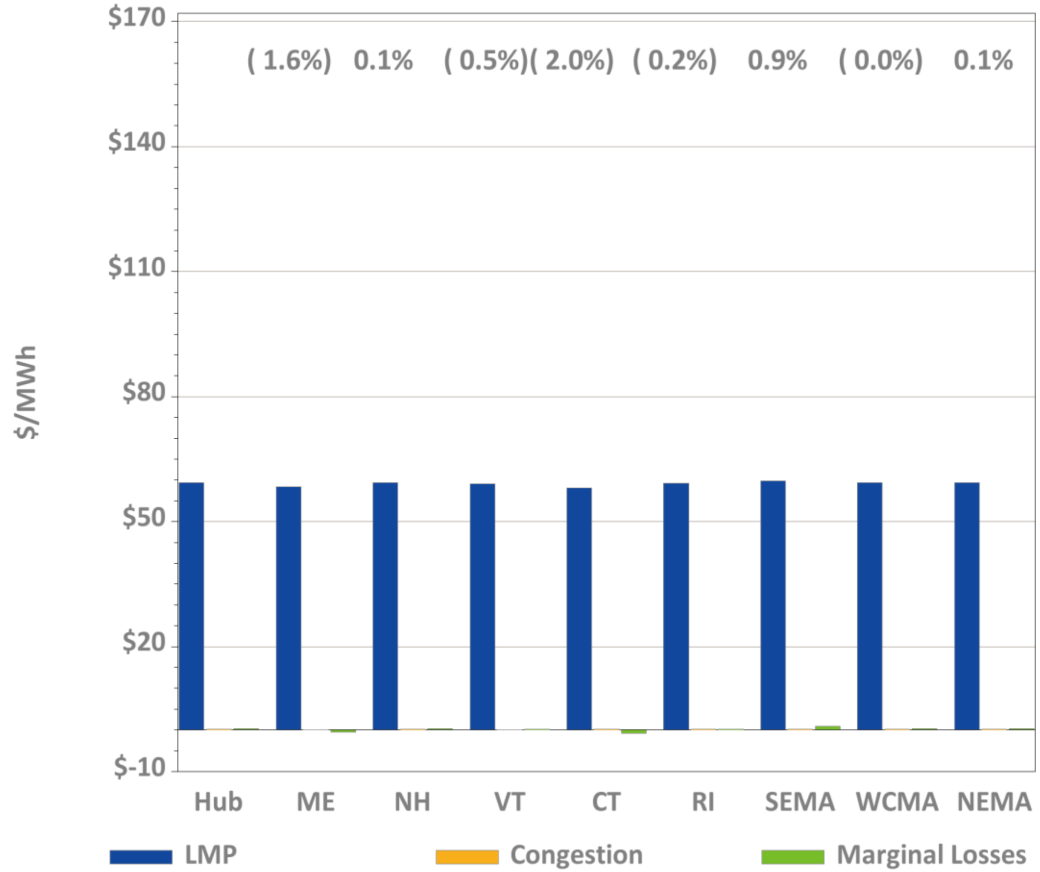


Underlying natural gas data furnished by:

ICE Global markets in clear view

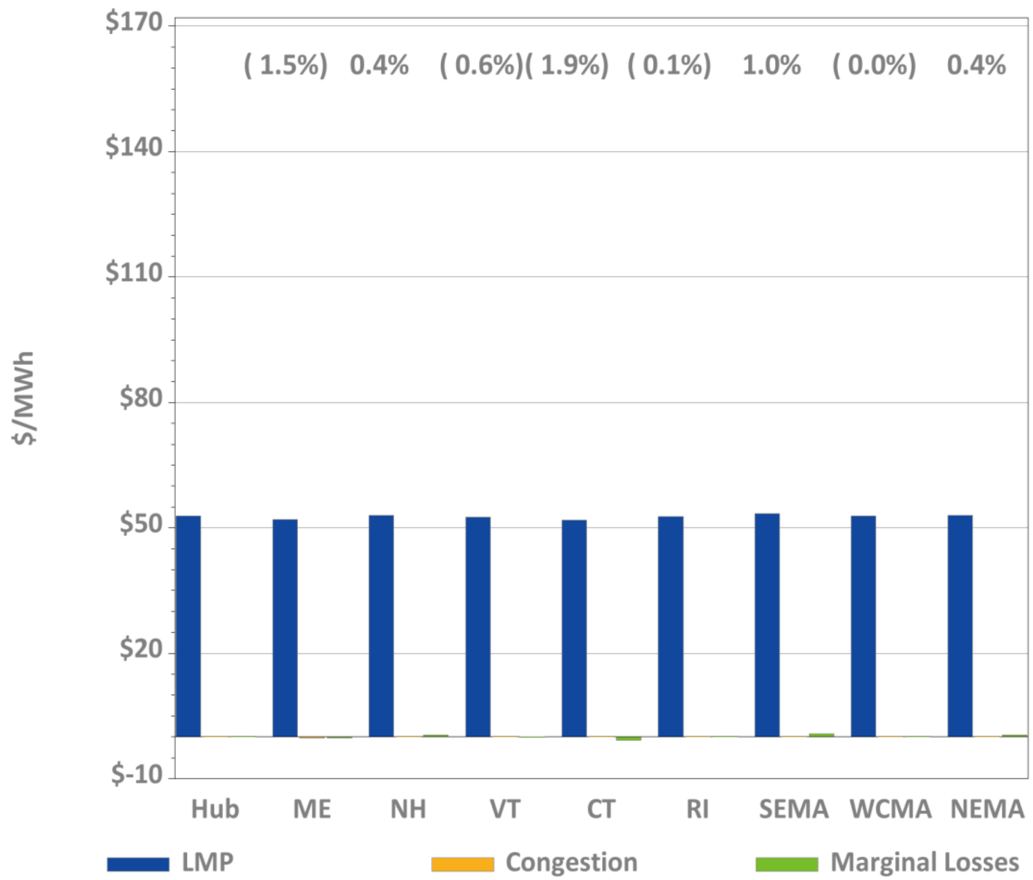
Average price difference over this period (DA-RT): $6.46
Average price difference over this period ABS(DA-RT): $11.50
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 22%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, February 2023



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

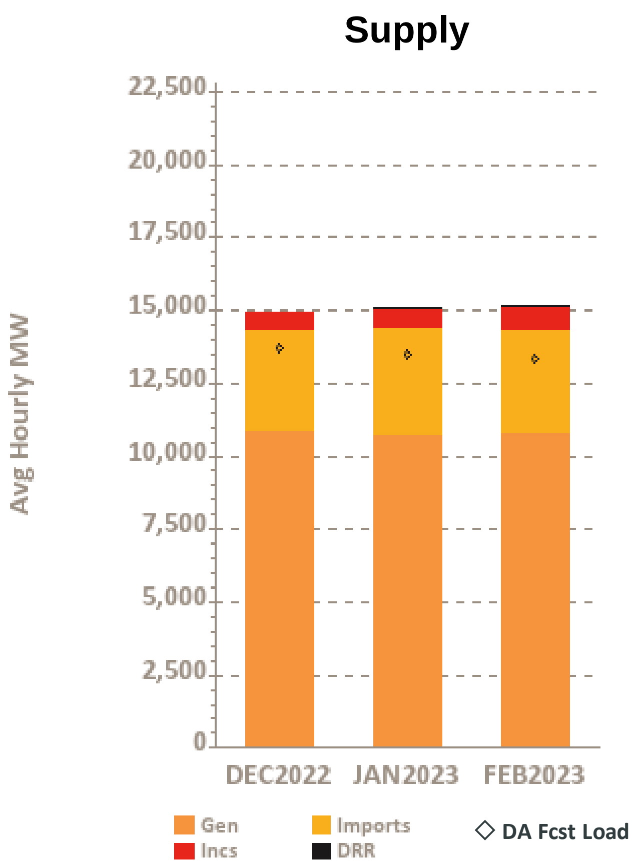
RT LMPs Average by Zone & Hub, February 2023

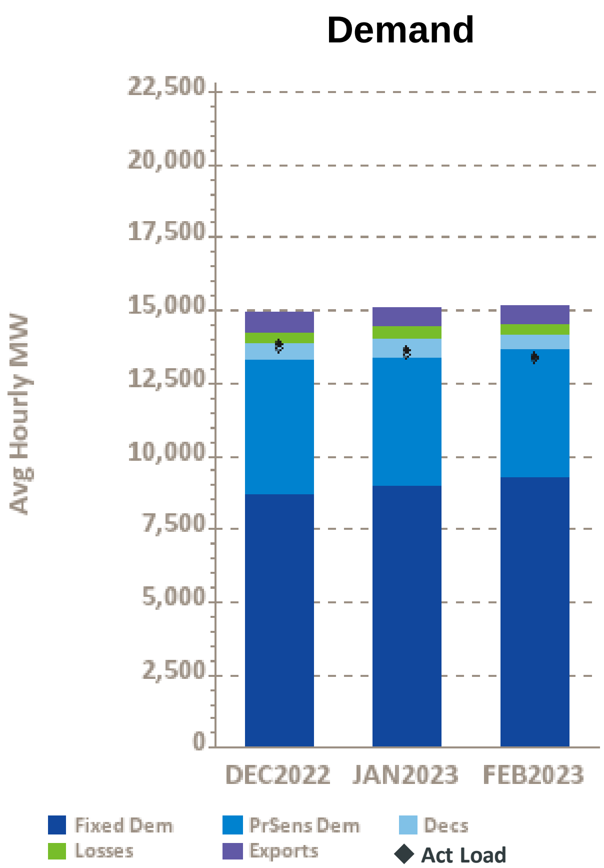


Definitions

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

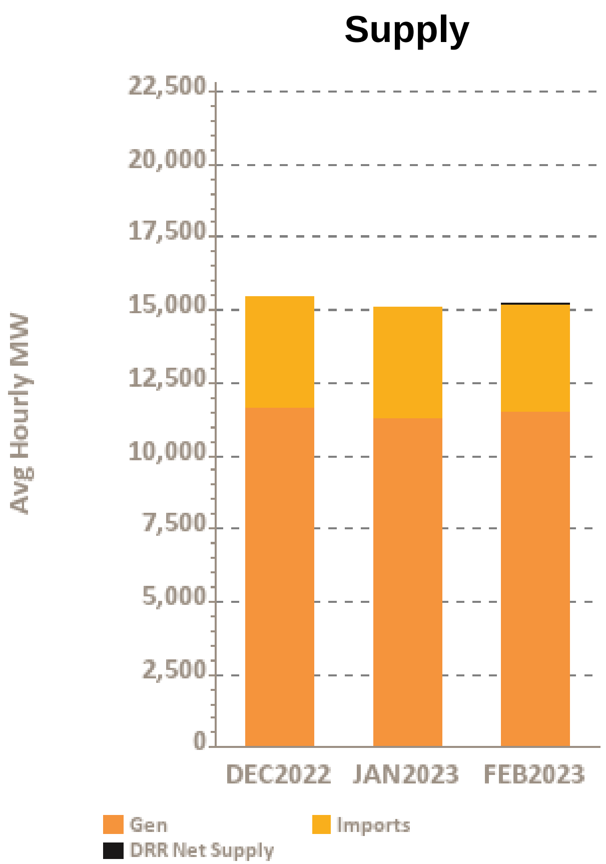


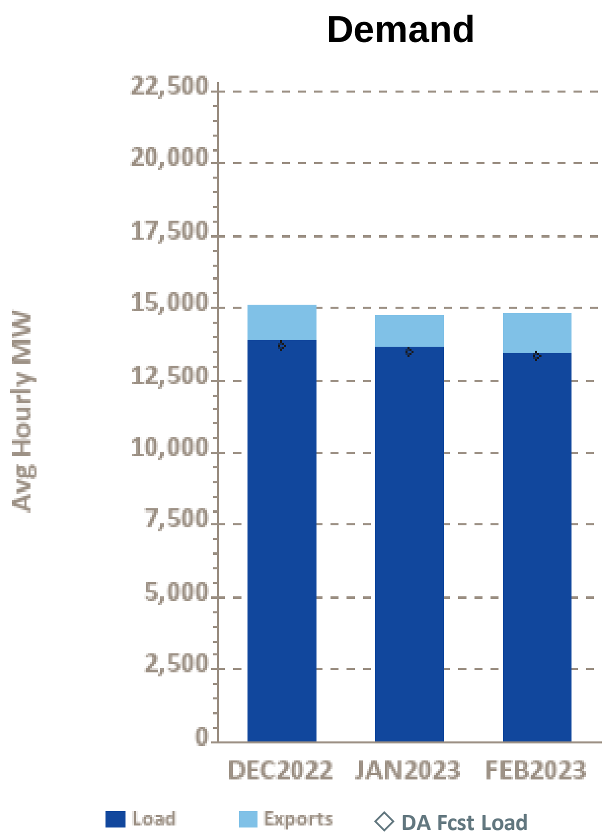


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

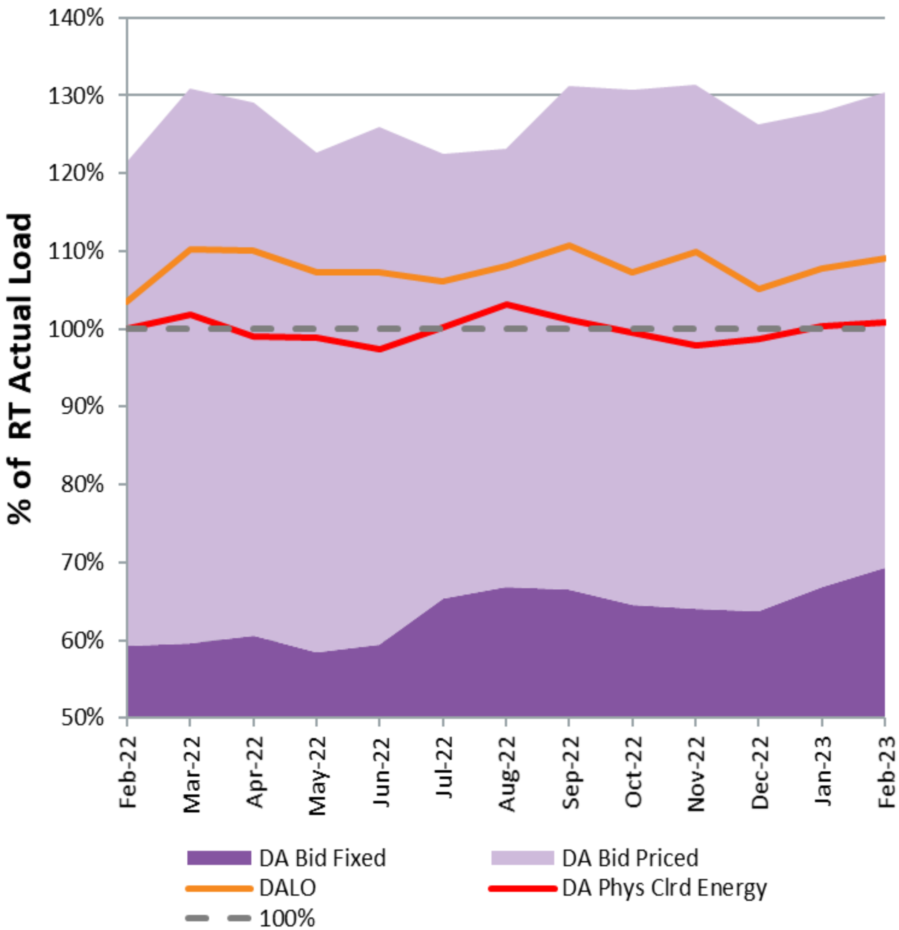
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

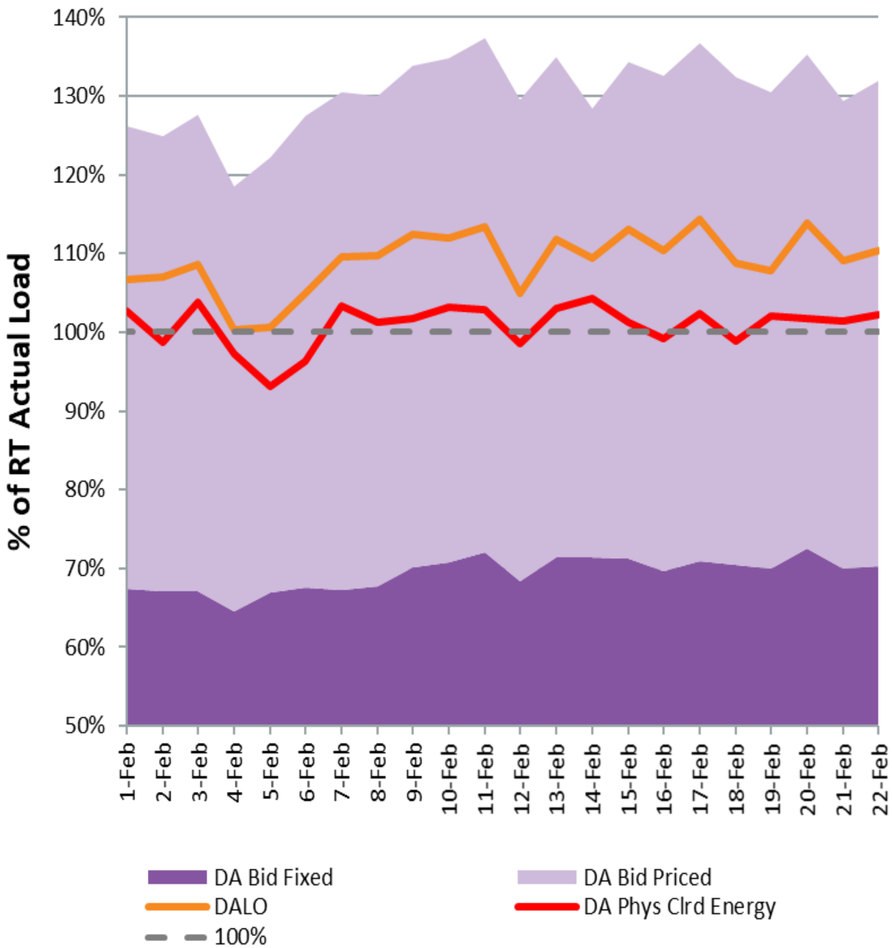
Components of RT Supply and Demand – Last Three Months





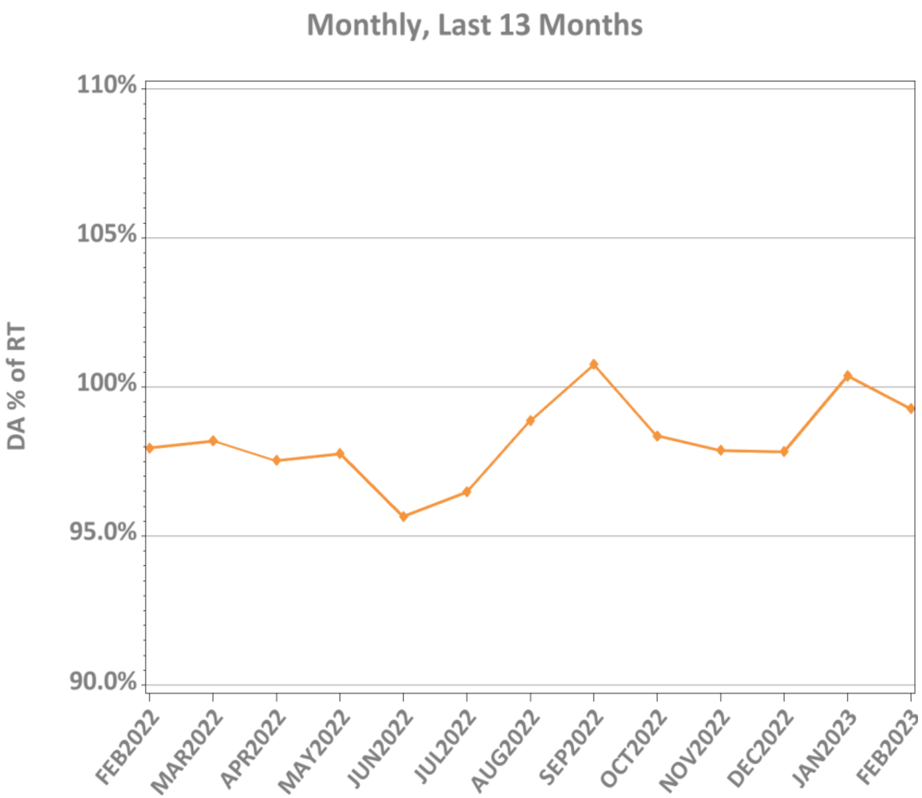
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

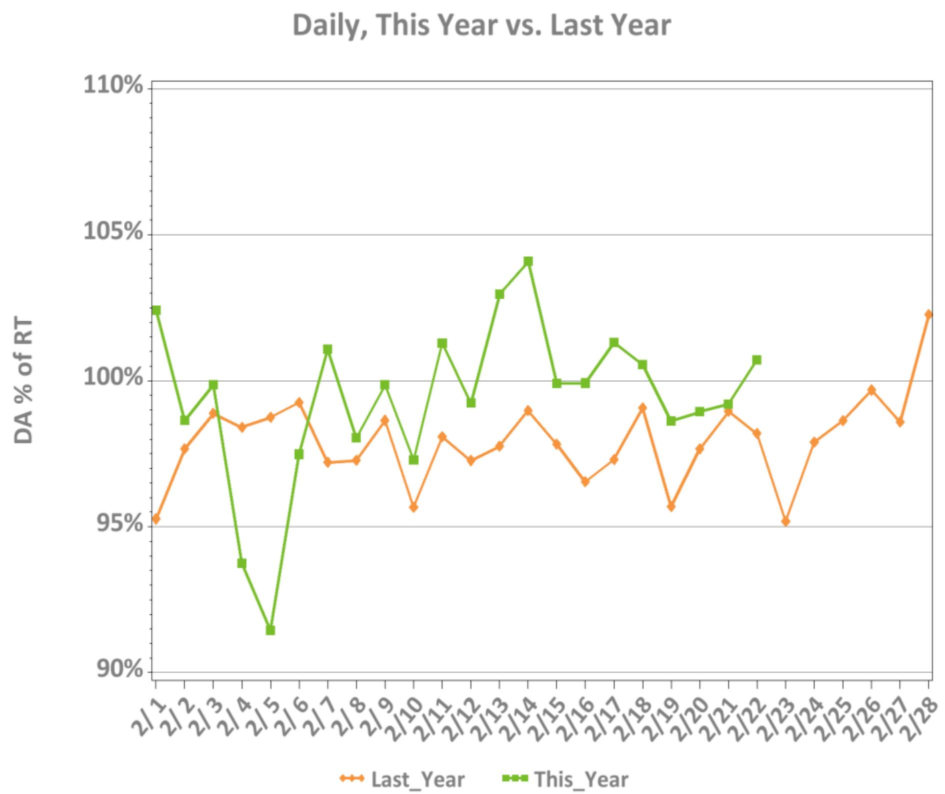




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

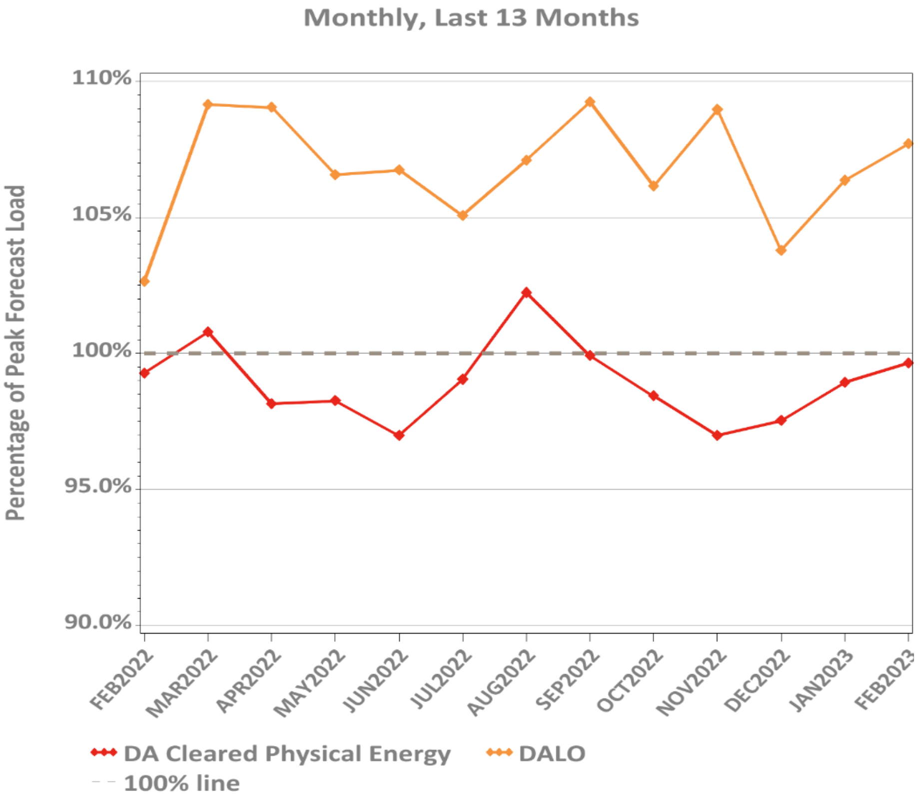
DA vs. RT Load Obligation: February, This Year vs. Last Year

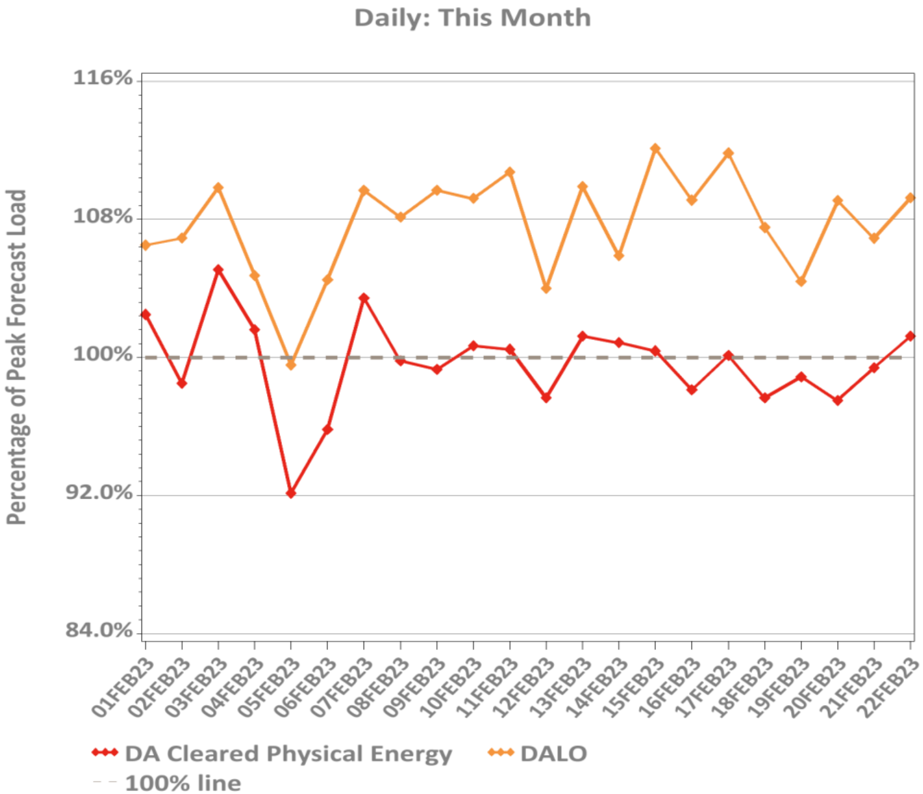




*Hourly average values

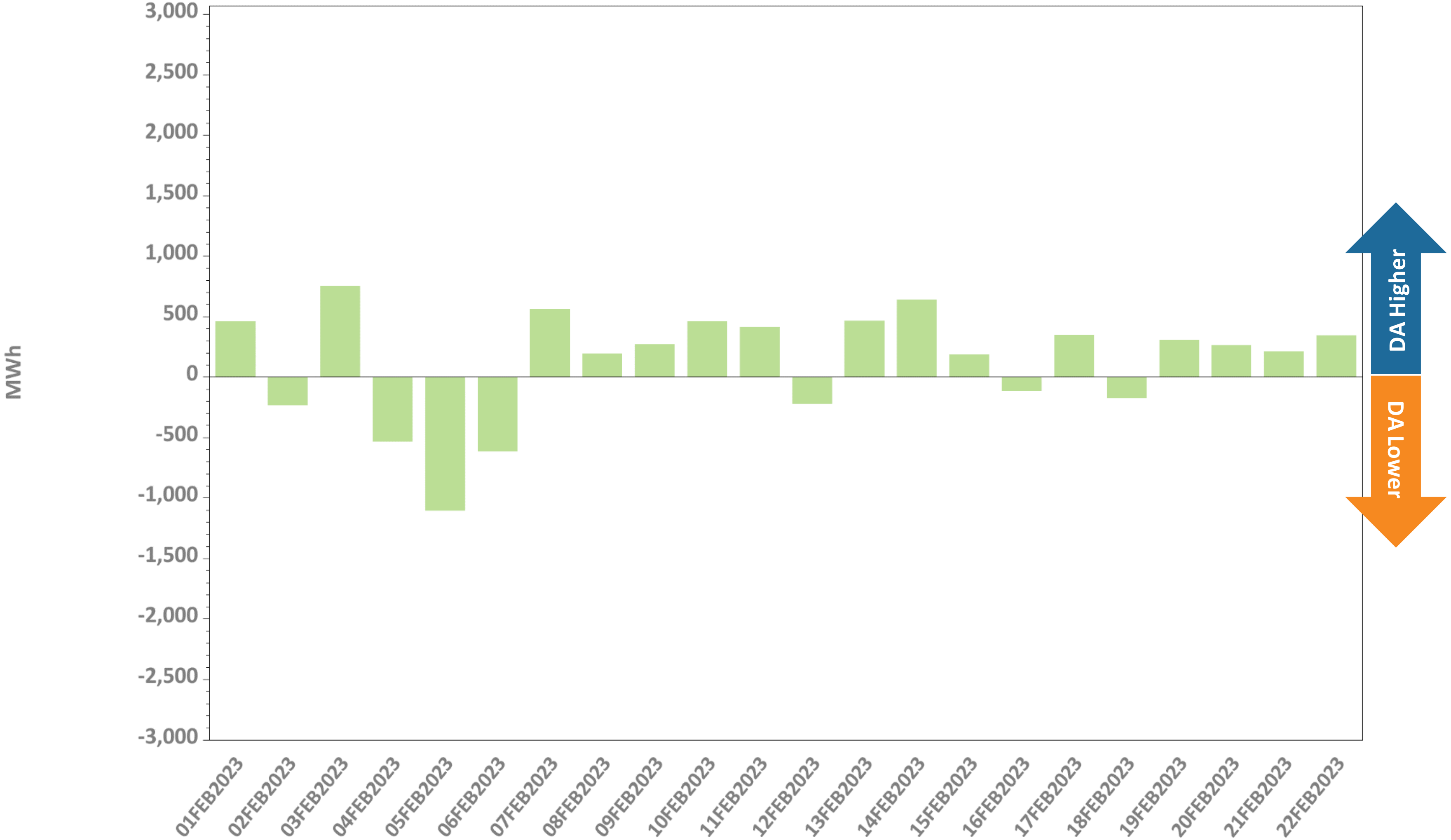
DA Volumes as % of Forecast in Peak Hour





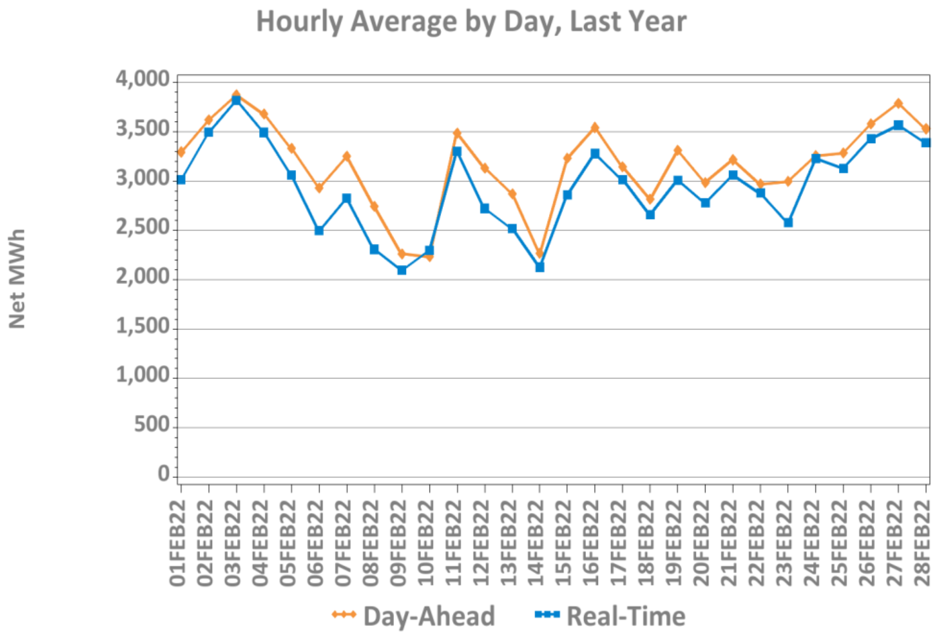
Note: There were no system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) period during the month.

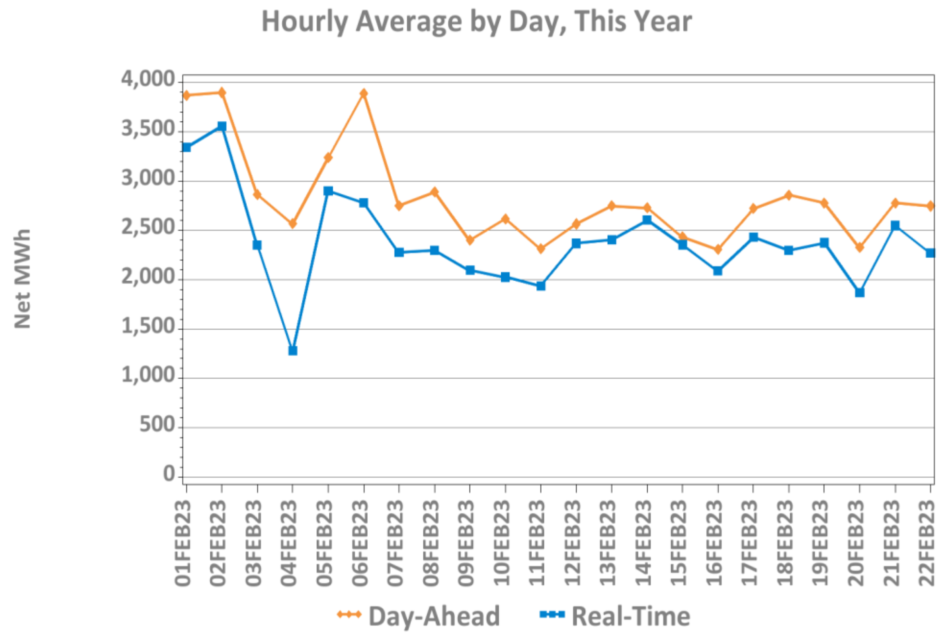
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



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

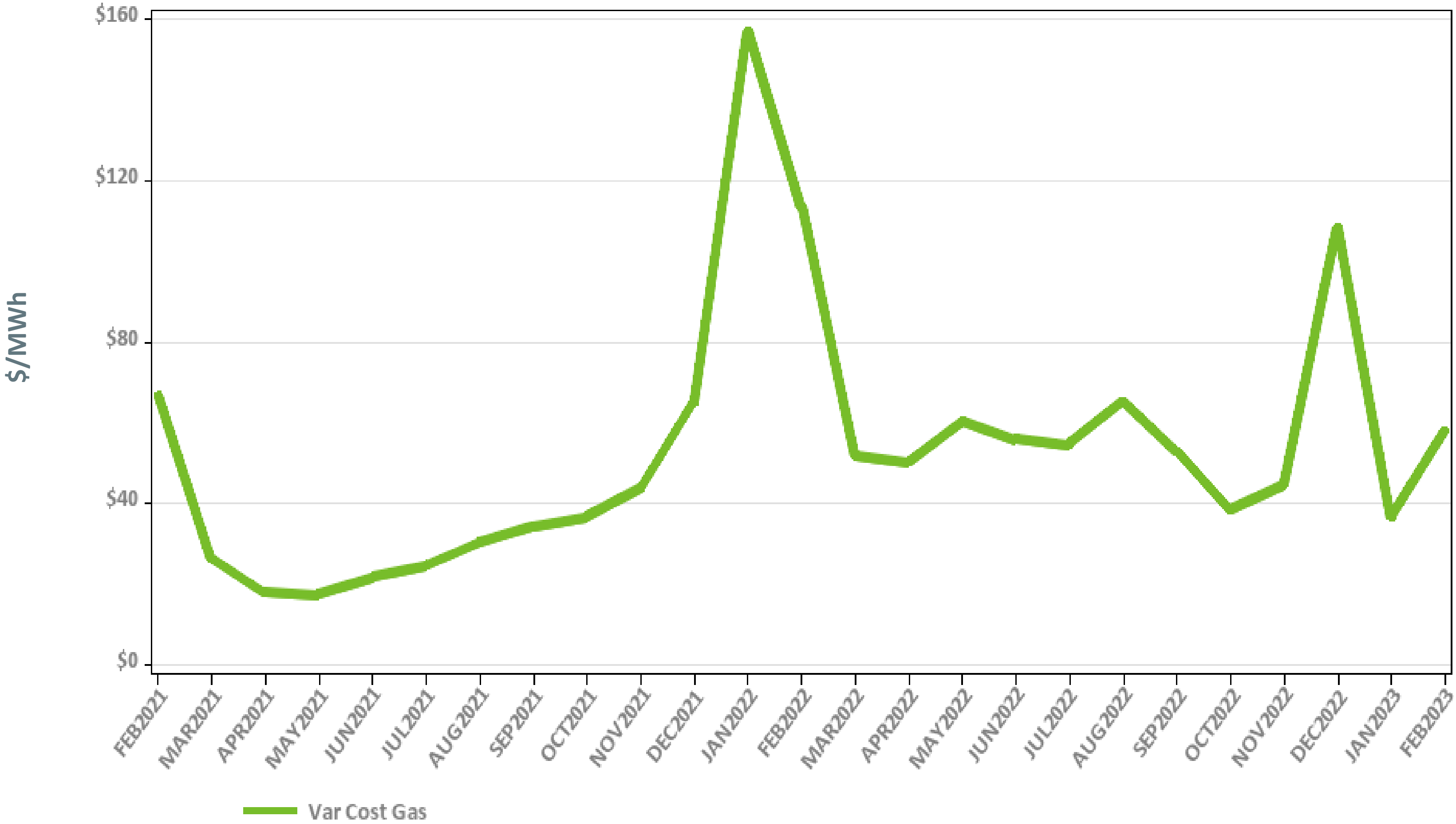
DA vs. RT Net Interchange February 2023 vs. February 2022





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

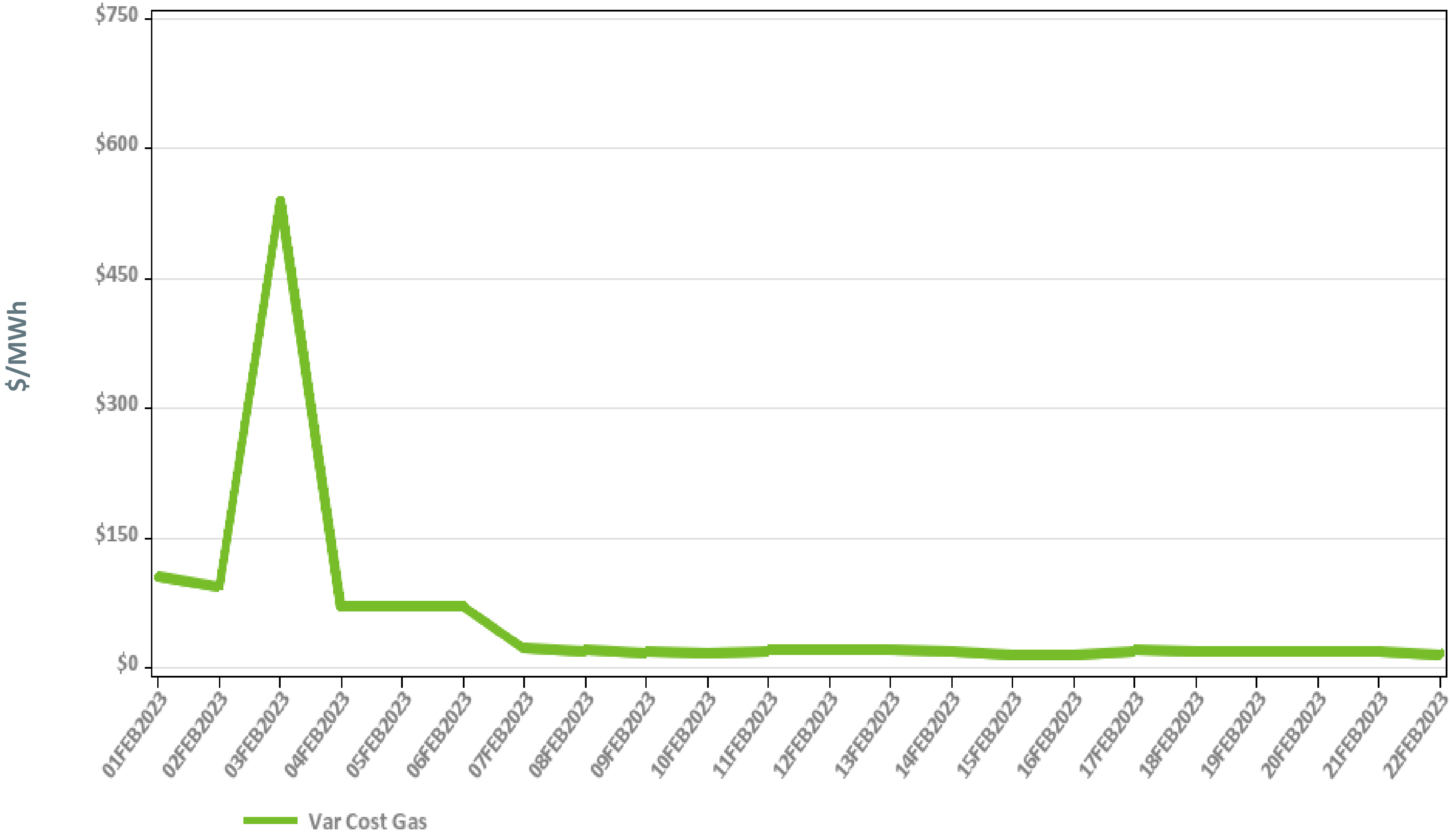


Underlying natural gas data furnished by:

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

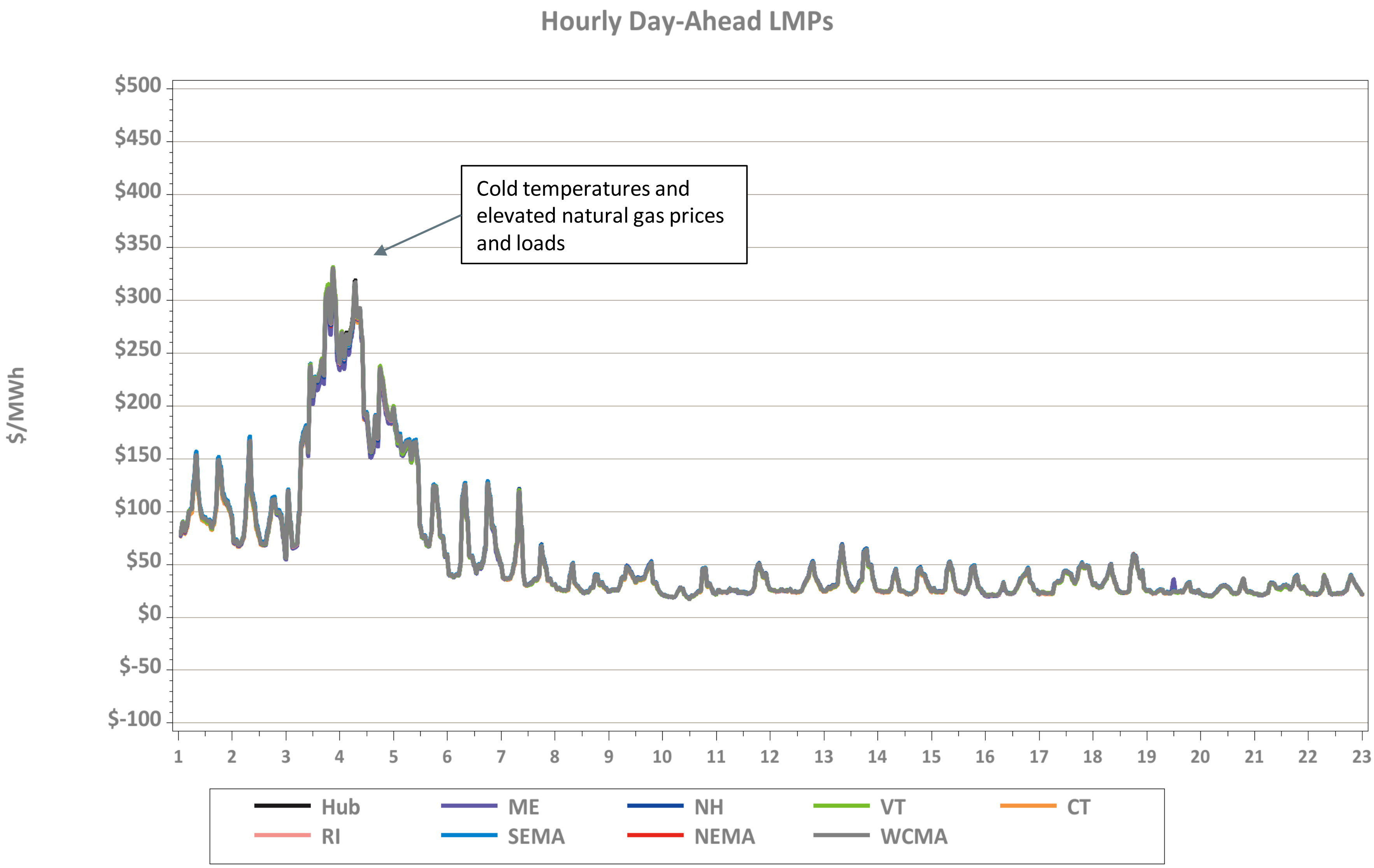


Underlying natural gas data furnished by:

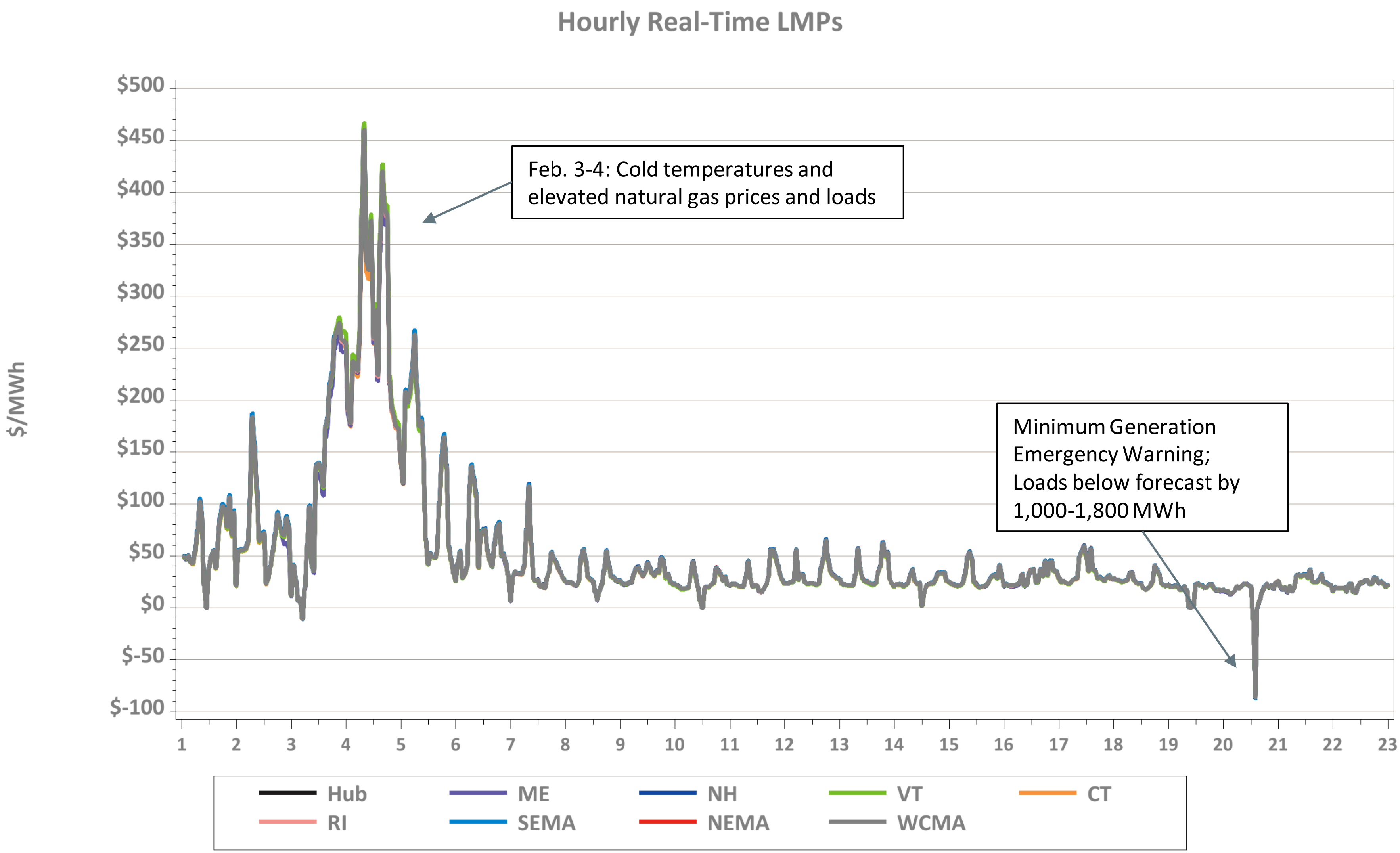
ICE Global markets in clear view

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

Hourly DA LMPs, February 1-22, 2023

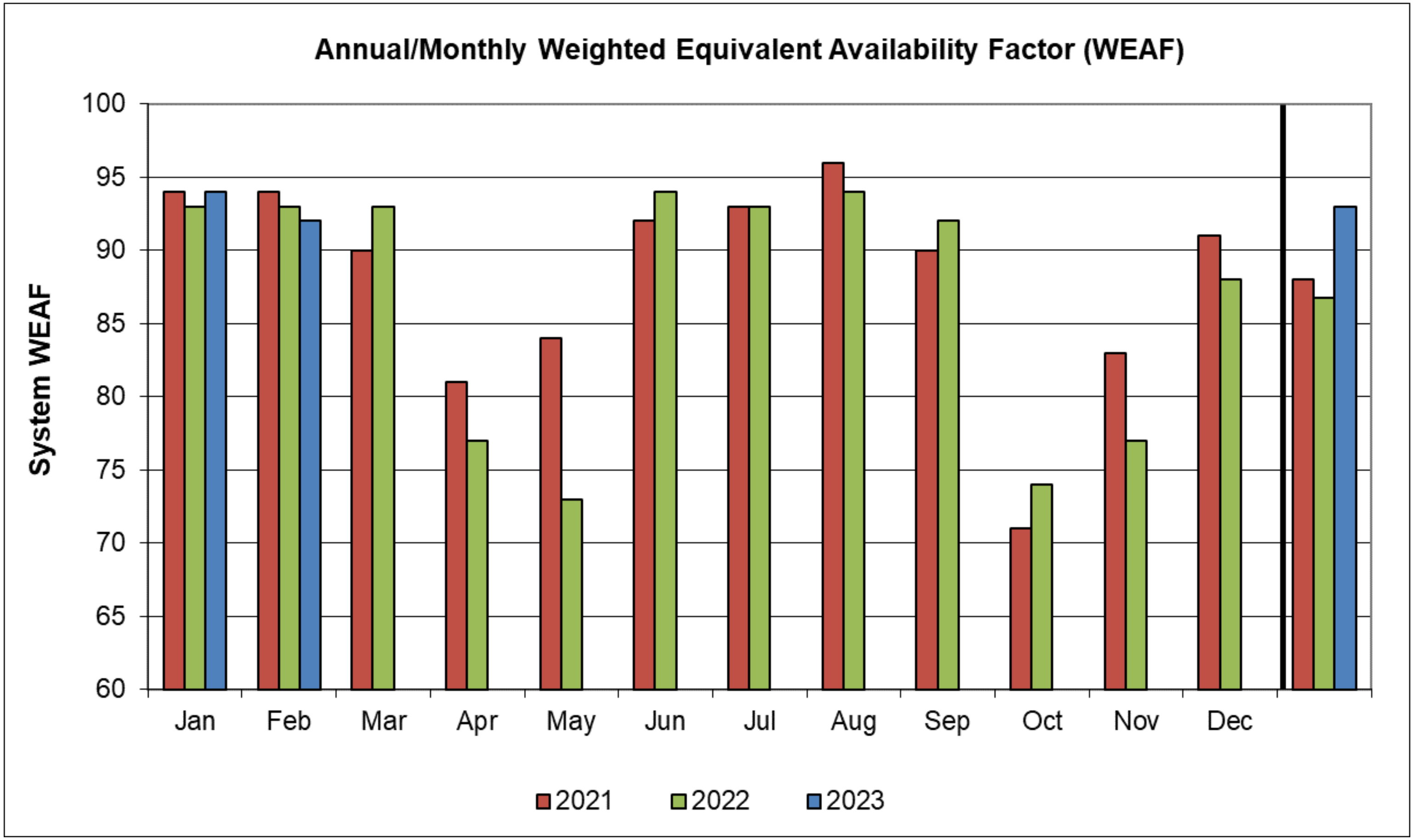


Hourly RT LMPs, February 1-22, 2023



* Telemetered load is referenced

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2023	94	92											93
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 2/21/2023

BACK-UP DETAIL

DEMAND RESPONSE

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

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	86.2	182.9	0.0	269.0
NH	34.5	168.0	0.0	202.5
VT	45.2	164.7	0.0	209.9
CT	98.0	110.9	687.4	896.4
RI	21.9	342.5	0.0	364.4
SEMA	37.3	497.7	0.0	534.9
WCMA	57.9	533.8	14.4	606.1
NEMA	49.3	844.3	0.0	893.6
Total	**430.2**	**2,844.8**	**701.8**	**3,976.9**

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

NEW GENERATION

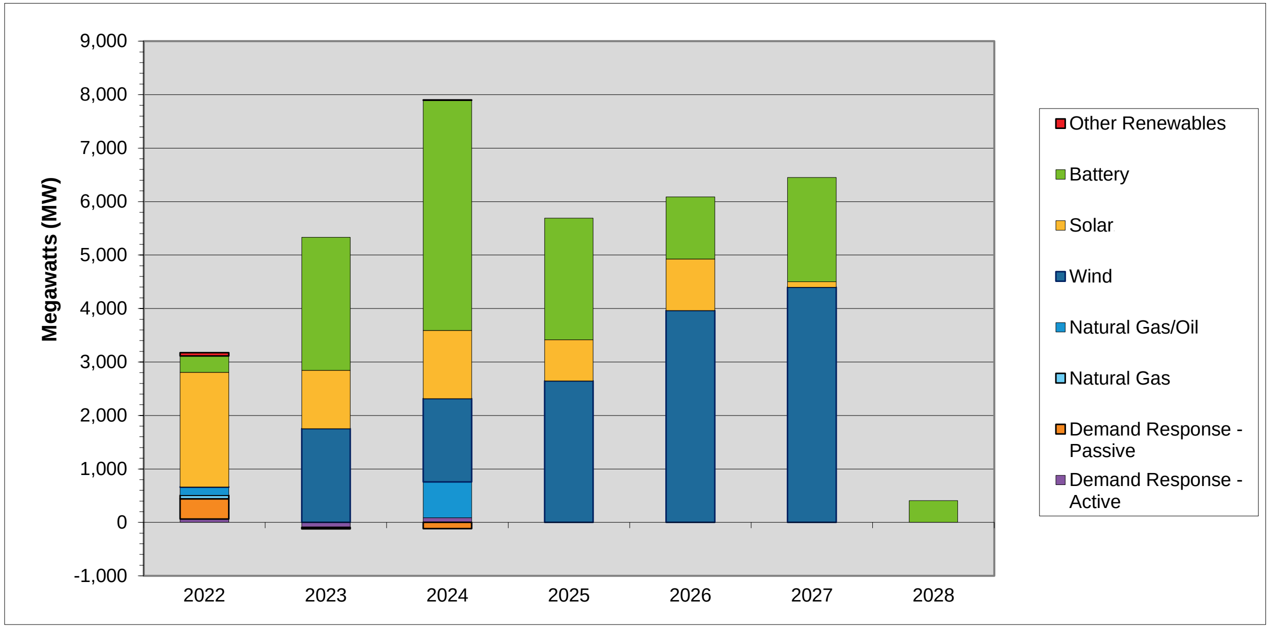
New Generation Update

Based on Queue as of 2/27/23

- Twelve projects totaling 2,472 MW were added to the interconnection queue since the last update
  - Eight battery projects, two wind projects, one solar project and one fuel cell project with in-service dates of 2024 to 2030
- Seven projects were withdrawn and no projects went commercial
- In total, 369 generation projects are currently being tracked by the ISO, totaling approximately 38,268 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



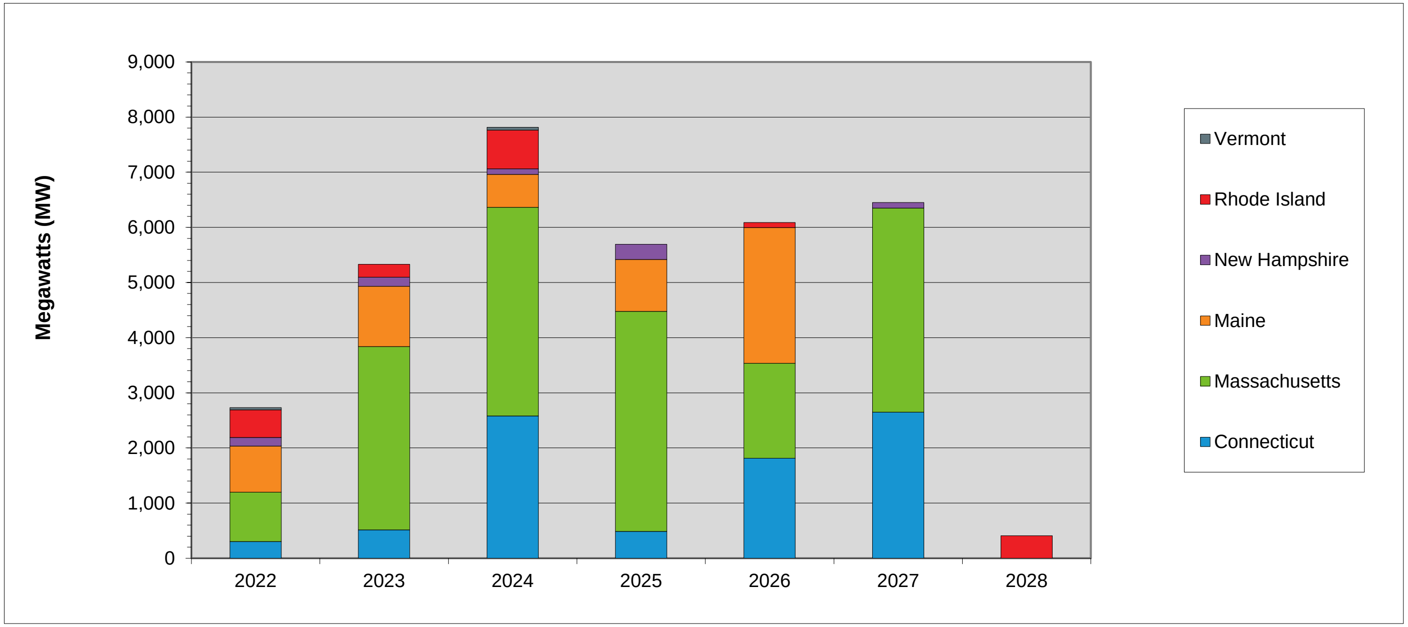
	2022	2023	2024	2025	2026	2027	2028	Total MW	% of Total[1]
Other Renewables	63	0	2	0	0	0	0	65	0.2
Battery	305	2,486	4,306	2,276	1,162	1,949	410	12,894	37.0
Solar[2]	2,142	1,094	1,277	770	964	102	0	6,349	18.2
Wind	4	1,752	1,556	2,645	3,962	4,399	0	14,318	41.1
Natural Gas/Oil[3]	151	0	672	0	0	0	0	823	2.4
Natural Gas	67	0	0	0	0	0	0	67	0.2
Demand Response - Passive	380	-28	-114	0	0	0	0	238	0.7
Demand Response - Active	62	-94	86	0	0	0	0	54	0.2
Totals	3,174	5,210	7,785	5,691	6,088	6,450	410	34,808	100.0

[1] Sum may not equal 100% due to rounding
[2] This category includes both solar-only, and co-located solar and battery projects
[3] The projects in this category are dual fuel, with either gas or oil as the primary fuel

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

Actual and Projected Annual Generator Capacity Additions

By State



	2022	2023	2024	2025	2026	2027	2028	Total MW	% of Total[1]
Vermont	40	0	50	0	0	0	0	90	0.3
Rhode Island	502	236	704	0	91	0	410	1,943	5.6
New Hampshire	156	164	97	272	0	102	0	791	2.3
Maine	838	1,092	597	942	2,461	0	0	5,930	17.2
Massachusetts	893	3,324	3,786	3,989	1,725	3,700	0	17,417	50.5
Connecticut	303	516	2,579	488	1,811	2,648	0	8,345	24.2
Totals	**2,732**	**5,332**	**7,813**	**5,691**	**6,088**	**6,450**	**410**	**34,516**	**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	88	12,894	3	32	85	12,862
Fuel Cell	3	32	0	0	3	32
Hydro	2	33	1	5	1	28
Natural Gas	7	67	0	0	7	67
Natural Gas/Oil	5	823	1	62	4	761
Nuclear	0	0	0	0	0	0
Solar	236	6,349	17	381	219	5,968
Wind	28	18,070	0	0	28	18,070
Total	369	38,268	22	480	347	37,788

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

New Generation Projection

By Operating Type

	Total		Green		Yellow	
Operating Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	6	72	1	5	5	67
Intermediate	7	804	0	0	7	804
Peaker	328	19,322	21	475	307	18,847
Wind Turbine	28	18,070	0	0	28	18,070
Total	369	38,268	22	480	347	37,788

- Green denotes projects with a high probability of going into service
- Yellow denotes projects with a lower probability of going into service or new applications

New Generation Projection
By Operating Type and Fuel Type

	Total		Baseload		Intermediate		Peaker		Wind Turbine	
Unit Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0	0	0	0	0
Battery Storage	88	12,894	0	0	0	0	88	12,894	0	0
Fuel Cell	3	32	3	32	0	0	0	0	0	0
Hydro	2	33	2	33	0	0	0	0	0	0
Natural Gas	7	67	1	7	3	43	3	17	0	0
Natural Gas/Oil	5	823	0	0	4	761	1	62	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Solar	236	6,349	0	0	0	0	236	6,349	0	0
Wind	28	18,070	0	0	0	0	0	0	28	18,070
Total	369	38,268	6	72	7	804	328	19,322	28	18,070

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 13

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

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

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

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

Capacity Supply Obligation FCA 14

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

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2022 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 15

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

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2022 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Capacity Supply Obligation FCA 16

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

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

Note: A resource's CSO may change for a variety of reasons outside ISO-NE administered trading windows. Reasons for CSO changes beyond bilaterals and reconfiguration auction may include terminations or recent declaration of commercial operation. Details of the changes that occurred due to non-annual event purposes are contained in the 2015-2022 CCP Monthly Capacity Supply Obligation Changes report on the ISO New England website.

Active/Passive Demand Response

CSO Totals by Commitment Period

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

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

What are Daily NCPC Payments?

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

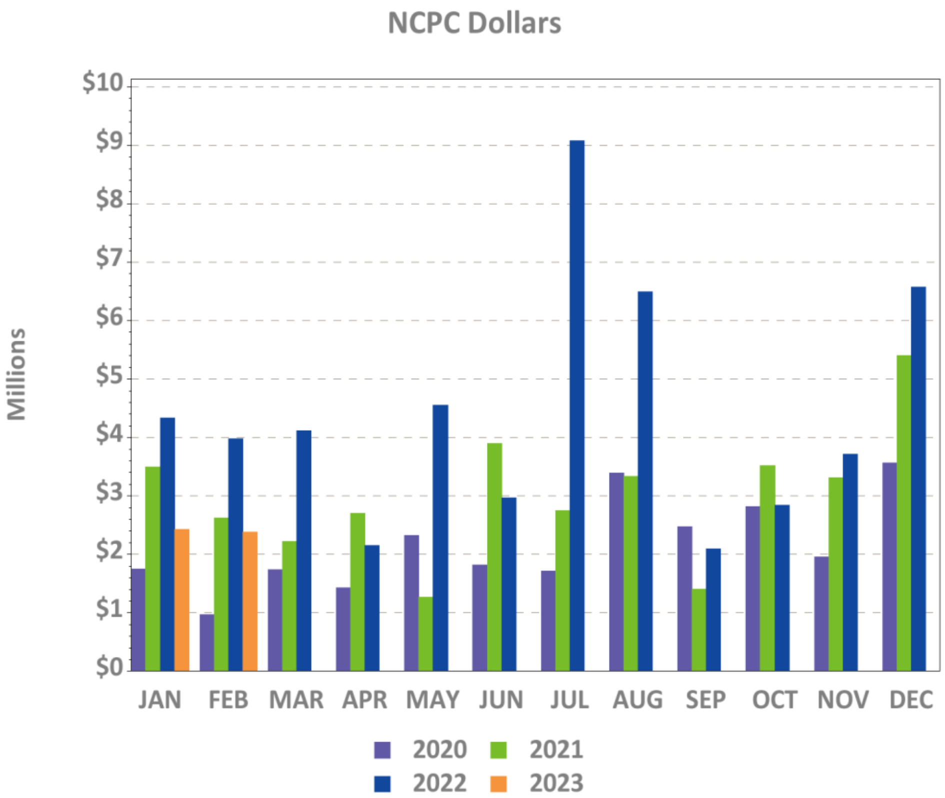
Definitions

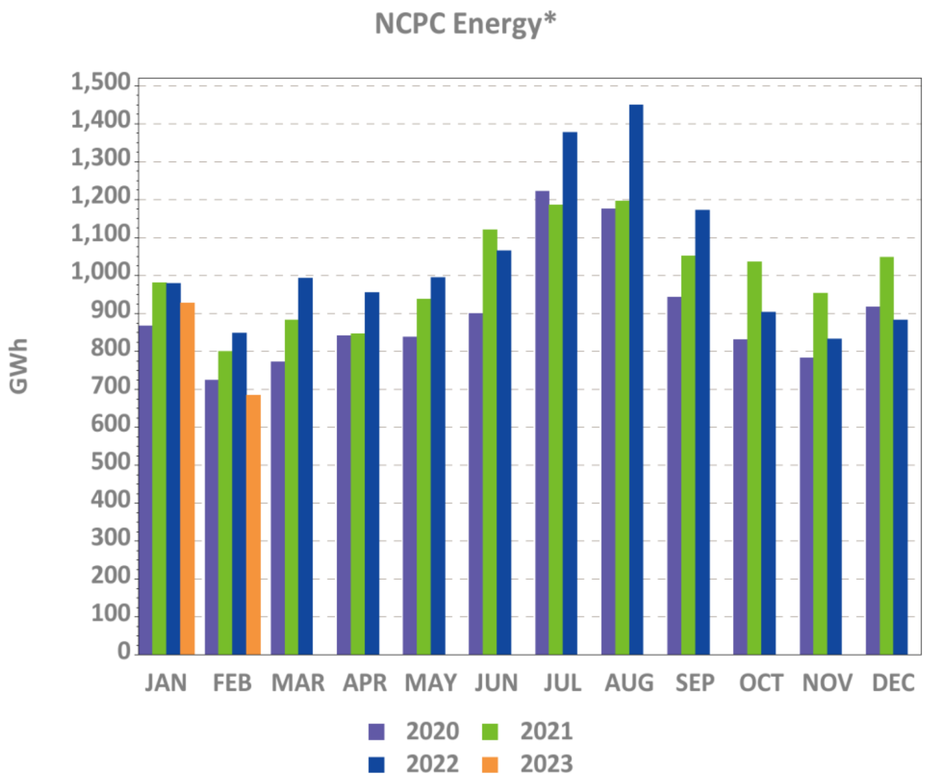
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

Charge Allocation Key

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

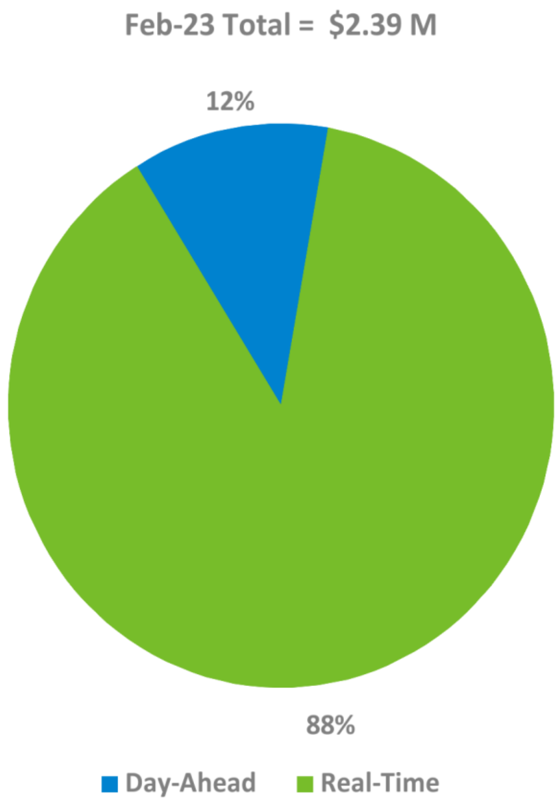
Year-Over-Year Total NCPC Dollars and Energy

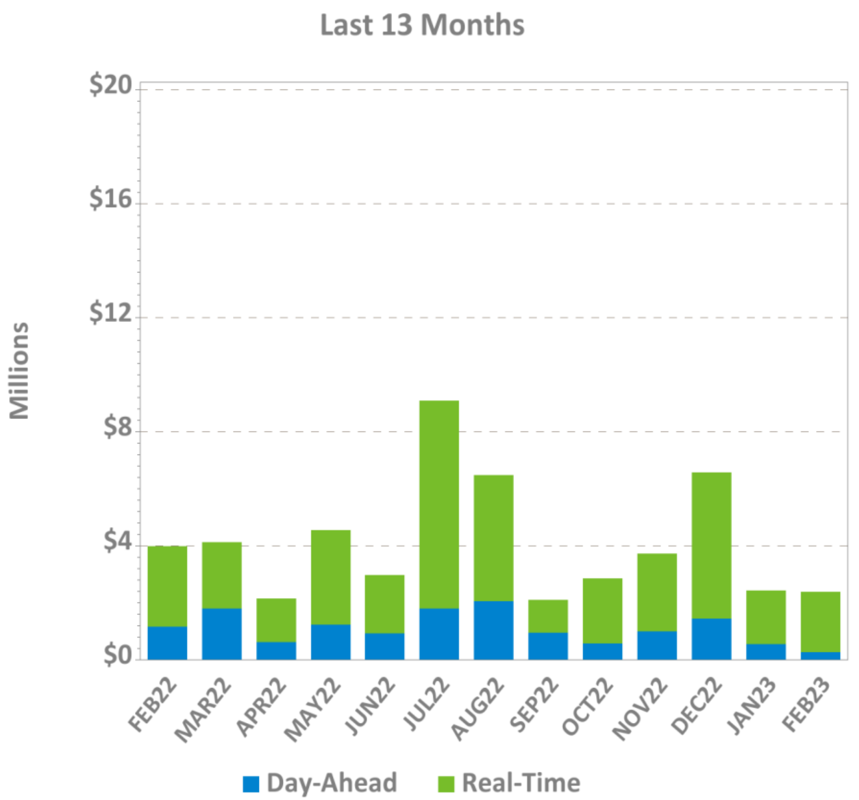




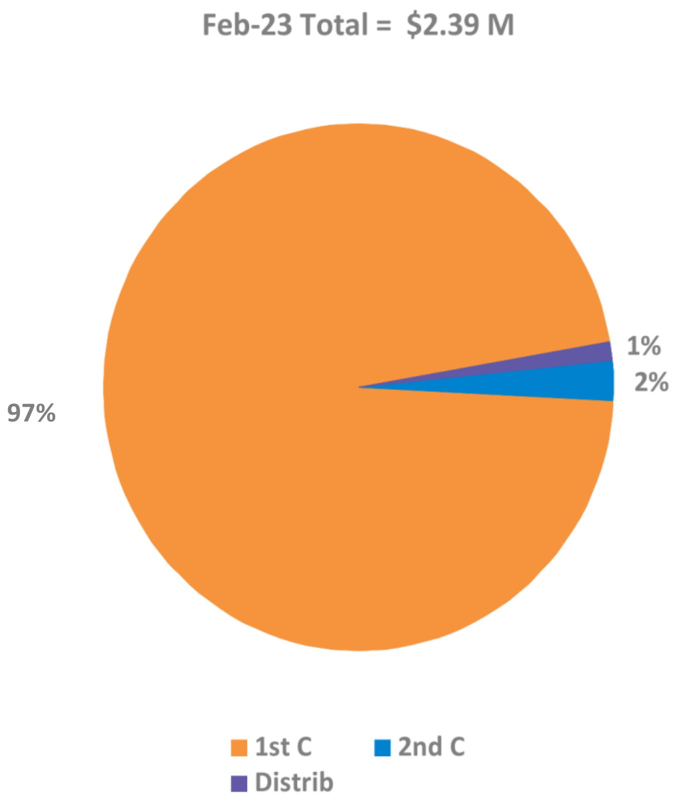
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

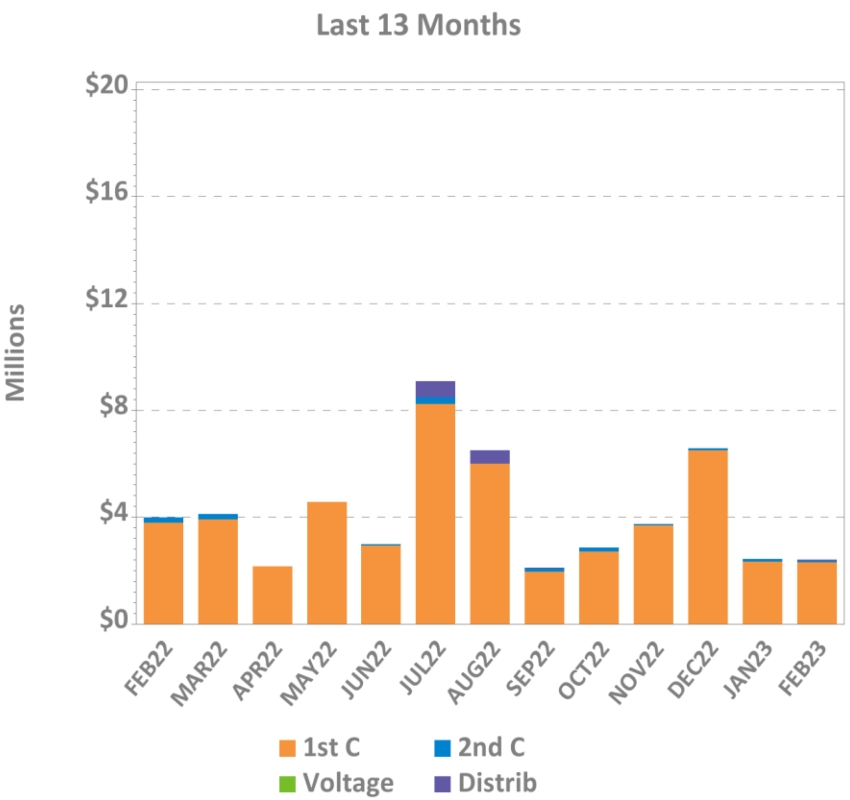
DA and RT NCPC Charges





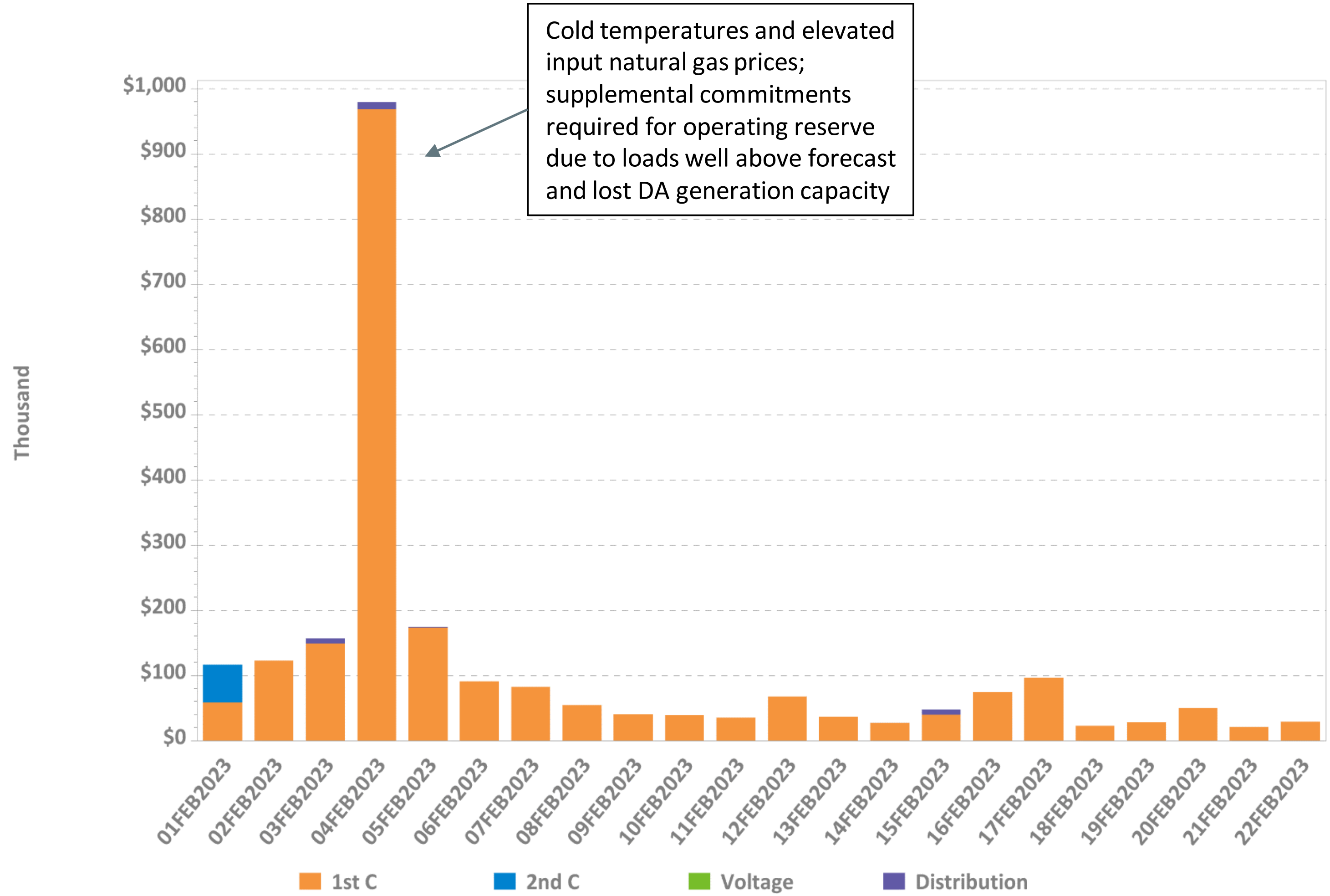
NCPC Charges by Type



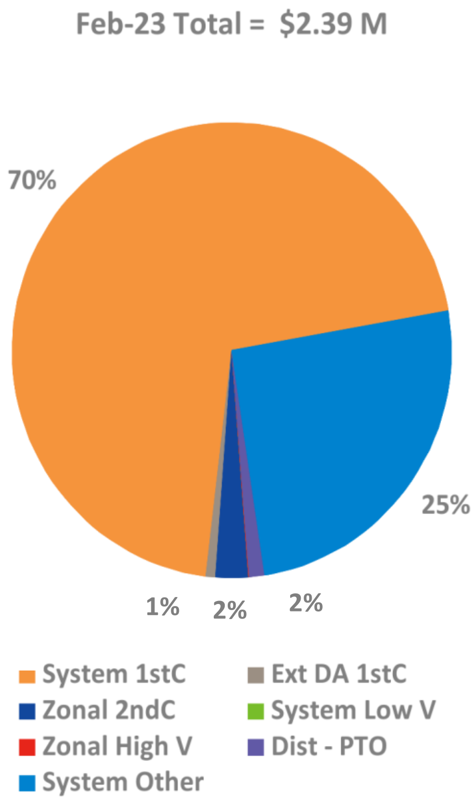


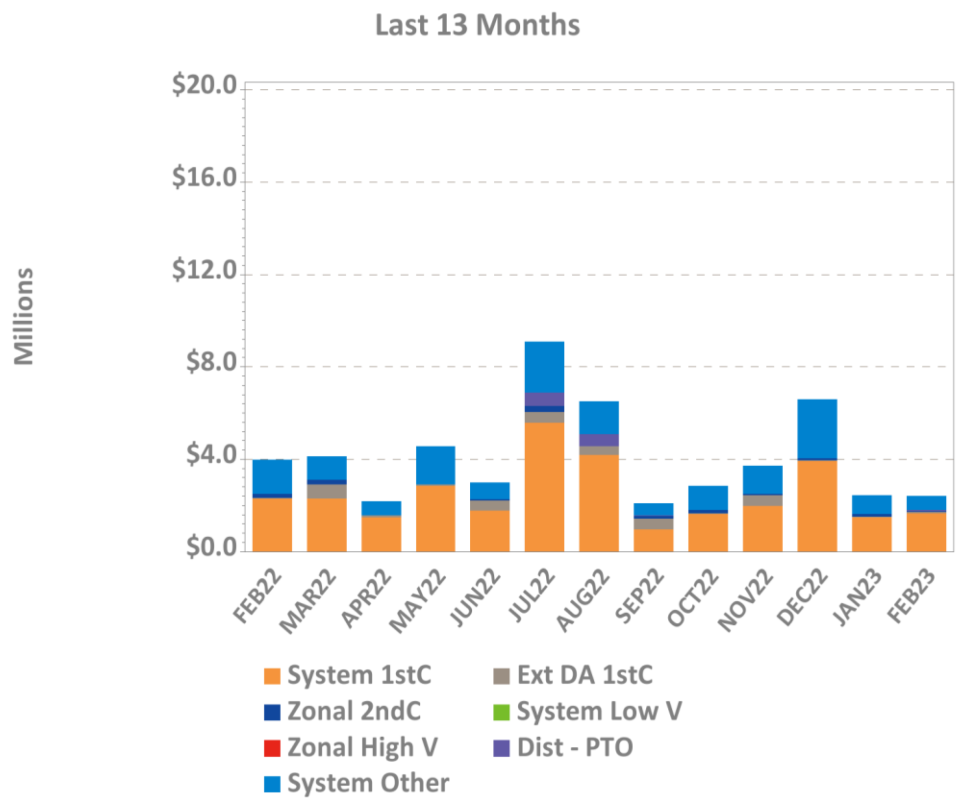
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



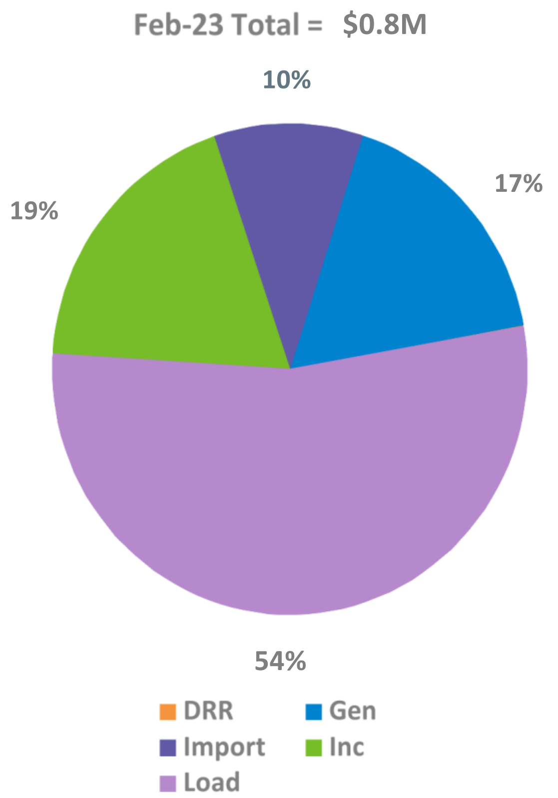
NCPC Charges by Allocation

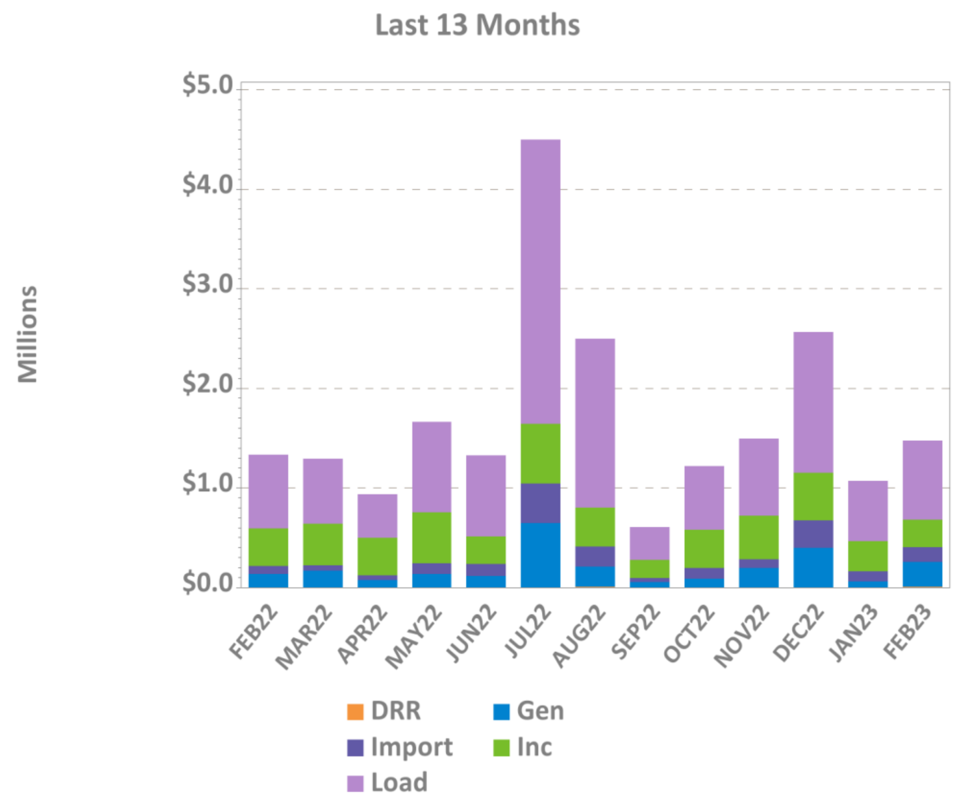




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

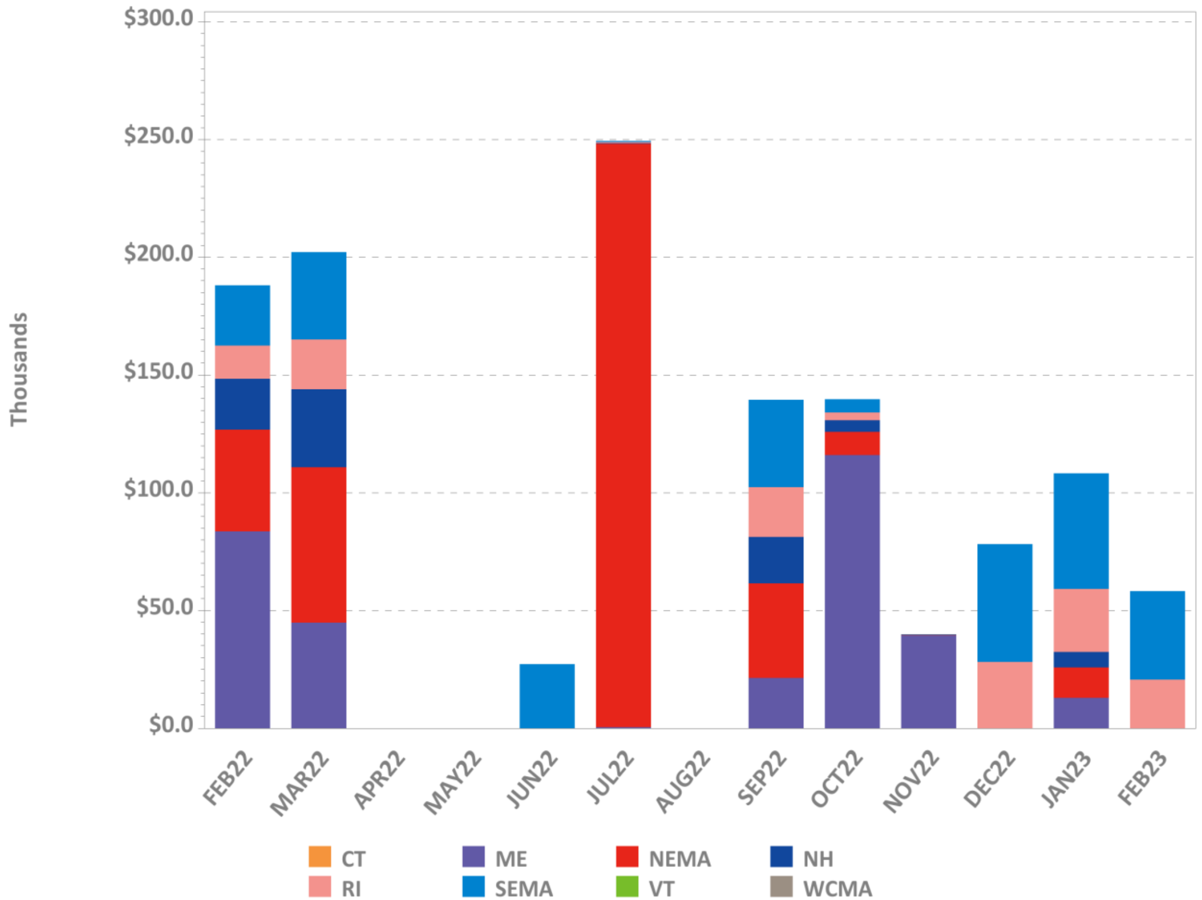
RT First Contingency Charges by Deviation Type





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

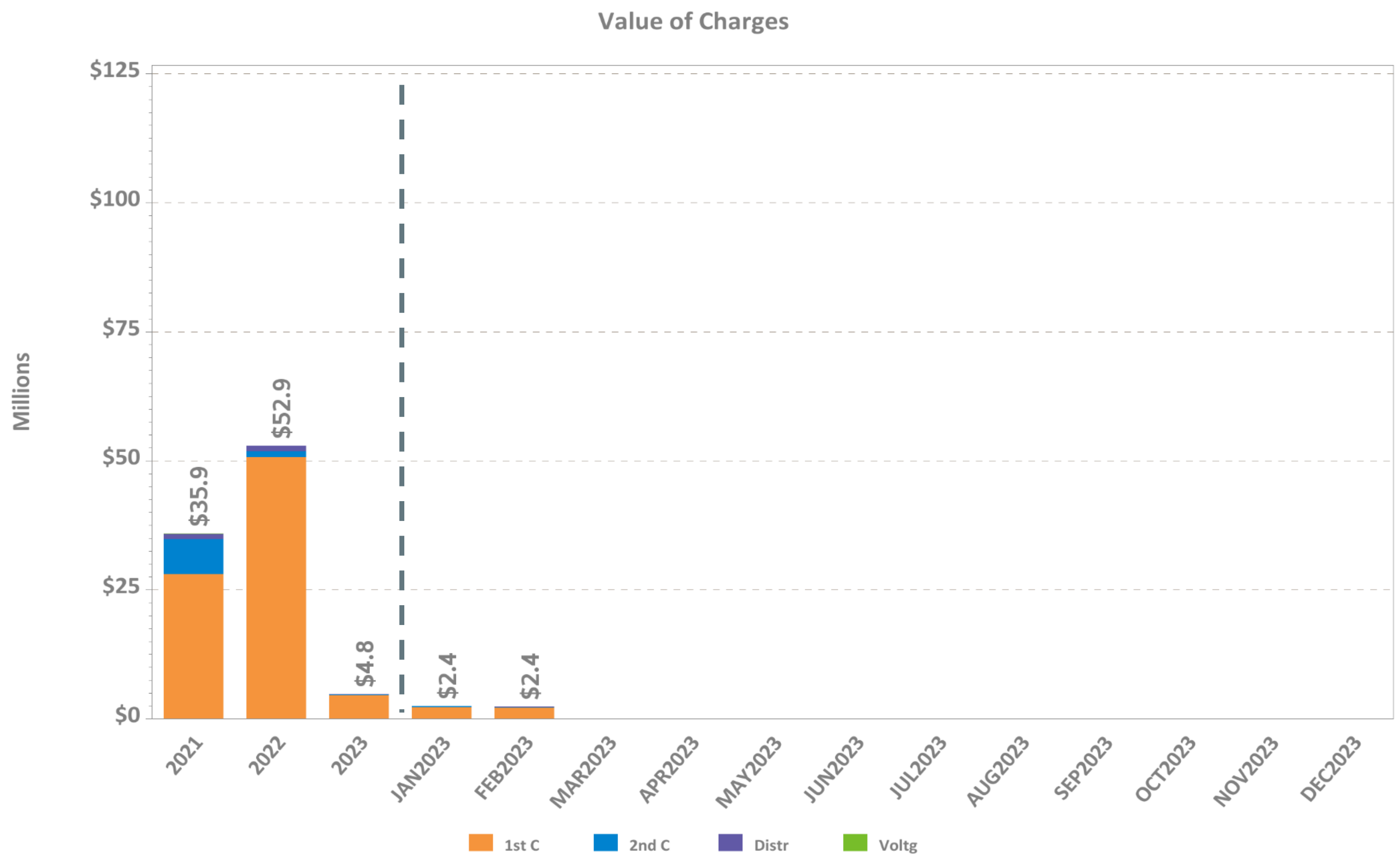
LSCPR Charges by Reliability Region



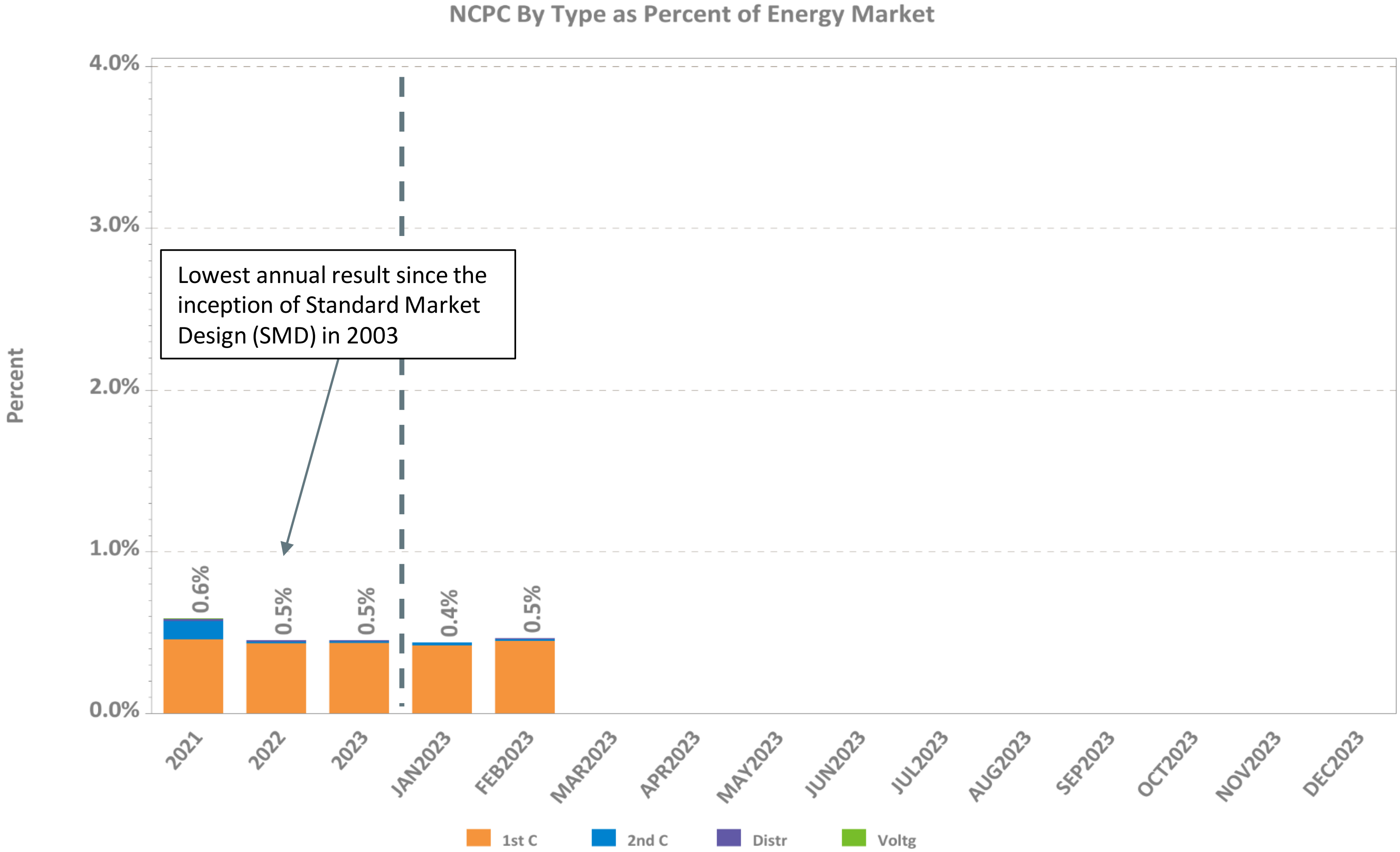
CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region

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

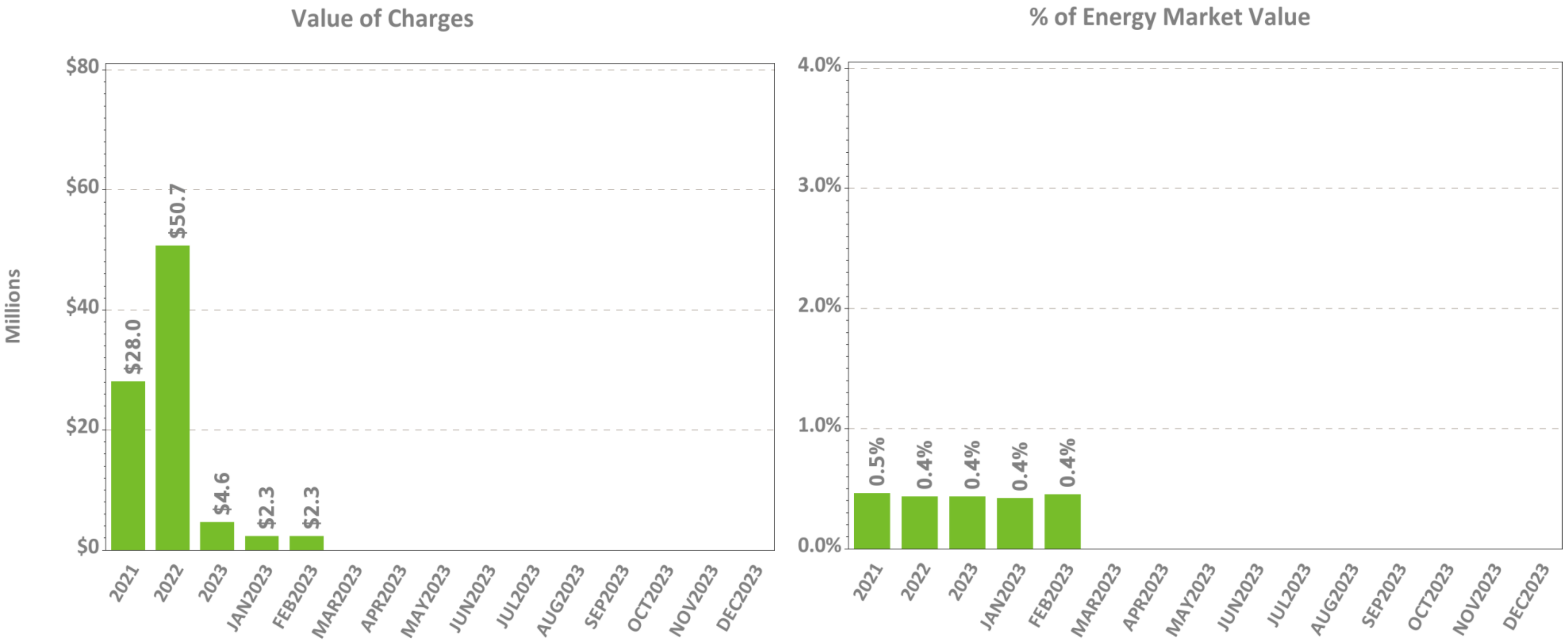
NCPC Charges by Type



NCPC Charges as Percent of Energy Market

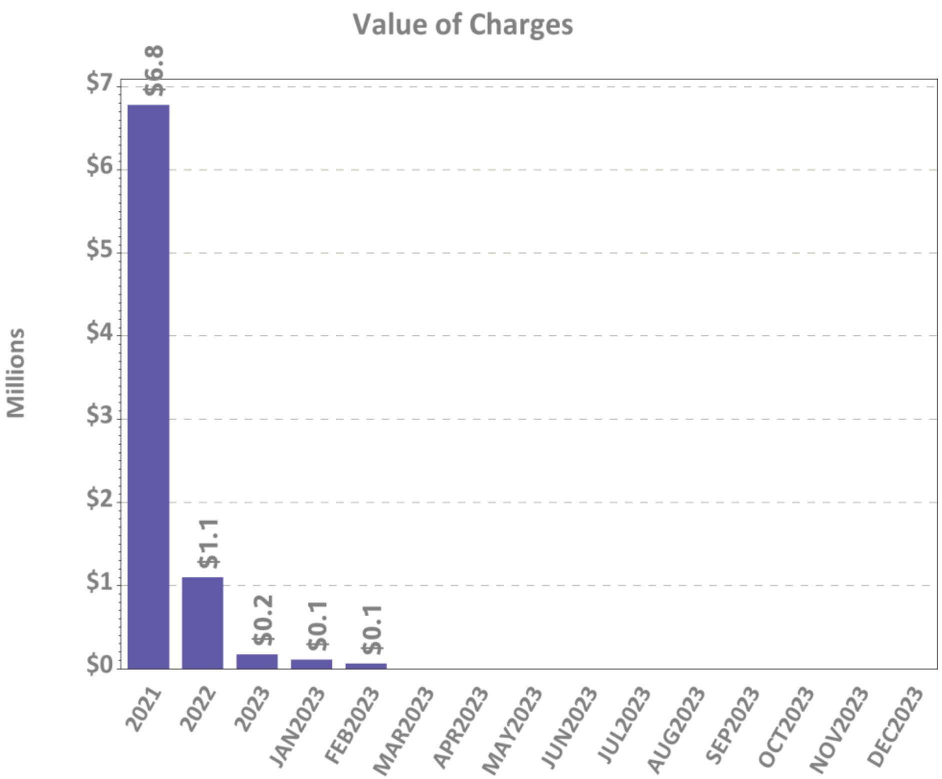


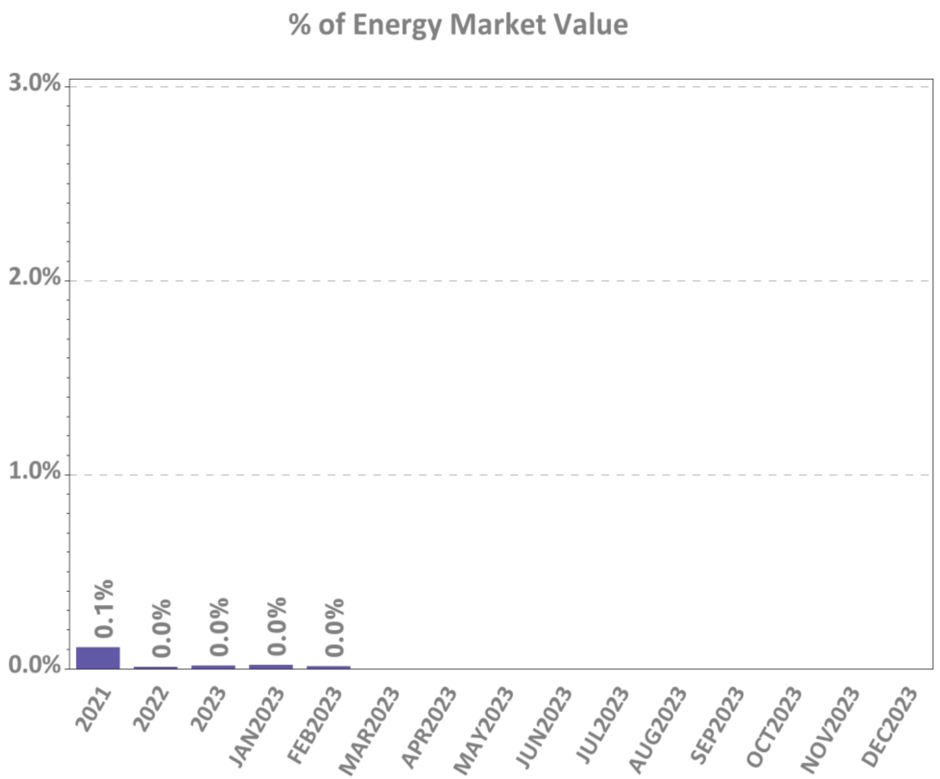
First Contingency NCPC Charges



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

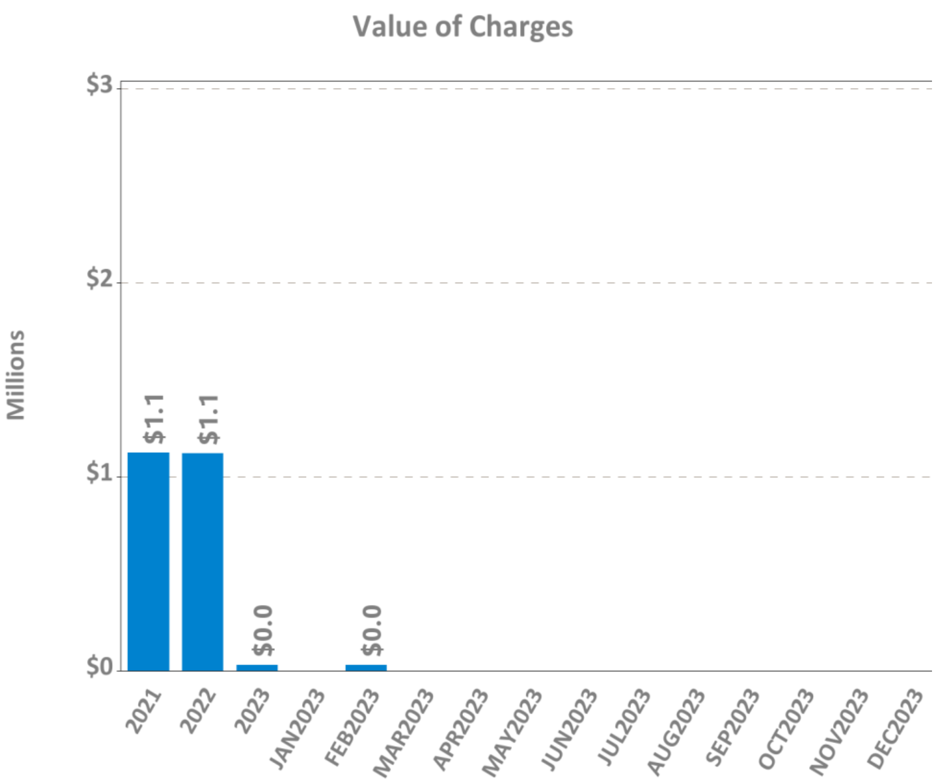
Second Contingency NCPC Charges

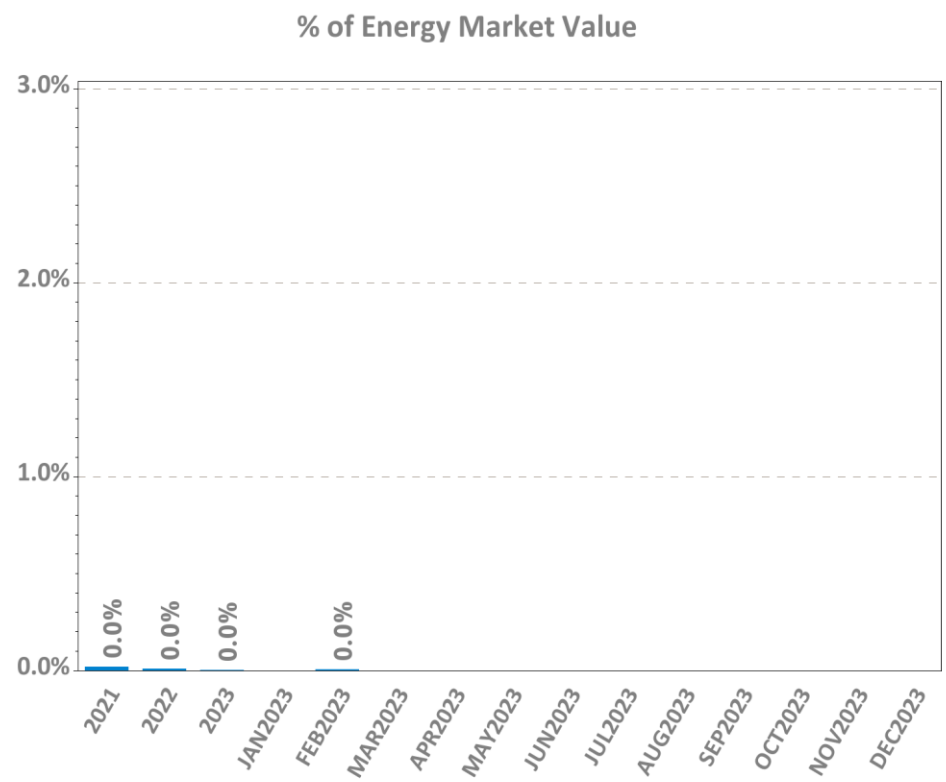




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution NCPC Charges





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

DA vs. RT Pricing

The following slides outline:

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

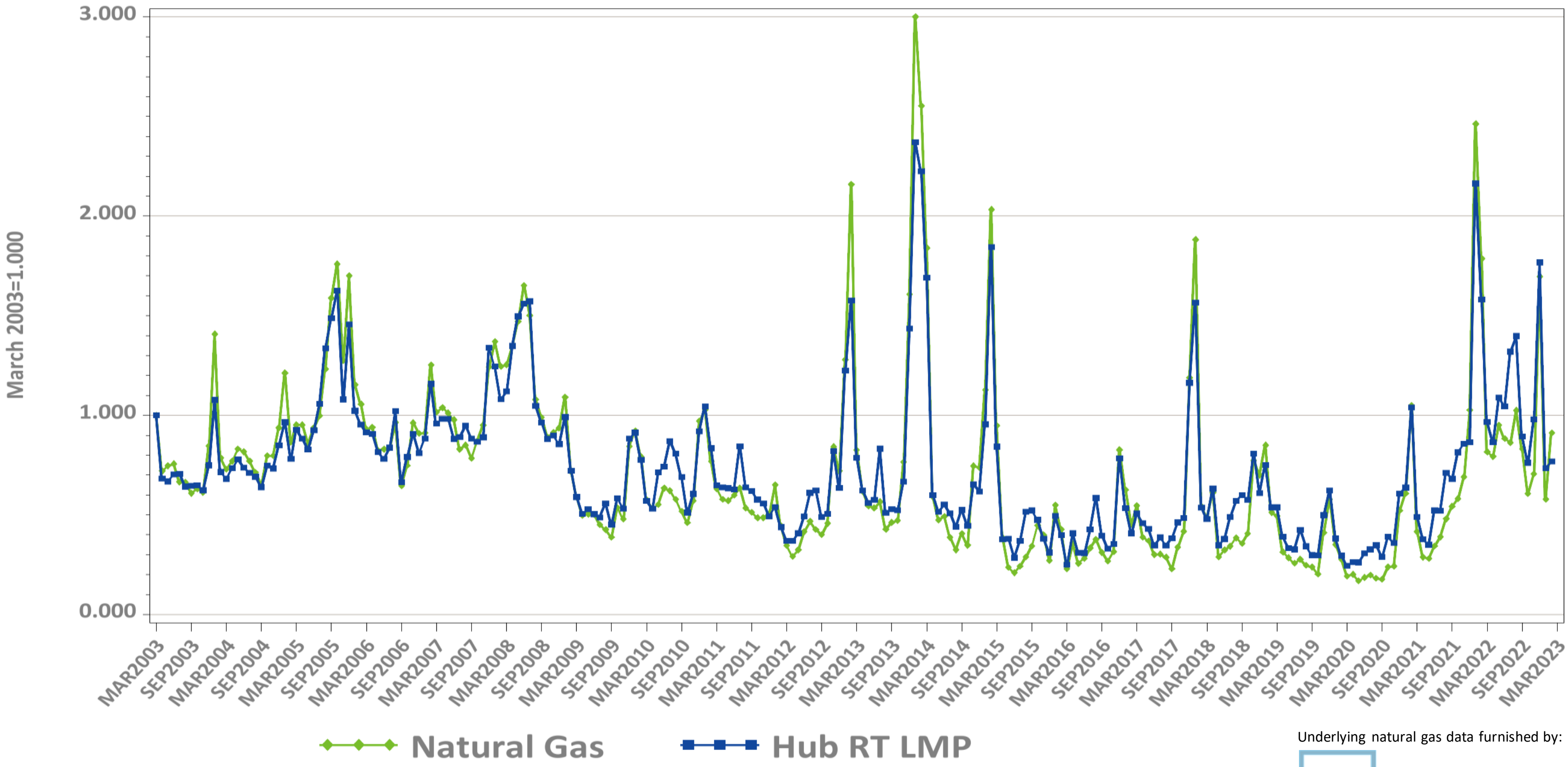
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2021	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$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%

February-22	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$118.95	$112.50	$118.03	$118.08	$114.26	$117.58	$118.63	$116.85	$117.08
Real-Time	$109.81	$105.59	$108.59	$109.31	$106.47	$108.64	$109.57	$108.54	$108.67
RT Delta %	-7.7%	-6.1%	-8.0%	-7.4%	-6.8%	-7.6%	-7.6%	-7.1%	-7.2%
February-23	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$59.33	$58.12	$58.35	$59.36	$59.00	$59.20	$59.81	$59.29	$59.30
Real-Time	$53.06	$51.84	$52.05	$53.05	$52.51	$52.77	$53.35	$52.82	$52.84
RT Delta %	-10.6%	-10.8%	-10.8%	-10.6%	-11.0%	-10.9%	-10.8%	-10.9%	-10.9%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-50.1%	-48.3%	-50.6%	-49.7%	-48.4%	-49.6%	-49.6%	-49.3%	-49.4%
Yr over Yr RT	-51.7%	-50.9%	-52.1%	-51.5%	-50.7%	-51.4%	-51.3%	-51.3%	-51.4%

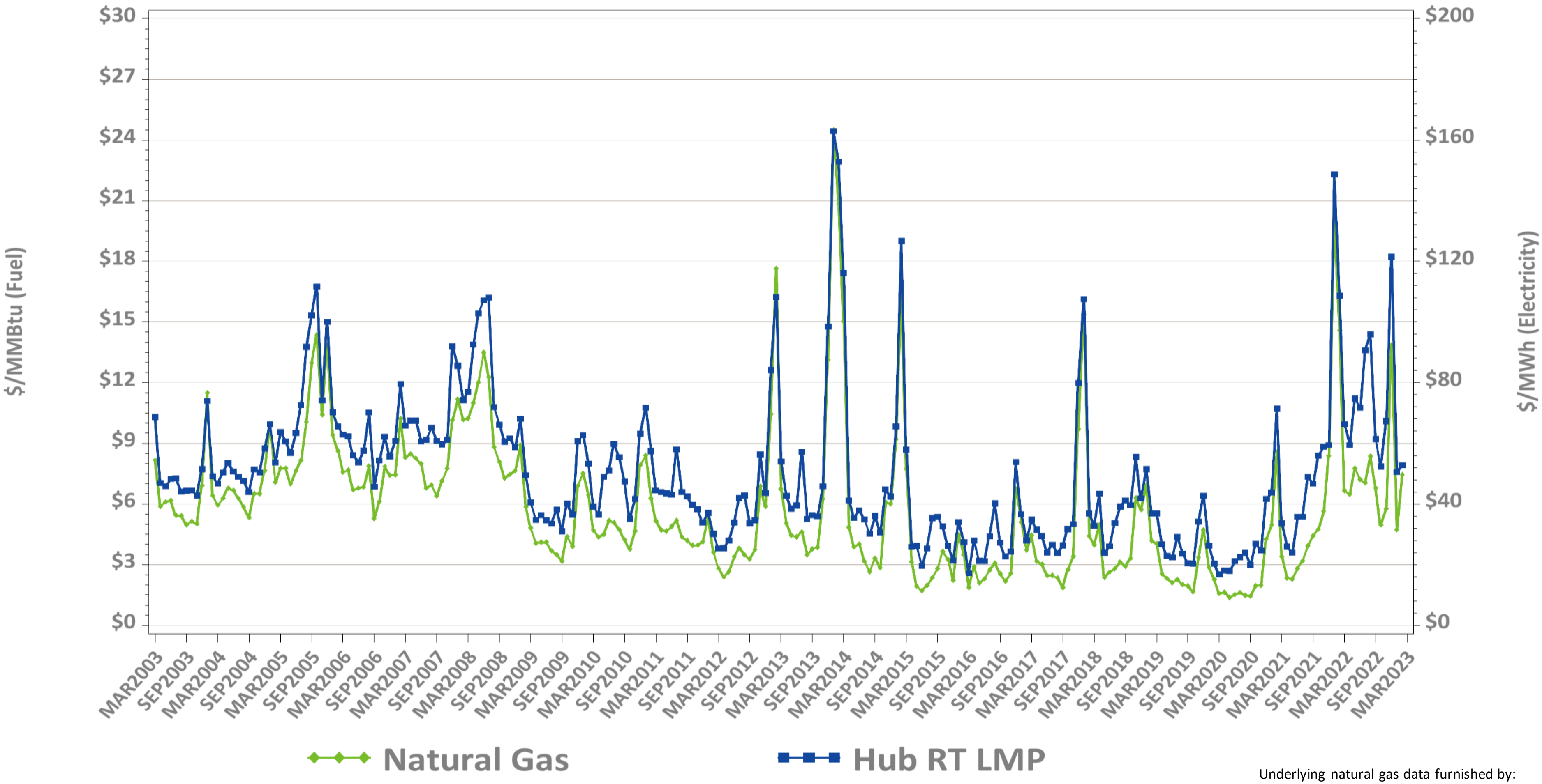
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ice Global markets in clear view

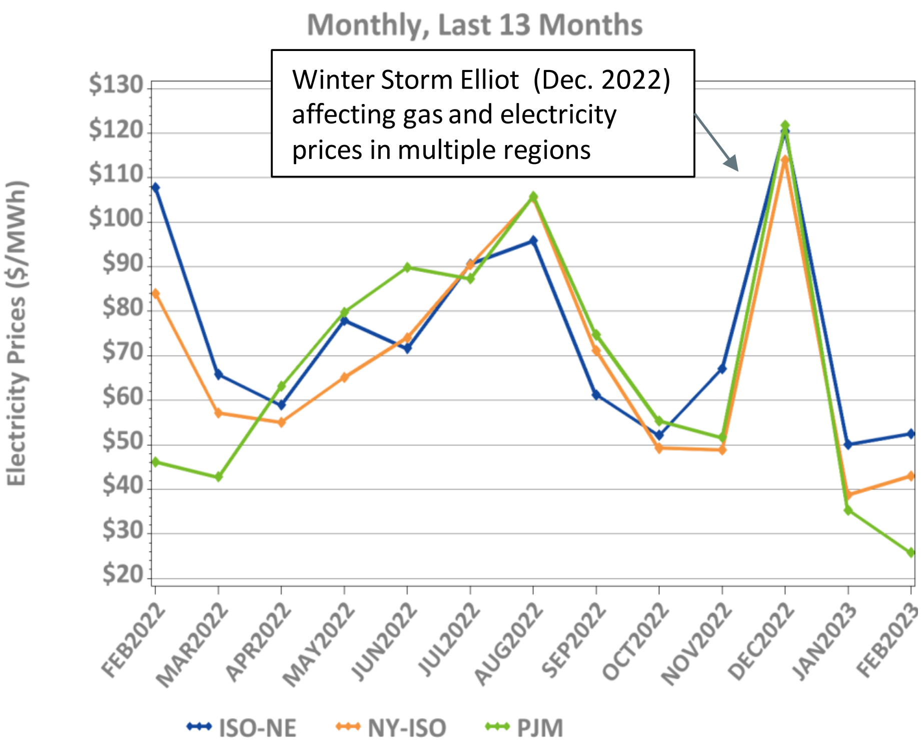
Monthly Average Fuel Price and RT Hub LMP



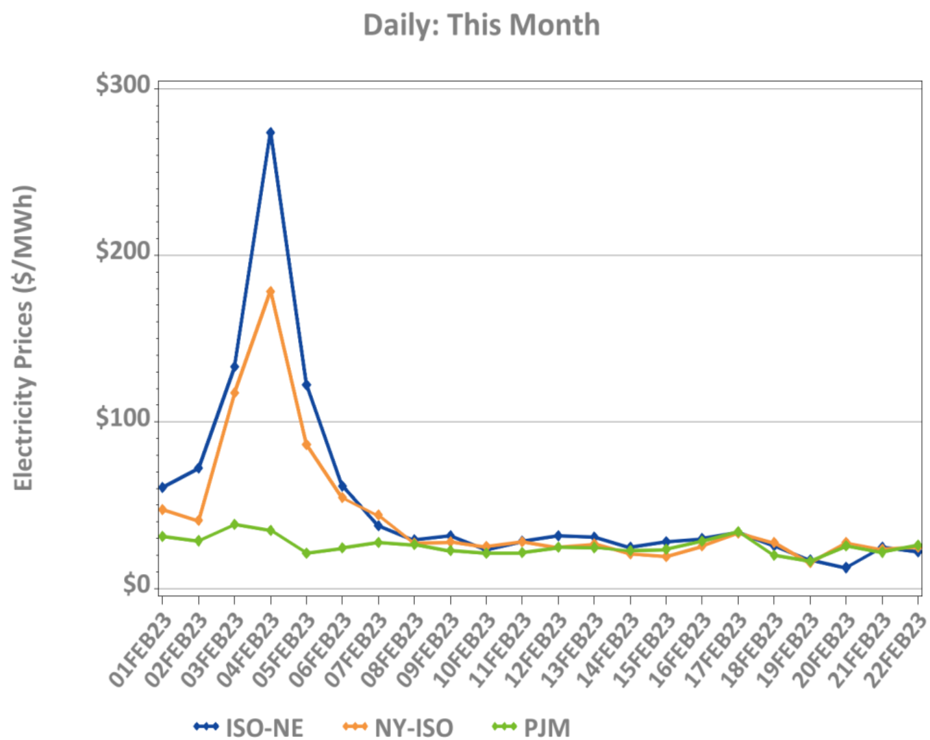
Underlying natural gas data furnished by:

ICE Global markets in clear view

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

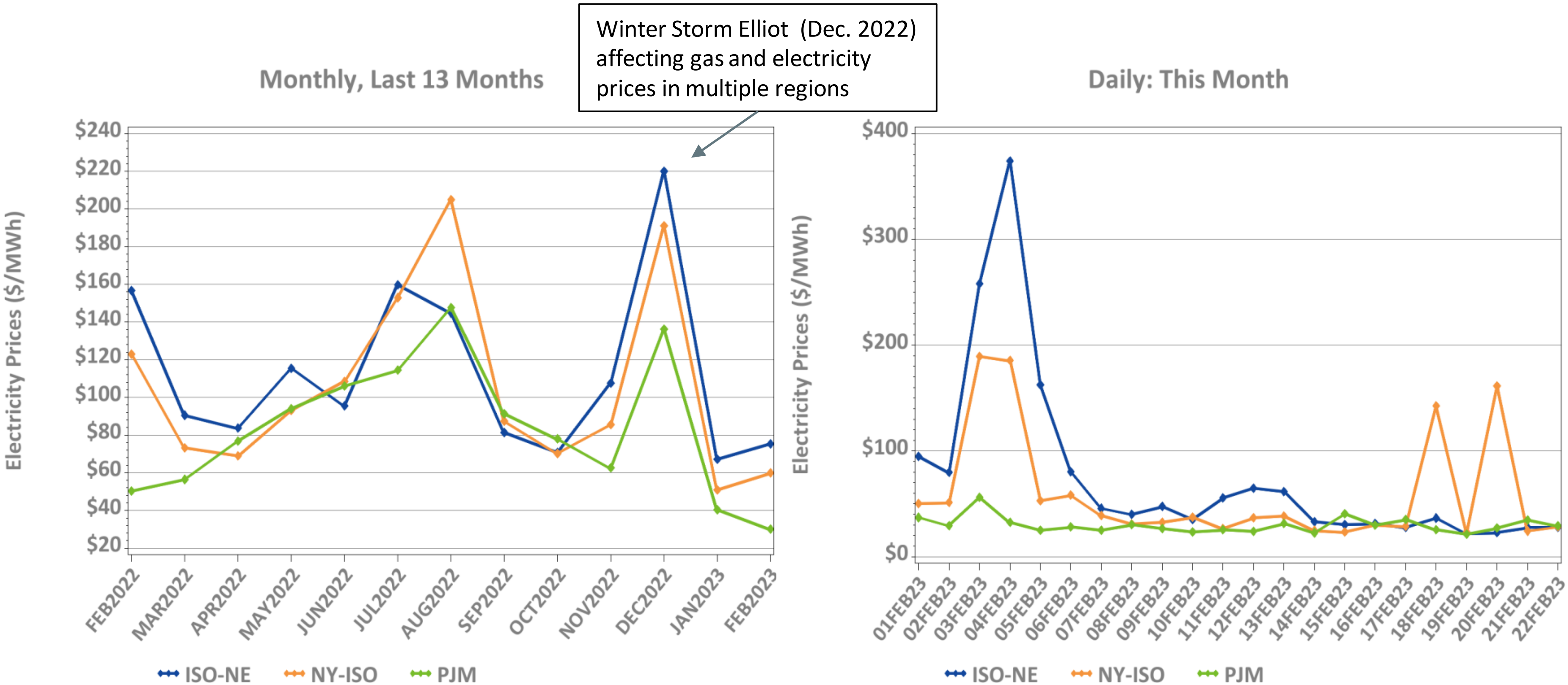


*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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



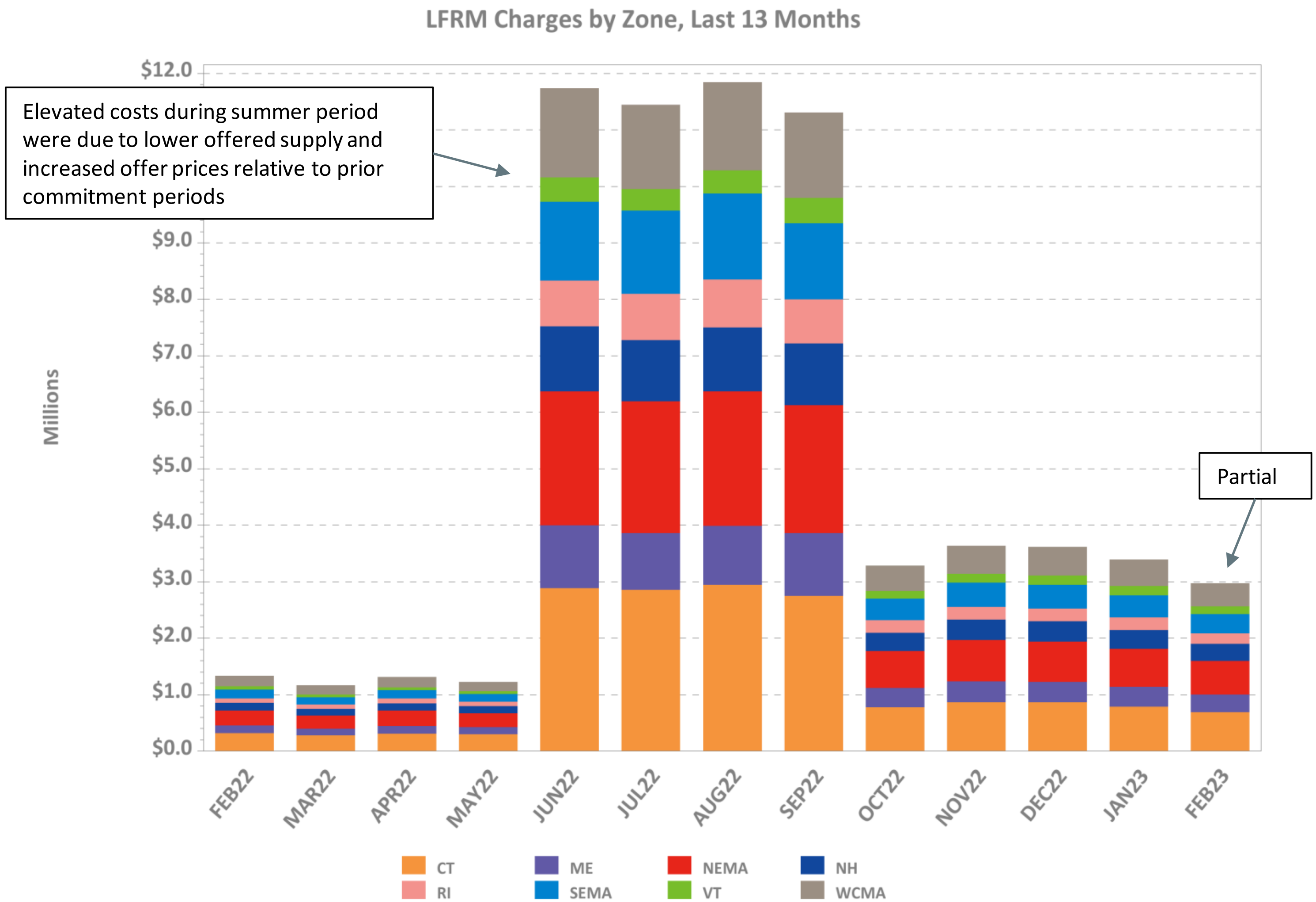
***Forecasted New England daily peak hours reflected**

Reserve Market Results – February 2023

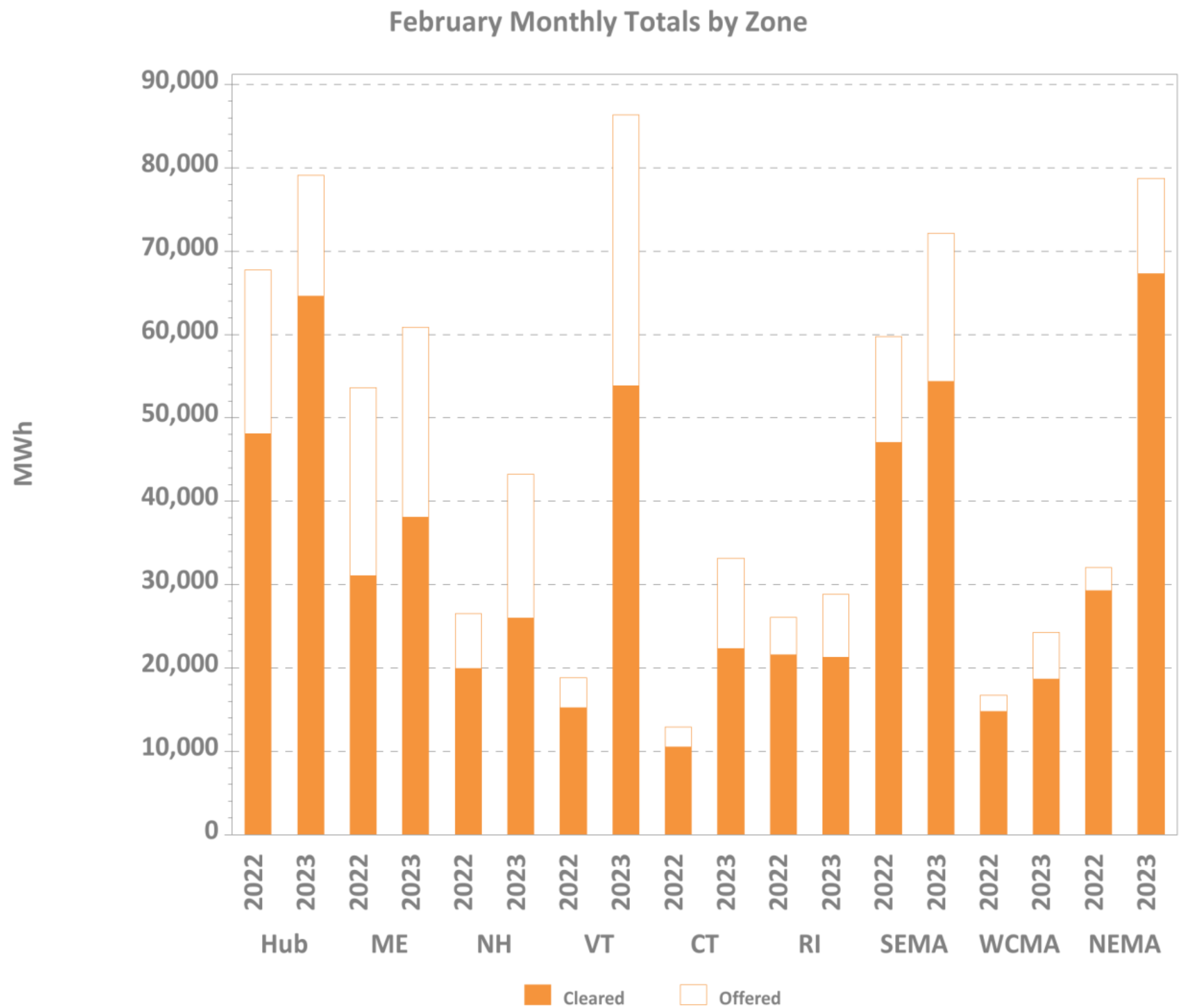
- Maximum potential Forward Reserve Market payments of $3M were reduced by credit reductions of $14K, failure-to-reserve penalties of $21K and no failure-to-activate penalties, resulting in a net payout of $2.97M or 99% of maximum
  – Rest of System: $2.04M/2.08M (98%)
  – Southwest Connecticut: $0.03M/0.03M (97%)
  – Connecticut: $0.9M/0.9M (100%)
- $115K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of $115K in Real-Time Reserve payments
  – Rest of System: 80 hours, $82K
  – Southwest Connecticut: 80 hours, $20K
  – Connecticut: 80 hours, $8K
  – NEMA: 80 hours, $6K

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.

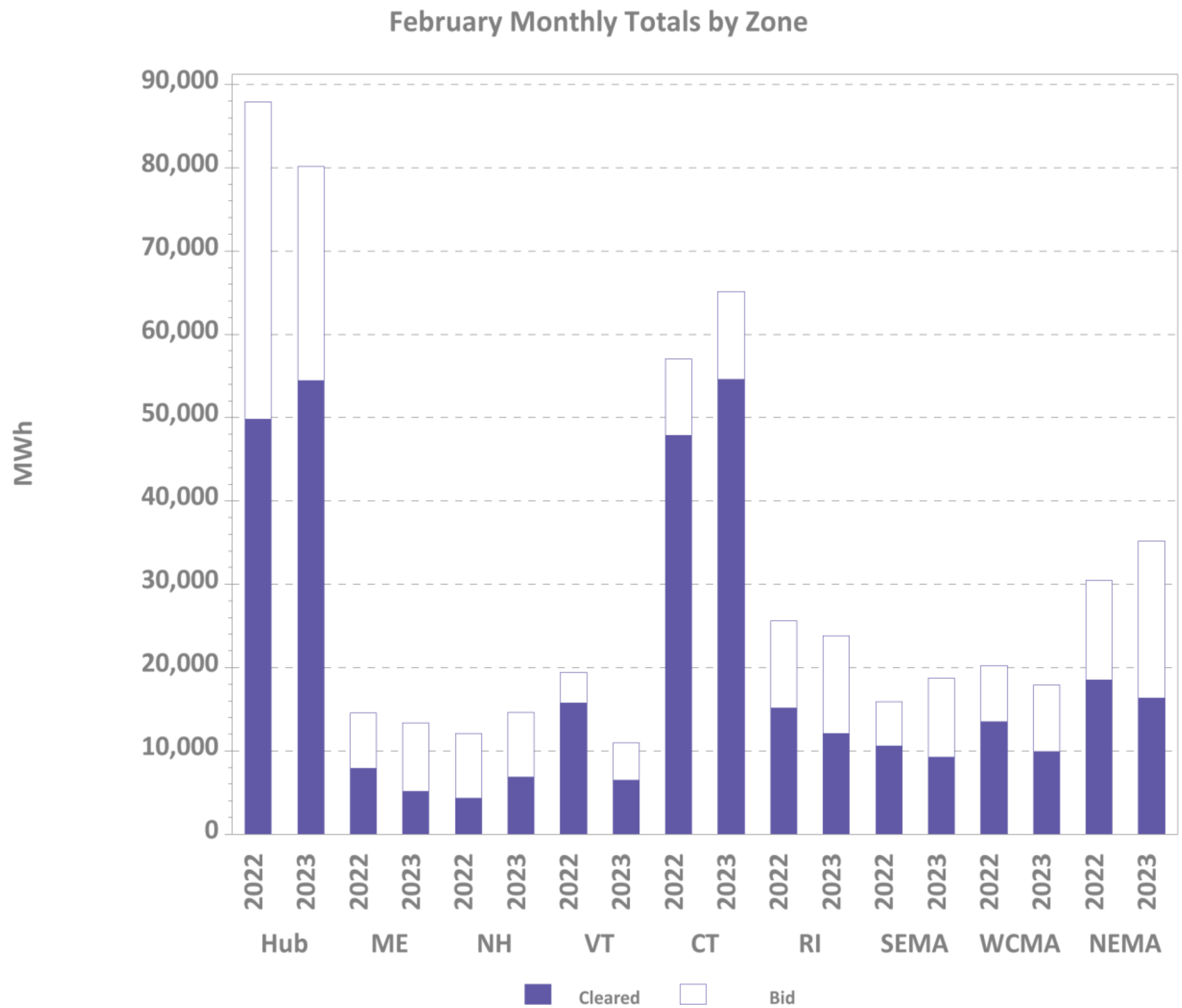
LFRM Charges to Load by Load Zone ($)



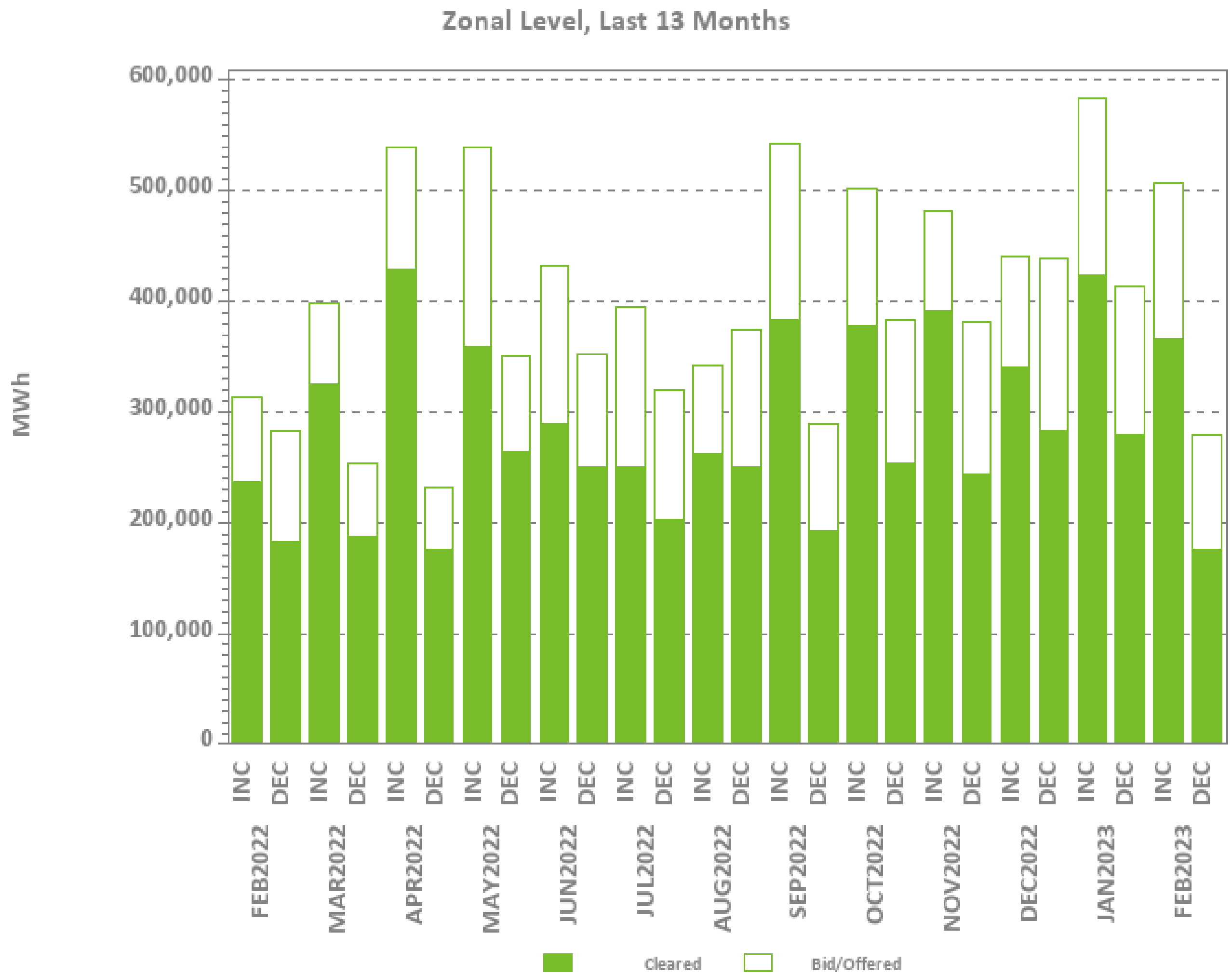
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

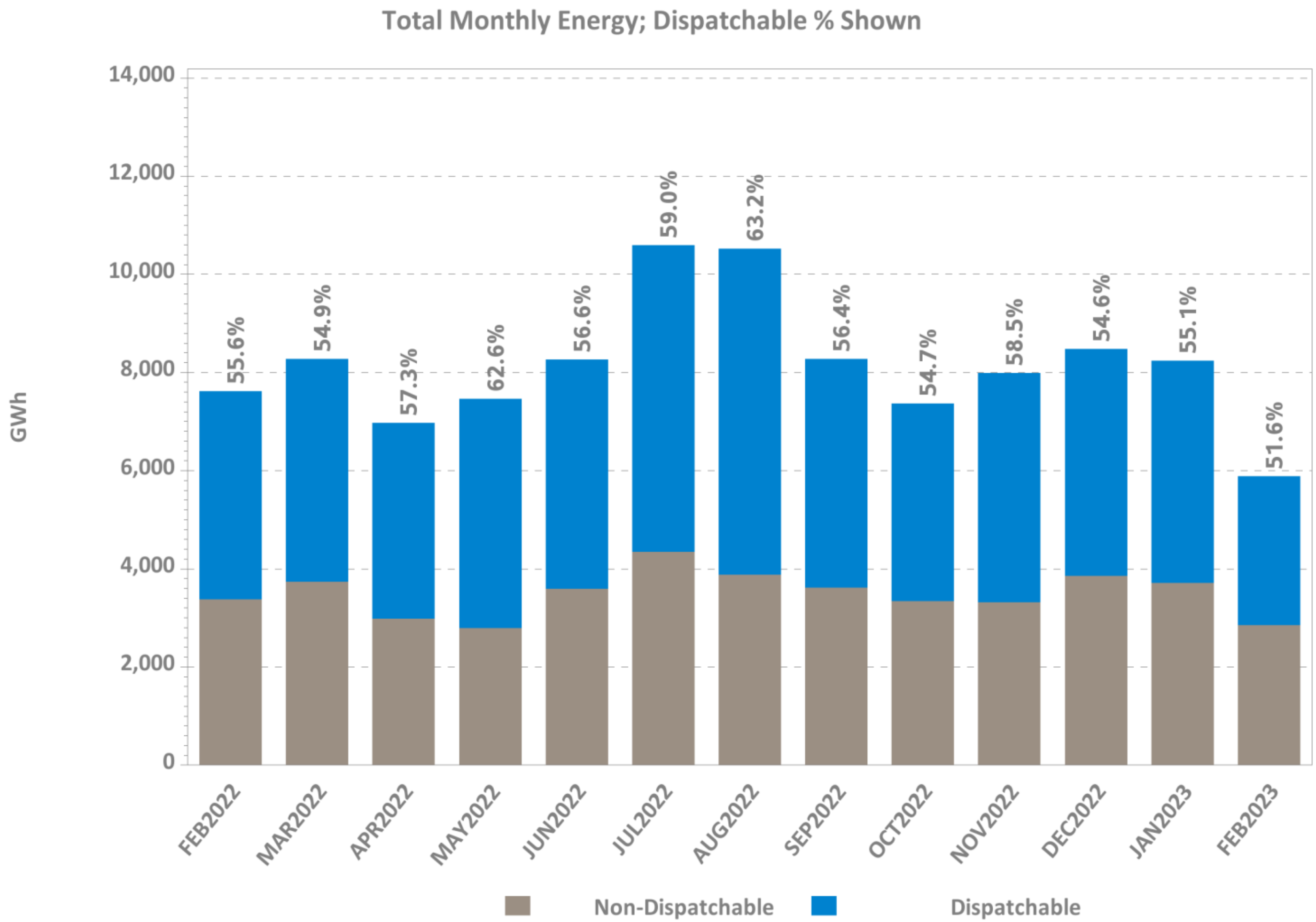


Total Increment Offers and Decrement Bids



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)

- March 16 PAC Meeting Agenda Topics*
  - Asset Condition Projects
    - Shutesbury #704 Station Rebuild (National Grid)
    - NH Line Asset Condition Projects (Eversource)
    - CT Line Asset Condition Projects (Eversource)
    - Laminated Wood Structure Replacement Program Phase 3a (Eversource)
    - Mystic to Woburn Cost Update on RSP #1356 (Component of Greater Boston) (Eversource)
    - New East Eagle Substation Update (Eversource)
  - Kick-off RSP 2023-2024 Process
  - RSP Transmission Projects and Asset Condition Update
  - Maine Interface Transfer Limit Updates
  - FCA 18 Transmission Transfer Capabilities and Capacity Zone Development

* 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; draft changes to the Transmission Planning Technical Guide (TPTG) reflecting assumption changes were discussed at the 11/15/22 PAC meeting; draft revisions to the TPTG were posted on 12/7/22, with feedback requested by 1/10/23
- The ISO is reviewing comments and revising the TPTG as appropriate; changes are expected to be finalized in February

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

Economic Studies

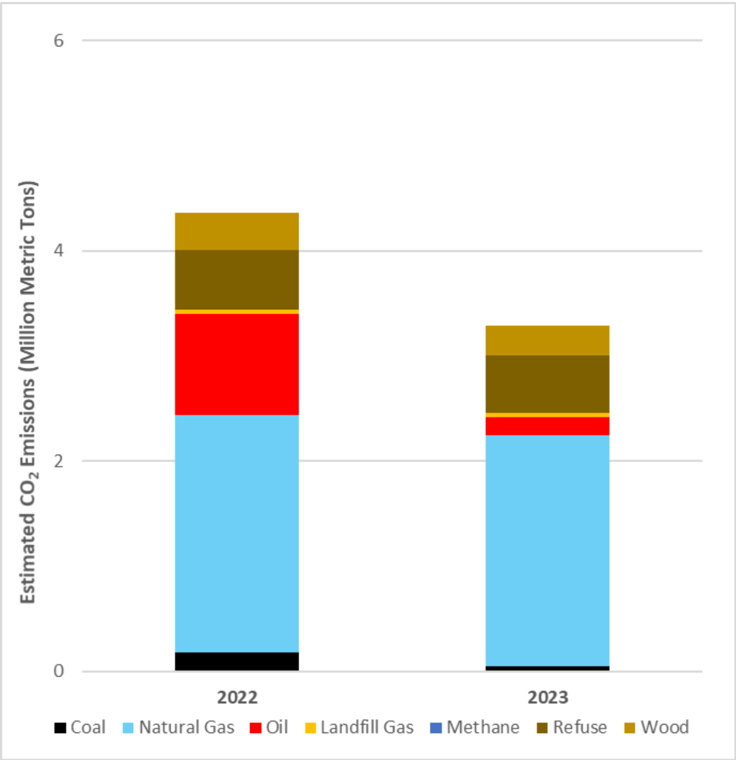
- Economic Planning for the Clean Energy Transition Pilot Study
  - New effort is to review all assumptions in economic planning and perform a test study consistent with the proposed changes to the Tariff
  - PAC presentations began in April 2022. To date, the ISO has presented new modeling features, 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 is expecting to present the first round of Policy scenario assumptions in April 2023

Future Grid Reliability Study (FGRS)

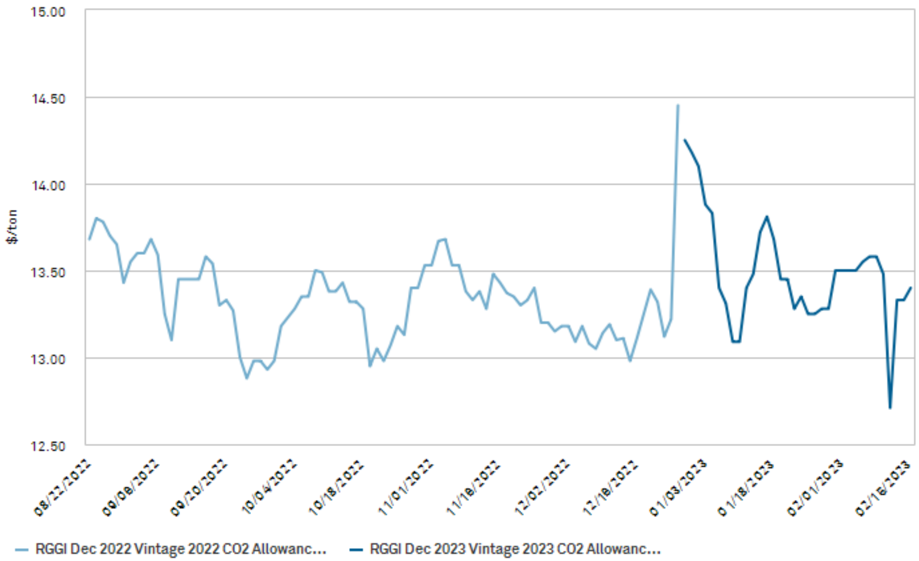
- Phase 1
  - Studies included: Production Cost Simulations; Ancillary Services Simulations; Resource Adequacy Screen; and Probabilistic Resource Availability Analysis
  - Phase 1 work was completed as the 2021 Economic Study
- Phase 2
  - In Phase 2, modeling tools and assumptions from the Pathways 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 expected to be shared with stakeholders in early 2023

New England Power System Carbon Emissions

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



RGGI Allowance Prices



- 2/15/23: RGGI allowance spot price - $13.40 per allowance (1 allowance = 1 short ton CO_2)

Data as of 02/12/2023

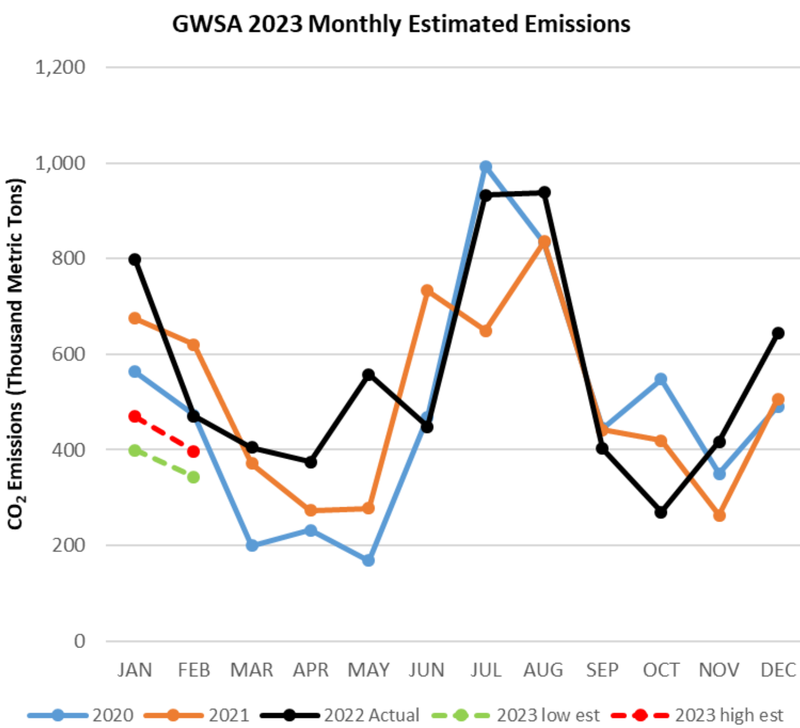
RGGI – Regional Greenhouse Gas Initiative

Massachusetts CO_2 Generator Emissions Cap

2023 Estimated Emissions Under CO_2 Cap

- As of 02/21/2023, estimated GWSA CO_2 emissions range between **343,299** and **396,790** metric tons
  - **9.5%** and **11.1%** of the 2023 cap of 7.84 MMT
- The total actual 2022 CO_2 emissions were **6.66 MMT**, 83% of 2022 cap (8.06 MMT)
- 12/14/2022: The first GWSA auction for the current (2023) vintage year cleared at $14.20 per metric ton
  - Most of the 2023 allowances were awarded to Regulated Entities to satisfy their forecasted compliance obligations for 2023
- Clearing price of $6.03 for future vintage (2024) allowances

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 2/16/2023

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 2/16/2023

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 2/16/2023

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 2/16/2023

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 2/16/2023

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 2/16/2023

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 2/16/2023

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	May-25	2
1721	Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor	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 2/16/2023

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	2
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 2/16/2023

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 2/16/2023

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 2/16/2023

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	Mar-23	3
1853	Convert Gales Ferry substation from 69 kV to 115 kV	Dec-23	3
1854	Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Jun-23	3

Eastern CT Reliability Projects, cont.

Status as of 2/16/2023

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.)	Apr-23	3
1857	Add one 115 kV circuit breaker and re-terminate the 400-1 line section into Tunnel substation. Energize 400 Line at 115 kV	Dec-23	3
1858	Rebuild 400-2 Line section to allow operation at 115 kV (Ledyard Jct. to Border Bus with CMEEC)	Sept-22	4
1859	Rebuild the 400-3 Line Section to allow operation at 115 kV (Gales Ferry to Ledyard Jct.)	Apr-23	3
1860	Install a 25.2 MVAR 115 kV capacitor and one capacitor breaker at Killingly	Dec-21	4

Eastern CT Reliability Projects, cont.

Status as of 2/16/2023

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 2/16/2023

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 2/16/2023

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 2/16/2023

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

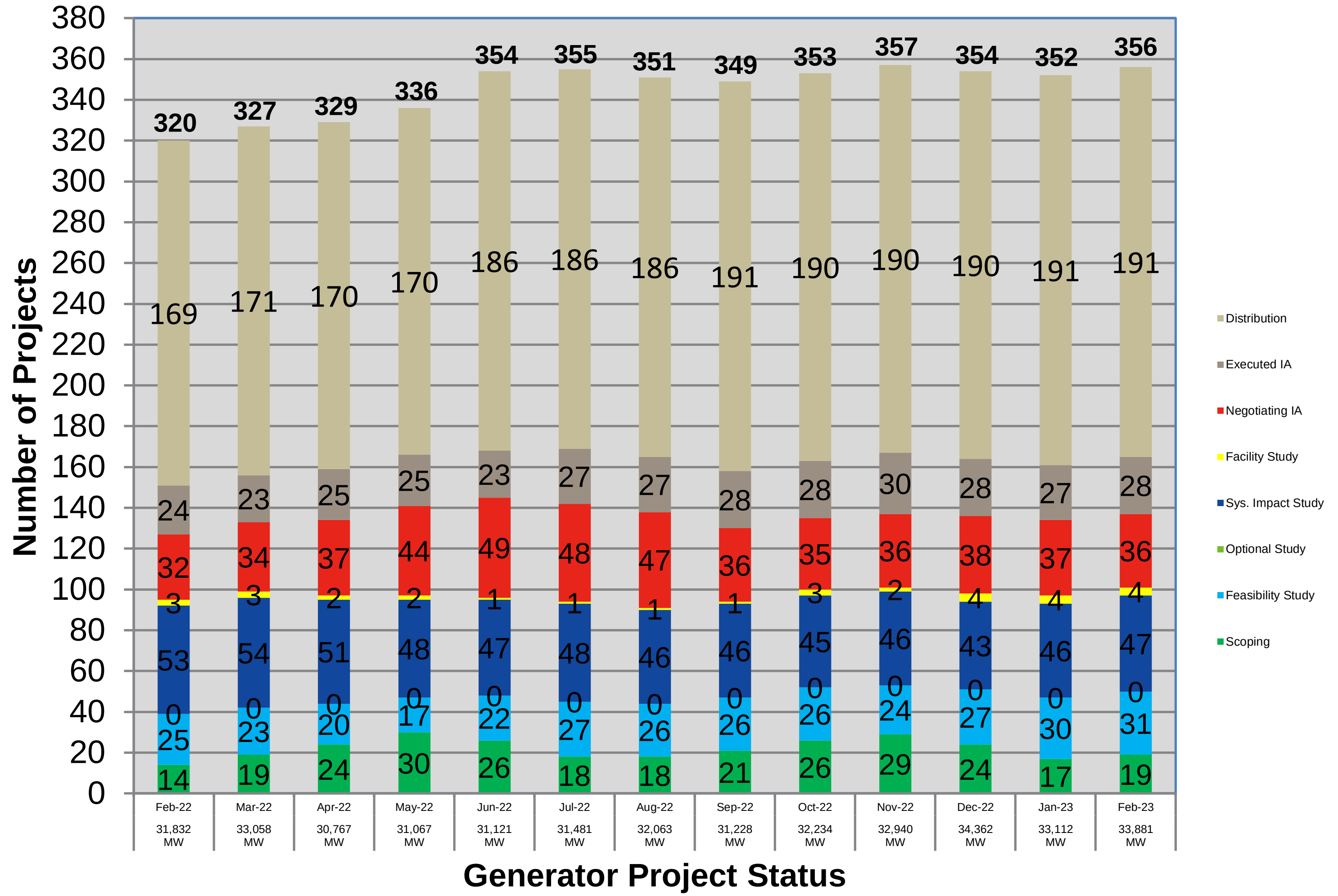
Upper Maine Solution Projects, cont.

Status as of 2/16/2023

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

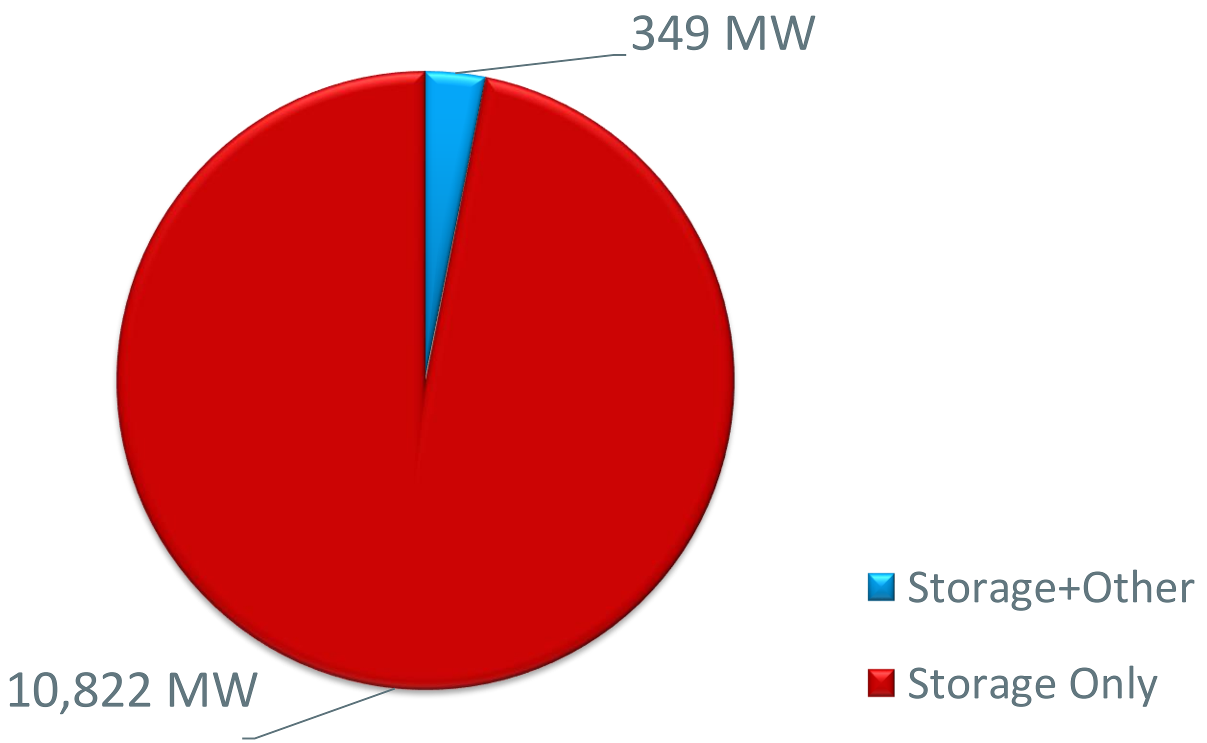
Status of Tariff Studies as of February 23, 2023



Note: February 2023 is based on partial data.
9 ETUs in Scoping, 3 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 February 23, 2023)

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



OPERABLE CAPACITY ANALYSIS

Winter 2023 and Spring 2023

OPERABLE CAPACITY ANALYSIS

Winter 2023 Analysis

Winter 2023 Operable Capacity Analysis

50/50 Load Forecast (Reference)	March - 2023[2] CSO (MW)	March - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,326	31,949
Active Demand Capacity Resource (+) [5]	398	383
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,050	1,050
Non Commercial Capacity (+)	22	22
Non Gas-fired Planned Outage MW (-)	1,656	2,032
Gas Generator Outages MW (-)	3,392	4,284
Allowance for Unplanned Outages (-) [4]	2,200	2,200
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	22,548	24,888
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	16,797	16,797
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	19,102	19,102
Operable Capacity Margin	3,446	5,786

[1]Operable Capacity is based on data as of **February 21, 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 **February 21, 2023.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **March 25, 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.

Winter 2023 Operable Capacity Analysis

90/10 Load Forecast	March - 2023[2] CSO (MW)	March - 2023[2] SCC (MW)
Operable Capacity MW [1]	28,326	31,949
Active Demand Capacity Resource (+) [5]	398	383
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,050	1,050
Non Commercial Capacity (+)	22	22
Non Gas-fired Planned Outage MW (-)	1,656	2,032
Gas Generator Outages MW (-)	3,392	4,284
Allowance for Unplanned Outages (-) [4]	2,200	2,200
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	22,548	24,888
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	17,383	17,383
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	19,688	19,688
Operable Capacity Margin	2,860	5,200

[1]Operable Capacity is based on data as of **February 21, 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 **February 21, 2023.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **March 25, 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.

Winter 2023 Operable Capacity Analysis
50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

February 21, 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 March.

Report created: 2/21/2023

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
3/11/2023	28326	398	1050	22	523	1324	2200	0	25749	17718	2305	20023	5726	N	Winter 2022/2023
3/18/2023	28326	398	1050	22	1692	2091	2200	0	23813	17357	2305	19662	4151	N	Winter 2022/2023
3/25/2023	**28326**	**398**	**1050**	**22**	**1656**	**3392**	**2200**	**0**	**22548**	**16797**	**2305**	**19102**	**3446**	**Y**	**Winter 2022/2023**

Column Definitions

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

Winter 2023 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

February 21, 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 March.

Report created: 2/21/2023

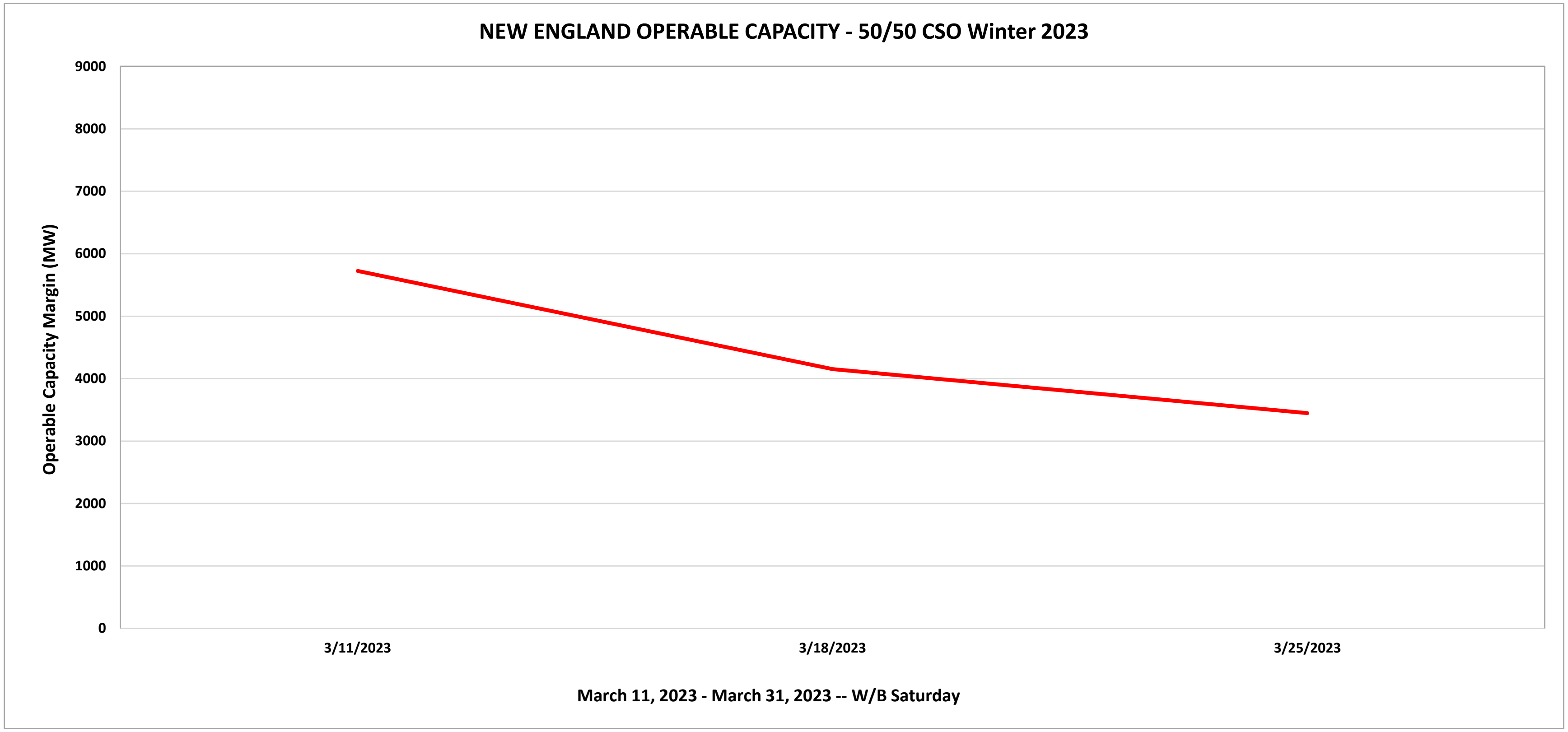
Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due 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
3/11/2023	28326	398	1050	22	537	1054	2200	442	25563	18333	2305	20638	4925	N	Winter 2022/2023
3/18/2023	28326	398	1050	22	1692	2091	2200	0	23813	17960	2305	20265	3548	N	Winter 2022/2023
3/25/2023	**28326**	**398**	**1050**	**22**	**1656**	**3392**	**2200**	**0**	**22548**	**17383**	**2305**	**19688**	**2860**	**Y**	**Winter 2022/2023**

Column Definitions

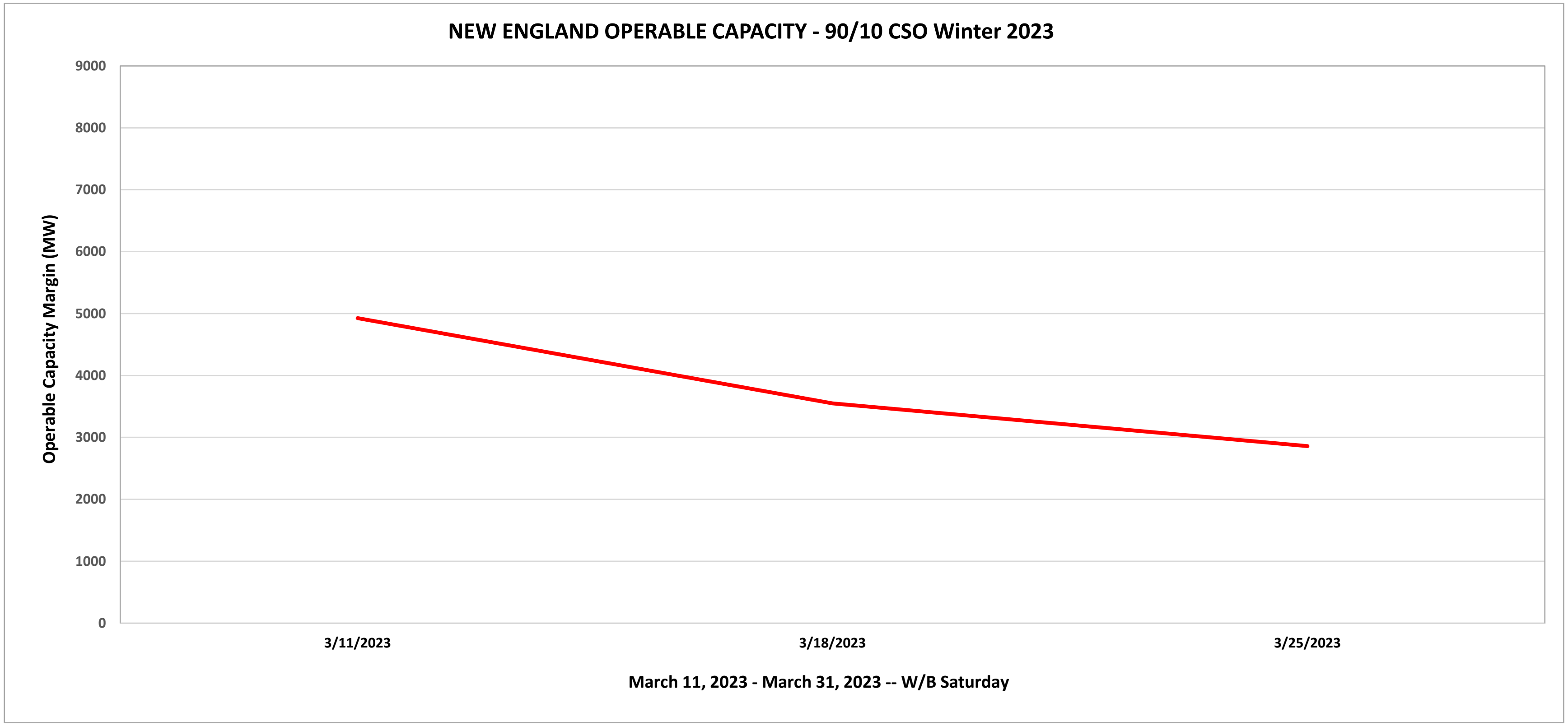
1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can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

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

Winter 2023 Operable Capacity Analysis
50/50 Forecast (Reference)



Winter 2023 Operable Capacity Analysis
90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Spring 2023 Analysis

Spring 2023 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2023[2] CSO (MW)	May – 2023[2] SCC (MW)
Operable Capacity MW [1]	28,171	31,949
Active Demand Capacity Resource (+) [5]	555	383
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,019	1,019
Non Commercial Capacity (+)	59	59
Non Gas-fired Planned Outage MW (-)	2,904	3,306
Gas Generator Outages MW (-)	2,747	3,247
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)	20,753	23,457
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	18,934	18,934
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,239	21,239
Operable Capacity Margin	-486	2,218

[1]Operable Capacity is based on data as of **February 21, 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 **February 21, 2023.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 13, 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]	28,171	31,949
Active Demand Capacity Resource (+) [5]	555	383
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,019	1,019
Non Commercial Capacity (+)	59	59
Non Gas-fired Planned Outage MW (-)	2,904	3,306
Gas Generator Outages MW (-)	2,747	3,247
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)	20,753	23,457
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,309	20,309
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,614	22,614
Operable Capacity Margin	-1,861	843

[1] Operable Capacity is based on data as of **February 21, 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 **February 21, 2023.**

[2] Load forecast that is based on the 2022 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 13, 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

February 21, 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 April and May.

Report created: 2/21/2023

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
4/1/2023	28171	555	1070	59	4813	3289	2700	0	19053	16176	2305	18481	572	N	Spring 2023
4/8/2023	28171	555	1070	59	4924	2946	2700	0	19285	15927	2305	18232	1053	N	Spring 2023
4/15/2023	28171	555	1070	59	4598	3257	2700	0	19300	15423	2305	17728	1572	N	Spring 2023
4/22/2023	28171	555	1070	59	4162	2536	2700	0	20457	15160	2305	17465	2992	N	Spring 2023
4/29/2023	28171	555	1070	59	4183	3376	3400	0	18896	15134	2305	17439	1457	N	Spring 2023
5/6/2023	28171	555	1070	59	3535	2575	3400	0	20345	17956	2305	20261	84	N	Spring 2023
5/13/2023	**28171**	**555**	**1019**	**59**	**2904**	**2747**	**3400**	**0**	**20753**	**18934**	**2305**	**21239**	**-486**	**Y**	**Spring 2023**
5/20/2023	28171	555	1070	59	1733	1738	3400	0	22984	19842	2305	22147	837	N	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 2022 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Spring 2023 Operable Capacity Analysis
90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

February 21, 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 April and May.

Report created: 2/21/2023

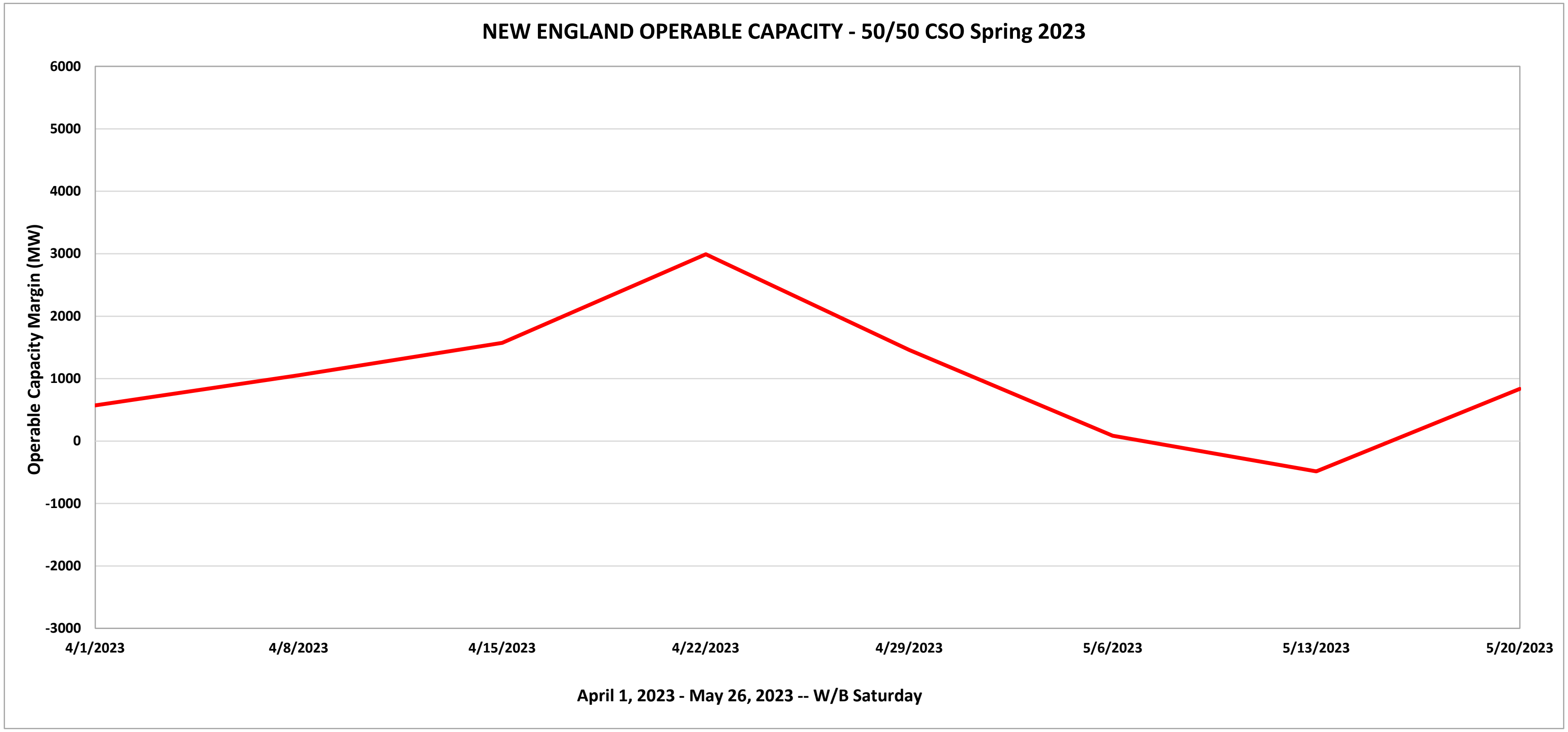
Study Week (Week Beginning, Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due 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
4/1/2023	28171	555	1070	59	4813	3289	2700	0	19053	16747	2305	19052	1	N	Spring 2023
4/8/2023	28171	555	1070	59	4924	2946	2700	0	19285	16490	2305	18795	490	N	Spring 2023
4/15/2023	28171	555	1070	59	4598	3257	2700	0	19300	15970	2305	18275	1025	N	Spring 2023
4/22/2023	28171	555	1070	59	4162	2536	2700	0	20457	15700	2305	18005	2452	N	Spring 2023
4/29/2023	28171	555	1070	59	4183	3376	3400	0	18896	15672	2305	17977	919	N	Spring 2023
5/6/2023	28171	555	1070	59	3535	2575	3400	0	20345	19270	2305	21575	-1230	N	Spring 2023
5/13/2023	**28171**	**555**	**1019**	**59**	**2904**	**2747**	**3400**	**0**	**20753**	**20309**	**2305**	**22614**	**-1861**	**Y**	**Spring 2023**
5/20/2023	28171	555	1070	59	1733	1738	3400	0	22984	21274	2305	23579	-595	N	Spring 2023

Column Definitions

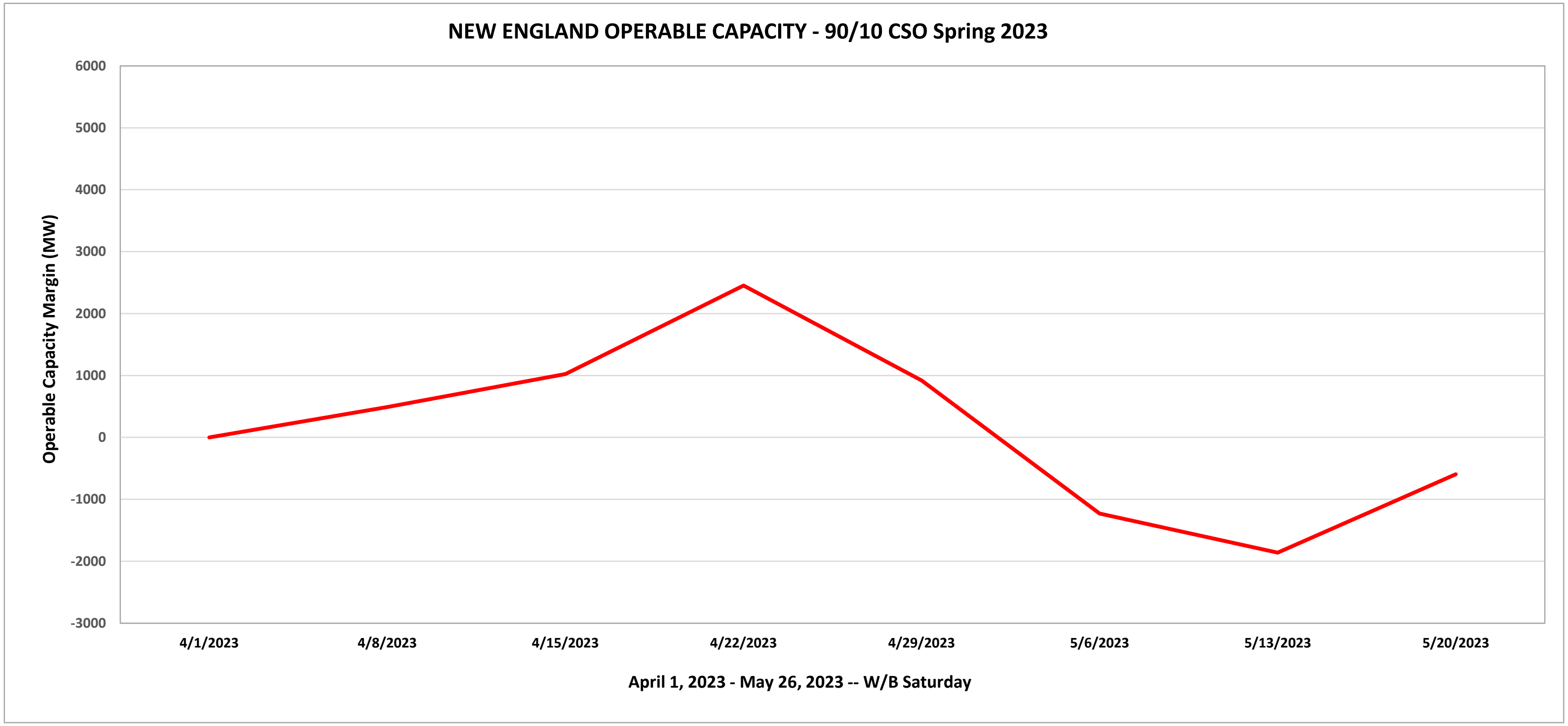
1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can 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 2022 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

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



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

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

Possible Relief Under OP4: Appendix A

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

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

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: February 23, 2023

RE: Inventoried Energy Program Parameter Updates

At the March 2, 2023 Participants Committee meeting, you will be asked to support revisions to Market Rule 1, Appendix K, to modify/update certain parameters of the Inventoried Energy Program (IEP), as proposed by ISO-NE and recommended by the NEPOOL Markets Committee (referred to herein as the IEP Parameter Updates). This memorandum provides an overview of the Markets Committee-recommended revisions and a summary of the stakeholder process to date, including information on a Participant-sponsored amendment to the IEP Parameter Updates that the Markets Committee considered.

Included with this memorandum are the following attachments:

- Attachment A: ISO-NE's Tariff redlines
- Attachment B: ISO-NE's Voting Memorandum
- Attachment C: Notice of Markets Committee Feb 7-9, 2023 Actions

Overview of IEP Parameter Updates

By way of brief background, the FERC-approved IEP is a voluntary program that will compensate specific resource types for maintaining inventoried energy during the winter months in 2023–24 and 2024–25.[1] Since the IEP's development and approval, the "global energy markets have experienced unprecedented changes in pricing levels and volatility," as stated in the ISO's voting memorandum included in Attachment B. Thus, the ISO proposes to revise Appendix K "to align key parameters of the IEP with current market conditions and improve the likelihood of attracting incremental inventoried energy to the region."

The ISO, in response to stakeholder feedback, incorporated into its proposal an indexed forward rate to the IEP that automatically adjusts to account for price fluctuations in the natural gas market before the winter period. The IEP Parameter Updates also modify the program's gas

[1] Note that other unrelated Tariff revisions are pending before the FERC to remove certain resources from being eligible from participating in the IEP. *See* ISO New England Inc., Compliance Filing (Revisions to Inventoried Energy Program Making Nuclear, Coal, Biomass and Hydroelectric Generators Ineligible), Docket No. ER19-1428-006 (filed Nov. 22, 2022); Comments of the New England Power Pool Participants Committee, Docket No. ER19-1428-006 (filed Dec. 5, 2022). *See also* Limited Protest of Brookfield Energy Marketing LP, Docket No. ER19-1428-006 (filed Dec. 13, 2022) (requesting FERC permit a pumped hydro resource operating as an electric storage facility to be eligible to participate in the IEP).

contracting eligibility provisions to align with industry practices and products. In addition, the ISO's proposal would require a Senior Officer of the Lead Market Participant to sign an ISO-developed affidavit attesting that the reported fuel was available to the Lead Market Participant as required by the IEP.

To review all of the revisions of the ISO's IEP Parameter Updates (with the unrelated Tariff revisions pending before the FERC, as noted in footnote 1, highlighted in yellow), see the ISO's Tariff redlines included in Attachment A.

STAKEHOLDER PROCESS TO DATE

Throughout four meetings that began in October 2022, the Markets Committee considered the ISO's proposal, which evolved to reflect input provided during the MC discussions. At its February 7–9, 2023 meeting, the Markets Committee considered ISO-NE's final, recommended proposal.

Before voting on that proposal, the Markets Committee also considered an amendment sponsored by Generation Bridge Connecticut Holdings LLC (Generation Bridge) that would have increased the duration of inventoried energy from 72 hours to 120 hours. This amendment failed to achieve the requisite voting threshold needed for Markets Committee support. After considering and voting on Generation Bridge's amendment, the Markets Committee then considered and recommended that the Participants Committee support ISO-NE's un-amended proposal to update certain IEP parameters, with an 81.63% Vote in favor.[2] The Markets Committee votes are reflected in Attachment C.

Consistent with past practice, Participants are reminded that neither NEPOOL nor ISO-NE will raise procedural objections at the FERC should any amendment considered but not supported at the Markets Committee be advocated at FERC, notwithstanding that such amendment was not presented to the Participants Committee for a vote. With this understanding, we have been informed that Generation Bridge does not plan to seek a Participants Committee vote on its amendment offered at the February Markets Committee meeting.

If anyone wishes to offer an amendment for Participants Committee consideration that was not previously considered by the Markets Committee, please provide that amendment to NEPOOL Counsel (slombardi@daypitney.com or rgarza@daypitney.com) as soon as possible so that we can circulate it in time for member review and consideration before the March 2 meeting.

[2] The individual Sector votes were as follows: Generation (16.7% in favor, 0% opposed, 2 abstentions), Transmission (16.7% in favor, 0% opposed, 0 abstentions), Supplier (15.03% in favor, 1.67% opposed, 4 abstentions), Publicly Owned Entity (16.7% in favor, 0% opposed, 25 abstentions), Alternative Resources (16.5% in favor, 0% opposed, 2 abstentions), and End User (0% in favor, 16.7% opposed, 1 abstention).

The IEP Parameter Updates revisions requires a 60% Vote for Participants Committee approval. The following form of resolution may be used for Participants Committee action:

> RESOLVED, that the Participants Committee supports the revisions to Appendix K of Market Rule 1 to update certain Inventoried Energy Program (IEP) parameters (the IEP Parameter Updates), as recommended by the Markets Committee at its February 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, it being understood that a vote in favor of this resolution reflects solely support for the IEP Parameter Updates, and is without prejudice to any position taken by a Participant(s) on the underlying IEP construct.

Note: Tariff revisions pending before the FERC are highlighted in yellow.

APPENDIX K

INVENTORIED ENERGY PROGRAM

III.K Inventoried Energy Program

For the winters of 2023-2024 and 2024-2025, the ISO shall administer an inventoried energy program in accordance with the provisions of this Appendix K.

III.K.1. Submission of Election Information

Participation in the inventoried energy program is voluntary. To participate in both the forward and spot components of the program, the information listed in this Section III.K.1 must be submitted to the ISO no later than the October 1 immediately preceding the start of the relevant winter period (a separate election submission must be made for each winter) and must reflect an ability to provide the submitted inventoried energy throughout the relevant winter period. To participate in the spot component of the program only, the information listed in this Section III.K.1 may be submitted to the ISO through the end of the relevant winter period, in which case participation will begin (prospectively only) upon review and approval by the ISO of the information submitted.

(a) A list of the Market Participant's assets that will participate in the inventoried energy program, with a description for each such asset of: the Market Participant's Ownership Share in the asset; the types of fuel it can use; the approximate maximum amount of each fuel type that can be stored on site ~~(and in upstream ponds)~~ or, in the case of natural gas, the amount that is subject to a contract meeting the requirements described in Section III.K.1(a)(iii), as measured pursuant to the provisions of Section III.K.3.2.1.1(a); and a list of other assets at the same facility that share the fuel inventory (or, in the case of natural gas, a list of assets at the same or any other facility that can also take fuel pursuant to the same contract).

(i) The following asset types may not be included in a Market Participant's list of assets: assets that run on coal, nuclear, biomass or hydropower (including pumped hydro and pondage); Settlement Only Resources; assets not located in the New England Control Area; assets being compensated pursuant to a cost-of-service agreement (as described in Section III.13.2.5.2.5) during the relevant winter period; and assets that cannot operate on stored fuel (or natural gas subject to a contract as described in Section III.K.1(a)(iii)) at the ISO's direction.

(ii) A Demand Response Resource with Distributed Generation may be included in a Market Participant's list of assets.

(iii) For any asset listed that will participate in the inventoried energy program using natural gas as a fuel type, the Market Participant must also submit ~~an~~one or more executed ~~contract~~contracts for supply and firm ~~delivery~~transportation of natural gas~~.~~ for the duration of the relevant winter period. Any such contract(s) must include no limitations ~~on~~that would further restrict when natural gas can be called during a day beyond the North American Energy Standards Board Wholesale Gas Quadrant scheduling and nominations standards, and must specify the parties to the contract, the volume of gas to be supplied over the relevant winter period, the maximum daily volume of gas to be delivered~~,~~ on a firm basis as described in this Section K.1(a)(iii), the price to be paid for that gas, the pipeline delivery point name and gas meter number of the listed asset, terms related to pipeline transportation to the meter of the listed asset (with indication of whether the gas supplier or another entity is providing the transportation), and all other terms, conditions, or related agreements affecting whether and when gas will be delivered, the volume of gas to be delivered, and the price to be paid for that gas. For any such contract(s) that specify an indexed strike price, the specified index must be at one of the Northeast trading locations for which Platt's publishes a daily value.

(b) A detailed description of how the Market Participant's energy inventory will be measured after each Inventoried Energy Day in accordance with the provisions of Section III.K.3.2.1.1 and converted to MWh (including the rates at which fuel is converted to energy for each asset). Where assets share fuel inventory, ~~if~~ the Market Participant ~~believes that~~shall include an allocation methodology to share fuel ~~should be allocated~~inventory among ~~those~~the relevant assets ~~in a manner other than the default~~

~~approach described in Section III.K.3.2.1.1(e)(ii), this description should explain~~. Such methodology must be consistent with any applicable contract provisions and ~~support that alternate allocation~~maximum daily production limits of the assets sharing fuel inventory.

(c) Whether the Market Participant is electing to participate in only the spot component of the inventoried energy program or in both the forward and spot components.

(d) If electing to participate in both the forward and spot components of the program, the total MWh value for which the Market Participant elects to be compensated at the forward rate (the “Forward Energy Inventory Election”). This MWh value must be less than or equal to the combined MW output that the assets listed by the Market Participant (adjusted to account for Ownership Share) could provide over a period of 72 hours, as limited by the maximum amount of each fuel type that can be stored on site ~~(and in upstream ponds)~~ for each asset and as limited by the terms of any natural gas contracts submitted pursuant to Section III.K.1(a)(iii). If the Market Participant is submitting one or more contracts for natural gas, the Market Participant must indicate whether any of the suppliers listed in those contracts have the capability to deliver vaporized liquefied natural gas to New England, and if so, what portion of its Forward Energy Inventory Election, in MWh, should be attributed to liquefied natural gas (the “Forward LNG Inventory Election”). (For Market Participants electing to participate in only the spot component of the program, the Forward Energy Inventory Election and Forward LNG Inventory Election shall be zero.)

III.K.1.1 ISO Review and Approval of Election Information

The ISO will review each Market Participant's election submission, and may confer with the Market Participant to clarify or supplement the information provided. ~~The ISO shall modify the amounts as necessary to ensure consistency~~The submissions are subject to verification by the ISO and must include an affidavit as available on the ISO's website signed by a Senior Officer of the Market Participant attesting that amounts are consistent with asset-specific operational characteristics, terms and conditions associated with submitted contracts, regulatory restrictions, and the requirements of the inventoried energy program. For election information that is submitted no later than October 1, the ISO will report the final program participation values to the Market Participant by the November 1 immediately preceding the start of the relevant winter period, and participation will begin on December 1. For election information that is submitted after October 1 (spot component participation only), the ISO will, as soon as practicable, report the final program participation values and the date that participation will begin to the Market Participant.

(a) In performing this review, the ISO shall reject all or any portions of a contract for natural gas that:

(i) does not meet the requirements of Section III.K.1(a)(iii); ~~or~~

(ii) requires (except in the case of an asset that is supplied from a liquefied natural gas facility adjacent and directly connected to the asset) the Market Participant to incur incremental costs to exercise the contract that may be greater than ~~250 percent of the average of the sum of the monthly Henry Hub natural gas futures prices and the Algonquin Citygates Basis natural gas futures~~(1) for contracts specifying a fixed strike price, 250 percent of the Dutch TTF Natural Gas Last Day Financial Futures (USD/MMBtu) prices for the December, January, and February of the relevant winter period on the earlier of the day the contract is executed and the first Business Day in October prior to that winter period~~.~~, or (2) for contracts specifying an indexed strike price, 250 percent of the published

Platt's gas daily average price for such index that is applicable during the relevant operating day; or

(iii) is not submitted with an accompanying affidavit as available on the ISO's website signed by a Senior Officer of the Lead Market Participant attesting that the reported amount of fuel is available as required by the provisions of the inventoried energy program.

(b) In performing this review, if the total of the Forward LNG Inventory Elections from all participating Market Participants (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, the ISO shall prorate each such Forward LNG Inventory Election such that the sum of such Forward LNG Inventory Elections is no greater than 560,000 MWh, and each Market Participant's Forward Energy Inventory Election shall be adjusted accordingly.

III.K.1.2 Posting of Forward Energy Inventory Election Amount

As soon as practicable after the November 1 immediately preceding the start of the relevant winter period, the ISO will post to its website the total amount of Forward Energy Inventory Elections and Forward LNG Inventory Elections participating in the inventoried energy program for that winter.

III.K.2 Inventoried Energy Base Payments

A Market Participant participating in the forward and spot components of the inventoried energy program shall receive a base payment for each day of the months of December, January, and February~~. Each such~~ for the relevant winter period as calculated pursuant to this section. A Market Participant's base payment shall be equal to the Market Participant's Forward Energy Inventory Election (adjusted as described in Section III.K.1.1) multiplied by ~~$82.49 per MWh~~the base payment rate as derived below and divided by the total number of days in those three months. The base payment rate shall not exceed $288/MWh.

The ISO shall establish the base payment rate on August 1 immediately preceding the start of each relevant winter period using the following formula:

Base payment rate ($/MWh) = 3.25 MMBTu/MWh x Commodity Price - 0.59 MMBTu/MWh x Liquidation Price + $45.98/MWh

Where:

Commodity price ($/MMBtu): Average of the December, January and February Dutch TTF Natural Gas Last Day Financial Futures (USD/MMBTU) (Source: ICE Futures U.S., contract symbol: TLD) prices for the relevant winter period as determined between July 17-31 immediately preceding the start of the relevant winter period

Liquidation price ($/MMBtu): Average of the February Algonquin Citygates Fixed Price Future (Source: ICE Futures U.S., contract symbol: ALG) price for the relevant winter period as determined between July 17-31 immediately preceding the start of the relevant winter period

The ISO shall post to its website the final base payment rate on or before August 8 immediately preceding the start of the relevant winter period.

III.K.3 Inventoried Energy Spot Payments

A Market Participant participating in the spot component of the inventoried energy program (whether or not the Market Participant is also participating in the forward component of the program) shall receive a spot payment for each Inventoried Energy Day as calculated pursuant to this Section III.K.3.

III.K.3.1 Definition of Inventoried Energy Day

An Inventoried Energy Day shall exist for any Operating Day that occurs in the months of December, January, or February and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit.

III.K.3.2 Calculation of Inventoried Energy Spot Payment

A Market Participant's spot payment for an Inventoried Energy Day, which may be positive or negative, shall equal the Market Participant's Real-Time Energy Inventory minus its Forward Energy Inventory Election, with the difference multiplied by ~~$8.25 per MWh.~~one-tenth of the applicable base payment rate ($/MWh).

III.K.3.2.1 Calculation of Real-Time Energy Inventory

A Market Participant's Real-Time Energy Inventory for an Inventoried Energy Day shall be the sum of the Real-Time Energy Inventories for each of the Market Participant's assets participating in the program (adjusted as described in Section III.K.3.2.1.2); provided, however, that where more than one Market Participant has an Ownership Share in an asset, the asset's

Real-Time Energy Inventory will be apportioned based on each Market Participant's Ownership Share.

III.K.3.2.1.1 Asset-Level Real-Time Energy Inventory

Each asset's Real-Time Energy Inventory will be determined as follows:

(a) The Lead Market Participant must measure ~~and report to the ISO~~ the Real-Time Energy Inventory for each of the assets participating in the program between 7:00 a.m. and 8:00 a.m. on the Operating Day immediately following each Inventoried Energy Day. The Real-Time Energy Inventory must be reported to the ISO by ~~1300~~1:00 p.m. on the second Business Day following the Inventoried Energy Day and must be stated both in MWh and in units appropriate to the fuel type and measured in accordance with the following provisions:

(i) Oil. The Real-Time Energy Inventory of an asset that runs on oil shall be the number of ~~dedicated~~ barrels of oil dedicated for the sole and exclusive use of the asset that are stored in an in-service tank (located on site or at an adjacent location with direct pipeline transfer capability to the asset), excluding any amount that is unobtainable or unusable (due to priming requirements, sediment, volume below the suction line, or any other reason).

~~(ii) Coal. The Real-Time Energy Inventory of an asset that runs on coal shall be the number of metric tons of coal stored on site, excluding any amount that is unobtainable or unusable for any reason.~~

~~(iii) Nuclear. The Real-Time Energy Inventory of a nuclear asset shall be the number of days until the asset's next scheduled refueling outage.~~

(~~iv~~(ii) Natural Gas. The Real-Time Energy Inventory for an asset that runs on natural gas shall be the amount of natural gas available to the asset pursuant to the terms of the relevant contracts submitted pursuant to Section III.K.1(a)(iii), adjusted to reflect any limitation that the suppliers listed in the contracts may have on the capability to deliver natural gas. The Lead Market Participant must specify what portion of the asset's Real-Time Energy Inventory, in MWh, is associated with liquefied natural gas.

~~(v) Pumped Hydro. The Real-Time Energy Inventory of a pumped storage asset shall be the amount of water (in gallons or by elevation, consistent with the description provided by the Market Participant pursuant to Section III.K.1(b)) in the on-site reservoir that is available for generation, excluding any amount that is unobtainable or unusable for any reason.~~

~~(vi) Pondage. The Real-Time Energy Inventory of an asset with pondage shall be the amount of water (in gallons or by elevation, consistent with the description provided by the Market Participant pursuant to Section III.K.1(b)) in on-site and upstream ponds controlled by the Market Participant with a transit time to the asset of no more than 12 hours, excluding any amount that is unobtainable or unusable for any reason.~~

~~(vii) Biomass/~~(iii) Refuse. The Real-Time Energy Inventory of an asset that runs on ~~biomass or~~ refuse shall be the number of metric tons of the relevant material stored on site, excluding any amount that is unobtainable or unusable for any reason.

(~~viii~~iv) Electric Storage Facility. The Real-Time Energy Inventory of an Electric Storage Facility shall be its available energy in MWh.

(b) If the Lead Market Participant fails to measure or report the energy inventory or fuel amounts for an asset as required, that asset's Real-Time Energy Inventory for the Inventoried Energy Day shall be zero.

(c) The Lead Market Participant must limit each asset's Real-Time Energy Inventory as appropriate to respect federal and state restrictions on the use of the fuel (such as ~~water flow or~~ emissions limitations).

(d) Where assets share fuel inventory, the Lead Market Participant must provide the individual asset fuel inventory values allocated pursuant to the methodology described under Section III.K.1(b).

(e) The reported amounts are subject to verification by the ISO~~. As part of any such verification, the ISO may request additional information or documentation from a Market Participant, or may require a certificate~~ and must include an affidavit as available on the ISO's website signed by a Senior Officer of the Lead Market Participant attesting that the reported amount of fuel was~~is~~ available to the Lead Market Participant as required by the provisions of the inventoried energy program.

(~~e~~f) In determining final Real-Time Energy Inventory amounts for each asset, the ISO will:

(i) adjust the reported amounts consistent with the results of any verification performed pursuant to Section III.K.3.2.1.1(~~d);~~e); and

~~(ii) allocate shared fuel inventory among the relevant assets in a manner that maximizes its use based on the efficiency with which the assets convert fuel to energy (unless information submitted pursuant to Section III.K.1(b) supports a different allocation) and that is consistent with any applicable contract provisions (in the case of natural gas) and maximum daily production limits of the assets sharing fuel inventory; and~~

(ii~~(iii~~) limit each asset's Real-Time Energy Inventory to the asset's average available outage-adjusted output on the Inventoried Energy Day for a maximum duration of 72 hours.

III.K.3.2.1.2 Proration of Liquefied Natural Gas

If the total amount of Real-Time Energy Inventory associated with liquefied natural gas (excluding amounts to be supplied to an asset from a liquefied natural gas facility adjacent and directly connected to the asset) exceeds 560,000 MWh, then the ISO shall prorate such Real-Time Energy Inventory associated with liquefied natural gas as follows:

(a) any Real-Time Energy Inventory associated with liquefied natural gas that corresponds to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be counted without reduction; and

(b) any Real-Time Energy Inventory associated with liquefied natural gas that does not correspond to a Market Participant's Forward LNG Inventory Election (prorated as described in Section III.K.1.1(b)) shall be prorated such that the sum of the Real-Time Energy Inventory associated with liquefied natural gas (including the amount described in Section III.K.3.2.1.2(a)) does not exceed 560,000 MWh.

III.K.4 Cost Allocation

Costs associated with the inventoried energy program shall be allocated on a regional basis to Real-Time Load Obligation, excluding Real-Time Load Obligation associated with Storage DARDs and Real-Time Load Obligation associated with Coordinated External Transactions. Costs associated with base payments shall be allocated across all days of the months of December, January, and February for the relevant winter period; costs associated with spot payments shall be allocated to the relevant Inventoried Energy Day.

memo

To: NEPOOL Markets Committee

From: Craig Martin, Principal Analyst

Date: February 1, 2023

Subject: Inventoried Energy Program (IEP) Parameter Updates (WMPP: 168)

The ISO is requesting a vote on proposed revisions to Appendix K of Market Rule 1 to align key parameters of the IEP with current market conditions and improve the likelihood of attracting incremental inventoried energy to the region.

By way of background, the IEP is a voluntary, FERC-approved program that will compensate certain asset types for maintaining inventoried energy during the winter months in 2023-24 and 2024-25. Compared to when the program was first designed, global energy markets have experienced unprecedented changes in pricing levels and volatility.

The proposed revisions recalibrate the IEP with global energy markets by incorporating an indexed forward rate that will automatically adjust to changes in gas market prices ahead of the winter period. In addition, the gas contracting eligibility provisions have been revised to align with current industry practices and products. These proposed updates will help increase the quantities of inventoried energy that will be attracted to the region for winters 2023-24 and 2024-25,[1] while tightening the alignment between the costs and the expected global conditions in a given year.

The proposal for the committee's consideration at its February 7-9, 2023 meeting has been presented previously to the Markets Committee at the meeting dates outlined below.

- October 12-13, 2022; agenda item #3
- November 8-10, 2022; agenda item #4
- December 6-8, 2022; agenda item #3
- January 10-12, 2023; agenda item #6

[1] *See* Inventoried Energy Program, Analysis Group Presentation to NEPOOL Markets Committee, dated January 12, 2023, available at https://www.iso-ne.com/static-assets/documents/2023/01/a06b_mc_2023_01_10-12_iep_analysis_group_presentation.pdf

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
413-535-4042
cmartin@iso-ne.com

memo

To: Participants Committee

From: Dennis Cakert, Secretary, Markets Committee

Date: February 10, 2023

Subject: Actions of the Markets Committee

This memo is notification to the Participants Committee of the following actions taken by the Markets Committee (MC) at the February 7-9, 2023 MC meeting and the February 8-9, 2023 Joint MC-Reliability Committee meeting. All sectors had a quorum for both Committees.

Agenda Item No. 5A – Inventoried Energy Program (IEP) Parameter Updates

ACTION: RECOMMEND SUPPORT

The following motion was moved and seconded by the Markets Committee:

RESOLVED, that the Markets Committee recommends that the Participants Committee support the revisions to Appendix K of Market Rule 1, to align key parameters of the IEP with current market conditions, as proposed by ISO New England, and as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

(Vote 1 – Failed) Agenda Item No. 5C – Generation Bridge Connecticut Holdings' Amendment – Increase the Maximum Inventoried Energy Duration

Before the main motion could be voted, the following motion was moved and seconded by the Markets Committee to amend the main motion as follows:

RESOLVED, that the main motion be amended to reflect the changes to Appendix K of Market Rule 1, as contained in the materials provided by Generation Bridge Connecticut Holdings, to increase the maximum inventoried energy duration from 72 hours to 120 hours, as circulated for this meeting, with those further changes recommended by this Committee and such further non-substantive changes as the Chair and Vice-Chair may approve.

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
413-540-4518 (office)
dcakert@iso-ne.com

The motion was then voted and, based on a roll call vote, failed to pass with a vote of 26.82% in favor. The individual Sector votes were Generation (13.92% in favor, 2.78% opposed, 1 abstention)[1], Transmission (5.57% in favor, 11.13% opposed, 2 abstentions), Supplier (0.00% in favor, 16.70% opposed, 7 abstentions), Publicly Owned Entity (0.00% in favor, 16.70% opposed, 21 abstentions), Alternative Resources (7.33% in favor, 9.17% opposed, 4 abstentions), and End User (0.00% in favor, 16.70% opposed, 1 abstention).

(Vote 2 – Passed) Agenda Item No. 5A – Main Motion

The main motion was then voted and, based on a roll call vote, the motion passed with a vote of 81.63% in favor. The individual Sector votes were Generation (16.70% in favor, 0.00% opposed, 2 abstentions), Transmission (16.70% in favor, 0.00% opposed, 0 abstentions), Supplier (15.03% in favor, 1.67% opposed, 4 abstentions), Publicly Owned Entity (16.70% in favor, 0.00% opposed, 25 abstentions), Alternative Resources (16.50% in favor, 0.00% opposed, 2 abstentions), and End User (0.00% in favor, 16.70% opposed, 1 abstention).

Agenda Item No. 6 – Approval of Minutes

ACTION: APPROVED

The following motion was moved and seconded by the Markets Committee:

RESOLVED, that the Markets Committee approves the minutes for the January 11-12, 2023 Joint NEPOOL Markets and Reliability Committees meeting and the minutes for the January 10-12, 2023 NEPOOL Markets Committee meeting, as circulated for the February 7-9, 2023 NEPOOL Markets Committee meeting, with such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion was voted and, based on a show of hands vote, was approved unanimously.

[1] Following the vote, it was discovered that a vote in opposition in the Generation Sector did not register in the totals reported in the voting tool. The issue was corrected and the revised voting percentages for the Generation Sector are reflected.

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EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of February 28, 2023

The following activity, as more fully described in the attached litigation report, has occurred since the report dated February 1, 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

	1	RENEW Network Upgrades O&M Cost Allocation Complaint (EL23-16)	Feb 3	RENEW answers ISO-NE's Jan 19 Motion
			Feb 7	RENEW, PTO AC, and National Grid file answers to protests/comments
			Feb 16	ISO-NE answers RENEW's Feb 7 answer
			Feb 22	CPV Towantic, Glenvale, MA AG file answers
	3	RENEW/ACPA RCA & Operating Reserve Designation Complaint (EL22-42)	Feb 16	FERC dismisses Complaint; challenges to *RENEW/ACPA RCA/ORD Complaint Order* due on or before ***Mar 20, 2023***

II. Rate, ICR, FCA, Cost Recovery Filings

	9	FCA17 Qualification Informational Filing (ER23-690)	Feb 17	FERC accepts FCA17 Informational Filing, as amended, and directs ISO-NE to use the corrected Qualified Capacity values for FCA17
*	9	Mystic. Request for Limited Waiver of Certain COSA True-Up Deadlines (ER23-1159)	Feb 17	Mystic requests Waiver of certain COSA true-up deadlines
			Feb 27	ISO-NE, Eversource, MA AG, NESCOE, CT PURA intervene
	9	Mystic 8/9 COSA *First* CapEx Info Filing Settlement Judge Procedures (ER18-1639-015)	Feb 6	Sixth settlement conference held; settlement agreement anticipated ("Anticipated Settlement")
	9	Mystic 8/9 COSA *Emergency Motion for Partial Disposition on Remand* (ER18-1639-019)	Feb 13	Mystic requests that the FERC refrain from acting on the pending claw back issue until the FERC acts on the Anticipated Settlement
	9	Mystic 8/9 COSA *Second CapEx Info Filing* (ER18-1639-018)	Feb 17	Mystic requests that the FERC refrain from acting on the pending formal challenges to its Second CapEx Info Filing until the FERC acts on the Anticipated Settlement
	11	Transmission Rate Annual (2022-23) Update/Informational Filing (ER09-1532; RT04-2)	Feb 23	FERC notices RENEW's formal challenge for public comment; comment deadline ***Mar 16, 2023***

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

12	PPU CTR Clarifications (ER23-911)	Feb 9	Eversource intervenes
13	SATOA Revisions (ER23-739; ER23-743)	Feb 3	NEPOOL answers VELCO comments; ISO-NE answers VELCO comments and National Grid limited protest
		Feb 7	NEPGA answers VELCO comments and National Grid limited protest
		Feb 16	National Grid answers Feb 3 NEPGA and Feb 7 ISO-NE answers

IV. OATT Amendments / TOAs / Coordination Agreements

	14	Attachment K Economic Study Revisions (ER23-971)	Feb 17	Public Systems submit comments supporting the Economic Study Revisions; Eversource, National Grid, NESCOE, RI Energy, MA DPU file doc-less interventions
	16	*Order 676-J* Compliance Filing (CSC-Schedule 18-Attachment Z) (ER22-1168)	Feb 23	FERC accepts filing, eff. Feb 23, 2023
	16	*Order 676-J* Compliance Filing (TOs-Schedule 20/21-Common) (ER22-1161)	Feb 23	FERC accepts filing, eff. Feb 23, 2023
	16	*Order 676-J* Compliance Filing (ISO-NE-Schedule 24) (ER22-1150)	Feb 23	FERC accepts filing, eff. Feb 23, 2023

V. Financial Assurance/Billing Policy Amendments

	16	FA/Billing Policies IEP Changes; Monthly Statement Issuance Date Update (ER23-705)	Feb 14	FERC accepts changes, eff. Feb 20, 2023

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

	17	Sched 21-RIE: Transfer of SAs from Sched 21-NEP; Updated Thundermist ISA (ER23-678; ER23-681)	Feb 17	FERC accepts filings, eff. Jan 1, 2023

VII. NEPOOL Agreement/Participants Agreement Amendments

	17	PA Amendment No. 12 (ISO Board Member Age Limit Increase) (ER23-980)	Feb 7-21	Eversource, National Grid, NESCOE, RI Energy intervene

VIII. Regional Reports

*	18	Capital Projects Report - 2022 Q4 (ER22-1125)	Feb 10 Feb 17	ISO-NE files 2022 Q4 Report NEPOOL intervenes and files comments supporting Q4 Report
*	18	Interconnection Study Metrics Processing Time Exceedance Report Q4 2022 (ER19-1951)	Feb 14	ISO-NE files required quarterly report

IX. Membership Filings

*	19	March 2023 Membership Filing (ER23-1197)	Feb 28	NEPOOL requests the FERC accept (i) Calpine Community Energy's membership; (ii) 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; comment deadline ***Mar 21, 2023***
	20	January 2023 Membership Filing (ER23-756)	Feb 24	FERC accepts filing, eff. Dec 1, 2022

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

	20	Revised Rel. Standards: EOP-011-3 and EOP-012-1 (RD23-1)	Feb 16	FERC conditionally approves these *Cold Weather Standards*, directing modifications to EOP-012-1 to be filed on or before ***Feb 16, 2024***; effectiveness of EOP-011-3 deferred pending submission of a revised EOP-012
	21	Inverter-Based Resource Registration (RD22-4)	Feb 15	NERC files IBR Work Plan; comment deadline ***Mar 17, 2023***
	22	NOPR: IBR Reliability Standards (RM22-12)	Feb 2-7	ISO-NE, the IRC, SPP, CAISO, Advanced Energy United, ACPA/SEIA, EEI, EPRI file comments
	23	*Order 887*: INSM for High and Medium Impact BES Cyber Systems (RM22-3)	Feb 9	*Order 887* published in *Federal Register*; eff. Apr 10, 2023

XI. Misc. - of Regional Interest

	25	203 Application: Great River Hydro (GRH) / HQI US (EC23-16)	Feb 3 Feb 10	FERC authorizes transaction Transaction consummated: HQ US and GRH become Related Persons (together will be members of AR Sector); Generation Bridge Companies become members of Generation Sector
*	25	National Grid/GRH McIndoes SGIA (ER23-1152)	Dec 23	National Grid files SGIA with GRH; comment deadline ***Mar 14, 2023***
*	25	Shared Structure Participation Agreement: VELCO/GMP (ER23-1101)	Feb 10	VTransco files Shared Structure Participation Agreement with Green Mountain Power; comment date ***Mar 3, 2023***
	25	LGIA: RI Energy / Deepwater Block Island Wind (ER23-1023)	Feb 23	RI Energy supplements LGIA filing to request a waiver of FERC's prior notice requirements (having officially filed the LGIA 31 days after service commenced)
	26	IA: RI Energy / Manchester Street (ER23-1007)	Feb 16	National Grid intervenes
	26	LSAs: RI Energy/ISO-NE/BIPCO (ER23-1003; ER23-1000)	Feb 16, 21	National Grid, RI Division intervene
	26	IA 2nd Amendment: CMP/Sappi Compl. Filing (ER22-1612-001)	Feb 14	FERC accepts compliance filing, eff. Nov 17, 2022
	27	Versant Power MPD OATT *Order 676-J* Compliance Filing Part I (ER22-1142)	Feb 23	FERC accepts compliance filing, eff. Feb 23, 2023, and grants Versant's request for waivers

XII. Misc. - Administrative & Rulemaking Proceedings

	27	Interregional HVDC Merchant Transmission (AD22-13)	Feb 6	FERC issues notice of request for tech conf; comment deadline ***Mar 8, 2023***
	27	Joint FERC-DOE Supply Chain Risk Management Tech Conf (Dec 7, 2022) (AD22-12)	Feb 13 Feb 17	FERC posts transcript of Dec 12 meeting to eLibrary AEP, APPA, EEI, North American Transmission Forum file comments
	28	Second New England Gas-Electric Forum (AD22-9)	Feb 16	FERC issues a notice of a 2nd New England Winter Gas-Electric Forum to be held ***Jun 20, 2023*** in Portland, Maine.
	29	Joint Federal-State Task Force on Electric Transmission (AD21-15)	Feb 15	FERC holds 6th JFSTF meeting in Washington, DC

35	NOPR: Transmission Siting (RM22-7)	Feb 27	NARUC requests 30-day extension of time, to ***May 17, 2023***, to file comments

XIII. FERC Enforcement Proceedings

No Activity to Report

XIV. Natural Gas Proceedings

No Activity to Report

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

41	Mystic II (ROE & True-Up) (21-1198 et al.) (consolidated)	Feb 3	Court issues an order keeping these proceedings in abeyance and directing that motions to govern future proceedings be filed by ***April 24, 2023***
43	Northern Access Project (22-1233)	Feb 14 Feb 21	FERC files Respondent's Brief Respondent-Intervenors file brief; NGA files amicus brief Petitioner's Reply Brief due ***Mar 14, 2023***; Joint Deferred Appendix ***Mar 21, 2023***
43	Algonquin Atlantic Bridge Project Orders (22-1146, 22-1147) (consol.)	Feb 17	Petitioners file Joint Reply Brief Deferred Appendix due ***Mar 2, 2023***; Final Briefs, **Mar 9, 2023**

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: March 1, 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 February 28, 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 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, National Grid, New Leaf Energy, NextEra, NRG, Versant, CT DEEP, MA DPU, the American Clean Power Association ("ACPA"), 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.

- **ENECOS Mystic COSA Complaint (EL23-4)**

As previously reported, On October 17, 2022, Eastern New England Consumer-Owned Systems ("ENECOS") filed a Complaint against Mystic and ISO-NE challenging the pass-through to ISO-NE customers of firm pipeline transportation costs under the 2nd Amended and Restated Mystic Cost-of-Service Agreement ("COSA"), which ENECOS claimed are associated with pipeline facilities that are neither used nor usable to supply fuel to Mystic 8 and 9, and therefore should not be charged to ISO-NE and its customers under the COSA. Specifically, ENECOS asked that all references to "Pipeline Transportation Agreements" be stricken from the COSA, template Line No. 7 "Fixed Pipeline Transportation" be removed from the true-up methodology, and Mystic be precluded from recovering the dollar amounts associated with that line item. ENECOS explained that the Complaint was filed as a procedural precaution as the charges that are the subject of the Complaint can be addressed by the FERC in proceedings on the DC Circuit's remand of issues relating to the FERC's allocation of Everett Marine Terminal costs under the COSA.[3]

Responses and Comments. Responses to and comments on ENECOS' Complaint were due on or before November 16, 2022. Mystic and ISO-NE filed responses. In its response, ***Mystic*** urged the FERC to dismiss the Complaint by asserting that (i) ENECOS have not, as required, sufficiently alleged changed circumstances since the pipeline transportation costs recovery mechanisms were found just & reasonable by the FERC; (ii) ENECOS are wrong on the merits; (iii) Mystic and the COSA are cost causative for Everett; and (iv) allocation of the costs is justified by tank management, which allows Mystic to meet the reliability need that the COSA is intended to address. For its part, ***ISO-NE*** also requested that the FERC deny the Complaint because the costs challenged are encompassed by the *Mystic Remand Order*. However, if the FERC does not dismiss the Complaint, ISO-NE urged the FERC to either consolidate the Complaint with the Mystic Remand Proceeding or hold the Complaint in abeyance. Comments supporting the Complaint were filed by MMWEC/NHEC (together, "Public Systems"), and by the Connecticut Public Utilities Regulatory Authority ("CT PURA") and the Connecticut Office of Consumer Counsel ("CT OCC", and together with CT PURA, the "CT Parties"). Doc-less interventions only were filed by NEPOOL, Calpine, Eversource, MA AG, National Grid, NESCOE, NRG, and the CT DEEP have intervened doc-lessly. ENECOS answered Mystic's November 16, 2022 answer and Mystic answered ENECOS' December 1, 2022 answer. There was no activity in this proceeding since the last Report. This matter is pending before the FERC. If you have questions on this proceeding, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Margaret Czepiel (202-218-3906; mczepiel@daypitney.com).

- **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.[4] 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.[5] 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,[6] a 2019 request by the Energy Trading Institute requesting a FERC-convened technical conference to consider a potential

[3] *Constellation Mystic Power, LLC v. FERC*, 45 F.4th 1028, 1050-1052 (D.C. Cir. 2022) ("*Mystic Remand Order*").

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

[5] *Id.* at P 31.

[6] *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

rulemaking to improve ISO/RTO credit practices,[7] and a two-day technical conference in February 2021 that discussed principles and best practices for credit risk management in organized wholesale electric markets.[8] 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."[9] 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.[10] 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[11] (out-of-time).

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 is pending before the FERC.

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

- **RENEW/ACPA RCA & Operating Reserve Designation Complaint (EL22-42)**

On February 16, 2023, the FERC dismissed the March 15, 2022 Complaint filed by RENEW and ACPA seeking a FERC order directing ISO-NE to make changes to its rules for capacity accreditation ("RCA") and Operating Reserve designations.[12] As previously reported, RENEW/ACPA asserted that the changes were needed to address undue preferences granted under ISO-NE's rules and procedures to gas-fired generation resources that

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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.

[7] 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).

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

[9] 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.

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

[11] "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."

[12] *RENEW Northeast, Inc. and the American Clean Power Association v. ISO New England Inc.,* 182 FERC ¶ 61,085 (Feb. 16, 2023) ("*RENEW/ACPA RCA/ORD Complaint Order*").

have neither dual-fuel capability nor dedicated, firm natural gas supply arrangements ("Gas-Only Resources"). RENEW/ACPA asserted that the undo preferences arise in the context of capacity accreditation through an assumption of 100% fuel availability for Gas-Only Resources, and in the context of operating reserves, through the absence of any pre-dispatch requirements to confirm fuel availability.

In dismissing the Complaint, the FERC found that RENEW/ACPA failed to show that there is a difference in the current Tariff provisions pertaining to capacity accreditation and operating reserves among similarly situated customers, thereby failing to establish the requisite prima facie case under FPA section 206 that the Tariff provisions are unjust, unreasonable, or unduly discriminatory or preferential. Specifically, the FERC found that RENEW/ACPA failed to establish that gas-only resources are not similarly situated to generators with fuel on-site,[13] that gas-only resources should be regarded as similarly situated with intermittent resources for capacity accreditation based on a lack of control over energy inputs,[14] or that gas-only resources are afforded undue preference in the Tariff's operating reserves requirements.[15] However, noting the region's efforts under way to address fuel limitations, as well as capacity accreditation and operating reserves reforms, the FERC urged prompt action on such reforms to address the underlying reliability concerns.[16]

Challenges, if any, to the *RENEW/ACPA RCA/ORD Complaint Order* are due on or before ***March 20, 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).

- **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.[17] 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.[18]

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[19] and included NEPOOL, NESCOE, Brookfield, Calpine, Dominion,

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[13] *Id.* at P 49.

[14] *Id.* at P 50.

[15] *Id.* at P 51.

[16] *Id.* at P 52.

[17] *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*").

[18] *Id.* at P 20.

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

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 Jan 7 comments.

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

- **NextEra / Avangrid/NECEC Dispute - ("Seabrook Complaint") (EL21-6)[20] and ("Seabrook Declaratory Order Petition") (EL21-3)[21]**

Nearly two and one-half years after these proceedings began, the FERC issued, on February 1, 2023, a single order addressing these two proceedings.[22] 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".[23] 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.[24] 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.[25] In dismissing the Declaratory Order Petition, the FERC noted that the issues raised in the Petition were addressed in the *Seabrook Dispute Order*, that

[20] 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").

[21] 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.

[22] *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*").

[23] *Id*. at P 74.

[24] *Id*.

[25] *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.

additional findings were unnecessary, and thus exercised its discretion to not take action on, and to dismiss, the Petition.[26]

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.[27] 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.[28] 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.[29]

Challenges, if any, to the *Seabrook Dispute Order* are due on or before Friday, ***March 3, 2023***. 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,[30] 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*).[31] However, the FERC's orders were challenged, and in *Emera Maine,*[32] 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)[33] and third (EL14-86)[34] ROE complaint proceedings were consolidated for purposes of hearing and

[26] *Id.* at P 112.

[27] 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).

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

[29] *Id.* at P 88.

[30] 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*")).

[31] *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*").

[32] *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).

[33] 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%.

[34] 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

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.[35] 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[36] also went to hearing before an Administrative Law Judge ("ALJ"), Judge Glazer, who issued his initial decision on March 27, 2017.[37] 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.[38] 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.[39] 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*[40] (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.[41]

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

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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.

[35] *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*").

[36] 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.

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

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

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

[40] *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*.

[41] *Id.* at P 19.

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

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

The FERC provided preliminary analysis of how it would apply the proposed methodology in the Base ROE I Complaint, suggesting that it would affirm its holding that an 11.14% Base ROE is unjust and unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[42] 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[43] 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*[44] 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.

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[42] *Id.* at P 59.

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

[44] *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).

These matters remain pending before the FERC. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com) or Joe Fagan (202-218-3901; jfagan@daypitney.com).

II. Rate, ICR, FCA, Cost Recovery Filings

- **FCA17 Qualification Informational Filing (ER23-690)**

On February 17, 2023, the FERC accepted ISO-NE's informational filing for qualification in FCA17 (the "FCA17 Informational Filing"),[45] as amended by its January 12, 2023 errata filing,[46] and directed ISO-NE to use the corrected Qualified Capacity values when it conducts FCA17.[47] FCA17 is scheduled to begin March 6, 2023. Unless the *FCA17 Info Filing Order* is challenged, this proceeding will be concluded. 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).

- **Mystic COS Agreement Updates to Reflect Constellation Spin Transaction[48] (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 ("COS Agreement") to reflect Mystic's current upstream ownership.[49] 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,[50] 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 the compliance filing is now 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).

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

Mystic I Remand. As previously reported, the DC Circuit issued a decision on August 23, 2022[51] 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;

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[45] The FCA17 Informational Filing contained ISO-NE's determinations that three Capacity Zones will be modelled for FCA17 -- Northern New England ("NNE"), Maine, and Rest of Pool. NNE and Maine will be modeled as export-constrained. The FCA17 Informational Filing reported that there will be 32,518 MW of existing capacity in FCA17 competing with 5,032 MW of new capacity under a Net ICR of 30,305 MW (ICR minus HQICCs). ISO-NE reported also that there were a total of 474 MW of De-List Bids. A summary of the De-List Bids accepted and those rejected for reliability purposes was included in a privileged Attachment E. ISO-NE qualified 2 demand bids, totaling 7.8 MW, and 88 supply offers, totaling 515 MW, to participate in the substitution auction.

[46] On Jan. 12, 2023, ISO-NE filed an errata disclosing that it had discovered a minimal error in the winter Qualified Capacity of one New Generating Resource, which resulted in an erroneous FCA Qualified Capacity for that resource, as well as for the post-RTR proration FCA Qualified Capacity of other resources that elected RTR treatment. ISO-NE stated that the impacts of its error were "1 MW or less". ISO-NE provided corrected FCA Qualified Capacity values in a revised confidential Attachment D.

[47] *ISO New England, Inc.*, 182 FERC ¶ 61,107 (Feb. 17, 2023) ("*FCA17 Info Filing Order*").

[48] 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.

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

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

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

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*.

(-019) Emergency Motion for Expedited Action. On November 22, 2022, as corrected on November 23, Mystic and Constellation filed an emergency motion requesting expedited action by ***January 9, 2023***, on the Cost Allocation and Clawback issues remanded to the FERC in the *Mystic I Remand Order*, asserting that expedited FERC action on remand is needed given the implications for sales of gas from the Everett facility during the term of the COSA and the future of the Everett facility post-COSA. That motion triggered a round of pleadings, most supporting expedited resolution (even if not agreeing with the underlying justification for emergency action presented by Mystic and Constellation); one pleading, by ENECOS, opposed the emergency action in its entirety, and requested post-remand briefing on the allocation of Everett Marine Terminal costs. Mystic and Constellation answered ENECOS' opposition on December 21, 2022. This round of pleadings is pending before the FERC. No remand order has yet been issued.

Other Mystic COSA-Related Matters Still Pending or With Activity Since the Last Report include:

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

On April 28, 2022, the FERC issued an order granting in part, and denying in part, ENECOS' and NESCOE's formal challenges, subject to refund, and established hearing and settlement judge procedures.[52] The FERC summarily denied NESCOE's challenge regarding the update to the AFRR and ENECOS' challenge with regard to the improper booking of items. Those items, and challenges to other underlying projected costs, may be challenged in connection with Mystic's Second Informational Filing (where the informal challenge process begins on April 1, 2022 and the formal challenge process begins on September 15, 202).[53] The FERC reiterated that all items except return on equity and depreciation are subject to the true-up process described in Schedule 3A of the COS Agreement, not just projected capital expenditures. However, with respect to NESCOE's and ENECOS' allegations that Mystic failed to support all of its projected capital expenditures, the FERC found that the First CapEx Projects Info. Filing raised issues of material fact that could not be resolved based on the record and would be more appropriately addressed under hearing and settlement judge procedures.[54] Accordingly, the FERC set these matters for a trial-type evidentiary hearing. The FERC encouraged the parties to make every effort to settle their disputes before hearing procedures are commenced, and to that end, is holding the hearing in abeyance pending the completion of settlement judge procedures (-015) summarized just below.[55]

(-015) First CapEx Info. Filing Settlement Judge Procedures. On May 4, Chief Judge Cintron designated Judge Andrea McBarnette as the Settlement Judge. Thus far, six settlement conferences have been held, with most recent settlement conference held on February 6, 2023. Based on recent reports in other sub-dockets, Mystic and the other settling parties intend to file a settlement agreement in the near future.

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

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

[54] *Id.* at P 26.

[55] *Id.* at P 27.

(-018) Second CapEx Info Filing. On September 15, 2022, Mystic submitted, as required by orders in this proceeding and Sections I.B.1.i. and II.6.of Schedule 3A of the COS Agreement ("Protocols") its "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 (*see* ENECOS Mystic COSA Complaint (EL23-4) above). Since the last Report, on December 6, 2022, ENECOS answered Mystic's November 17, 2022 answer. 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.

However, since the last Report, and 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* ("Anticipated Settlement"), Mystic requested that the FERC hold off on acting on the pending Formal Challenges in this proceeding until after the FERC acts on the Anticipated Settlement. That request is pending before the FERC.

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

(-020) Fuel Supply Agreement Revision Info Filing. On December 9, 2022, Mystic submitted a revision to its Fuel Supply Agreement ("FSA") that memorializes Constellation LNG's pre-existing business practice of crediting Mystic under the FSA to account for firm gas transportation ("FT") charges that Constellation LNG collects from forward third-party sales of gas. This crediting mechanism, along with the other credits already included in the FSA, Mystic explained, ensures that Mystic (and thus ISO New England) only bears the cost responsibility for the pipeline transportation costs that are not offset by third-party sales of gas. Mystic stated the credit to the FSA reduces Mystic's cost-of-service. This informational filing was not noticed for public comment.

Request for Limited Waiver of Certain Mystic COSA True-Up Deadlines (ER23-1159). On February 17, 2023, Mystic requested waiver of certain deadlines required by Schedule 3A of the Mystic COSA to provide Settling Parties sufficient time to implement the terms of the Anticipated Settlement as part of the Mystic COSA annual true-up process ("Waiver Request"). Mystic asked the FERC to act on its Waiver Request no later than ***March 20, 2023***. No comments on the Waiver Request were filed. Doc-less interventions were filed by ISO-NE, Eversource, MA AG, NESCOE, and CT PURA. The Waiver Request is pending before the FERC.

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; RT04-2)**

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,[56] the formula rates that will be in effect for 2023 include a billing true up of seven months of 2021 (June-December). The PTO AC states that the annual updates results in a Pool "postage stamp" RNS Rate of $140.94 /kW-year effective January 1, 2023, a decrease of $1.84 /kW-year from the charges that went into effect on January 1, 2022. In addition, the filing includes updates to the revenue requirements for Scheduling, System Control and Dispatch Services (the Schedule 1 formula rate), which result in a Schedule 1 charge of $1.75 kW-year (effective June 1, 2022 through May 31, 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.

Formal Challenge by RENEW. On January 31, 2023, RENEW filed a formal 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); 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 formal challenge have been noticed for public comment and any comments are due on or before March 16, 2023.

Supplement. On January 31, 2023, the PTO AC supplemented its July 29 filing with updated rates and associated revenue requirements for Regional and Local Service, effective January 1, 2023 – December 31, 2023, under transition arrangements to the Attachment F Settled Formula Rate. The changes relate to revisions to Attachment F to establish transmission revenue requirements for Narragansett Electric Co. ("Narragansett" or "RIE") and a related tariff waiver submitted by New England Power Company ("NEP"), both recently accepted by the FERC and that became effective on January 1, 2023, the date RIE became a PTO.

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

- **PPU CTR Clarifications (ER23-911)**

On January 20, 2023, ISO-NE and NEPOOL jointly filed revisions to Section III.13.7.5.4.5 of Market Rule 1 (the "PPU CTR Clarifications") to clarify the calculation of FCM Capacity Transfer Rights ("CTR") that are related to

[56] 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").

Pool-Planned Units ("PPU"). Specifically, the revisions clarify (i) the allocation of PPU CTRs for each Capacity Commitment Period, (ii) PPU CTR self-supply designations, and (iii) the settlement of any remaining PPU CTRs not designated as self-supply. The PPU CTR Clarifications were supported by the Participants Committee at its October 6, 2022 meeting (Consent Agenda Item #1). ISO-NE requested a March 21, 2023 effective date. Comments on the PPU CTR Clarifications were due on or before February 10, 2023; none were filed. Doc-less interventions were filed by Eversource and National Grid. 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: Advanced Energy United, FirstLight, National Grid, NEPGA, NESCOE, UCS, and VELCO. Doc-les interventions only were filed by Avangrid, Narragansett ,Vistra, MA DPU, LSP Transmission Holdings, RENEW, ACPA, EPSA. Since the last Report, on February 3, 2023, NEPOOL answered VELCO's comments and 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, National Grid answered NEPGA's and ISO-NE's answers. 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)**

New England's *Order 2222* Compliance Filing remains pending before the FERC. As previously reported, ISO-NE, NEPOOL and the PTO AC ("Filing Parties") submitted on February 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.

Comments, following an extension of time granted by the FERC in response to a request by Advanced Energy Management Alliance ("AEMA"), were due on or before April 1, 2022. NEPOOL filed supplemental comments on March 28. Protests and comments were filed by: AEU/PowerOptions/SEIA; Environmental Organizations;[57] MA AG; Voltus; AEMA and 4 New England US Senators.[58] Doc-less interventions were filed by: Avangrid (CMP/UI), Calpine, Centrica Business Solutions Optimize (out-of-time), Constellation, ENE, Enerwise, Eversource, FirstLight, MA AG, National Grid, NESCOE, NRG, MA DPU, MPUC (out-of-time), APPA, and EEI. ISO-NE

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

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

(April 20) and National Grid/Avangrid/Eversource (April 19) filed answers to the protests and adverse comments. AEU/PowerOptions/SEIA and AEMA answered the ISO-NE and National Grid/Avangrid/ Eversource answers.

(-001) Deficiency Letter. On May 18, 2022, the FERC issued a 25-page deficiency letter directing ISO-NE to provide, on or before June 17, 2022, additional information and clarifications. ISO-NE filed its 39-page response to the deficiency letter on June 17, 2022. Comments in response to ISO-NE's deficiency letter response were due on or before July 8, 2022 and a joint protest was filed by AEU, AEMA, PowerOptions, and SEIA ("Joint Protest"). The Joint Protest, while supportive of certain responses (those regarding the exemption of DERAs from the Small Generator Interconnection Procedures ("SGIP") prior to 2026, locational requirements for DER aggregation, and the role of host utilities in identifying potential conflicts with retail program participation), protested the adequacy of ISO-NE responses regarding proposed metering and telemetering requirements for behind-the-meter ("BTM") DERs. On July 25, 2022, ISO-NE answered the July 8 Joint Protest. On August 9, 2022, AEU, AEMA, PowerOptions, and SEIA answered ISO-NE's July 25 answer.

This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com); Eric Runge (617-345-4735; ekrunge@daypitney.com); or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

On November 22, 2022, ISO-NE filed Tariff provisions governing the Inventoried Energy Program ("IEP") consistent with the D.C. Circuit's *IEP Decision*.[59] ISO-NE's proposed Tariff changes remove nuclear, biomass, coal, and hydroelectric generators from the IEP. ISO-NE's Tariff changes were supported by the Participants Committee at its November 2 meeting (as were alternative Tariff changes proposed by Brookfield that explicitly allow pumped hydro resources to participate in the IEP as Electric Storage Facilities).

Comments were due on or before December 13, 2022, and were filed by: NEPOOL, Brookfield, MA AG, National Hydropower Association, and RENEW; doc-less interventions only, by Calpine, FirstLight and National Grid. On December 28, 2022, New England Consumer-Owned Systems[60] and Energy New England ("ENE") responded to those protests and comments (urging the FERC to accept ISO-NE's compliance filing without modification). ISO-NE did not respond. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

IV. OATT Amendments / TOAs / Coordination Agreements

- **Attachment K Economic Study Revisions (ER23-971)**

On January 27, 2023, ISO-NE and NEPOOL filed revisions to Attachment K to the OATT to require ISO-NE (1) to identify market efficiency issues, and as applicable, market efficiency needs on the Pool Transmission Facilities ("PTF") portion of the New England Transmission System as part of the Economic Study process; (2) to provide the New England region more insight into system trends and consistent analysis; and (3) to facilitate

[59] *Belmont Mun. Light Dept., et al., v. FERC*, 2022 WL 2182810 (June 17, 2022) (the "*IEP Decision*"). The *IEP Decision* leaves 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.

[60] New England Consumer-Owned Systems ("NECOS") are Belmont, Block Island Utility District, Braintree, Georgetown, Groveland, Hingham, Littleton (MA), Merrimac, Middleborough, Middleton, Norwood, Pascoag, Reading, Rowley, Stowe, Taunton, Wellesley, and Westfield.

comparison across Economic Study cycles, all of which can inform future decisions in transmission investment (the "Economic Study Revisions"). The Economic Study Revisions were supported by the Participants Committee at its January 5, 2023 meeting (Consent Agenda Item #1). ISO-NE requested a March 31, 2023 effective date for the Economic Study Revisions. Comments on the Economic Study Revisions were due on or before February 17, 2023. On February 17, Public Systems[61] submitted comments supporting the Economic Study Revisions. No adverse comments were filed. Doc-less interventions were filed by Eversource, National Grid, NESCOE, RI Energy, and MA DPU. 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,[62] and the Schedule 20A Service Providers.[63] 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*[64] ("*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).

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[61] "Public Systems" are for this proceeding: CMEEC, MMWEC, NHEC, and VPPSA.

[62] 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").

[63] 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.

[64] *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*").

- ***Order 676-J* Compliance Filings**

On February 23, 2023, the FERC accepted three pending *Order 676-J*[65] compliance filings that incorporate into various portions of the ISO-NE Tariff cybersecurity and PFV standards contained in the North American Energy Standards Board ("NAESB") Wholesale Electric Quadrant ("WEQ") Version 003.3 Standards:

(1) ***CSC-Schedule 18-Attachment Z (ER22-1168)***. Changes filed by ISO-NE and CSC to ISO-NE Tariff Schedule 18 Attachment Z;[66]
(2) ***TOs-Schedule 20/21-Common (ER22-1161).*** Changes filed by the PTO AC, ISO-NE, and the Schedule 20A Service Providers ("S20SPs") to ISO-NE Tariff Schedules 20A-Common and 21-Common;[67] and
(3) ***ISO-NE-Schedule 24 (ER22-1150).*** Changes filed by ISO-NE to ISO-NE Tariff Schedule 24 (Incorporation by Reference of NAESB Standards).[68]

Each set of changes were accepted effective as of February 23, 2023. Unless the orders are challenged, these proceeding will be concluded. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

- **IEP Changes to Financial Assurance and Billing Policies; Ministerial Change to Monthly Statements Issuance Date (ER23-705)**

On February 14, 2023, the FERC accepted IEP-related changes to the Tariff and a definition change revising "Monthly Issuance" in Section I's omnibus definition section (the "FAP/BP Changes").[69] As previously reported, the revisions to the FAP are designed (i) to ensure adequate collateral is provided by Market Participants participating in the IEP; (ii) to revise the Billing Policy ("BP") to reflect charges and credits related to the IEP; and to revise the definition of "Monthly Issuances" in Section I.2.2 to ensure consistency with the Billing Policy. The FAP/BP Changes were accepted effective as of February 23, 2023, as requested. Unless the February 14 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

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

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

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. A December 19, 2022 effective date for the SGIA was requested. Comments on this filing were due on or before

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

[66] *ISO New England Inc. and Cross-Sound Cable Company, LLC*, Docket No. ER22-1168-000 (Feb. 23, 2023) (unpublished letter order).

[67] *ISO New England Inc.*, Docket No. ER22-1161-000 (Feb. 23, 2023) (unpublished letter order).

[68] *ISO New England Inc.*, Docket No. ER22-1150-000 (Feb. 23, 2023) (unpublished letter order).

[69] *ISO New England Inc.,* Docket No. ER23-705-000 (Feb. 14, 2023) (unpublished letter order).

February 8, 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).

- **Schedule 21-RIE: Transfer of SAs from Sched 21-NEP; Updated Thundermist ISA (ER23-678; ER23-681)**
On February 17, 2023, the FERC accepted filings (i) to move certain RIE service agreements ("SAs") to Schedule 21-RIE from Schedule 21-NEP (Docket No. ER23-678) and to revise RIE's Interconnection Service Agreement ("ISA") with Thundermist Hydropower LLC ("Thundermist");[70] and (ii) to cancel the NEP Tariff database that previously contained the SAs (Docket No. ER23-681).[71] The filings were accepted effective as of January 1, 2023, as requested. Unless the February 17 orders are challenged, these proceedings will be concluded. If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-VP: Revised 2021 Annual Update Settlement Agreement (ER20-2119-002)**
On January 12, 2023, Versant submitted a revised uncontested Joint Offer of Settlement ("Revised 2021 Annual Update Settlement") between itself and the MPUC that replaces in full the Versant 2021 Annual Update Settlement Agreement submitted March 25, 2022. Versant stated that, if approved, the Revised 2021 Annual Update Settlement would resolve all issues raised by the MPUC with respect to the 2021 Annual Update. Comments on the Revised 2021 Annual Update Settlement were due on or before February 2, 2023; none were filed. The Revised 2021 Annual Update Settlement is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-VP: Revised 2020 Annual Update Settlement Agreement (ER15-1434-006)**
Similarly, and also on January 12, 2023, Versant submitted a revised uncontested Joint Offer of Settlement ("Revised 2020 Annual Update Settlement") between itself and the MPUC that replaces in full the Versant 2020 Annual Update Settlement Agreement submitted November 19, 2021.[72] Versant stated that, if approved, the Revised 2020 Annual Update Settlement would resolve all issues raised by the MPUC with respect to the 2020 Annual Update. Comments on the Revised 2020 Annual Update Settlement were due on or before February 2, 2023; none were filed. The Revised 2020 Annual Update is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

- **Participants Agreement Amendment No. 12 (ISO Board Member Age Limit Increase) (ER23-980)**
On January 30, 2023, ISO-NE and NEPOOL filed for approval Amendment No. 12 to the Participants Agreement ("PA12"), which would raise the age limitation prohibiting the election or re-election of any candidate to the ISO Board of Directors from 70 to 75. PA12 was approved by NEPOOL following a second balloting period during which the Minimum Response Requirement was satisfied. Comments, if any, on PA12 were due on or before February 21, 2023; none were filed. Doc-less interventions were filed by Eversource, National Grid, NESCOE, and RI Energy. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

[70] *The Narragansett Elec. Co.*, Docket No. ER23-678-000 (Feb. 17, 2023) (unpublished letter order).

[71] *The Narragansett Elec. Co.*, Docket No. ER23-681-000 (Feb. 17, 2023) (unpublished letter order).

[72] As previously reported, on Nov. 19, 2021, Versant Power submitted a joint offer of settlement between itself and the MPUC to resolve all issues raised by the MPUC in response to Versant's 2020 annual charges update (the "Versant 2020 Annual Update Settlement Agreement").

VIII. Regional Reports

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

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

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

The TOs' November 2, 2015 refund report documenting resettlements of regional transmission charges by ISO-NE in compliance with *Opinions No. 531-A*[73] *and 531-B*[74] also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

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

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

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

- **Capital Projects Report - 20212 Q4 (ER23-1125)**

On February 10, 2023, ISO-NE filed its Capital Projects Report and Unamortized Cost Schedule covering the fourth quarter ("Q4") of calendar year 2022 (the "Report"). ISO-NE is required to file the Report under section 205 of the FPA pursuant to Section IV.B.6.2 of the Tariff. Report highlights include the following new projects: (i) Solar Do-Not-Exceed ("DNE") Dispatch Phase II ($2 million); (ii) Windows Server 2019R Deployment Phase I ($1.15 million); (iii) Security Orchestration and Automation Response ($359,400); (iv) Control Room Voice Recorder Upgrade ($297,000); and (v) Mobile Application Rebuild ($195,400). Due to a reallocation of funds from 2022 to 2023, significant changes to the 2023 capital budget projects included increases of $678,600 for the nGEM Market Clearing Engine Implementation and nGEM Software Development Part II project and $411,200 for Windows Server 2019R2 Deployment Phase I project. Comments on this filing are due on or before ***March 3, 2023***. NEPOOL filed comments on February 17 supporting the 2022 Q4 Report. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **Interconnection Study Metrics Processing Time Exceedance Report Q3 2022 (ER19-1951)**

On February 14, 2023, ISO-NE filed, as required,[75] public and confidential[76] versions of its Interconnection Study Metrics Processing Time Exceedance Report (the "Exceedance Report") for the Fourth Quarter of 2022 ("2022 Q4"). ISO-NE reported that with respect to:

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

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

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

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

- ***Interconnection Feasibility Study ("IFS") Reports***
  - all 10 of the 2022 Q4 IFS Reports delivered to Interconnection Customers were delivered ***later*** than the best efforts completion timeline (90 days from the Interconnection Customer's execution of the study agreement).
  - 7 IFS Reports not yet completed have exceeded the 90-day completion expectation.
  - The average mean time from ISO-NE's receipt of the executed IFS Agreement to delivery of the completed IFS report to the Interconnection Customer was 192 days (roughly 5 days longer than in 2022 Q3).
- ***System Impact Study ("SIS") Reports***
  - 7 of the 8 SIS Reports delivered to Interconnection Customers were delivered ***later*** than the best efforts completion timeline of 270 days.
  - 16 SIS Studies that are not yet completed have exceeded the 270-day completion expectation.
  - The average mean time from ISO-NE's receipt of the executed SIS Agreement to delivery of the completed SIS report to the Interconnection Customer was 446 days (a decrease of roughly 3 days from 2022 Q3).
- ***Facility Study Reports***
  - There were no Facility Study reports were delivered to an Interconnection Customer and no Facility Studies are in process that have exceeded completion expectations.

Section 4 of the Report identified steps ISO-NE has identified to remedy issues and prevent future delays, including mitigating the impact of backlogs and initiating clustering, moving to earlier in the process certain Interconnection Customer data reviews, and enhanced information sharing and coordination efforts with Interconnecting TOs. This report was not noticed for public comment.

- **Transmission Projects Annual Informational Filing (ER13-193)**

On January 30, 2023, ISO-NE filed, as required under Section 4.1(j)(iii) of the OATT, its annual informational filing of projects on the Regional System Plan ("RSP") project list that had a year of need three years or less from the completion of the Needs Assessment. The list of prior year designations is maintained on the ISO-NE website at https://www.iso-ne.com/static-assets/documents/2023/01/2022-prior-year-projects-section-4-j-iii.pdf. This filing will not be noticed for public comment by the FERC.

IX. Membership Filings

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

On February 28, 2023, NEPOOL requested that the FERC accept (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.). Comments on the March membership filing are due on or before ***March 21, 2023***.

- **February 2023 Membership Filing (ER23-1020)**

On January 31, 2023, NEPOOL requested that the FERC accept (i) 3 memberships - those of CommonWealth New Bedford Energy LLC (AR Sector, RG Sub-Sector, Small RG Group Seat); GF Power LLC (Supplier Sector); and Industrial Wind Action Corp (End User Sector); (ii) the termination of the Participant status of 8 Participants -- Backyard Farms Energy, LLC and Backyard Farms LLC (End User Sector); Bruce Power Inc. (Supplier Sector); CommonWealth Resource Management Corporation (Replaced by CommonWealth New Bedford Energy); Darby Energy, LLC [Related Person to Protor Energy, LLC (Supplier Sector)]; DFC ERG CT, LLC [Related Person to Bridgeport and Derby Fuel Cell (AR Sector, RG Sub-Sector)]; Stones DR, LLC [Related Person to Jericho Power, CPower, et al. (AR Sector, RG Sub-Sector)]; and Vineyard Wind LLC [Related Person to Avangrid (Transmission Sector)]; and (iii) one name change – that of Advanced Energy United Inc. (f/k/a Advanced Energy

Economy Inc.) ("AEU"). Comments on the February membership filing were due on or before February 21, 2023; none were filed. This matter is pending before the FERC.

- **January 2023 Membership Filing (ER23-756)**

On February 25, 2023, the FERC accepted[77] (i) the memberships of Just Energy Limited [Related Person to Just Energy (U.S.) Corp. and Hudson Energy Services, LLC (Supplier Sector); and Think Energy, LLC (Supplier Sector); (ii) the termination of the Participant status of Josco Energy MA (Supplier Sector), Starion Energy (Supplier Sector), and Rhode Island Bioenergy Facility [Related Person to Rhode Island Bioenergy, LLC (AR Sector, RG Sub-Sector, Small RG Group Seat)]; and (iii) the name changes of BP Energy Retail Company LLC (f/k/a EDF Energy Services, LLC), BP Energy Holding Company LLC (f/k/a BP Energy Retail LLC), and Rhode Island Bioenergy Facility, LLC (f/k/a formerly known as Rhode Island Bioenergy, LLC). Unless the February 25 order is challenged, this proceeding will be concluded.

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

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

- **NERC Annual Report on FFT & Compliance Exception Programs (RC11-6-016)**

On November 29, 2022, NERC filed its annual report on Find, Fix, and Track ("FFT") and Compliance Exception programs, in accordance with prior FERC Orders.[78] In the report, NERC stated that the ERO Enterprise appropriately handles noncompliance posing a minimal or moderate risk through these programs and that the results of the annual report show consistent improvement in program implementation. The report also demonstrates, NERC suggests, significant alignment across the ERO Enterprise, particularly in the processing and understanding of the risk associated with individual noncompliance. Comments on the FFT annual report were due on or before January 24, 2023; none were filed. This matter is pending before the FERC.

- **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*").[79] As previously reported, the changes to the *Cold Weather Standards*, which address certain key recommendations from the *Feb 2021 Cold Weather Outages Joint Report,*[80] 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

[77] *New England Power Pool Participants Comm.*, Docket No. ER23-756-000 (Feb. 24, 2023) (unpublished letter order).

[78] *See N. Am. Elec. Rel. Corp.*, 138 FERC 61,193 (2012) ("March 2012 Order"); *N. Am. Elec. Rel. Corp.,* 143 FERC 61,253 (2013) ("June 2013 Order"); *N. Am. Elec. Rel. Corp.,* 148 FERC 61,214 (2014) ("September 2014 Order"); and *N. Am. Elec. Rel. Corp.*, Docket No. RC11-6-004 (Nov. 13, 2015) (unpublished letter order) ("November 2015 Order").

[79] *N. Amer. Elec. Rel. Corp.*, 182 FERC ¶ 61,094 (Feb. 16, 2023).

[80] 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*").

"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";[81]

- 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";[82]
- 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;[83]
- to increase the length of R2's continuous operations requirement (one hour being too short);[84]
- to include in R7 deadlines for implementation completion of corrective action plans, as recommended in the *November 2021 Report*;[85]
- to shorten the implementation plan for existing generating units, staggering the implementation for existing unit(s) in a generator owner's fleet;[86] 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.[87]

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."[88]

- **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

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81 *Id.* at P 4.

82 *Id.* at P 6.

83 *Id.* at P 7.

84 *Id.* at P 8.

85 *Id.* at P 9.

86 *Id.* at P 10.

87 *Id.* at P 11.

88 *Id.* at P 5.

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*").

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 are due on or before ***March 17, 2023***.

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

As previously reported, NERC is required to file on an informational basis quarterly status updates regarding the development of new or modified Reliability Standards pertaining to virtualization and cloud computing services. NERC submitted its most recent informational filing regarding one active CIP standard development project (Project 2016-02 – Modifications to CIP Standards ("Project 2016-02"))[91] on December 15, 2022. Project 2016-02 focuses on modifications to the CIP Reliability Standards to incorporate applicable protections for virtualized environments. In the December 15 report, NERC reported that, because ballot body approval was not achieved for two related Reliability Standards, the schedule for Project 2016-02 has been revised and now calls for final balloting of revised standards in March 2023, NERC Board of Trustees Adoption in May 2023 and filing of the revised standards with the FERC in June 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 are due ***March 6, 2023***.

- **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

[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*").

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 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. This matter is pending before the FERC.

XI. Misc. - of Regional Interest

- **203 Application: Saddleback / CPV (EC23-52)**

On January 13, 2023, Saddleback Ridge Wind, LLC ("Saddleback") requested FERC authorization for a proposed transaction pursuant to which CPV Mountain Wind Holdings, LLC ("Buyer") will acquire all of the membership interests in Saddleback. Comments on this 203 application were due on or before February 3, 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).

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[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.

[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*").

- **203 Application: Salem Harbor / Castleton Commodities (EC23-50)**

On January 6, 2023, Salem Harbor Power Development LP ("Salem Harbor") requested FERC authorization for a proposed transaction pursuant to which CCI U.S. Asset Holdings LLC 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. Once consummated, Salem Harbor will become a Related Person of Supplier Sector member Castleton Commodities Merchant Trading LP. Comments on this 203 application were due on or before January 27, 2023; none were filed. Public Citizen filed a doc-less intervention. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: Talen Energy Supply Reorganization (EC23-42)**

On December 15, 2022, Talen Energy Supply, LLC ("TES") requested the required FPA Section 203 approvals for a change in control transaction whereby 10% or more of the voting securities of a new parent of TES and its affiliated debtors ("Reorganized Talen") 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. Comments on the 203 application were due on or before January 30, 2023; none were filed. Doc-less interventions were filed by the PJM IMM, Public Citizen, PPL and an ad hoc group of Noteholders. 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: Cogentrix / EGCO (Rhode Island State Energy Center) (EC23-41)**

On December 14, 2022, Rhode Island State Energy Center, LP ("RISEC") and EGCO RISEC II, LLC ("Buyer") requested FERC authorization for a proposed transaction pursuant to which Buyer, a wholly owned indirect subsidiary of Electricity Generating Public Company Limited ("EGCO"), will acquire a 49% indirect ownership interest in RISEC from Cogentrix Sellers.[101] Following the transaction, RISEC will be indirectly owned by Buyer (49%) and the Cogentrix Sellers (51%). Comments on this 203 application were due on or before January 30, 2023; none were filed. Public Citizen intervened doc-lessly. 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: Agilitas Companies / AB CarVal Funds (EC23-30)**

On January 24, 2023, the FERC authorized[102] a transaction pursuant to which the AB CarVal Funds[103] 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,[104] into 21.3% of the voting interests in Agilitas Energy. Pursuant to the January 24 order, AB CarVal Funds 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: ConEd / RWE (EC23-17)**

On January 20, 2023, the FERC authorized a transaction pursuant to which RWE Renewables Americas, LLC ("RWE") will acquire 100% of the equity interests in ConEd's[105] Clean Energy Businesses (including NEPOOL

[101] "Cogentrix Sellers" are RISEC CPP II Holdings, LLC and Cogentrix RISEC CPOCP Holdings, LLC.

[102] *Madison BTM, LLC et al.*, 182 FERC ¶ 62,048 (Jan. 24, 2023).

[103] The "AB CarVal Funds" are CEF Master Fund IV LP, CVI CEF II Pooling Fund IV LP, and CVI CSF Master Fund II LP.

[104] 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.

[105] "ConEd" includes Consolidated Edison, Inc., its wholly-owned subsidiary Con Edison Clean Energy Businesses, Inc. ("CEB"), and CEB's public utility subsidiaries (together, members of the Supplier Sector). RWE's NEPOOL Related Person (Cassadaga Wind LLC) is a member of the Supplier Sector.

members Consolidated Edison Energy, Inc.; Consolidated Edison Development, Inc.; and Consolidated Edison Solutions, Inc. (but not Consolidated Edison Company of New York)).[106] Pursuant to the January 20 order, RWE 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: Great River Hydro / HQI US (EC23-16)**

On February 3, 2023, the FERC authorized a transaction pursuant to which HQI US Holding LLC ("HQI US"), an indirect and wholly-owned subsidiary of Hydro-Québec ("HQ") indirectly acquired 100% of the membership interests in Great River Hydro, LLC ("Great River Hydro").[107] The transaction was consummated on February 10, 2023. As a result of the transaction, HQ US and Great River Hydro became Related Persons and will together be members of the AR Sector. Great River Hydro's former Related Persons, the Generation Bridge Companies,[108] will together be members of the Generation Sector. Reporting on this matter has now concluded. 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 February 21, 2023, National Grid filed a non-conforming Small Generation Interconnection Agreement ("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. The SGIA, which replaces a 2005 SGIA, was filed to supersede and replace the 2005 SGIA. A January 30, 2023 effective date was requested. Comments on this filing are due on or before ***March 14, 2023***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **VTransco/GMP Shared Structure Participation Agreement (ER23-1101)**

On February 10, 2023, VTransco filed a Shared Structure Participation Agreements ("ShPA") between itself and GMP. The ShPA establishes the allocation of costs associated with the design, construction, repair, replacement, general maintenance, operation, and preventative maintenance of certain structures that VTransco and GMP share, where those facilities are used either exclusively by GMP or in common with VTransco. The purpose of the Agreement is to calculate and allocate those costs that are not recovered through a regional transmission tariff. VTransco requested an effective date of February 1, 2023 for the ShPA. Comments on this filing are due on or before ***March 3, 2023***. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA: RI Energy / Deepwater Block Island Wind (ER23-1023)**

On February 1, 2023, Narragansett Electric Company ("RI Energy") filed an LGIA with Deepwater Block Island Wind, LLC ("Deepwater Wind") to govern the interconnection of Deepwater Wind's 30 MW off-shore wind facility that interconnects to RI Energy's transmission facilities. The LGIA replaces the current LGIA and reflect revisions primarily related to the transition of ownership from New England Power to RI Energy. A January 1, 2023 effective date was requested. Comments on this filing were due on or before February 22, 2023; none were filed. On February 23, 2023, RI Energy supplemented its filing by requesting a waiver of FERC's prior notice requirements (which, absent a waiver, require service agreements to be filed and posted not more than 30 days after electric service has commenced),[109] so that the requested January 1, 2023

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[106] *RWE Aktiengesellschaft et al.*, 182 FERC ¶ 62,042 (Jan. 20, 2023).

[107] *Great River Hydro, LLC and HQI US Holding LLC*, 182 FERC ¶ 62,067 (Feb. 3, 2023).

[108] The "Generation Bridge Companies" are: Generation Bridge Connecticut Holdings, Generation Bridge M&M Holdings, GB II Connecticut and GB II New Haven LLC.

[109] 18 CFR §35.3 (2023).

effective date (31 days prior to the filing) can be granted. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA: RI Energy / Manchester Street (ER23-1007)**

On January 31, 2023, RI Energy filed an replacement Interconnection Agreement ("IA") with Manchester Street, LLC ("Manchester Street") to govern the interconnection of Manchester Street's 468 MW combined-cycle generating facility that interconnects to RI Energy's transmission facilities. The IA replaces the current IA and reflects revisions primarily related to the transition of ownership from New England Power to RI Energy, but also to reflect Manchester Street corporate changes. A January 1, 2023 effective date was requested. Comments on this filing were due on or before February 21, 2023; none were filed. National Grid filed a doc-less intervention. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **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. A January 1, 2023 effective date was requested. Comments on the LSAs are due on or before February 21, 2022; none were filed. National Grid and the RI Division intervened. This matter is pending before the FERC. 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 is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **IA 2nd Amendment: CMP/Sappi Compliance Filing (ER22-1612-001)**

On February 14, 2023, the FERC accepted CMP's compliance filing that included a Second Amended Agreement and Schedules between CMP and Sappi North America, Inc. ("Sappi").[110] As previously reported, the Second Amended Agreement reflected the November 17, 2022 closing date of the FERC-authorized transaction in which Sappi transferred its hydroelectric facilities to Presumpscot Hydro LLC ("Presumpscot Hydro") and its membership interests in Presumpscot Hydro to an unrelated third-party buyer. The compliance filing was accepted effective as of November 17, 2022, as requested. Unless the February 14 order is challenged, this proceeding will be concluded. If you have any questions, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

[110] *Central Maine Power Co.*, Docket No. ER22-1612-001 (Feb. 14, 2023).

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

On February 23, 2023, the FERC accepted[111] revisions to Section 4 of the Versant OATT for the Maine Public District ("MPD OATT") to incorporate the new cybersecurity and PFV standards contained in NAESB WEQ Version 003.3 Standards in response to the requirements of *Order 676-J*, ("Versant MPD OATT *Order 676-J* Part I Changes").[112] The FERC also granted Versant's request for waivers. The Versant MPD OATT Order 676-J Part I Changes were accepted effective as of February 23, 2023. Unless the February 23 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

XII. Misc. - Administrative & Rulemaking Proceedings[113]

- **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. Any comments to be considered by the FERC in its determination of any action to be taken were due on or before August 26, 2022. Comments were filed by 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, 202, 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*** deadline for doing so. Comments will be considered by the FERC in determining the appropriate action to be taken.

- **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.

- **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

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[111] *Versant Power*, 182 FERC ¶ 61,116 (Feb. 23, 2023).

[112] *Versant Power*, 182 FERC ¶ 61,116 (Feb. 23, 2023).

[113] Reporting on the following Rulemaking proceeding has been suspended since the last Report and will be continued if and when there is new activity to report: Electric Transmission Incentives Policy NOPR (RM20-10).

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 EPSA and Public Power Associations.[114] A transcript of the technical conference was posted in the FERC's eLibrary on January 17, 2023. This matter is now pending before the FERC.

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

On February 16, 2023, the FERC issued a notice of a Second New England Winter Gas-Electric Forum to be held the week before the NPC Summer Meeting, on Tuesday, ***June 20, 2023*** in Portland, Maine. The purpose of this forum is to continue discussions from the September 8, 2022 forum (summarized immediately below) regarding the electricity and natural gas challenges facing the New England Region. The objective of the forum is to shift from defining electric and natural gas system challenges in the New England Region to discussing potential solutions, including both infrastructure and market-based solutions.

Registration for in-person attendance, which will be open to the public, will be required and there will be no fee for attendance. The forum will also be available on webcast. A supplemental notice will be issued with further details regarding the forum agenda, as well as any updates on timing and logistics, including registration for members of the public and the nomination process for panelists. 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

[114] "Public Power Associations" are American Public Power Association ("APPA"), the Large Public Power Council ("LPPC"), and Transmission Access Policy Study Group ("TAPS").

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 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 are due on or before ***March 23, 2023***.

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

On February 17, 2022, the FERC issued a notice of inquiry ("NOI")[115] seeking comments on (i) whether and how the required use of dynamic line ratings ("DLR") is needed to ensure just and reasonable wholesale rates; (ii) whether the lack of DLR requirements renders current wholesale rates unjust and unreasonable; (iii) potential criteria for DLR requirements; (iv) the benefits, costs, and challenges of implementing DLRs; (v) the nature of potential DLR requirements; and (vi) potential timeframes for implementing DLR requirements. This NOI represents the first step in the FERC's effort to gather more information about the costs and benefits, and potentially mandating the use, of DLRs. A more detailed summary was provided to the Transmission Committee and is posted on the Transmission Committee's webpage.

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

Reply comments were due on or before May 25, 2022[116] and were filed by: AEP, Clean Energy Entities,[117] EEI, Joint Consumer Advocates, MISO TOs, and the R Street Institute. This matter is pending before the FERC.

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

A sixth meeting of the FERC-established Joint Federal-State Task Force on Electric Transmission ("Transmission Task Force" or "JFSTF")[118] was held February 15, 2023 in Washington, DC.[119] An agenda for the

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

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

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

[118] *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).

[119] Summaries of the first – fifth meetings of the Transmission Task Force can be found in previous Reports.

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.

Comments on the topics/questions related to the FERC's October 6, 2022 technical conference on Transmission Planning and Cost Management (*see* AD22-8 above), also posted in this docket, are due on or before ***March 23, 2023***.

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

ISO/RTO Reports. On April 21, 2022, the FERC issued an order[120] 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* follows a series of staff-led technical conferences, convened in 2021 and summarized in previous Reports, addressing ISO/RTO resource adequacy[121] and energy and ancillary services markets.[122]

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. Since the last Report, comments were filed by, among others: Advanced Energy United, API, Constellation, New England Public Systems,[123] 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.

- ***Order 886*: 2022 Civil Monetary Penalty Inflation Adjustments (RM23-3)**

On January 6, 2023, the FERC issued *Order 886*[124] to amend its regulations governing the maximum civil monetary penalties assessable for violations of statutes, rules, and orders within FERC's jurisdiction. The FERC is

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

[121] 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"), PJM Power Providers ("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.

[122] 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.

[123] "New England Public Systems" are CMMEC, MMWEC, NHEC, and VPPSA.

[124] *Civil Monetary Penalty Inflation Adjustments*, Order No. 886, 182 FERC ¶ 61,002 (Jan. 6, 2023) ("*Order 886*").

required to update each such civil monetary penalty on an annual basis every January 15.[125] Of particular interest is the increase in potential civil penalties for market manipulation, which were increased from $1,388,496 to $1,496,035 per violation, per day. *Order 886* became effective January 12, 2023.[126]

- **2023 Annual FERC Filing Fees Update (RM23-2)**

On January 23, 2023, the FERC issued a final rule updating its filing fees.[127] Because the FERC concluded that the rule will not significantly affect regulated entities or the general public, no public comment period was required. The rule will become effective on March 2, 2023.[128]

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

On July 28, 2022, the FERC issued a NOPR[129] 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[130] requested an additional month to submit comments.[131] 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, 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.

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[125] *See* Federal Civil Penalties Inflation Adjustment Act Improvements Act of 2015, Sec. 701, Pub. L. 114-74, 129 Stat. 584, 599. The FERC made its first adjustment under the Act in July 2016. *See Civil Monetary Penalty Inflation Adjustments*, Order No. 826, 81 FR 43937 (July 6, 2016), FERC Stats. & Regs. ¶ 31,386 (2016). The second adjustment was made January 9, 2017. *Civil Monetary Penalty Inflation Adjustments*, Order No. 834, 158 FERC ¶ 61, 170 (Jan. 9, 2017). The third adjustment as made January 8, 2018. *Civil Monetary Penalty Inflation Adjustments*, Order No. 839, 162 FERC ¶ 61,010 (Jan. 8, 2018). The fourth adjustment was made January 9, 2019. *Civil Monetary Penalty Inflation Adjustments*, Order No. 853, 166 FERC ¶ 61,041 (Jan. 8, 2019). The fifth adjustment was made January 14, 2020. *Civil Monetary Penalty Inflation Adjustments*, Order No. 865, 170 FERC ¶ 61,001 (Jan. 2, 2020). The sixth adjustment was made January 8, 2021. *Civil Monetary Penalty Inflation Adjustments*, Order No. 875, 174 FERC ¶ 61,015 (Jan. 8, 2021). The seventh adjustment was made January 7, 2022. *Civil Monetary Penalty Inflation Adjustments*, Order No. 882, 178 FERC ¶ 61,008 (Jan. 7, 2022).

[126] *Order 886* was published in the *Fed. Reg.* on Jan. 12, 2023 (Vol. 88, No. 8) pp. 1,989-1,991.

[127] *Annual Update of Filing Fees*, 182 FERC ¶ 62.043 (Jan. 23, 2023).

[128] The *Annual Update of Filing Fees* final rule was published in the *Fed. Reg.* on Jan. 31, 2023 (Vol. 88, No. 20) pp. 6,614-6,165.

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

[130] "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").

[131] The *Duty of Candor NOPR* was published in the *Fed. Reg.* on Aug. 12, 2022 (Vol. 87, No. 155) pp. 49,784-49,793.

- **NOPR: Advanced Cybersecurity Investment (RM22-19)**

On September 22, 2022, the FERC issued a NOPR[132] proposing to provide incentive-based rate treatments for the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce by utilities for the purpose of benefitting consumers by encouraging 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 ("Infrastructure and Jobs Act"). This NOPR also terminated the NOPR proceeding in Docket RM21-3 (*Dec 2020 Cybersecurity Incentives NOPR*)[133] described in previous Reports.

Initial comments on the *Advanced Cybersecurity Investment NOPR* were due on or before November 7, 2022 and reply comments were due November 21, 2022.[134] Nearly 30 sets of initial comments were filed, including by: Avangrid, APPA, EEI, EPSA, INGA, Joint Consumer Advocates, Microsoft, MISO TOs, PJM TOs, NERC, NRECA, TAPS, and the Operational Technology Cybersecurity Coalition. Reply comments were filed by DOE, EEI, ELCON, CA PUC, AEP, and Anterix. This matter is pending before the FERC.

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

On June 16, 2022, as corrected on July 12, 2022, the FERC issued a notice[135] 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[136] (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[137] 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"),[138] 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* Small Generator Interconnection Agreement ("SGIA") to address interconnection queue backlogs, improve certainty, and prevent undue discrimination for new technologies.

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[132] *Incentives for Advanced Cybersecurity Investment; Cybersecurity Incentives*, 180 FERC ¶ 61,189 (Sep. 22, 2022) ("*Advanced Cybersecurity Investment NOPR*").

[133] *Cybersecurity Incentives*, 173 FERC ¶ 61,240 (Dec. 17, 2020) ("*Dec 2022 Cybersecurity Incentives NOPR*"). As described in previous Reports, the *Dec 2022 Cybersecurity Incentives NOPR* proposed to establish rules for incentive-based rate treatment for voluntary cybersecurity investments by a public utility for or in connection with the transmission or sale of electric energy subject to FERC jurisdiction, and rates or practices affecting or pertaining to such rates for the purpose of ensuring the reliability of the Bulk Power System.

[134] The *Advanced Cybersecurity Investment NOPR* was published in the *Fed. Reg.* on Oct. 6, 2022 (Vol. 87, No. 193) pp. 60,567-60,580.

[135] *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*").

[136] "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".

[137] 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.

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

As previously reported, the proposed reforms fall into three main categories: (1) reforms to implement a first-ready, first-served cluster study process;[139] (2) reforms to increase the speed of interconnection queue processing;[140] and (3) reforms to incorporate technological advancements to the interconnection process.[141] 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[142] 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,

[139] To implement the **first-ready, first-served cluster study process**, the FERC proposed to:
- Require transmission providers offer an alternative option for an informational interconnection study that would not require a project enter the interconnection queue;
- Make cluster studies the required interconnection study method under the *pro forma* LGIP;
- Allocate the shared costs of the cluster studies so that 90% of the applicable study costs are allocated to interconnection customers on a pro rate basis based on the requested MWs included in the applicable cluster, and 10% of the applicable study costs are allocated to interconnection customers on a per capita basis based on the number of interconnection requests in the applicable cluster;
- Require transmission providers to allocate network upgrade costs to interconnection customers within a cluster using a proportional impact method, in which the transmission provider will determine the degree to which each generating facility in the cluster contributes to the need for a specific network upgrade;
- Allow interconnection customers in an earlier-in-time cluster to share the costs of network upgrades with interconnection customers who will significantly benefit from those upgrades but would not share the cost of the network upgrades solely by virtue of being in a later cluster;
- Increase study deposits based on the size of the generating facility from $35,000 to $250,000;
- Require more stringent site control requirements, and proposes to require an interconnection customer to demonstrate 100% site control for a proposed generating facility when they submit the interconnection request;[139]
- 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.

[140] 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.

[141] 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.

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

ACRE, APPA, US DOE, EEI, ELCON, EPRI, EPSA, IRC, NARUC, NERC, NRECA, PIOs, R Street Institute, SEIA, State Agencies, and WIRES.

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, Enel, ENGIE, Invenergy, the IRC, Longroad Energy, NERC, NESCOE, NextEra, Orsted, SEIA, Shell, Sierra Club, UCS, WIRES.

There was no activity in this proceeding since the last Report. 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[143] proposing to revise its regulations to permit ISO/RTOs to share among themselves[144] credit-related information regarding market participants.[145] 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[146] 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.

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

[144] 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).

[145] 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.

[146] 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[147] 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. Comments on the *Transmission Siting NOPR* are due on or before April 17, 2023.[148] Since the last Report, NARUC asked for a 30-day extension of time, to May 17, 2023, to file comments. NARUC's request is pending before the FERC.

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

Following its ANOPR process,[149] the FERC issued on April 21, 2022 a NOPR[150] 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

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147 *Applications for Permits to Site Interstate Electric Transmission Facilities*, 181 FERC ¶ 61,205 (Dec. 15, 2022) ("*Transmission Siting NOPR*").

148 The *Transmission Siting NOPR* was published in the *Fed. Reg.* on Jan. 17, 2023 (Vol. 88, No. 10) pp. 2,770-2,794.

149 *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.

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

regional transmission facilities establishing joint ownership of the transmission facilities. While the ANOPR sought comment on reforms related to cost allocation for interconnection-related network upgrades, interconnection queue processes, interregional transmission coordination and planning, and oversight of transmission planning and costs, the *Transmission NOPR* does not propose broad or comprehensive reforms directly related to these topics. The FERC indicated that it would continue to review the record developed to date and expects to address possible inadequacies through subsequent proceedings that propose reforms, as warranted, related to these topics.

A number of the elements of the *Transmission NOPR*, if adopted as part of a final rule, would result in some significant changes to how the region's transmission needs are identified, solutions are evaluated and selected, and costs recovered and allocated. A more fulsome high-level summary from NEPOOL Counsel of the *Transmission NOPR* was distributed to, and was reviewed with, the Transmission Committee.

Comments. Following a number of requests for extensions of time, comments on the *Transmission NOPR* were due August 17, 2022.[151] 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. There was no substantive activity in this proceeding since the last Report.

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[152] 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* were due November 17, 2022.[153] Seven sets of comments were filed by: Dominion, ACPA/SEIA, EEI, Liquid Energy

[151] 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.

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

[153] 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.

Pipeline Assoc., RESA, PG&E/SDG&E, C. Pechman. There was no activity in this proceeding since the last Report. This matter is 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,[154] 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[155] 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,[156] 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;[157] (ii) failing to adequately monitor the right-of-way at the site of the Tuscarawas River HDD operation; and (iii) improperly disposing of inadvertently released drilling mud that was contaminated with diesel fuel and hydraulic oil. The FERC directed Respondents to show why they should not be assessed civil penalties in the amount of ***$40 million***.

On March 21, 2022, Respondents answered and denied the allegations in the *Rover/ETP CPCN Show Cause Order*. On April 20, 2022, OE Staff answered Respondents' March 21 answer. On May 13, Respondents submitted a surreply, reinforcing their position that "there is no factual or legal basis to hold either [Respondent] liable for the intentional wrongdoing of others that is alleged in the Staff Report." The FERC denied Respondents' request for rehearing of the FERC's January 21, 2022 designation notice.[158] This matter is pending before the FERC.

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[154] 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.

[155] *Rover Pipeline, LLC, and Energy Transfer Partners, L.P.,* 177 FERC ¶ 61,182 (Dec. 16, 2021) ("*Rover/ETP Tuscarawas River HDD Show Cause Order*").

[156] *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").

[157] 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.

[158] *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.

- **BP (IN13-15)**

On December 17, 2020, the FERC issued *Opinion 549-A*,[159] a 159-page decision addressing arguments raised on rehearing requested of *Opinion 549.*[160] *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.[161] 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.[162]

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[163] 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.[164]

The FERC also directed TGPNA to show cause why it should not be required to disgorge unjust profits of ***$9.18 million***, plus interest; TGPNA, Tran and Hall to show cause why they should not be assessed civil penalties (TGPNA - ***$213.6 million***; Hall - ***$1 million*** (jointly and severally with TGPNA); and Tran - ***$2 million*** (jointly and severally with TGPNA)). In addition, the FERC directed TGPNA's parent company, Total, S.A. ("Total"), and TGPNA's affiliate, Total Gas & Power, Ltd. ("TGPL"), to show cause why they should not be held liable for TGPNA's, Hall's, and Tran's conduct, and be held jointly and severally liable for their disgorgement and civil penalties based on Total's and TGPL's significant control and authority over TGPNA's daily operations. Respondents filed their

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

[160] *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*")).

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

[162] *Id*. at P 319.

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

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

answer on July 12, 2016. OE Staff replied to Respondents' answer on September 23, 2016. Respondents answered OE's September 23 answer on January 17, 2017, and OE Staff responded to that answer on January 27, 2017.

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.[165] 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***.[166]

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.[167] 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.

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

[166] *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).

[167] *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,[168] and that effectively halted construction of the NECEC Project,[169] 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).

XVI. Federal Courts

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

- ***2nd Revised Narragansett LSA Orders*** **(22-1161, 22-1108) (consolidated)**
  Underlying FERC *Proceeding*: ER22-707[170]
  Petitioner: Green Development
  Status: Briefing Completed; Oral Argument Scheduled for March 20, 2023

On June 15, 2022, Green Development petitioned the DC Circuit for review of the FERC's *2nd Revised Narragansett LSA Orders*.[171] Since the last Report, briefing was completed with Petitioner's Reply Brief filed on January 9, 2023; Joint Appendix, January 17, 2023; New England Power's (Intervenor for Respondent FERC) Final Brief, January 27, 2023; and Green Development's Final Brief and Reply Brief, January 31, 2023. On January 23,

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[168] 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?"

[169] 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.

[170] *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*".

[171] 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.

2023, the Court scheduled oral argument in this matter for ***March 20, 2023*** (with the composition of the argument panel to be revealed approximately 30 days prior to the date of oral argument).

- **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,[172] -013[173] -017[174]
  Petitioners: Mystic, CT Parties,[175] MA AG, ENECOS
  Status: Being Held in Abeyance; Motions to Govern Future Proceedings Due Apr 24, 2023

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 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***.

[172] *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).

[173] *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).

[174] *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*).

[175] In this appeal, "CT Parties" are the CT PURA CT PURA, Connecticut Department of Energy and Environmental Protection ("CT DEEP"), and the CT OCC.

- ***CASPR* (20-1333, 21-1031) (consolidated)****
  Underlying FERC Proceeding: ER18-619[176]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF
  Status: Being Held in Abeyance (until March 1, 2024)

As previously reported, the Sierra Club, NRDC, RENEW Northeast, and CLF petitioned the DC Circuit Court of Appeals on August 31, 2020 for review of the FERC's order accepting ISO-NE's CASPR revisions and the FERC's subsequent *CASPR Allegheny Order*. Appearances, docketing statements, a statement of issues to be raised, and a statement of intent to utilize deferred joint appendix were filed. A motion by the FERC to dismiss the case was dismissed as moot by the Court, referred to the merits panel (Judges Pillard, Katsas and Walker), and is to be addressed by the parties in their briefs.

Petitioners have moved to hold this matter in abeyance three times. The Court has granted each request. The most recent request was submitted on July 22, 2022 (third abeyance request) and moved the Court to hold this matter in abeyance until March 1, 2024, the date on which the elimination of MOPR is to be implemented, with motions to govern due 30 days thereafter. The Court granted the third abeyance request on July 25, 2022.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[177]
  Petitioners: TOs' (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[178] 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*[179] decision. On September 22, 2020, the FERC submitted an unopposed motion to hold this proceeding in abeyance for four months to allow for the Commission to "a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the Commission." On October 2, 2020, the Court granted the FERC's motion, and directed the parties to file motions to govern future proceedings in this case by February 2, 2021. On January 25, 2021, the FERC requested that the Court continue to hold this petition for review in abeyance for an additional three months, with parties to file motions to govern future proceedings at the end of that period. The FERC requested continued abeyance because of its intention to issue a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the FERC. Petitioners consented to the requested abeyance. On February 11, 2021, the Court issued an order that that this case remain in abeyance pending further order of the court. On April 21, 2021, the FERC filed an unopposed motion for continued abeyance of this case *because* the Commission intends to issue a future order on Petitioners' request for rehearing of the challenged Order Rejecting Compliance Filing, and because the remand proceeding in which the challenged order was issued remains ongoing.

On May 4, 2021, the Court ordered that this case remain in abeyance pending further order of the Court, directing the FERC to file a status report by September 1, 2021 and at 120-day intervals thereafter. The parties were directed to file motions to govern future proceedings in this case within 30 days of the completion of agency proceedings. 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 December 6, 2022.

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

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

[178] 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.

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

Other Federal Court Activity of Interest

- ***Northern* Access *Project (22-1233)***
  Underlying FERC Proceeding: *CP15-115*[180]
  Petitioners: Sierra Club
  Status: Filing of Initial Submissions Underway

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,[181] 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; Remaining submissions include: Petitioner's Reply Brief (March 14, 2023); Joint Deferred Appendix (March 21, 2023); and Final Briefs (April 4, 2023).

- ***Order 872* (20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[182]
  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*.[183] Briefing is complete and oral argument was held March 8, 2022 before Judges Nguyen, Miller and Bumatay. This matter remains pending before the Court.

- **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[184]
  Petitioners: LS Power, Algonquin, INGA
  Status: Cases 22-1146/47 Deconsolidated and Briefing Schedule Set; Remaining Cases (21-1115 et al.) Being Held in Abeyance Pending Disposition of 22-1146/47

On May 3, 2021, Algonquin petitioned the DC Circuit Court of Appeals for review of the *Briefing Order* and the *April 19 Notice of Denial of Rehearings by Operation of Law*. Appearances, docketing statements and a statement of issues were due and filed June 4, 2021. Also on June 4, 2021, the FERC filed an unopposed motion to hold this proceeding in temporary abeyance, until August 2, 2021, including the fling of the certified index to the record, because "the May 3 petition for review no longer reflects the [FERC]'s latest determination in this matter." The Court granted the first abeyance motion. On November 15, 2021, the Court granted a third abeyance motion by the FERC, directing the parties to file motions to govern future proceedings by January 31, 2022. On January 31, 2022, Algonquin and INGA asked the Court to extend the abeyance by an additional 120 days (to May 31,

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[180] *National Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 179 FERC ¶ 61,226 (June 29, 2022) ("*Northern Access Project Add'l Extension Order*").

[181] *Corpus Christi Liquefaction Stage III, LLC*, 181 FERC ¶ 61,033 (Oct. 14, 2022).

[182] *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).

[183] *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.

[184] *Briefing Order*; *April 19 Notice of Denial of Rehearings by Operation of Law.*

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. Since the last Report, Petitioners filed their Joint Reply Brief on February 16, 2023. The Deferred Joint Appendix is due ***March 2, 2023;*** Final Briefs, ***March 9, 2023***. The date of oral argument and the composition of the merits panel will be provided at a later date.

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