David T. Doot
Secretary

April 29, 2021

VIA ELECTRONIC MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of May 6, 2021 NEPOOL Participants Committee Teleconference Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the May meeting of the Participants Committee will be held **via teleconference on *Thursday*, May 6, 2021, at 10:00 a.m.** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/. The dial-in number, to be used only by those who otherwise attend NEPOOL meetings and their approved guests, is **866-803-2146; Passcode: 7169224.** To join WebEx, click this link and enter the event password **nepool**.

For your information, the May 6 meeting will be recorded. NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, consumer advocates that are not members, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those in attendance or participating 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.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the draft minutes of the March 24 and April 1, 2021 Participants Committee meetings. The draft preliminary minutes of those meetings, marked to show changes from the drafts circulated with the initial notice, are included with this supplemental notice and posted with the meeting materials.

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

3. To receive an ISO Chief Executive Officer report.

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

5. To receive an ISO update on the 2021 Annual Work Plan. Materials regarding the updated 2021 Annual Work Plan will be circulated and posted in advance of the meeting.

6. To consider and take action, as appropriate, on proposed changes to the Financial Assurance Policy related to Non-Commercial Capacity trading financial assurance. Background materials and a draft resolution are included with this supplemental notice and posted with the meeting materials.

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
   - Joint Nominating Committee
   - Others

9. Administrative matters.

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

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held via teleconference beginning at 10:00 a.m. on Wednesday, March 24, 2021. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the teleconference meeting.

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

ISO-PROPOSED MODIFICATIONS TO PREVIOUSLY-CONSIDERED UPDATES TO FCA16 CONE, NET CONE AND PPR VALUES

Mr. Cavanaugh began by turning to Ms. Mariah Winkler, Markets Committee Chair, who provided an overview of the ISO's memo on the updates to the Cost of New Entry (CONE), Net CONE, and Performance Payment Rate (PPR), as circulated in advance of the meeting.

Following this overview, the following main motion was duly made and seconded:

> RESOLVED, that the Participants Committee approves the Tariff changes to CONE, Net CONE, and the PPR from those values previously considered at its December 3, 2020 meeting, as proposed by ISO-NE, all as contained in the materials provided to this Committee for this meeting, together with such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

Mr. Cavanaugh then introduced Mr. Mark Karl to discuss the issues concerning the CONE reference unit's siting in New London County, Connecticut, which was proposed by the ISO's consultant. On the ISO's behalf, he acknowledged the siting error. Mr. Karl noted that the ISO agreed with the consultant's new recommendation on how to reconcile the issue of the generic CONE reference unit being within two miles of the Algonquin gas transmission mainline by moving the reference unit location from New London County to Tolland County. Other than

the difference in the counties' tax rates, Mr. Karl further noted that the ISO believed that there would be no additional cost impacts with this move. In referencing a map the ISO requested to be circulated earlier that morning, Mr. Karl identified a "yellow cloud site" in Tolland County the consultant selected as a representative location that meets the criteria the ISO used for the CONE reference unit, which the ISO did not visit because it is meant to be a generic location for the reference unit. He further noted that the corresponding CONE, Net CONE and PPR value changes as a result of the site re-location had been included in the materials provided by the ISO, which would also be included in their response to the FERC's deficiency notice (Deficiency Notice).

In response to questions and comments regarding concerns with the process to consider the changes, the timing of the materials provided by the ISO, and the absence of the consultants during the meeting for comments, Mr. Karl noted that the consultants were not available for this meeting and Mr. Chris Hamlen, ISO Counsel, noted that the ISO was under an obligation to respond to the Deficiency Notice within 30 days. Mr. Karl further noted that the information included in the addendum circulated that morning was documentation of the presentation that took place at the March 19, 2021 Markets Committee meeting and would serve as part of the ISO's response to the Deficiency Notice.

In response to concerns with the overall process for selecting the CONE reference unit location and whether that location was chosen to match the same elevation selected in the original selection, Mr. Karl noted there were other potential locations in the area with slightly different elevations. He clarified that the ISO did not seek a desired outcome in the CONE unit's siting. He explained that, early in the process, the ISO had evaluated another site, in New Hampshire, and that the ISO considered likely retirements, which may have been part of the

rationale for picking a site in Connecticut. Further, when addressing concerns with additional costs that may be incurred with siting the CONE reference unit in Tolland County (e.g., interconnection and storm water permitting) and with the selected location being within a flood plain and agriculturally zoned areas, Mr. Karl indicated that the CONE reference unit site was not intended to be a specific site location, noting that, were an alternate nearby location to be chosen, the impact of the change in elevation would be *de minimis*. He further noted that the "yellow cloud," as referenced on the map in the meeting materials, was a generic location and was not intended to provide a specific location for the reference unit. In response to a question about industrial zoning choices and how zoning challenges may be addressed, Mr. Karl noted that it would be the developers, when developing a specific site, that would consider the trade-offs that may need to be addressed during a siting process, such as re-zoning or changing the location of the unit.

Mr. Karl then turned to Mr. Hamlen to clarify the filing process and how it ~~relates~~would relate to the sixteenth Forward Capacity Auction (FCA16). Mr. Hamlen indicated that the ~~deficiency~~ISO's response to the Deficiency Notice would be submitted on March 30 and would include answers to the FERC's questions, as well as an explanation of the reasons behind the changes in CONE/Net CONE/PPR values and the resulting impacts. He also noted that the ISO's response would include an addendum from Concentric Energy Advisors, Inc. (CEA) and the map, as presented by the ISO, that includes the "yellow cloud" as a generic location for a CONE reference unit. The ISO intended to request a 60-day effective date so not to impact the FCA16 schedule.

In addition, Mr. Hamlen responded to a question about the site selection process by noting that the November CEA draft report included the use of the Algonquin gas transmission

mainline and that the ISO did not realize the inconsistency with the two-mile gas interconnection, as originally raised by NEPGA, until the ISO prepared to respond to the Deficiency Notice. When asked about how the ISO planned to respond to the issue of gas availability on the mainline and what information the ISO's consultants analyzed, Messrs. Karl and Hamlen referenced disagreement between the consultants, i.e., CEA/Mott MacDonald and Levitan, on this issue, which would be addressed in ~~the~~its deficiency response. Finally, in response to overall concerns raised by various stakeholders about the entirety of the process, Mr. Karl acknowledged the need for an overall review and assessment of the process.

Following further discussion on the ISO-proposed modifications to previously-considered updates to FCA16 CONE, Net CONE and PPR values, the Committee considered and did not approve the motion to support the ISO's proposed modifications. The motion failed with a 45.09% Vote in favor (Generation Sector – 0%; Transmission Sector – 16.7%; Supplier Sector – 0%; AR Sector – 0%; Publicly Owned Entity Sector – 16.7%; End User Sector – 11.69%; and Provisional Members – 0%). (*See* Vote 1 on Attachment 2.)

TARIFF REVISIONS TO PROVIDE ADDITIONAL FLEXIBILITY FOR DE-LIST BIDS FOR FCA16

Mr. Cavanaugh then turned to Ms. Winkler, who provided an overview on the Tariff revisions, as circulated in advance of the meeting.

Following this overview, the following motion was duly made and seconded:

> RESOLVED, that the Participants Committee approves revisions to Section III.13 of the Tariff to permit increased flexibility for adjusting/withdrawing Retirement De-List Bids, Permanent De-List Bids, and substitution auction test prices for FCA16, as recommended by the Markets Committee at its March 19 meeting, together with such further non-substantive changes as the Chair and Vice-Chair of the MC may approve.

In response to a question about De-List Bid submission timing, Mr. Hamlen acknowledged the issue of a possible FERC response to the filing of proposed rule changes after submission of De-List Bids. He stated that providing additional flexibility was an appropriate step because the De-List Bids were conditional and, given the conditional nature of those bids, providing flexibility at this point would not be in his view a violation of the filed rate doctrine.

The motion was then voted and passed unanimously with abstentions noted by FirstLight, Marco DM Holdings, Kleen, Calpine, CPV, Jericho, Deepwater Wind, PSEG, and Mr. Kuser's alternate.

MODIFICATIONS TO NEPOOL'S PREVIOUSLY-APPROVED SET OF ORTPS AND RELATED TARIFF REVISIONS

Ms. Winkler provided an overview of the proposed revisions to the Offer Review Trigger Prices (ORTP) to become effective for use in FCA16.

Following this overview, the following main motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports amending its previously-approved ORTP values and related Tariff revisions, as recommended by the Markets Committee at its March 19, 2021 meeting and as circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

In response to a question about the filing timeline, Mr. Hamlen clarified that the filing would not be submitted before the end of the month but would be submitted as soon as possible thereafter and was intended to be effective as early as possible in June.

With the opportunity to comment, a member noted the belief by the Participant he represented that the Internal Market Monitor (IMM) should be permitted to look at any new supply offers that the IMM reasonably believed could be uncompetitive. Thus, he noted the

Participant's opposition the NEPOOL ORTPs because, according to that Participant, denying the IMM the opportunity to review offers would inappropriately undermine the independence of the IMM and the integrity of the process.

Although no amendment was offered due to the abbreviated process, NEPGA's representative noted that it was NEPGA's position that, as explained in analysis conducted by its consultants regarding the Investment Tax Credit, there were- misapplications of an inflation value and the equity debt ratio in the model used to calculate ORTPs. As such, NEPGA suggested that the recommendation offered by its consultant should be used for the applicable ORTPs (not just the solar ORTP as the ISO proposed) in both the ISO and NEPOOL set of proposed ORTP values. In response, Ms. Deborah Cooke from the ISO noted that one such recommendation identified by NEPGA's consultants pertaining to the discounted cash flow model was applied to all ORTPs but only the solar ORTP was impacted. Lastly, to clarify, it was noted that the main motion currently at hand, which was recommended by the Markets Committee, included the ORTP correction across all technologies.

The motion was then voted and passed with a 72.50% Vote in favor (Generation Sector – 3.34%; Transmission Sector – 16.68%; Supplier Sector – 6.07%; AR Sector – 12.96%; Publicly Owned Entity Sector – 16.68%; End User Sector – 16.68%; and Provisional Members – 0.09%). (*See* Vote 2 on Attachment 2.)

ISO'S MODIFIED ORTP PROPOSAL

At the request of the ISO, the Committee considered and did not approve the motion to support the ISO's proposed modified ORTP proposal as circulated to this Committee in advance of the meeting. Participants, who planned to support the ISO's proposal, noted their concerns

with calculations included in the proposal, including those raised by NEGPA regarding the tax advantage financing. Separately, a Participant offered its support for the ISO's proposal because it favored the IMM ~~should be~~being afforded the latitude to review offers the IMM deems necessary. Those opposing the ISO's proposal noted the fundamental difference between the ISO's model with how projects are actually financed, as well as shortcomings in the way in which the ISO's proposal reflected the current market of the newer clean technologies. They cited, by way of example, the model's understatement of cost of capital and overstatement of tax benefits. The ISO was encouraged to review further the financing and tax credits elements.

The motion to support the ISO's modified ORTP proposal was then voted and failed to pass with 19.04% Vote in favor (Generation Sector – 7.41%; Transmission Sector – 0%; Supplier Sector – 9.27%; AR Sector – 2.36%; Publicly Owned Entity Sector – 0%; End User Sector – 0%; and Provisional Members – 0%). (*See* Vote 3 on Attachment 2.)

There being no further business, the meeting adjourned at 1:48 p.m.

Respectfully submitted,

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David Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN MARCH 24, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User			Bruce Ho
Advanced Energy Economy	Fuels Industry Participant	Caitlin Marquis		
American PowerNet Management	Supplier			Michael Macrae
Anbaric Development Partners LLC	Provisional			Francis Pullaro
AR Large Renewable Generation (RG) Group Member	AR-RG	Alex Worsley		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell		
AR Small RG Group Member	AR-RG	Erik Abend		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
Associated Industries of Massachusetts (AIM)	End User			Roger Borghesani
AVANGRID: CMP/UI	Transmission		Alan Trotta	
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Borrego Solar Systems Inc.	AR-DG	Liz Delaney		Sarah Bresolin
Boylston Municipal Light Department	Publicly Owned Entity		Brian Thomson	
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity			Dave Cavanaugh
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Calpine Energy Services, LP	Supplier	Brett Kruse		Bill Fowler
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield		
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		
Conservation Law Foundation (CLF)	End User	Phelps Turner		
Consolidated Edison Energy, Inc.	Supplier	Norman Mah		
CPV Towantic, LLC (CPV)	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Deepwater Wind Block Island	Generation			Abby Krich
Dominion Energy Generation Mktg	Generation	Mike Purdie	Weezie Nuara	
DTE Energy Trading, Inc.	Supplier			José Rotger
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		Bill Fowler
Emera Energy Services	Supplier			Bill Fowler
Enel X North America, Inc.	AR-LR	Michael Macrae		
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Environmental Defense Fund	End User	Jolette Westbrook		
Eversource Energy	Transmission	James Daly	Dave Burnham	Vandan Divatia; Dave Erichetti
Exelon Generation Company	Supplier	Steve Kirk	Bill Fowler	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger		
Generation Group Member	Generation	Dennis Duffy	Abby Krich	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Great River Hydro	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned Entity		Brian Thomson	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	Louis Guilbault	Bob Stein	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN MARCH 24, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Harvard Dedicated Energy Limited	End User			Doug Hurley
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity	John Coyle	Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Holyoke Gas & Electric Department	Publicly Owned Entity		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Ipswich Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Jericho Power LLC (Jericho)	AR-RG	Mark Spencer	Nancy Chafetz	Herb Healy; Marji Philips
Kleen Energy Systems, LLC	Generation			Tom Kaslow
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 Killgoar	
Maine Public Advocate's Office	End User			Jason Frost
Mansfield Municipal Electric Department	Publicly Owned Entity		Brian Thomson	
Maple Energy LLC	AR-LR			Doug Hurley
Marble River, LLC	Supplier	John Brodbeck		Abby Krich
Marblehead Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Marco DM Holdings	Generation			Tom Kaslow
Mass. Attorney General's Office (MA AG)	End User	Tina Belew		
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Brian Thomson		
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Michael Kuser	End User		Jason York	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
National Grid	Transmission		Tim Martin	
Natural Resources Defense Council	End User	Bruce Ho		
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski		Brian. Forshaw; Dave Cavanaugh; Brian Thomson
New Hampshire Office of Consumer Advocate (NHOCA)	End User			Jason Frost
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Power Marketing LLC	Generation		Pete Fuller	
Onward Energy (Blue Sky West)	AR-RG			Abby Krich
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Peabody Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PowerOptions, Inc.	End User			Jason Frost
Princeton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PSEG Energy Resources & Trade LLC	Supplier		Eric Stallings	
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Brian Thomson	
Shell Energy North America (US), L.P.	Supplier	Matt Picardi		
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Brian Thomson	
South Hadley Electric Light Department	Publicly Owned Entity		Brian Thomson	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN MARCH 24, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Sterling Municipal Electric Light Department	Publicly Owned Entity		Brian Thomson	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Pete Fuller
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
The Energy Consortium	End User	Roger Borghesani		
Union of Concerned Scientists	End User		Francis Pullaro	
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny		
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Brian Thomson	
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	Jim Ginnetti

ATTACHMENT 2

VOTES TAKEN AT
MARCH 24, 2021 PARTICIPANTS COMMITTEE MEETING

TOTAL

Sector/Group	Vote 1	Vote 2	Vote 3
GENERATION	0.00	3.34	7.41
TRANSMISSION	16.70	16.68	0.00
SUPPLIER	0.00	~~6.06~~6.07	9.27
ALTERNATIVE RESOURCES	0.00	12.96	2.36
PUBLICLY OWNED ENTITY	16.70	16.68	0.00
END USER	11.69	16.68	0.00
PROVISIONAL MEMBERS	0.00	0.09	0.00
% IN FAVOR	**45.09**	**72.50**	**19.04**

GENERATION SECTOR

Participant Name	Vote 1	Vote 2	Vote 3
CPV Towantic, LLC	O	O	F
Deepwater Wind Block Island	A	F	O
Dominion Energy Generation Mktg	O	O	O
FirstLight Power Management, LLC	O	O	F
Generation Group Member	A	F	O
Kleen Energy Systems, LLC	O	O	A
Marco DM Holdings, LLC	O	O	O
Nautilus Power, LLC	O	O	F
NextEra Energy Resources, LLC	O	O	F
NRG Power Marketing, LLC	O	O	O
IN FAVOR (F)	0	2	4
OPPOSED (O)	8	8	5
TOTAL VOTES	8	10	9
ABSTENTIONS (A)	2	0	1

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote 1	Vote 2	Vote 3
Renewable Generation Sub-Sector			
ENGIE Energy Marketing NA, Inc.	A	F	O
Great River Hydro, LLC	O	O	F
Jericho Power LLC	O	O	O
Onward Energy	A	F	O
Wheelabrator/Macquarie	O	O	F
Large RG Group Member	A	F	O
Small RG Group Member	A	F	O
Distributed Gen. Sub-Sector			
Borrego Solar Systems Inc.	A	F	O
CLEAResult Consulting, Inc.	A	F	O
Sunrun Inc.	A	F	O
Load Response Sub-Sector			
Enel X North America, Inc.	A	F	O
Maple Energy	O	F	O
Vermont Energy Investment Corp.	O	F	O
Small LR Group Member	O	F	O
IN FAVOR (F)	0	11	2
OPPOSED	6	3	12
TOTAL VOTES	6	14	14
ABSTENTIONS (A)	8	0	0

TRANSMISSION SECTOR

Participant Name	Vote 1	Vote 2	Vote 3
Avangrid (CMP/UI)	F	F	O
Eversource Energy	F	F	O
National Grid	F	F	A
IN FAVOR (F)	3	3	0
OPPOSED	0	0	2
TOTAL VOTES	3	3	2
ABSTENTIONS (A)	0	0	1

SUPPLIER SECTOR

Participant Name	Vote 1	Vote 2	Vote 3
American PowerNet Management, LP	A	F	O
BP Energy Company	A	A	A
Brookfield Renewable Trading & Mktg	O	O	F
Calpine Energy Services, LP	O	O	F
Castleton Comm. Merchant Trading	O	O	F
Cross-Sound Cable Company	A	A	A
DTE Energy Trading, Inc.	A	A	A
Clearway Power Marketing LLC	A	F	O
Dynegy Marketing and Trade, LLC	O	O	A
Emera Energy Companies	O	O	A
Exelon Generation Company	O	A	A
Galt Power, Inc.	A	A	A
H.Q. Energy Services (U.S.) Inc.	O	O	F
LIPA	A	A	A
Marble River, LLC	A	F	O
Mercuria Energy America, Inc	A	A	A
PSEG Energy Resources & Trade	O	O	F
Shell Energy North America (US) LP	A	F	O
IN FAVOR (F)	0	4	5
OPPOSED	8	7	4
TOTAL VOTES	8	11	9
ABSTENTIONS (A)	10	7	9

ATTACHMENT 2

VOTES TAKEN AT
MARCH 24, 2021 PARTICIPANTS COMMITTEE MEETING

END USER SECTOR

Participant Name	Vote 1	Vote 2	Vote 3
Acadia Center	F	F	O
Associated Industries of Mass.	F	F	O
Conservation Law Foundation	F	F	O
Environmental Defense Fund	F	F	O
Harvard Dedicated Energy Limited	A	F	O
High Liner Foods (USA) Inc.	A	F	O
Michael Kuser	A	A	A
Maine Public Advocate Office	O	F	O
Mass. Attorney General's Office	F	F	O
Natural Resources Defense Council	F	F	O
NH Office of Consumer Advocate	O	F	O
PowerOptions, Inc.	O	F	O
The Energy Consortium	F	F	O
Union of Concerned Scientists	A	F	O
IN FAVOR (F)	7	13	0
OPPOSED	3	0	13
TOTAL VOTES	10	13	13
ABSTENTIONS (A)	4	1	1

PUBLICLY OWNED ENTITY SECTOR

Participant Name	Vote 1	Vote 2	Vote 3
Ashburnham Municipal Light Plant	F	F	O
Belmont Municipal Light Dept.	F	F	O
Block Island Utility District	F	F	O
Boylston Municipal Light Dept.	F	F	O
Braintree Electric Light Dept.	F	F	O
Chester Municipal Light Dept.	F	F	O
Chicopee Municipal Lighting Plant	F	F	O
Concord Municipal Light Plant	F	F	O
Conn. Mun. Electric Energy Coop.	F	F	O
Danvers Electric Division	F	F	O
Georgetown Municipal Light Dept.	F	F	O
Groton Electric Light Dept.	F	F	O
Groveland Electric Light Dept.	F	F	O
Hingham Municipal Lighting Plant	F	F	O
Holden Municipal Light Dept.	F	F	O
Holyoke Gas & Electric Dept.	F	F	O
Hull Municipal Lighting Plant	F	F	O
Ipswich Municipal Light Dept.	F	F	O
Littleton (MA) Electric Light Dept.	F	F	O
Mansfield Municipal Electric Dept.	F	F	O

PUBLICLY OWNED ENTITY SECTOR (cont.)

Participant Name	Vote 1	Vote 2	Vote 3
Marblehead Municipal Light Dept.	F	F	O
Mass. Mun. Wholesale Electric Co.	F	F	O
Mass. Bay Transportation Authority	F	F	O
Merrimac Municipal Light Dept.	F	F	O
Middleborough Gas and Elec. Dept.	F	F	O
Middleton Municipal Electric Dept.	F	F	O
New Hampshire Electric Cooperative	F	F	O
North Attleborough Electric Dept.	F	F	O
Norwood Municipal Light Dept.	F	F	O
Pascoag Utility District	F	F	O
Paxton Municipal Light Dept.	F	F	O
Peabody Municipal Light Plant	F	F	O
Princeton Municipal Light Dept.	F	F	O
Reading Municipal Light Dept.	F	F	O
Rowley Municipal Lighting Plant	F	F	O
Russell Municipal Light Dept.	F	F	O
Shrewsbury's Elec. & Cable Ops.	F	F	O
South Hadley Electric Light Dept.	F	F	O
Sterling Municipal Electric Light Dept.	F	F	O
Stowe (VT) Electric Dept.	F	F	O
Taunton Municipal Lighting Plant	F	F	O
Templeton Municipal Lighting Plant	F	F	O
VT Public Power Supply Authority	F	F	O
Village of Hyde Park (VT) Elec. Dept.	F	F	O
Wakefield Mun. Gas and Light Dept.	F	F	O
Wallingford, Town of	F	F	O
Wellesley Municipal Light Plant	F	F	O
West Boylston Mun. Lighting Plant	F	F	O
Westfield Gas & Electric Light Dept.	F	F	O
IN FAVOR (F)	49	49	0
OPPOSED	0	0	49
TOTAL VOTES	49	49	49
ABSTENTIONS (A)	0	0	0

PROVISIONAL MEMBERS

Participant Name	Vote 1	Vote 2	Vote 3
Anbaric Development Partners, LLC	A	F	F
IN FAVOR (F)	0	1	1
OPPOSED	0	0	0
TOTAL VOTES	0	1	1
ABSTENTIONS (A)	1	0	0

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held via teleconference beginning at 10:00 a.m. on Thursday, April 1, 2021. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the teleconference meeting.

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

APPROVAL OF MARCH 4, 2021 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the March 4, 2021 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of the March 4, 2021 meeting were unanimously approved as circulated, with an abstention by Mr. Michael Kuser's alternate noted.

CONSENT AGENDA

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

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), began by reporting on his participation at the FERC's March 23 Technical Conference on Resource Adequacy, where he addressed: (i) the importance of the evolution of all major market components to support a clean energy transition, (ii) the commitment of ISO-NE, together with NYISO and PJM, to capacity

markets as the foundational reliability service to supplement the energy market and; (iii) the increasing value that should be recognized in the markets during the clean energy transition of ancillary services markets for operating and energy reserves and other important temporal characteristics (e.g. ramping and inertia), which the ISO ~~sees~~viewed as vital complements to energy and capacity markets. He noted that appropriate incremental market changes ~~can~~could be anticipated to produce additional revenues, and that the design and approval process ~~will be~~would be challenging and time consuming. He emphasized that, as indicated by the FERC, the Minimum Offer Price Rule (MOPR) was no longer sustainable and an alternative solution must be developed. He expressed his concern that the FERC expects the Eastern RTOs to propose acceptable alternatives to MOPR within the next year or so or risk the initiation of a Federal Power Action (FPA) Section 206 proceeding. He described the ISO's strong preference that an acceptable alternative be worked as fully as possible within the stakeholder process and reported that the ISO would work to develop a high level scope and schedule by June/July 2021. He anticipated further details and insight ~~will~~would be gained from the FERC's ~~yet-to-be-scheduled~~yet-to-be-scheduled New England-focused technical conference. He stated that identifying an alternative to MOPR that could be filed with the FERC on a voluntary basis under FPA Section 205 would be the highest priority for the ISO in the second half of 2021 and would likely impact the timing for completion of other deliverables.

Responding to questions about how the effort to identify an alternative to MOPR would affect the ISO's current project schedule and future grid discussions, Mr. van Welie explained that while alternative future grid frameworks, such as the net carbon pricing and forward clean energy market (FCEM) constructs, might in the long term provide solutions for the elimination of the MOPR, the region would not have enough time to define and implement such solutions in

the timeframe he believed the FERC ~~expects~~expected. He opined that there would be similar timing issues with defining and implementing ancillary services solutions to address the concerns that led to the establishment of the MOPR. He suggested that the issues would need to be addressed in sequence, with an acceptable alternative to address the concerns that led to the MOPR identified first, with efforts continuing thereafter to define further market reforms to advance clean energy objectives and reposition the markets for ancillary services.

ISO COO REPORT

Dr. Chadalavada, ISO Chief Operating Officer (COO), referred the Committee to his April report, which included an analysis of the prior winter and had been circulated and posted in advance of the meeting. He noted that the data in the report was through March 24, 2021, unless otherwise noted. The report highlighted: (i) Energy Market value for March 2021 was $324 million, down $435 million from the updated February 2021 value of $759 million and up $152 million from March 2020; (ii) March 2021 average natural gas prices were 55% lower than February average prices; (iii) the average Real-Time Hub Locational Marginal Prices (LMPs) for March ($37.10/MWh) were 48% lower than February averages; (iv) average March 2021 natural gas prices and Real-Time Hub LMPs over the period were up 144% and 121%, respectively, from March 2020 average prices; (v) the average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 99% during March (down from 99.1% in February), with the minimum value for the month (94.3%) on March 6; and (vi) the Daily Net Commitment Period Compensation (NCPC) payments for March totaled $1.8 million, which was down $0.8 million from February 2021 and up $0.1 million from March 2020. March NCPC payments, which were 0.6% of total Energy Market value, were comprised of (a) $1.7 million in first contingency payments (down $0.6 million from February); (b) $131,000 in second contingency

payments (down $12,000 from February), and (c) zero in distribution payments (down $259,000 from February).

Turning to operational highlights from March, Dr. Chadalavada reported that the ISO had missed its load forecast metric in March, which he attributed to highly variable temperatures during the month. He noted that overnight loads on March 20 and 21 were higher than midday loads those days, which he reported were deviations in amounts greater than previously experienced~~ deviations~~. He predicted there would be many more days to come when midday loads ~~were~~would be lower than overnight loads.

Regarding transmission outages, Dr. Chadalavada reported on a planned May 3-29 outage on Line 373 (Deerfield-Scobie) for the replacement of certain structures. He also identified a planned outage for Line Q169, from April 14-16, which the ISO expected would result in first contingency uplift given the impact of that Line on dispatch for the Northeast Massachusetts Load Zone.

In response to a question regarding second contingency payments, he explained that on some cold days, with modest loads, high west-to-east transfers, and constrained interface limits, the ISO needed to dispatch units out of merit order to cover for contingencies on the east side of New England. That dispatch produced uplift costs.

Turning to the aggregate winter load curve (December through February), Dr. Chadalavada noted the increased midday loads and peaks resulting from work at home arrangements during the pandemic. In response to questions, Dr. Chadalavada noted that the ISO continued to evaluate the impact of the pandemic on load averages and how loads might change as pandemic impacts diminish. He said the ISO was also evaluating the impacts of other

factors, such as snowfall on ~~PV~~photovoltaic production which he estimated could be responsible for 20-25% of the load variations experienced over the winter.

REMOVAL OF APPENDIX B FROM MARKET RULE 1 AND DELETION OF ASSOCIATED TARIFF PROVISIONS

Ms. Mariah Winkler, Markets Committee (MC) Chair, provided an overview of the proposal to remove Appendix B from Market Rule 1 (which established procedures and standards by which the ISO could impose sanctions, if subsequently approved by the FERC, for sanctionable conduct) and to make conforming changes to the Tariff reflecting the removal of that Appendix. She reported that, at its March 9, 2021 meeting, the Markets Committee had voted, but had not recommended, the proposed changes.

Following her overview, the following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports removing Appendix B from Market Rule 1 and deleting associated Tariff provisions, as proposed by ISO New England and as circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

Referring to the discussion at the Markets Committee, Participants opposing the removal of Appendix B reiterated concerns with the elimination of Appendix B from the filed rate, without any other guidance provided on conduct that the Internal Market Monitor (IMM) might conclude to be sanctionable. They clarified that they had no objections to the removal of provisions in Appendix B that the ISO concluded were outdated, unclear, or internally inconsistent with other Tariff provisions. They urged the ISO to identify an alternative means for providing such guidance on a going-forward basis.

The motion was then voted and passed with a 60.12% Vote in favor (Generation Sector – 0%; Transmission Sector – 16.70%; Supplier Sector – 10.02%; AR Sector – 0%; Publicly Owned Entity Sector – 16.70%; and End User Sector – 16.70%). (*See* Vote 1 on Attachment 2)

LITIGATION REPORT

Mr. Doot referred the Committee to the March 30 Litigation Report that had been circulated and posted in advance of the meeting. He highlighted the following:

- ***Deficiency Letter Response in Net Cost of New Entry (CONE) proceeding (ER21-787).*** The ISO's responses to the FERC's March 1, 2021 deficiency letter were filed on March 30, 2021. Comments on those responses would be due April 20, 2021.
- ***Exemption of Energy Efficiency Resources from Pay-for-Performance Settlement (ER21-943).*** The FERC issued an order accepting the ISO's filing, effective April 1, 2021.
- ***FCA16 ORTP Jump Ball Filing:*** The filing of alternative Tariff changes to establish Offer Review Trigger Prices (ORTPs) for the sixteenth Forward Capacity Auction (FCA16) was anticipated to be submitted early the following week (on or about April 7, 2021). In response to questions, the ISO indicated that the filing would request an effective date 60 days from the date of filing.

COMMITTEE REPORTS

Markets Committee. Mr. William Fowler, the MC Vice-Chair, reported that the April meeting would be a one-day meeting to be held on April 6, rather than a two-day meeting.

Transmission Committee (TC). Mr. José Rotger, the TC Vice-Chair, reported that the TC was scheduled to meet on April 27. The agenda would likely include a vote on the

Participating Transmission Owners' proposal to address reconstitution of behind-the-meter generation into the Regional Network Load calculation.

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that the RC was scheduled to meet on April 13 and the agenda would include a review of the draft load forecast, with a revised Moody's economic forecast incorporated, to be included in the ISO's 2021 Report of Capacity, Energy, Loads, and Transmission.

Joint MC/RC (Future Grid - Reliability Study). Mr. Stein reported that discussion of the Future Grid Reliability Study would move to the Planning Advisory Committee (PAC), with a first report to be provided at the May PAC meeting. There were no joint MC/RC meetings scheduled at that time.

Budget & Finance Subcommittee. Mr. Thomas Kaslow, the Subcommittee Chair, announced that the next meeting of the Subcommittee was scheduled for April 22. The April 22 agenda would include consideration of exchange clearing of financial transmission rights (FTRs), clarifying changes to Non-Commercial Capacity Trading Financial Assurance and acceleration of FCM settlement and billing.

Joint Nominating Committee (JNC). Mr. Cavanaugh referred the Committee to the summary of the March 25-26 JNC meetings, which had been circulated with the materials for the meeting. He reported that, during the March 25-26 meetings, the JNC reviewed the qualifications of 23 candidates. The ~~Committee~~JNC had ranked the candidates and selected nine for first round interviews to take place April 8, 9 and 16. In addition, the JNC discussed the impact of the age limit, waivable by the JNC, on the potential candidate pool but had decided to table further discussion on the age requirement at that time.

ADMINISTRATIVE MATTERS

With respect to review of the 2021 ISO audit results and audit plans, Mr. Cavanaugh reported that no additional audit requests had been received and the audit plan would proceed as described in his ~~March 4~~February 25, 2021 memo to the Participants Committee included with the materials for the March 4 meeting.

Turning to evolving plans for a return to in-person meetings, Mr. Cavanaugh reported that, subject to further review and evaluation over the summer, the current thinking was to target September for a potential return to in-person committee meetings. He noted that the NPC Summer meeting would be held via WebEx as a regular meeting on June 24. Meetings with the ISO Board would be tentatively scheduled for June 25 and June 28. He noted the need for each Sector to prepare meeting agendas and materials for those meetings with the Board, and identified June 7 as the date for submitting those materials.

Mr. Doot reminded members of the Committee's April 15 Future Grid Pathways working session and of its May 6 meeting.

FEBRUARY EXTREME COLD WEATHER CHALLENGES (ERCOT EXPERIENCE)

Dr. Chadalavada provided an overview of the extreme weather events in Texas as included in the COO presentation circulated with the materials for the meeting. He summarized the conditions experienced by the Electric Reliability Council of Texas (ERCOT), noting temperature deviations that were 37 to 47 degrees Fahrenheit lower than normal. Such conditions were not part of ERCOT's planning ~~and~~. The conditions led to high loads ~~and~~, roughly 50% of ERCOT's 107 gigawatts of installed capacity being unavailable and requiring ERCOT to shed 20 gigawatts of load. Referring to the presentation ERCOT shared with its

stakeholders and included with the materials for this meeting, he noted the extreme differences between the 2021 and 2011 ERCOT load shed events~~ in ERCOT~~.

He then reported that, in response to the Texas experience, the ISO was incorporating in its work plan discussions, evaluations and analyses designed to ensure that lessons learned from the Texas experience could be appropriately incorporated in New England in order to minimize the possibility of similar experiences here. He acknowledged in response to comments New England's reliance on external fuel sources and the need for New England to fully understand and plan for the availability of fuel to generation sources. He reported that the ISO currently was comprehensively reviewing what types of extreme weather and contingencies should be studied, what tools should be used and how outcomes should be quantified in any such study, and how the region should proceed after taking into account all of those factors. He suggested that the studies would initially be conducted using a seven-year time frame, analyzing both current system parameters and parameters emerging from the various future grid models. Responding to a question about how market design ~~can~~could help to protect against such issues, Dr. Chadalavada noted at high level the differences between the New England and ERCOT markets, opining that many aspects of ERCOT's market design that would not work in New England.

At the request of Mr. Cavanaugh, Dr. David Patton, President, Potomac Economics, which is ERCOT's Independent Market Monitor (IMM), provided his perspectives on the issues ERCOT experienced and his recommendations for an overall review and plan for extreme weather events in the future across the country. Dr. Patton first noted from lessons learned how important it was that the system operator have the tools and ability to proactively manage load shed instead of relying on an automated load shed protocol. He opined and members discussed the suggestion that set points for protective devices to shed load during a sustained drop in

frequency were set too low, requiring the system operator to step in to shed load in order to protect equipment before the automated devices did so. He said that the ERCOT transmission and distribution utilities had the ability to rotate outages to only 25-30% of load. As a result, ERCOT was required to shed roughly 30% of the load for extended periods, rather than rotate outages in a way that might have reduced the overall impact on customers. Related, he also noted the importance of separating essential and nonessential circuits to permit rotating outages, and in the case of ERCOT, to reduce the potential for power loss and damage to natural gas facilities, well heads and pipeline equipment, that exacerbated supply challenges.

Dr. Patton recommended that ISOs and RTOs evaluate extreme conditions in both summer and winter, noting the simultaneous, unforecasted movement of load and supply in opposite directions. ~~System~~He recommended further that system operators ~~should~~ undertake to identify when spikes in forced outages might occur based on ambient temperatures, what supply losses will most likely occur, and when and how loads might increase during such times. With that information, ~~they~~system operators would be better prepared to consider actions to lessen system risks.

In response to questions and comments, Dr. Patton opined that ERCOT's issues did not demonstrate that an energy only market is less reliable than a market like New England's with its pay-for-performance (PFP) program. He expressed his view that ~~market participants~~Market Participants do react to strong economic signals during infrequent shortage events and that the challenge is to properly balance how much can be earned during such low probability events against the risks to generators and costs to customers. He opined that many generators will use the ERCOT experiences to support efforts to improve their weatherization protocols.

Continuing the discussion of the markets, Dr. Patton explained that the Texas energy-only structure relies on administrative add-ons in some circumstances to set energy prices. During the weather event, ERCOT held the energy price at $9,000 for 32 hours after the energy shortage was over, erroneously inflating prices and creating large uplift and serious economic problems for many participants. He noted the importance to market operations of having reliable, objective and repeatable market mechanisms to set prices during such events.

He repeated his previously expressed concern, now reinforced by the ERCOT experience, of setting the PFP rate in New England too high. He worried that, even in less severe circumstances than those experienced by ERCOT, an inflated PFP rate could produce economic issues similar to ERCOT and create major economic consequences through settlements. He urged that the rate more accurately reflect the value of lost load which varies based on circumstances and is best sloped.

He then reacted to comments and responded to questions. He emphasized his view that the Texas event was not a resource adequacy issue but rather was a gas supply and weatherization issue. He explained that, in his view, to provide necessary incentives to perform, the PFP rate needs to be known so market participants can develop probabilities and make financially prudent decisions. PFP is a resource adequacy design that depends on shortage of available capacity. Incentive payments are random and unpredictable. He indicated that turbine availability in New England has helped to eliminate reserve shortages and avoid random PFP events. He observed that the ERCOT experiences will impact future decision making, particularly relating to how risk is evaluated, how hedging is done, and how weatherization of resources occurs. He expected that the FERC would consider whether transmission and pipeline owners could be incentivized to enhance the reliability of their systems to serve load.

Reacting to Dr. Patton's observations, Dr. Chadalavada compared the load shedding relays in Texas, which were set to shed at 59.4 Hz, with New England's set points of 59.5 Hz and rapid rate of change in frequency. He explained that, at the 59.5 Hz set point, relays would shed roughly 7.5 percent of load. With relays also calibrated to measure the rate of change in frequency, a rapid rate of change could cause and extra one to three percent of load to be shed even earlier. He acknowledged the importance of stress tests within the markets and agreed with Dr. Patton on the need for a sloped curve for prices in Real-Time during extreme events. He further expressed his desire to continue discussion on this topic. He also reminded members that the PFP in New England included both monthly and annual stop-loss provisions, which resources could account for in their FCM offers. Lastly, he agreed with Dr. Patton about the importance of reviewing and planning for how load shed could play out during various Real-Time scenarios.

There being no further business, the meeting adjourned at 2:00 p.m.

Respectfully submitted,

_____

David Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN APRIL 1, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Actual Energy, Inc.	Supplier		John Driscoll	
Advanced Energy Economy	Fuels Industry Participant	Caitlin Marquis		
American Petroleum Institute	Fuels Industry Participant	Paul Powers		
AR Large Renewable Generation (RG) Group Member	AR-RG	Alex Worsley		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell		
AR Small RG Group Member	AR-RG	Erik Abend		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
AVANGRID: CMP/UI	Transmission		Alan Trotta	
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Borrego Solar Systems Inc.	AR-DG	Liz Delaney		
Boylston Municipal Light Department	Publicly Owned Entity		Brian Thomson	
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity			Dave Cavanaugh
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Calpine Energy Services, LP	Supplier	Brett Kruse		Bill Fowler
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Central Rivers Power	AR-RG		Dan Allegretti	
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield		
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		Dave Thompson	
Conservation Law Foundation (CLF)	End User	Phelps Turner		
Consolidated Edison Energy, Inc.	Supplier	Norman Mah		
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
DC Energy, LLC	Supplier	Bruce Bleiweis		
Dominion Energy Generation Mktg	Generation	Mike Purdie	Weezie Nuara	
DTE Energy Trading, Inc.	Supplier			José Rotger
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		Bill Fowler; Arnie Quinn
Emera Energy Services	Supplier			Bill Fowler
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Englehart CTP (US) LLC	Supplier	Danielle Fazio		
Environmental Defense Fund	End User	Jolette Westbrook		
Eversource Energy	Transmission	James Daly	Dave Burnham	Vandan Divatia
Exelon Generation Company	Supplier		Bill Fowler	
Excelerate Energy LP	Fuels Industry Participant	Gary Ritter		
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger		
Generation Group Member	Generation	Dennis Duffy	Abby Krich	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Great River Hydro	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned Entity		Brian Thomson	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN APRIL 1, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	Louis Guilbault	Bob Stein	
Harvard Dedicated Energy Limited	End User			Erin Camp
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity	John Coyle	Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Holyoke Gas & Electric Department	Publicly Owned Entity		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Industrial Energy Consumer Group	End User	Alan Topalian		
Ipswich Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Jericho Power LLC (Jericho)	AR-RG	Mark Spencer	Nancy Chafetz	Marji Philips
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 Killgoar	
Maine Power LLC	Supplier	Jeff Jones		
Maine Public Advocate's Office	End User	Drew Landry		Erin Camp
Maine Skiing, Inc.	End User	Alan Topalian		
Mansfield Municipal Electric Department	Publicly Owned Entity		Brian Thomson	
Maple Energy LLC	AR-LR		Luke Fishback	Doug Hurley
Marble River, LLC	Supplier	John Brodbeck		
Marblehead Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Mass. Attorney General's Office (MA AG)	End User	Tina Belew		
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Brian Thomson		
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Michael Kuser	End User		Jason York	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
National Grid	Transmission		Tim Martin	
Natural Resources Defense Council	End User	Bruce Ho		
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski		Brian. Forshaw; Dave Cavanaugh; Brian Thomson
New Hampshire Office of Consumer Advocate (NHOCA)	End User		Erin Camp	
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Power Marketing LLC	Generation		Pete Fuller	
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Peabody Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PowerOptions, Inc.	End User			Erin Camp
Princeton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PSEG Energy Resources & Trade LLC	Supplier		Eric Stallings	
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Rodan Energy Solutions (USA) Inc.	Provisional	Aaron Breidenbaugh		
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Brian Thomson	
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Brian Thomson	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN APRIL 1, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
South Hadley Electric Light Department	Publicly Owned Entity		Brian Thomson	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Brian Thomson	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Pete Fuller
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
The Energy Consortium	End User		Mary Smith	
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny		
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori	Karin Stamy	
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley	
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		Brian Thomson	
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	

ATTACHMENT 2

VOTE TAKEN AT
APRIL 1, 2021 PARTICIPANTS COMMITTEE MEETING

TOTAL

Sector/Group	Vote 1
GENERATION	0.00
TRANSMISSION	16.70
SUPPLIER	10.02
ALTERNATIVE RESOURCES	0.00
PUBLICLY OWNED ENTITY	16.70
END USER	16.70
PROVISIONAL MEMBERS	0.00
% IN FAVOR	**60.12**

TRANSMISSION SECTOR

Participant Name	Vote 1
Avangrid (CMP/UI)	F
Eversource Energy	F
National Grid	F
Versant Power	F
IN FAVOR (F)	4
OPPOSED	0
TOTAL VOTES	4
ABSTENTIONS (A)	0

GENERATION SECTOR

Participant Name	Vote 1
CPV Towantic, LLC	A
Dominion Energy Generation Mktg	A
FirstLight Power Management, LLC	A
Generation Group Member	A
Nautilus Power, LLC	O
NextEra Energy Resources, LLC	O
NRG Power Marketing, LLC	O
IN FAVOR (F)	0
OPPOSED (O)	3
TOTAL VOTES	3
ABSTENTIONS (A)	4

SUPPLIER SECTOR

Participant Name	Vote 1
BP Energy Company	F
Brookfield Renewable Trading & Mktg	O
Calpine Energy Services, LP	A
Castleton Comm. Merchant Trading	A
Cross-Sound Cable Company	F
DTE Energy Trading, Inc.	F
Clearway Power Marketing LLC	A
Consolidated Edison Energy, Inc.	A
DC Energy, LLC	A
Dynegy Marketing and Trade, LLC	O
Emera Energy Companies	A
Exelon Generation Company	O
Galt Power, Inc.	F
H.Q. Energy Services (U.S.) Inc.	A
LIPA	A
Maine Power, LLC	F
Marble River, LLC	A
Mercuria Energy America, Inc	F
PSEG Energy Resources & Trade	O
IN FAVOR (F)	6
OPPOSED	4
TOTAL VOTES	10
ABSTENTIONS (A)	9

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote 1
Renewable Generation Sub-Sector	
Central Rivers Power	O
ENGIE Energy Marketing NA, Inc.	A
Great River Hydro, LLC	O
Jericho Power LLC	A
Wheelabrator/Macquarie	O
Large RG Group Member	A
Small RG Group Member	A
Distributed Gen. Sub-Sector	
CLEAResult Consulting, Inc.	A
Sunrun Inc.	A
Load Response Sub-Sector	
Maple Energy	A
Vermont Energy Investment Corp.	A
Small LR Group Member	A
IN FAVOR (F)	0
OPPOSED	3
TOTAL VOTES	3
ABSTENTIONS (A)	9

VOTE TAKEN AT
APRIL 1, 2021 PARTICIPANTS COMMITTEE MEETING
~~PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES~~
~~PARTICIPATING IN MARCH 4, 2021 TELECONFERENCE MEETING~~

END USER SECTOR

Participant Name	Vote 1
Conn. Office of Consumer Counsel	A
Conservation Law Foundation	A
Environmental Defense Fund	A
Harvard Dedicated Energy Limited	A
High Liner Foods (USA) Inc.	F
Industrial Energy Consumer Group	F
Michael Kuser	A
Maine Public Advocate Office	F
Maine Skiing, Inc.	F
Mass. Attorney General's Office	A
Natural Resources Defense Council	A
NH Office of Consumer Advocate	F
PowerOptions, Inc.	A
IN FAVOR (F)	5
OPPOSED	0
TOTAL VOTES	5
ABSTENTIONS (A)	8

PUBLICLY OWNED ENTITY SECTOR

Participant Name	Vote 1
Ashburnham Municipal Light Plant	F
Belmont Municipal Light Dept.	F
Block Island Utility District	F
Boylston Municipal Light Dept.	F
Braintree Electric Light Dept.	F
Chester Municipal Light Dept.	F
Chicopee Municipal Lighting Plant	F
Concord Municipal Light Plant	F
Conn. Mun. Electric Energy Coop.	F
Danvers Electric Division	F
Georgetown Municipal Light Dept.	F
Groton Electric Light Dept.	F
Groveland Electric Light Dept.	F
Hingham Municipal Lighting Plant	F
Holden Municipal Light Dept.	F
Holyoke Gas & Electric Dept.	F
Hull Municipal Lighting Plant	F
Ipswich Municipal Light Dept.	F
Littleton (MA) Electric Light Dept.	F
Littleton (NH) Water & Light Dept.	F
Mansfield Municipal Electric Dept.	F

PUBLICLY OWNED ENTITY SECTOR (cont.)

Participant Name	Vote 1
Marblehead Municipal Light Dept.	F
Mass. Mun. Wholesale Electric Co.	F
Mass. Bay Transportation Authority	F
Merrimac Municipal Light Dept.	F
Middleborough Gas and Elec. Dept.	F
Middleton Municipal Electric Dept.	F
New Hampshire Electric Cooperative	F
North Attleborough Electric Dept.	F
Norwood Municipal Light Dept.	F
Pascoag Utility District	F
Paxton Municipal Light Dept.	F
Peabody Municipal Light Plant	F
Princeton Municipal Light Dept.	F
Reading Municipal Light Dept.	F
Rowley Municipal Lighting Plant	F
Russell Municipal Light Dept.	F
Shrewsbury's Elec. & Cable Ops.	F
South Hadley Electric Light Dept.	F
Sterling Municipal Electric Light Dept.	F
Stowe (VT) Electric Dept.	F
Taunton Municipal Lighting Plant	F
Templeton Municipal Lighting Plant	F
Vermont Electric Cooperative	F
VT Public Power Supply Authority	F
Village of Hyde Park (VT) Elec. Dept.	F
Wakefield Mun. Gas and Light Dept.	F
Wallingford, Town of	F
Wellesley Municipal Light Plant	F
West Boylston Mun. Lighting Plant	F
Westfield Gas & Electric Light Dept.	F
IN FAVOR (F)	51
OPPOSED	0
TOTAL VOTES	51
ABSTENTIONS (A)	0

PROVISIONAL MEMBERS

Participant Name	Vote 1
Rodan Energy Solutions (USA) Inc.	A
IN FAVOR (F)	0
OPPOSED	0
TOTAL VOTES	0
ABSTENTIONS (A)	1

CONSENT AGENDA

Markets Committee (MC)

From the previously-circulated notice of actions of the MC's April 6, 2021 meeting, dated April 6, 2021.[1]

1. **Revisions to OP-9 and Appendix B to OP-9 (Adjusting Actions Taken During Operating Reserve Deficiencies and Minimum Generation Emergencies for CTS Transactions)**

   Support revisions to ISO New England Operating Procedure (OP) No. 9 (Scheduling and Dispatch of External Transactions) (OP-9) and Appendix B to OP-9 (Scheduling Reductions and Curtailments of Real-Time External Transactions), which clarify the order of actions between Coordinated Transaction Scheduling (CTS) and non-CTS transactions and the timing of when actions are taken on CTS transactions in advance of, or during, Operating Reserve Deficiencies and Minimum Generation Emergencies, and other clarifying changes, all as recommended by the MC at its April 6, 2021 meeting, together with such further non-material changes as the Chair and Vice-Chair of the MC may approve.

   The motion to recommend Participants Committee support was approved unanimously with 13 abstentions recorded (Generation (2), Transmission (1), Supplier (6), AR (2), and End User (2)).

Reliability Committee (RC)

From the previously-circulated notice of actions of the RC's April 13, 2021 meeting, dated April 14, 2021.[2]

2. **Revisions to OP-21 (Incorporating Generator Fuel and Emission Survey Into OP-21; Appendix A Retirement)**

   Support revisions to OP-21 (Operational Surveys, Energy Forecasting & Reporting, and Actions During an Energy Emergency), which move, with minor updates, the content from Appendix A into the main body of OP-21 and retire Appendix A, as recommended by the RC at its April 13, 2021 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

   The motion to recommend Participants Committee support was approved unanimously.

3. **Revisions to OP-5 (AMS Timeframe Changes; Clean-up and Clarifications)**

   Support revisions to OP-5 (Resource Maintenance and Outage Scheduling), which include revisions that change from monthly to daily the publication timeframe of the Annual Maintenance Schedule (AMS), conforming AMS changes, removal of obsolete references to annual Capacity Supply Obligation bilateral transactions, and other clarifications, all as recommended by the RC at its April 13, 2021 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

   The motion to recommend Participants Committee support was approved unanimously.

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

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

NEPOOL Participants Committee Report

May 2021

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: March 2021 Energy Market value totaled $372M
  - April 2021 Energy market value was $229M, down $144M from March 2021 and up $69M from April 2020
    - April 2021 natural gas prices over the period were 31% lower than March average values
    - Average RT Hub Locational Marginal Prices ($26.19/MWh) over the period were 22% lower than March averages
      - DA Hub: $26.07/MWh
    - Average April 2021 natural gas prices and RT Hub LMPs over the period were up 43% and 45%, respectively, from April 2020 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 99.8% during April, up from 98.9% during March*
    - The minimum value for the month was 94.6% on Sunday, April 4th

Data through April 28th.

Underlying natural gas data furnished by:

ICE Global markets in clear view

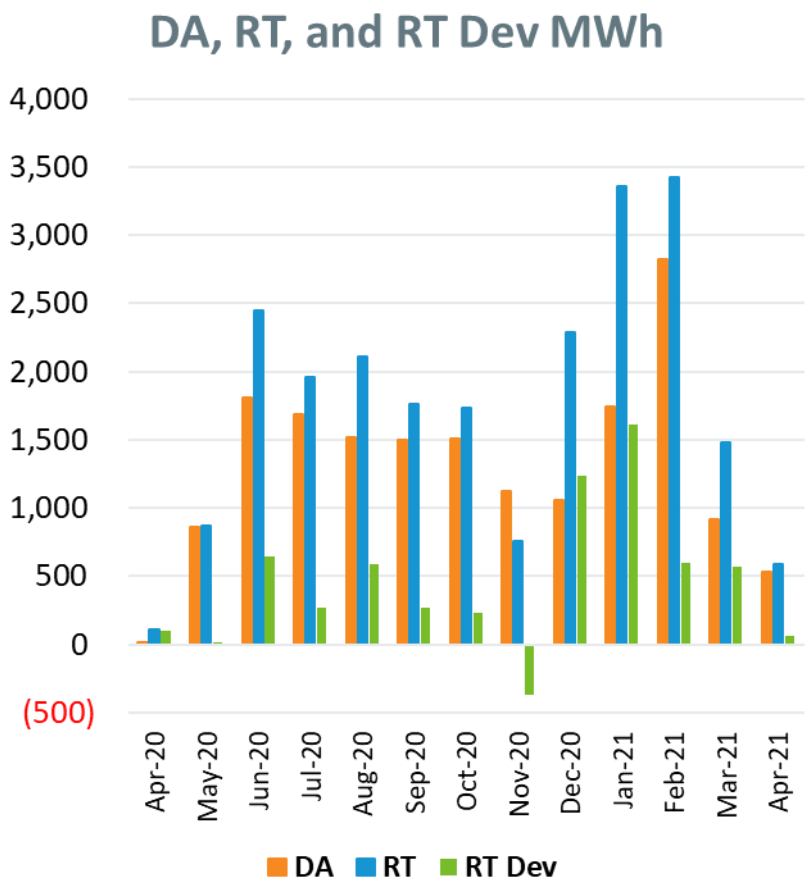
***DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market**

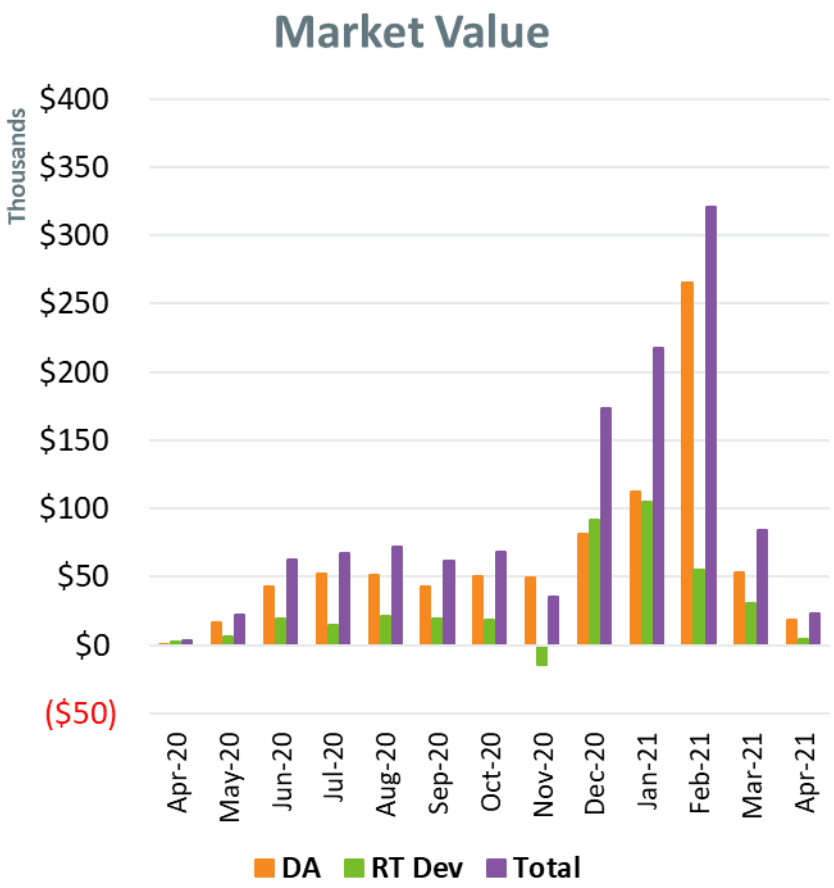
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - April 2021 NCPC payments totaled $2.6M over the period, up $0.4M from March 2021 and up $0.5M from April 2020
    - First Contingency payments totaled $2.6M, up $0.5M from March
      - $2.5M paid to internal resources, up $0.5M from March
        - » $1.5M charged to DALO, $476K to RT Deviations, $532K to RTLO*
      - $56K paid to resources at external locations, up $15K from March
        - » $5K charged to DALO at external locations, $49K to RT Deviations
    - Second Contingency & Voltage payments were both zero
    - Distribution payments were negligible ($11K)
  - NCPC payments over the period as percent of Energy Market value were 1.1%

* NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $191K; Rapid Response Pricing (RRP) Opportunity Cost - $147K; Posturing - $194K; 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 2021 CELT report was posted on April 30 and included the 10-year load forecast
- ICR and Related Values development will commence in May
  - PSPC to meet on May 20 to discuss the load forecast, demand resource availabilities, battery-storage modeling, and capacity zones
- Transmission Planning Clean-Energy Transition Study results are expected in Q2 or Q3
- RSP21 Public Meeting date is set for October 6
  - Venue and format have yet to be decided

Forward Capacity Market (FCM) Highlights

- CCP 12 (2021-2022)
  - Third and final annual reconfiguration auction (ARA3) was held on March 1-3, and results were posted on March 29
- CCP 13 (2022-2023)
  - Second annual reconfiguration auction (ARA2) will be held on August 2-4, and results will be posted no later than September 1
- CCP 14 (2023-2024)
  - First annual reconfiguration auction (ARA1) will be held on June 1-3, and results will be posted no later than July 1
- CCP 15 (2024-2025)
  - Auction results were filed with FERC on February 26, and the filing is pending at FERC

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 16 (2025-2026)
  - FCA 16 will evaluate the same zones as evaluated in FCA 15
    - Potential export-constrained zones: Northern New England and Maine nested inside Northern New England
    - Potential import-constrained zones: Southeast New England and Connecticut
  - Existing capacity values were posted on March 5
  - Retirement and permanent delist bids summary was posted on March 17
  - Show of Interest window closed on April 23
  - ISO has submitted filings addressing the Net CONE deficiency letter and proposing offer-review trigger price (ORTP) values to FERC
    - ISO requested orders from FERC on the Net CONE filing on or before May 29 and for the ORTP values filing on or before June 8
  - ICR and Related Values development will commence in May
    - PSPC to meet on May 20 to discuss the load forecast, demand resource availabilities, battery-storage modeling, and capacity zones

CONE – Cost of New Entry

Load Forecast

- Efforts continue to enhance load forecast models and tools to improve day-ahead and long-term load forecast performance
- Continuing to evaluate the impacts of COVID-19 to the load forecast
- On April 30, as part of the 2021 CELT report, the final 10-year forecast was published

FERC Order 1000

- Qualified Transmission Project Sponsor (QTPS)
  - 25 companies have achieved QTPS status

Competitive Solution Process: Order 1000/Boston 2028 Request for Proposal Lessons Learned

- The ISO began one-on-one discussions with each QTPS that participated in the Boston 2028 RFP where QTPS specific questions regarding their proposals and/or the process can be discussed
- The lessons-learned process, with respect to competitive transmission solutions, was discussed at the October PAC meeting
- Stakeholder feedback was discussed at the 12/16/20 PAC meeting, and initial ISO responses were discussed at the 2/17/21 PAC meeting
- At the 4/14/21 PAC meeting, the ISO provided its plans for the remaining open items
- The ISO anticipates discussing associated Tariff changes at the July TC meeting

Highlights

- The lowest 50/50 and 90/10 Spring Operable Capacity Margins are projected for week beginning May 8, 2021.
- The lowest 50/50 and 90/10 Summer Operable Capacity Margins are projected for week beginning September 11, 2021.

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (2.7°F) Max: 78°F, Min: 29°F Precipitation: 4.29" – Above Normal Normal: 3.62" Snow: 0.01"	Hartford	Temperature: Above Normal (1.8°F) Max: 78°F, Min: 25°F Precipitation: 2.76" - Below Normal Normal: 3.60" Snow: 0.01"

Peak Load:	14,404 MW	April 16, 2021	12:00 (ending)

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

Procedure	Declared	Cancelled	Note
None for April 2021			

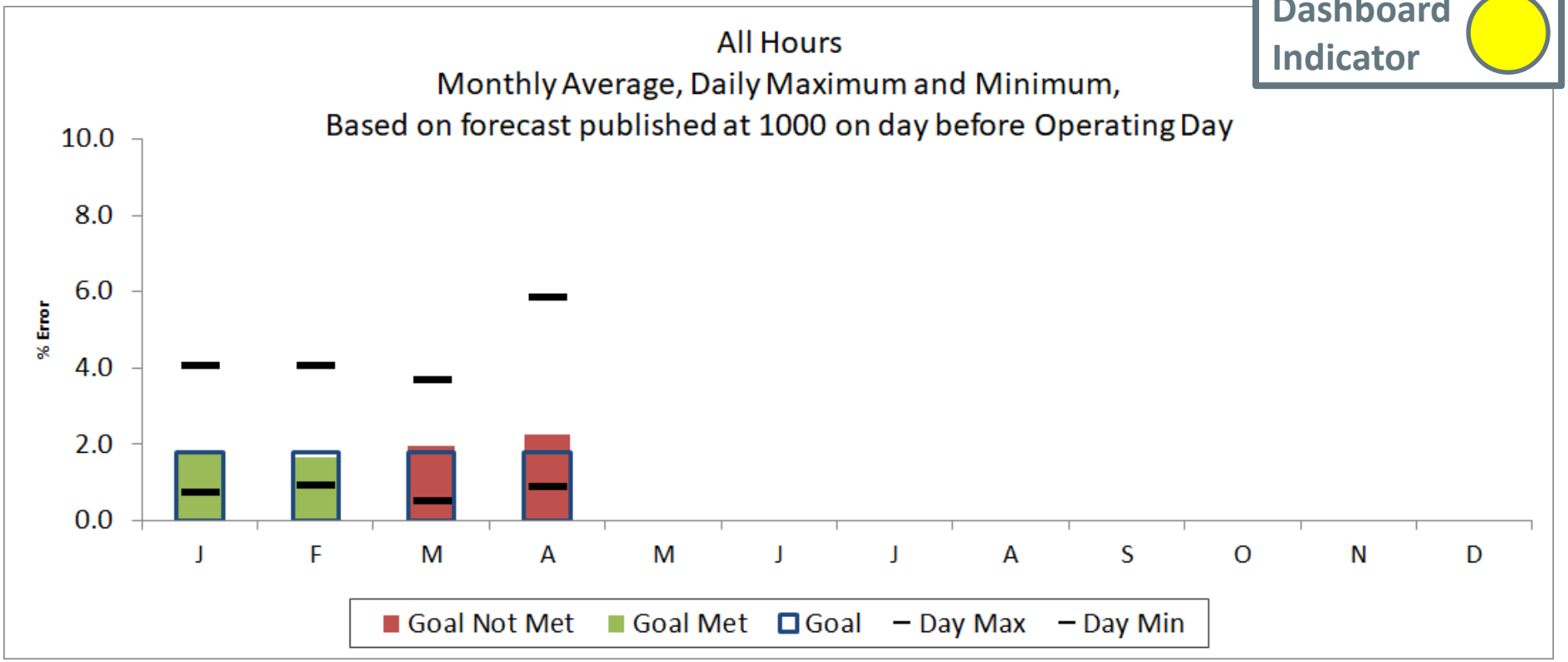
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
4/17	NB	700
4/30	PJM	940

2021 System Operations - Load Forecast Accuracy

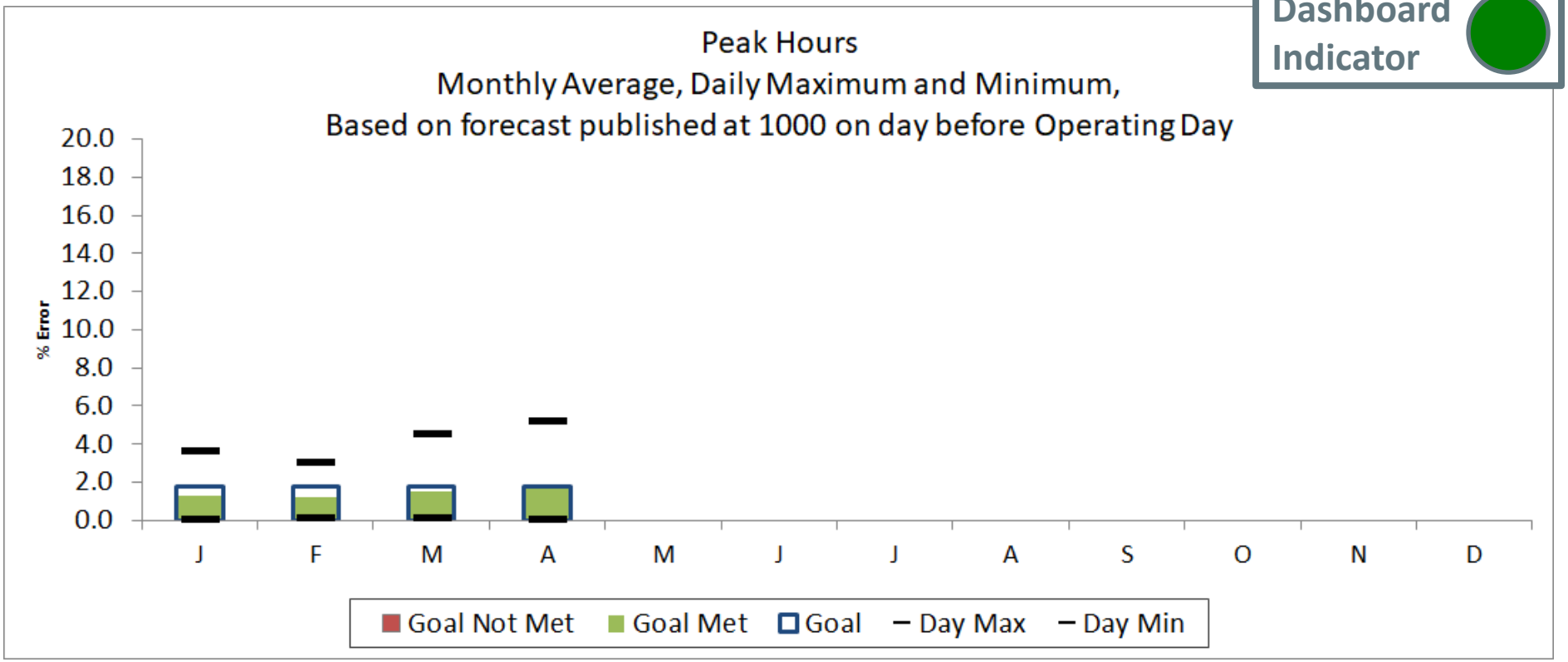
Dashboard Indicator



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.04	4.03	3.67	5.85									5.85
Day Min	0.70	0.92	0.49	0.88									0.49
MAPE	1.72	1.66	1.97	2.24									1.90
Goal	1.80	1.80	1.80	1.80									

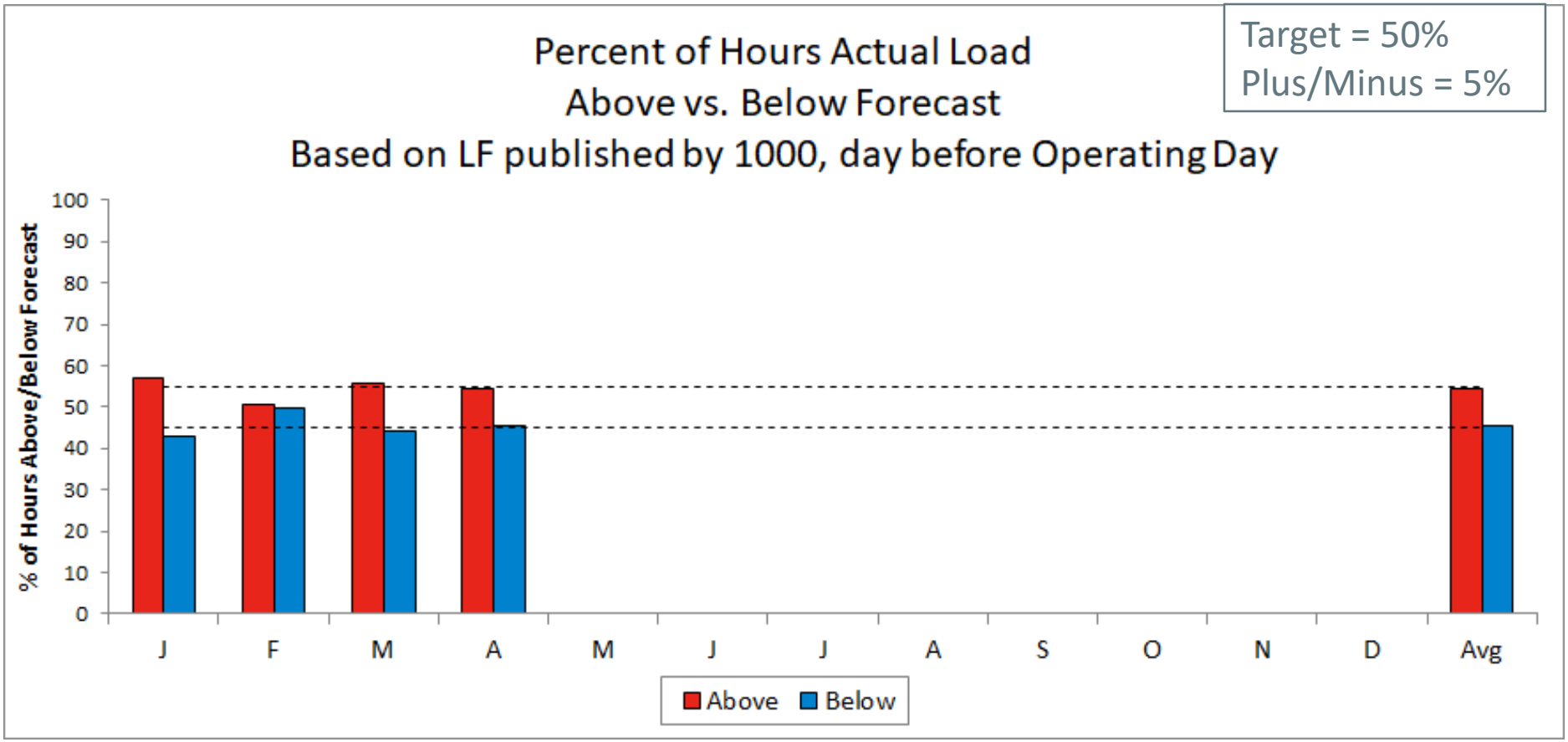
2021 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



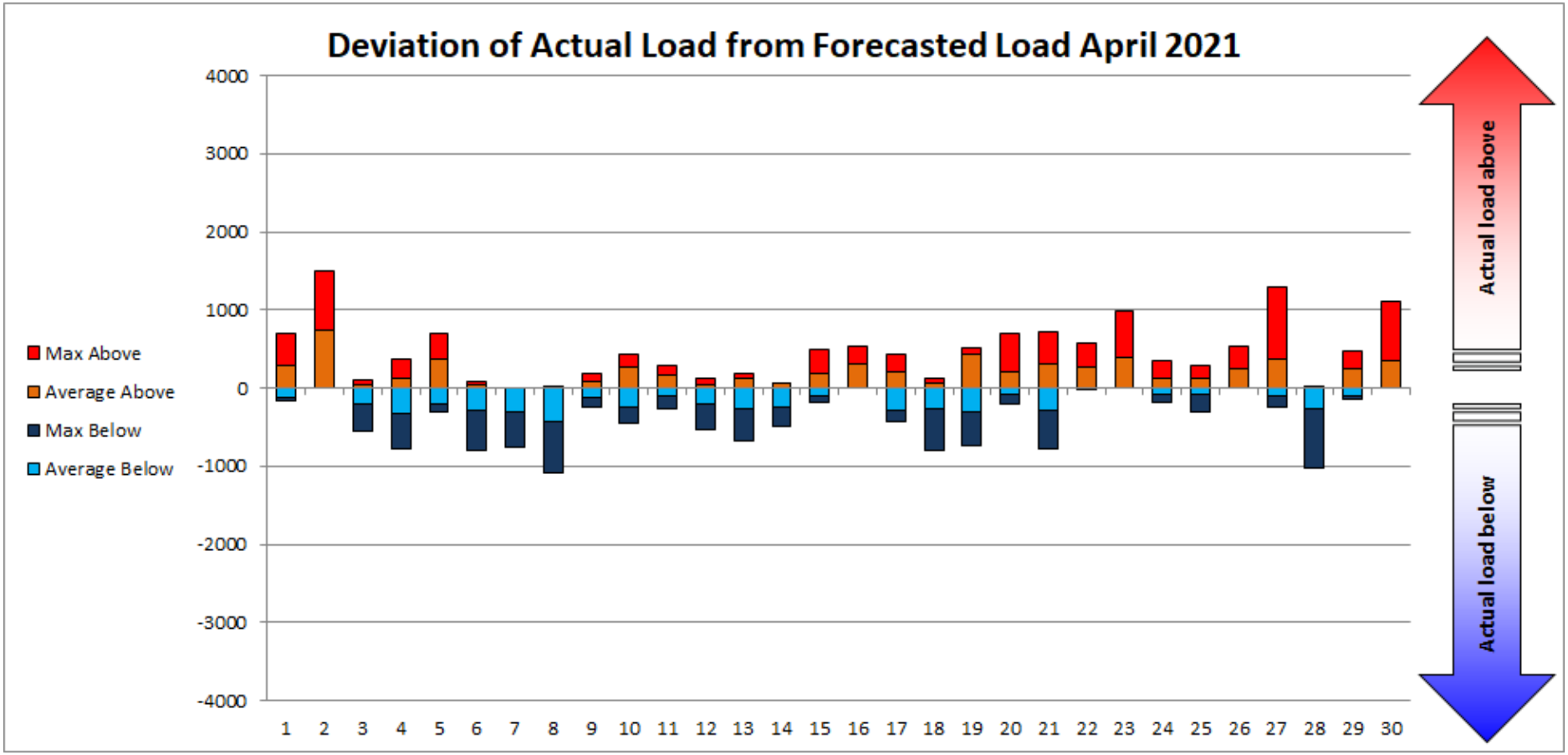
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	3.61	3.03	4.47	5.19									5.19
Day Min	0.02	0.06	0.08	0.03									0.02
MAPE	1.26	1.18	1.48	1.66									1.40
Goal	1.80	1.80	1.80	1.80									

2021 System Operations - Load Forecast Accuracy cont.

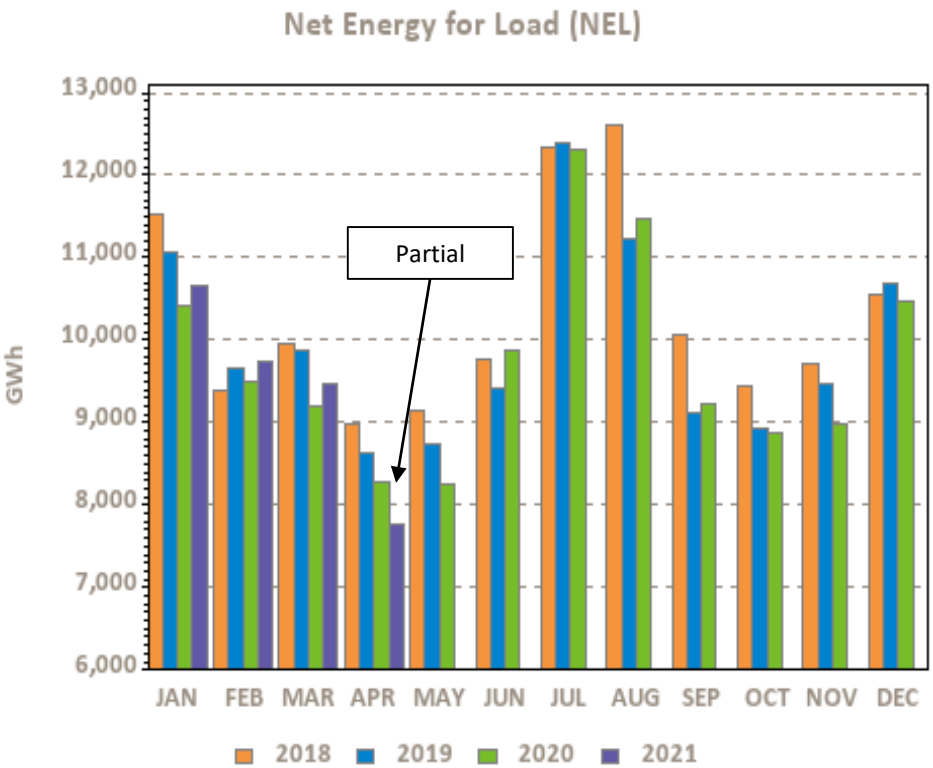


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	57.1	50.4	55.6	54.4									54
Below %	42.9	49.6	44.4	45.6									46
Avg Above	209.5	166.7	185.4	206.1									210
Avg Below	-147.6	-216.4	-188.0	-167.9									-216
Avg All	60	-25	30	40									28

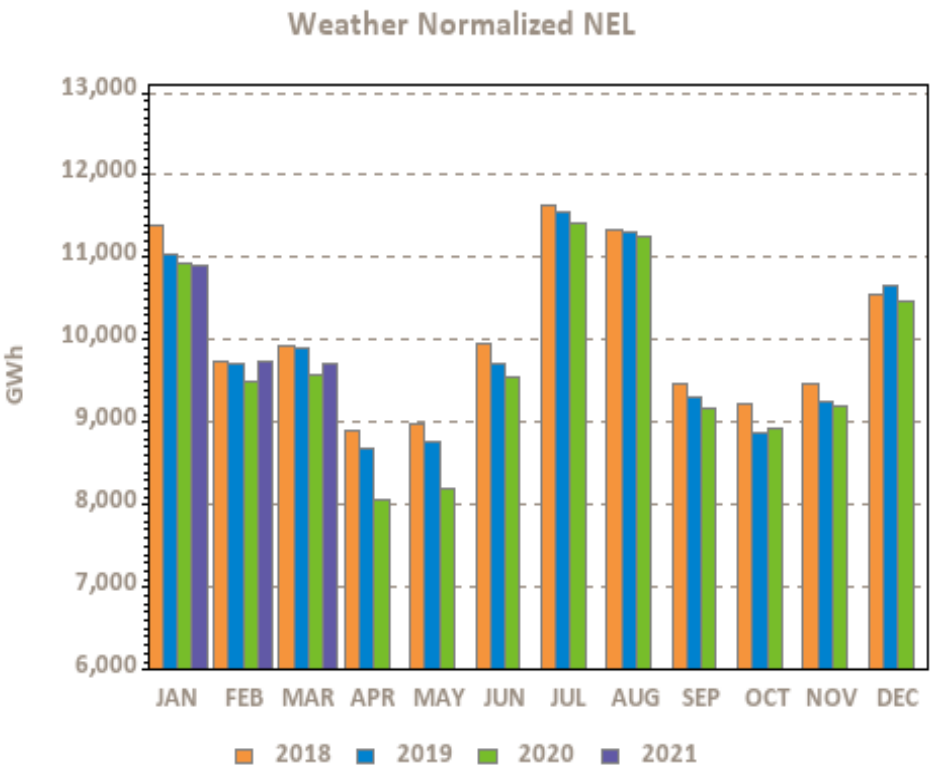
2021 System Operations - Load Forecast Accuracy cont.



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



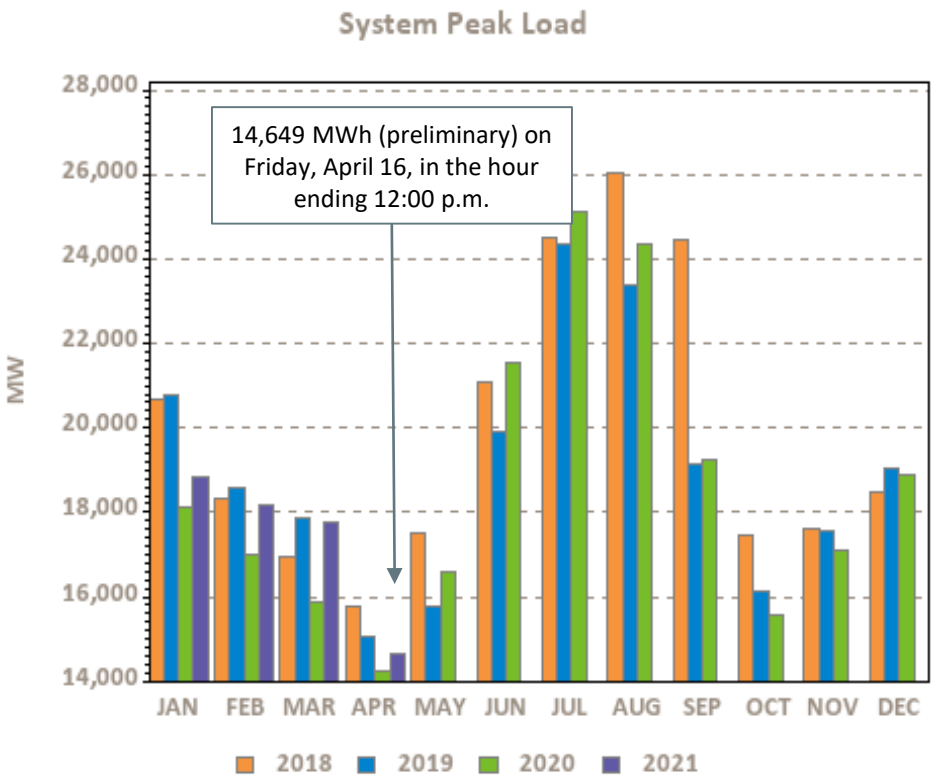
Ann Tot (TWh): 123.5 119.2 116.9 37.6



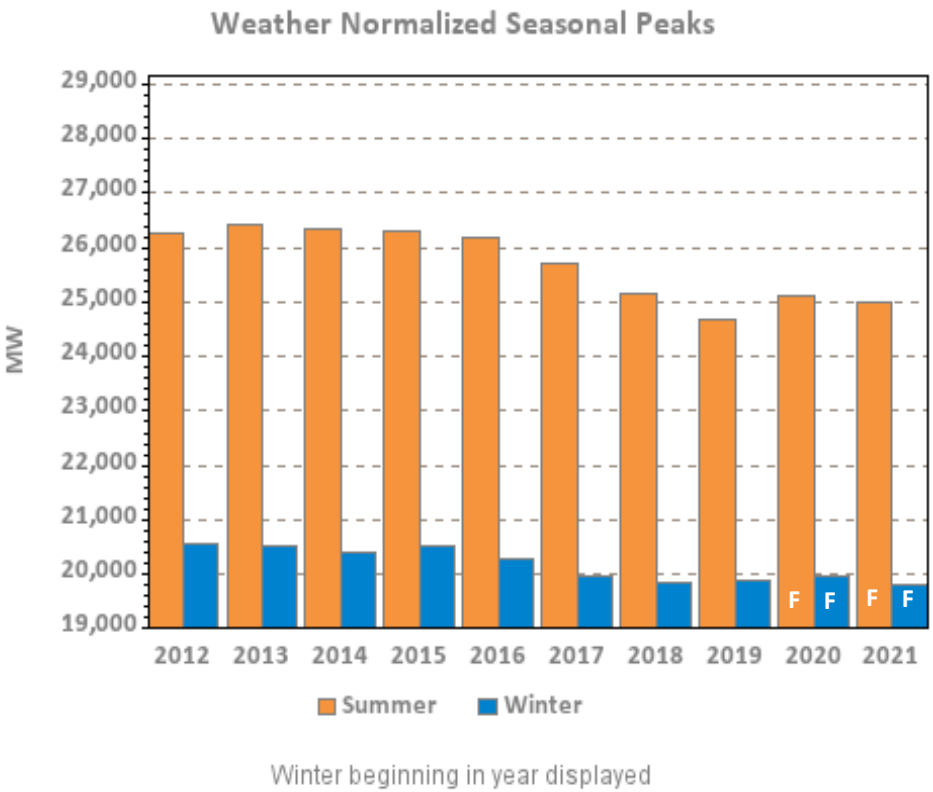
Ann Tot (TWh): 120.6 118.8 116.3 30.4

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 may be reported on a one-month lag.

Monthly Peak Loads and Weather Normalized Seasonal Peak History



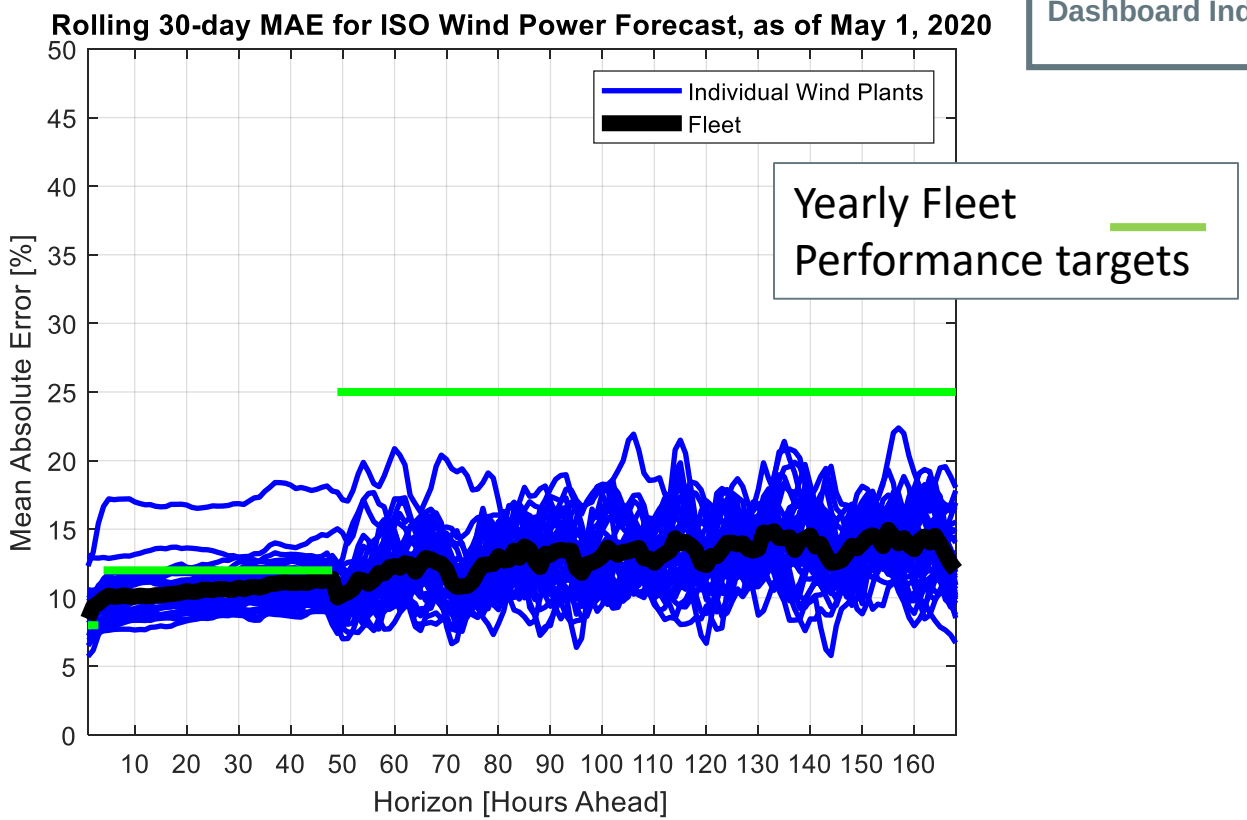
Revenue quality metered value



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

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

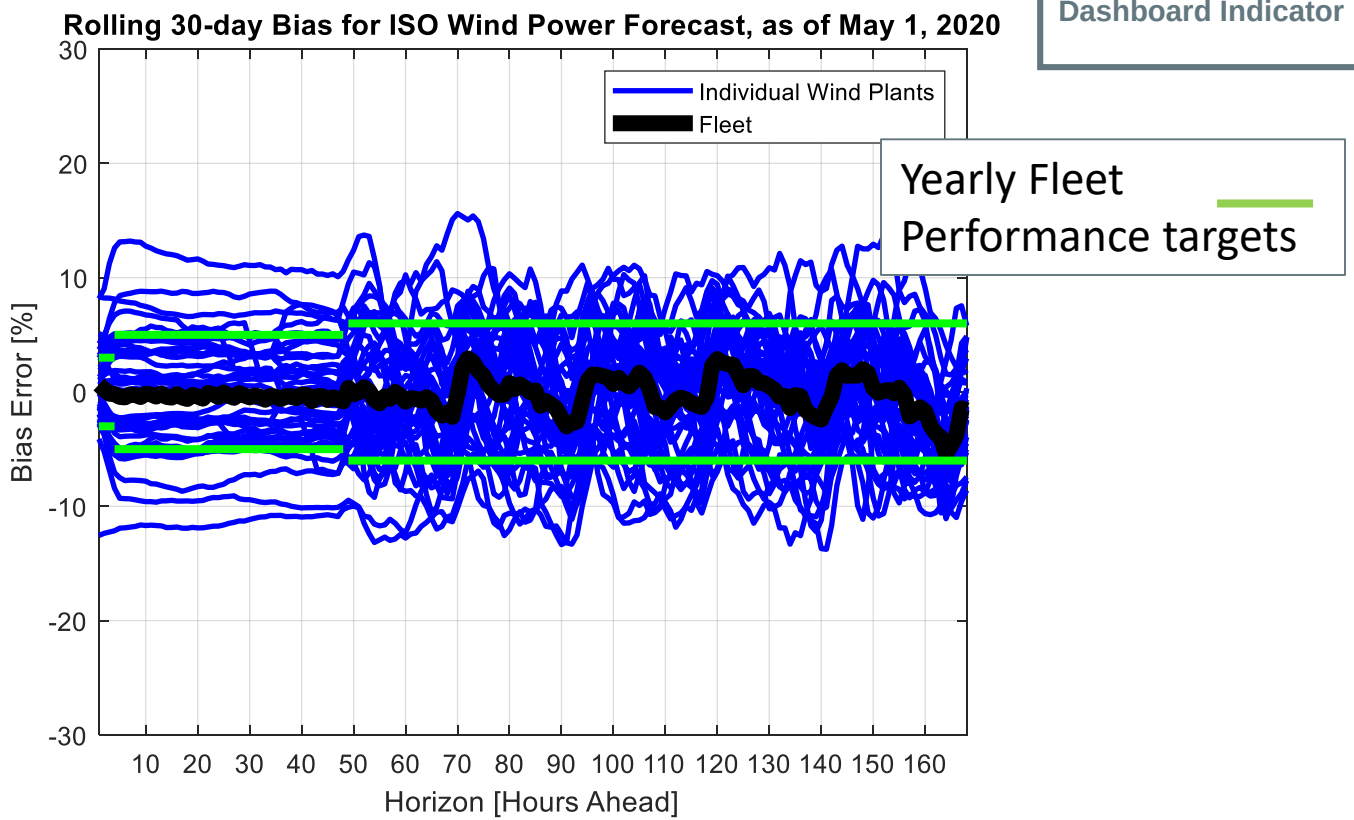
Dashboard Indicator



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-GL forecast is very good compared to industry standards, and monthly MAE is within the yearly performance targets.

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

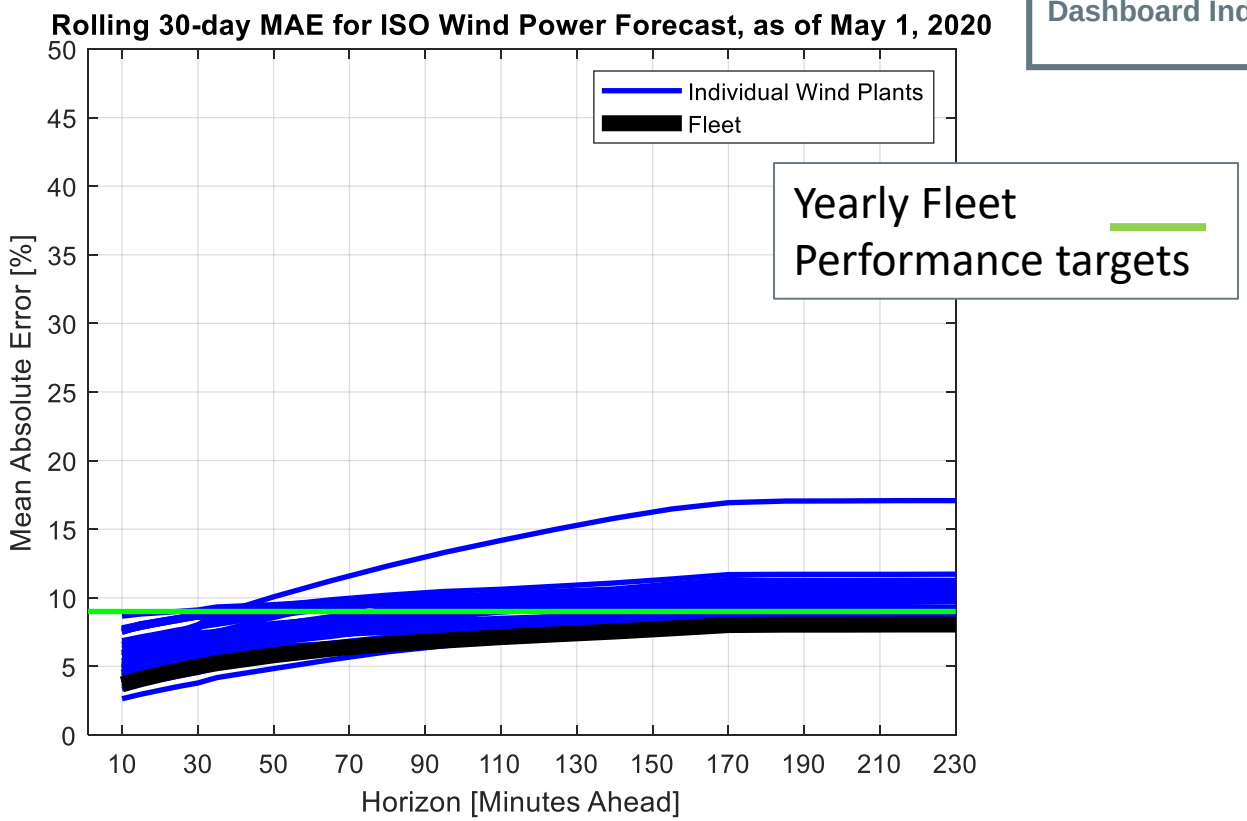
Dashboard Indicator



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

Wind Power Forecast Error Statistics: Short Term Forecast MAE

Dashboard Indicator



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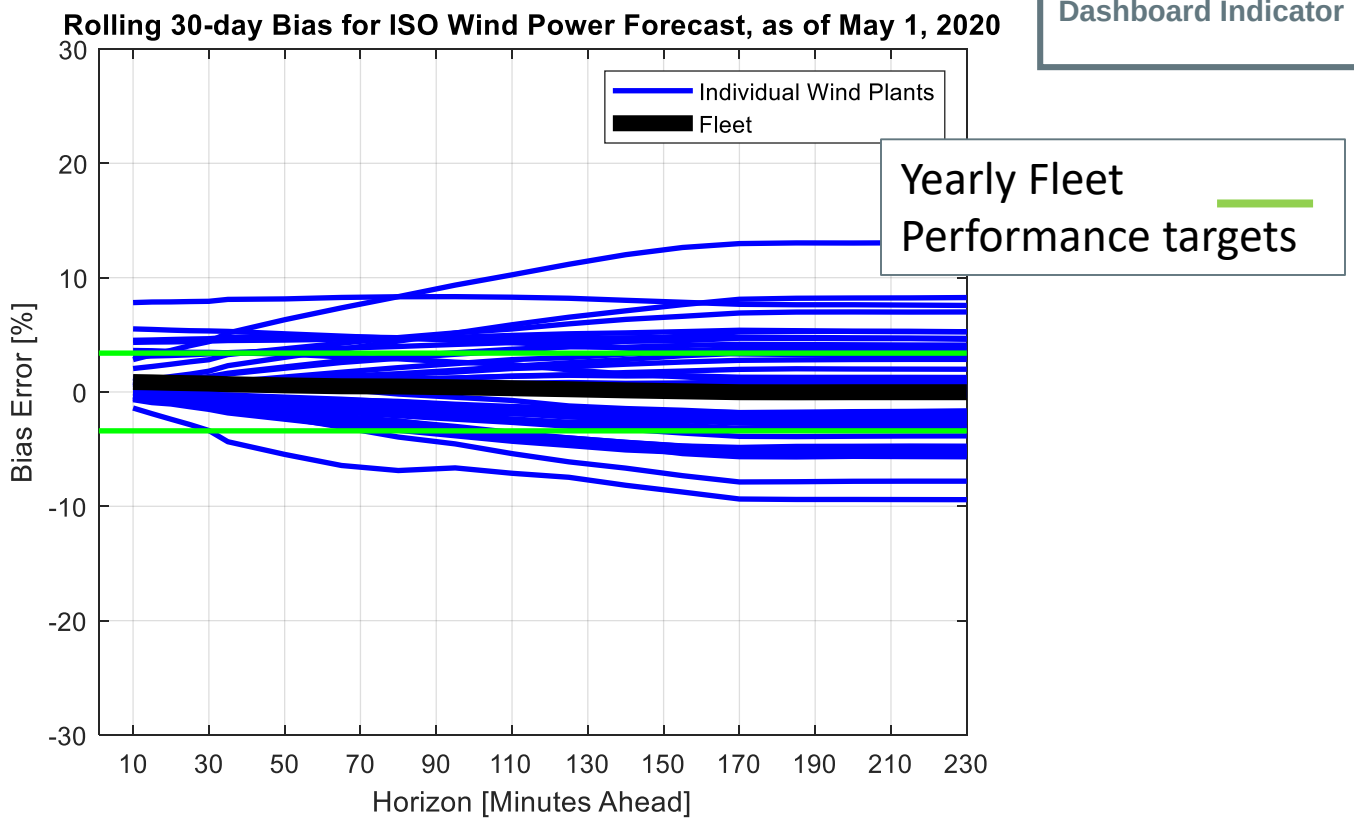
Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator



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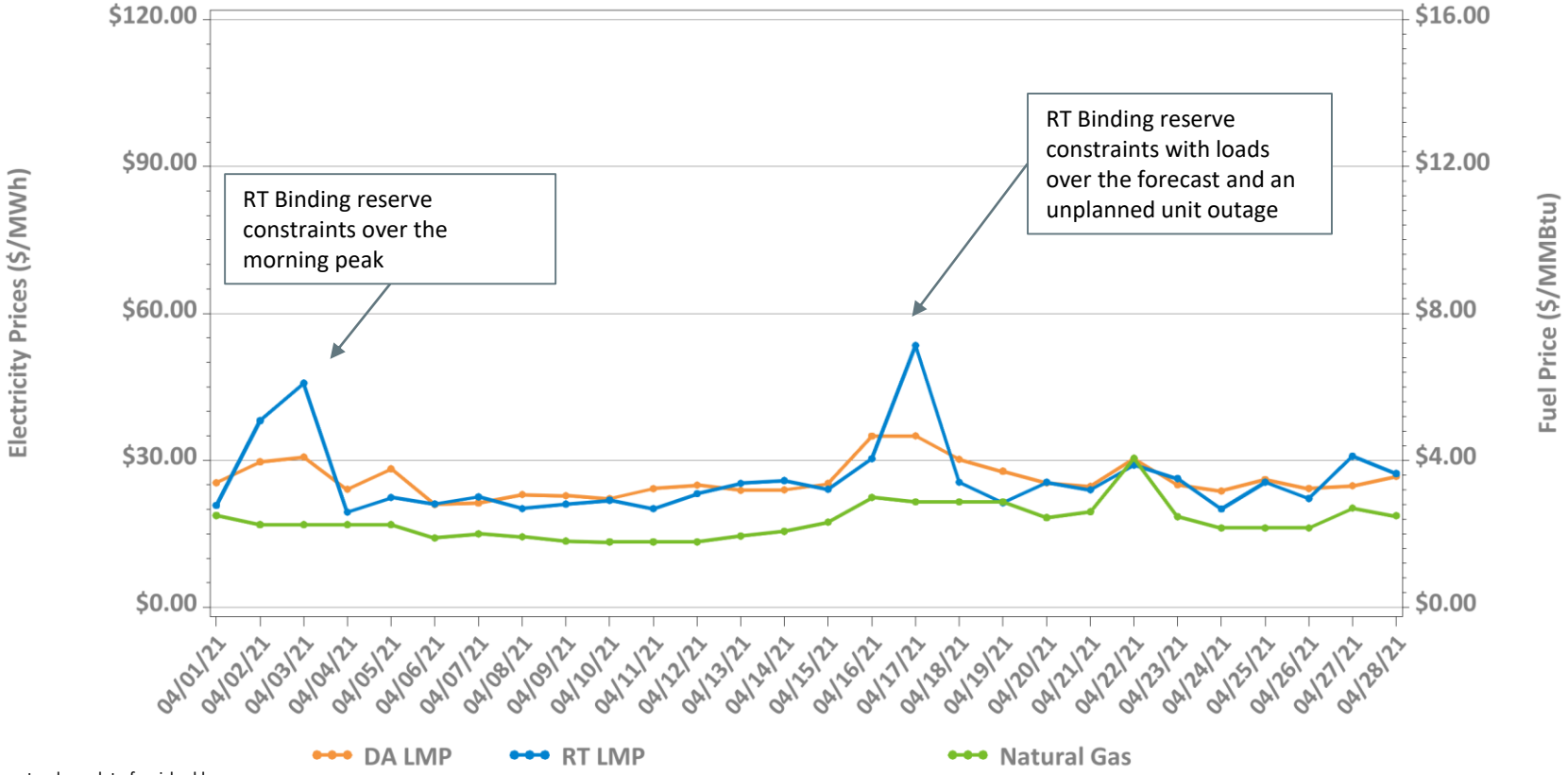
MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: April 1-28, 2021

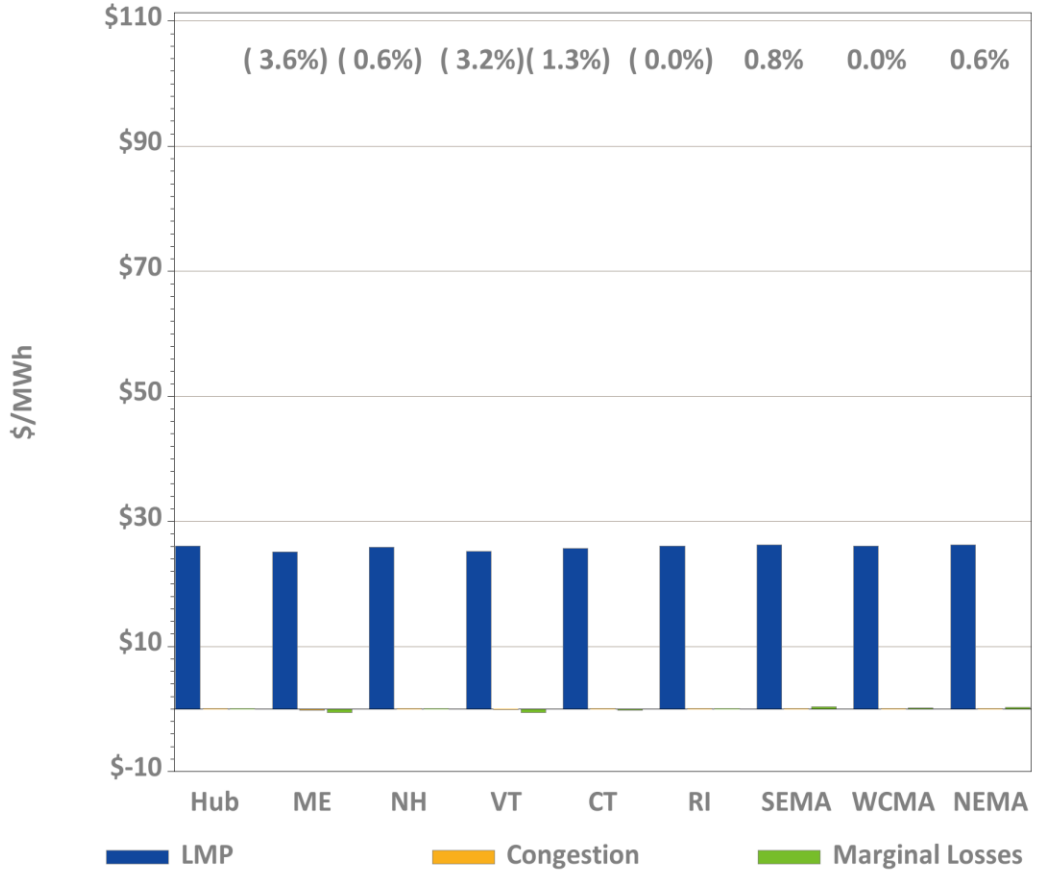


Underlying natural gas data furnished by:

ICE Global markets in clear view

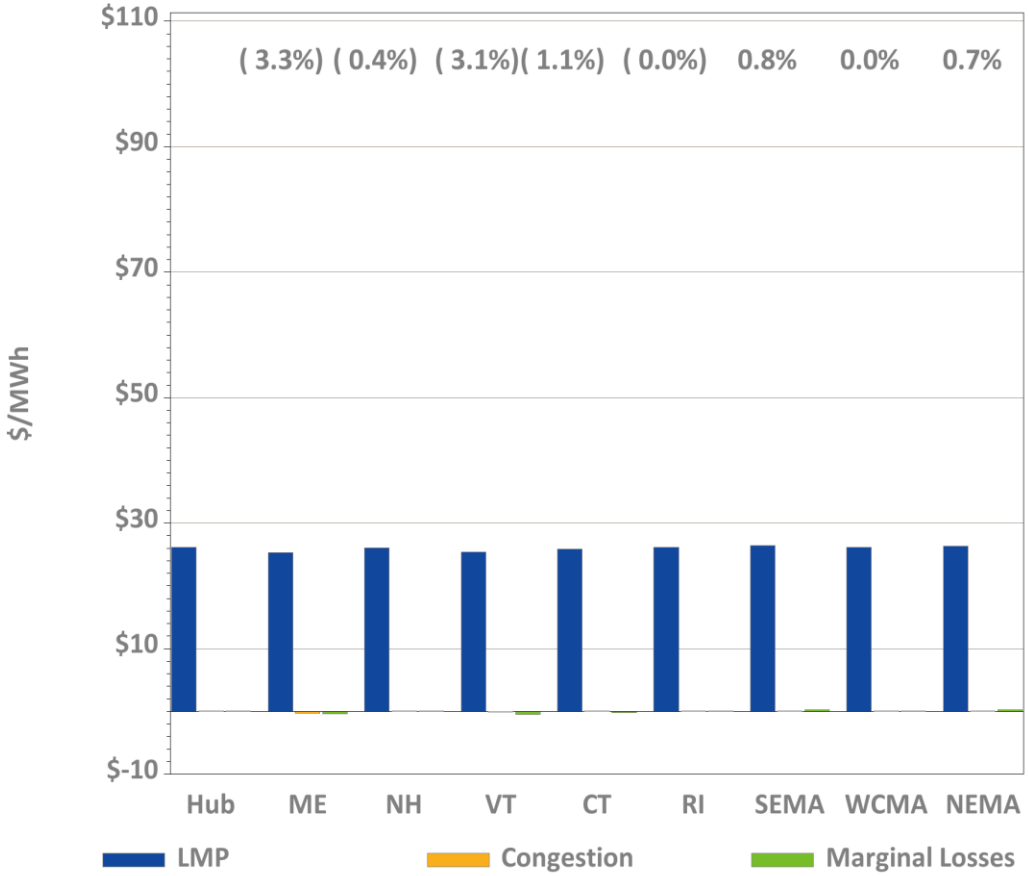
Average price difference over this period (DA-RT): $-0.13
Average price difference over this period ABS(DA-RT): $3.77
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 14%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, April 2021



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

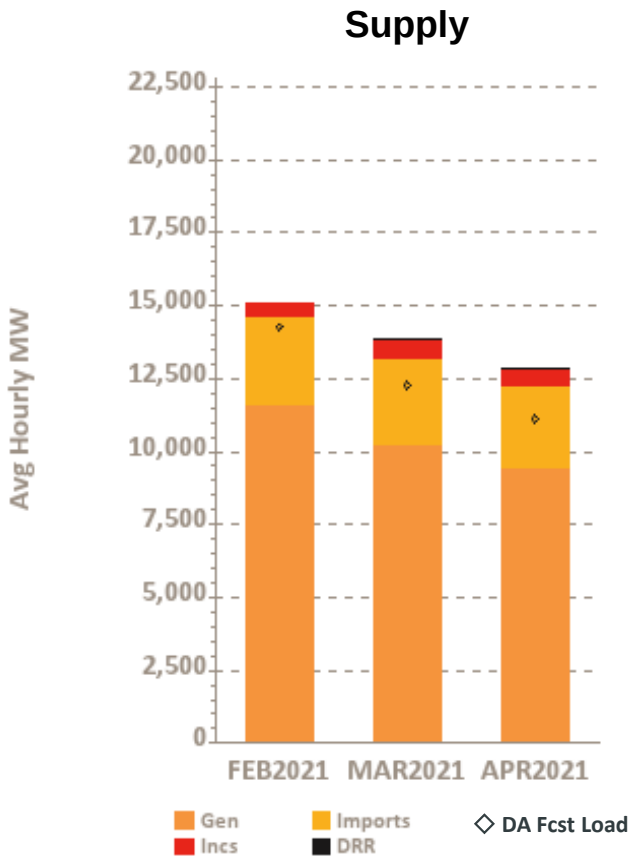
RT LMPs Average by Zone & Hub, April 2021

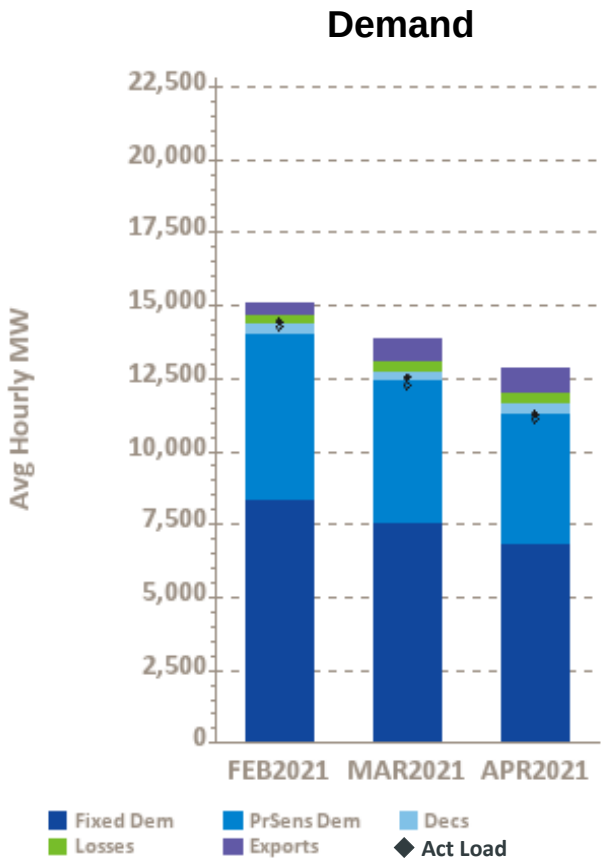


Definitions

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

Components of Cleared DA Supply and Demand – Last Three Months

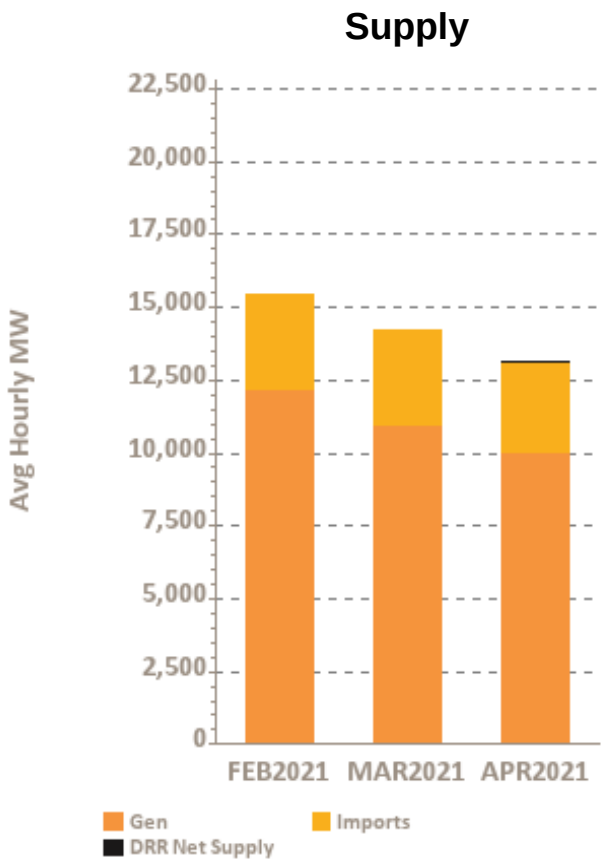


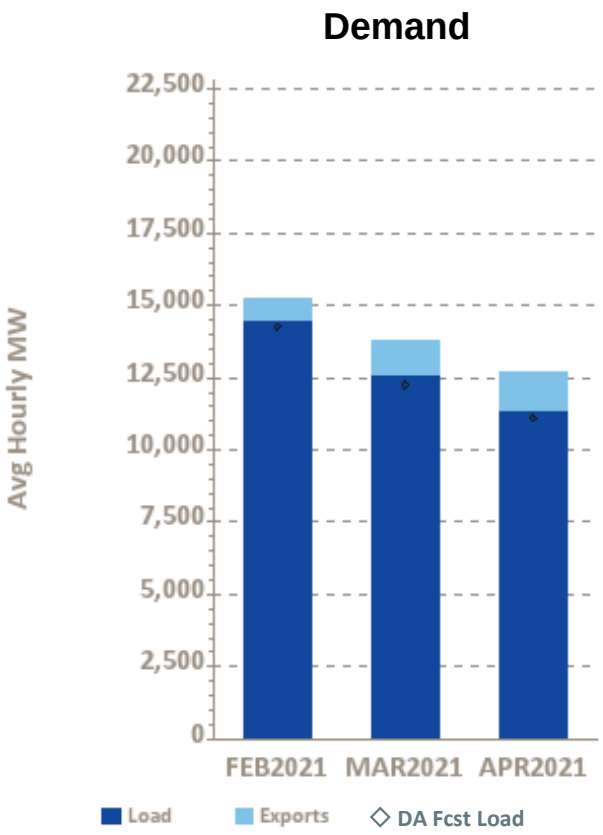


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

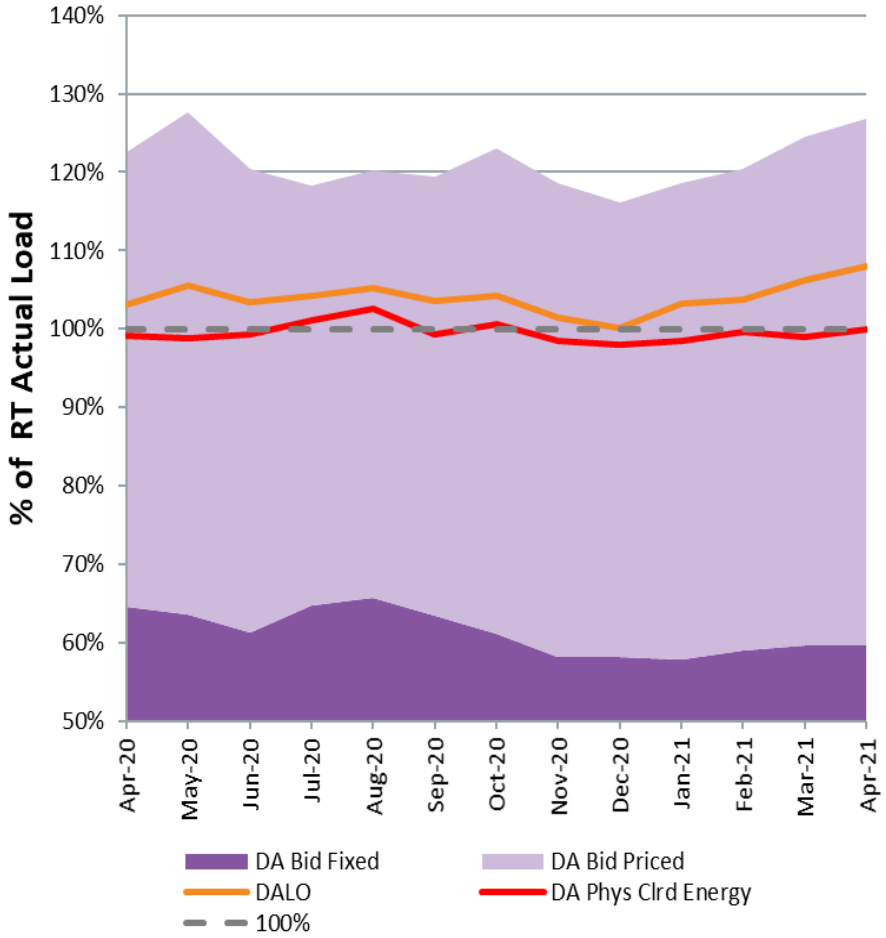
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

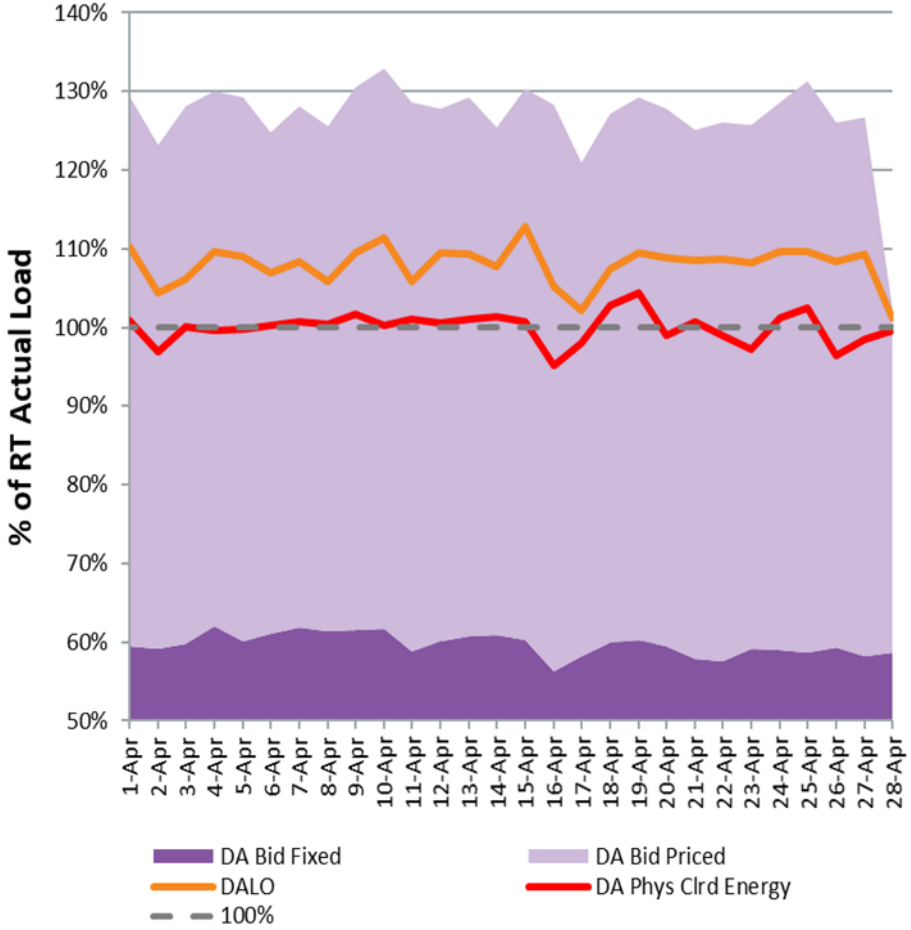
Components of RT Supply and Demand – Last Three Months





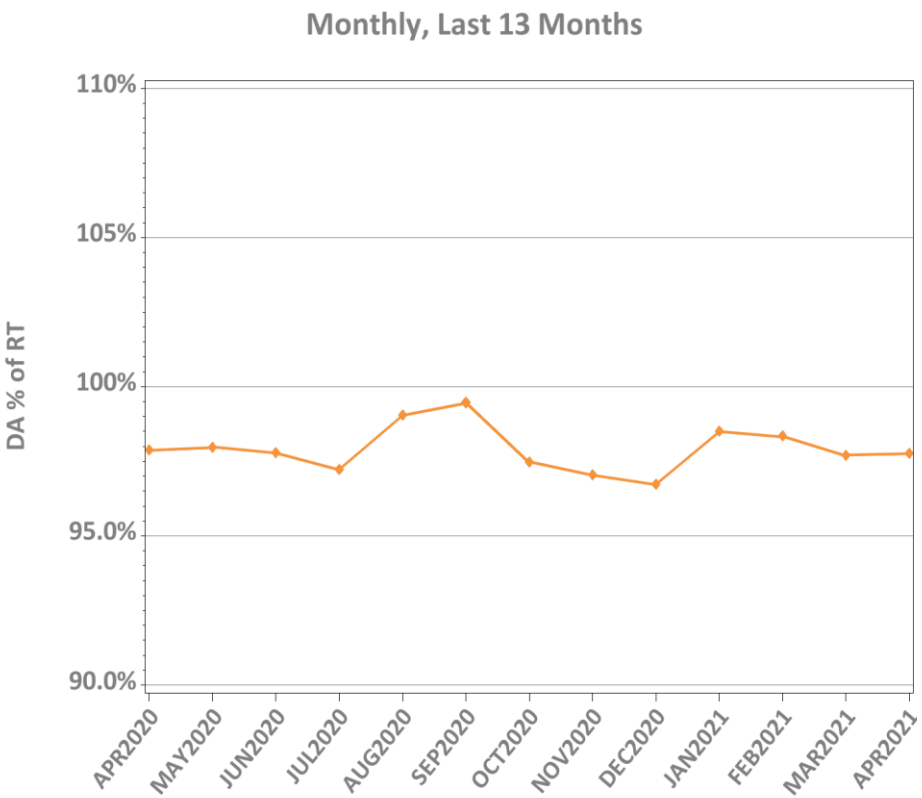
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

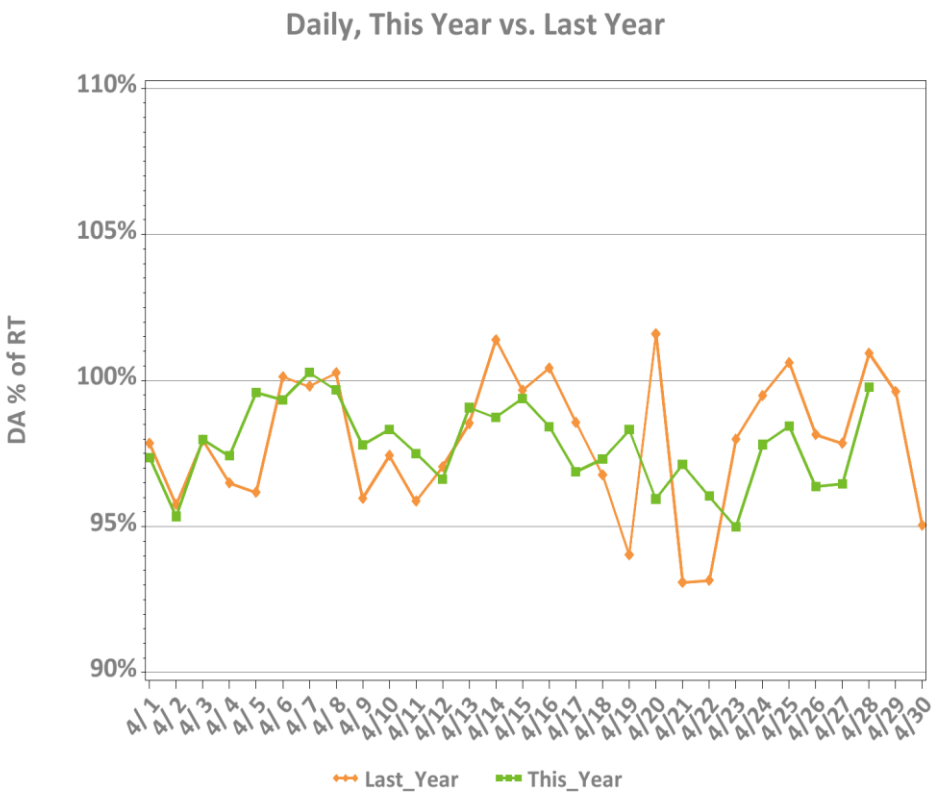




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

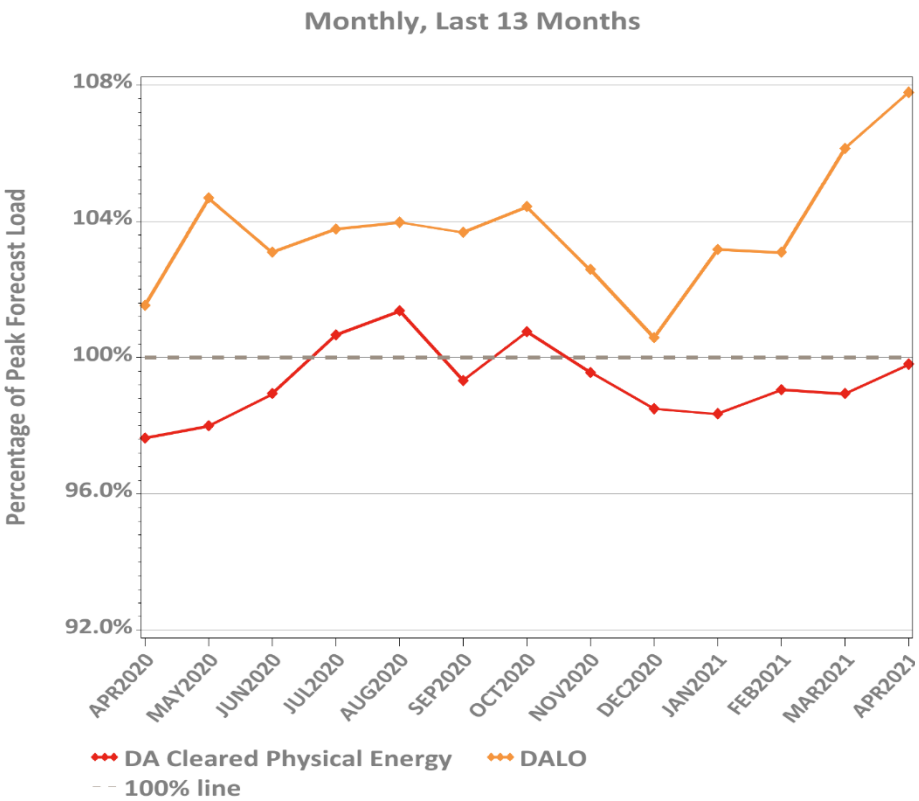
DA vs. RT Load Obligation: March, This Year vs. Last Year

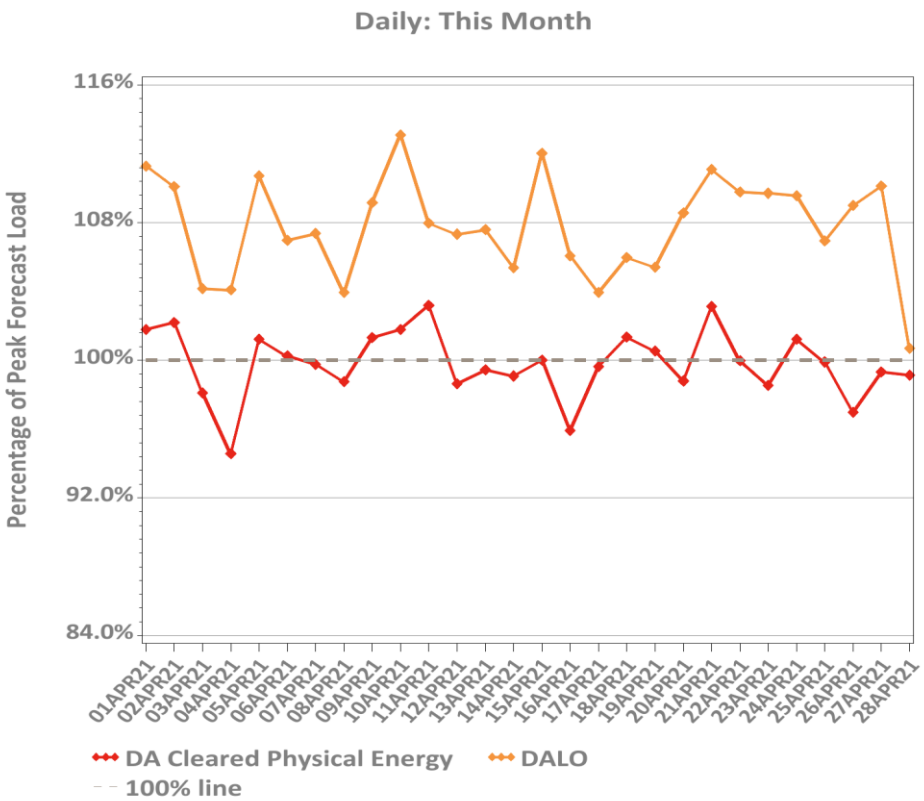




*Hourly average values

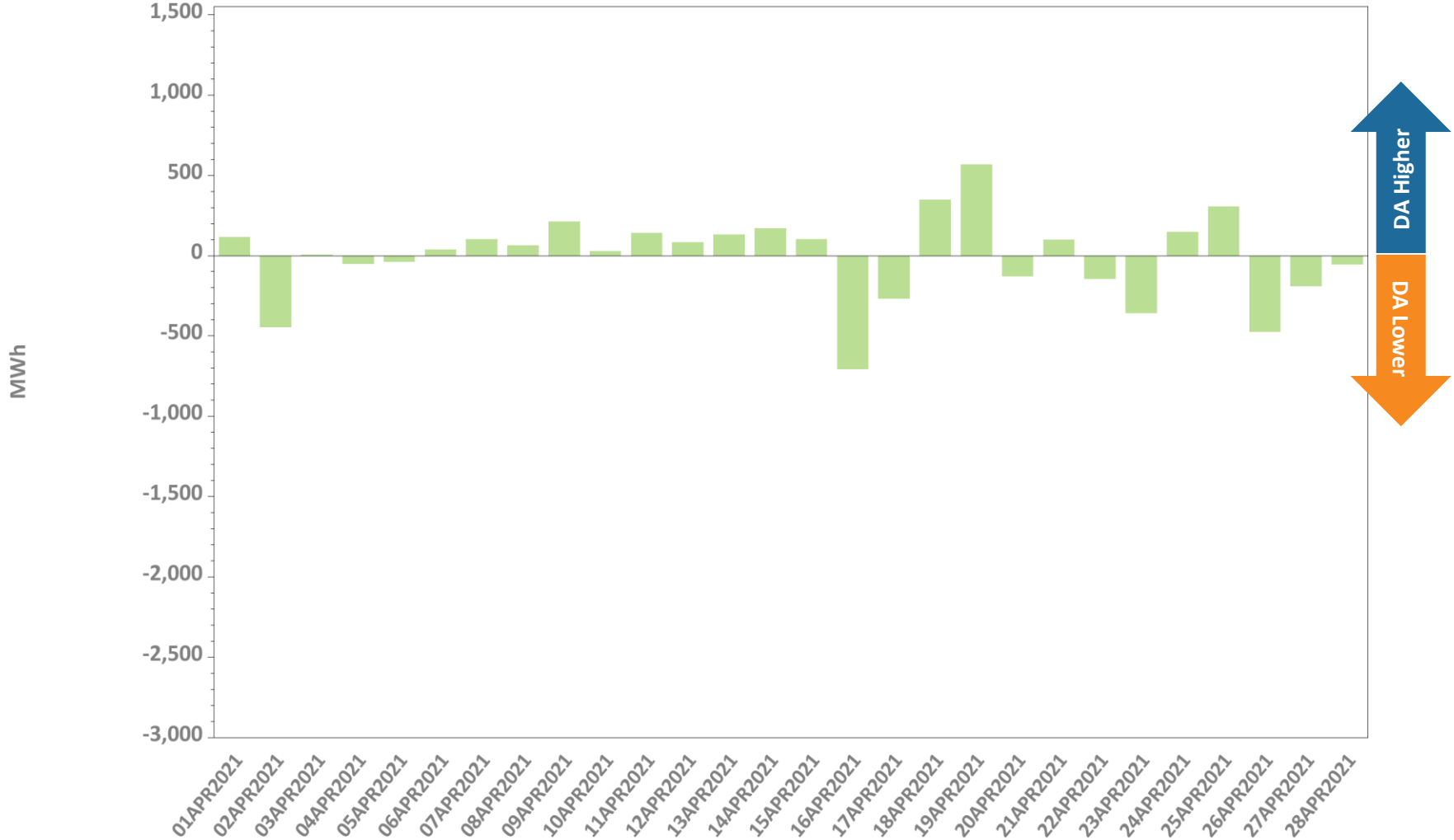
DA Volumes as % of Forecast in Peak Hour





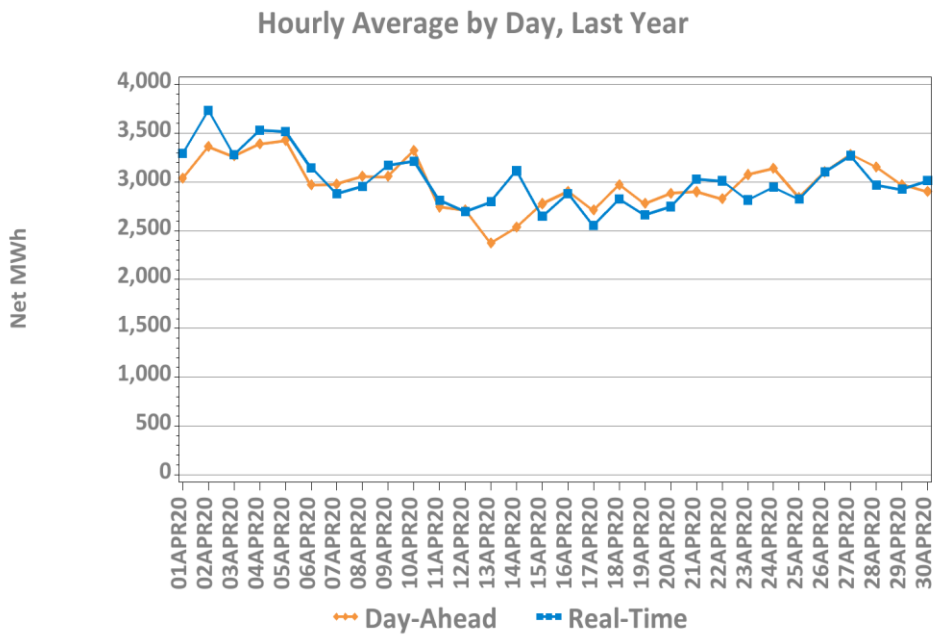
Note: There were no instances of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during April.

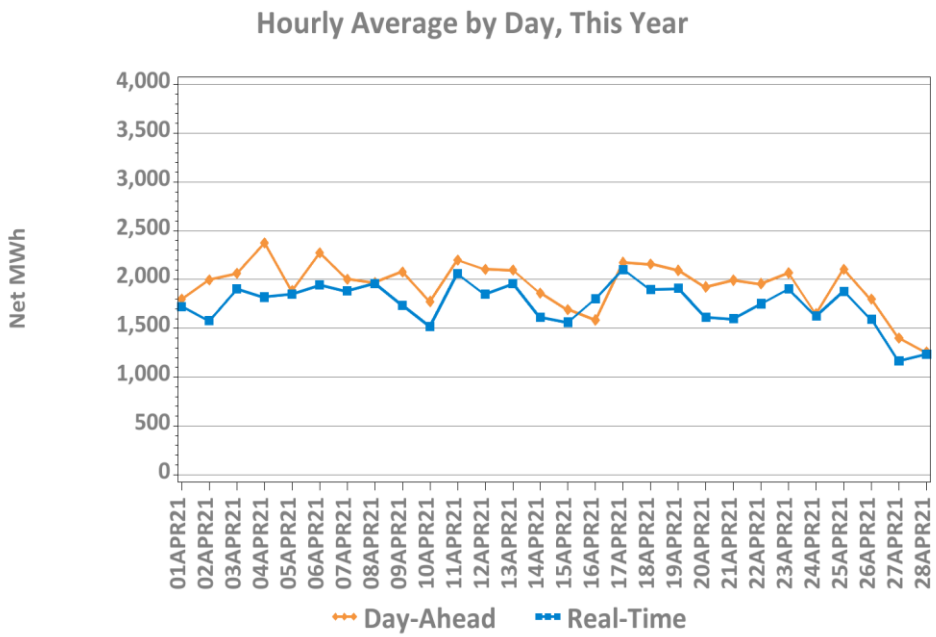
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

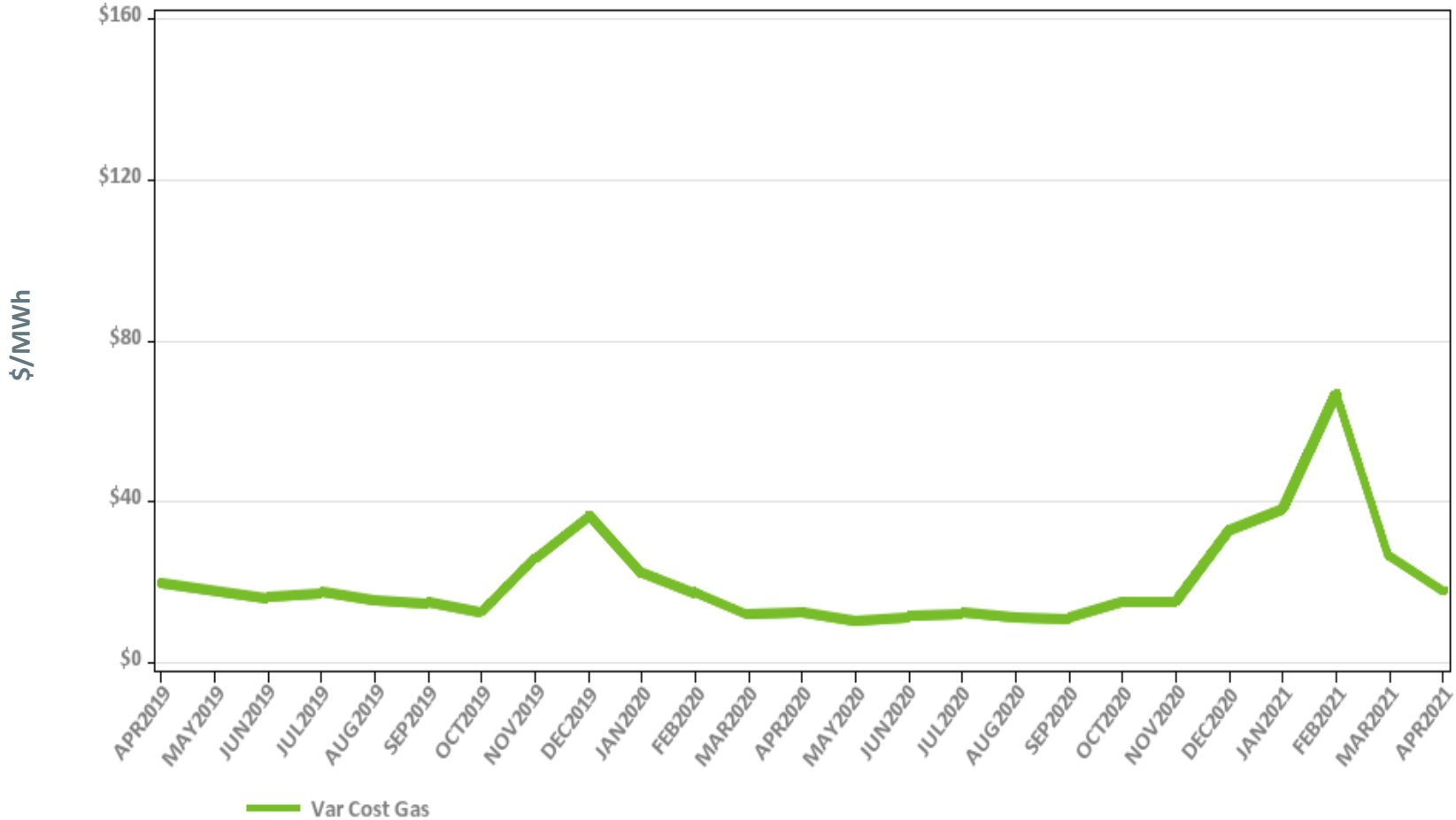
DA vs. RT Net Interchange April 2020 vs. April 2021





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

Variable Production Cost of Natural Gas: Monthly

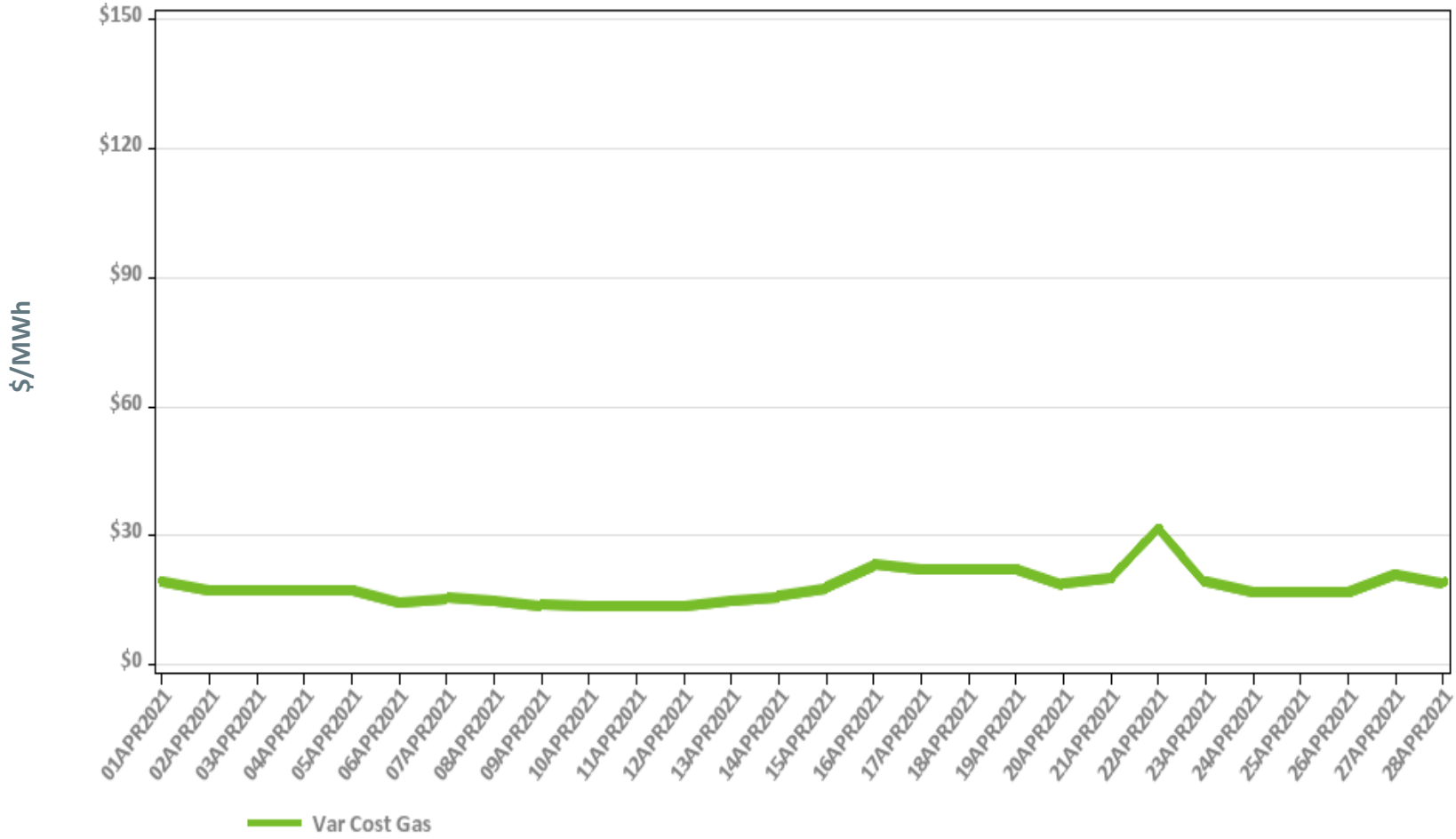


Underlying natural gas data furnished by:

ICE Global markets in clear view

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

Variable Production Cost of Natural Gas: Daily

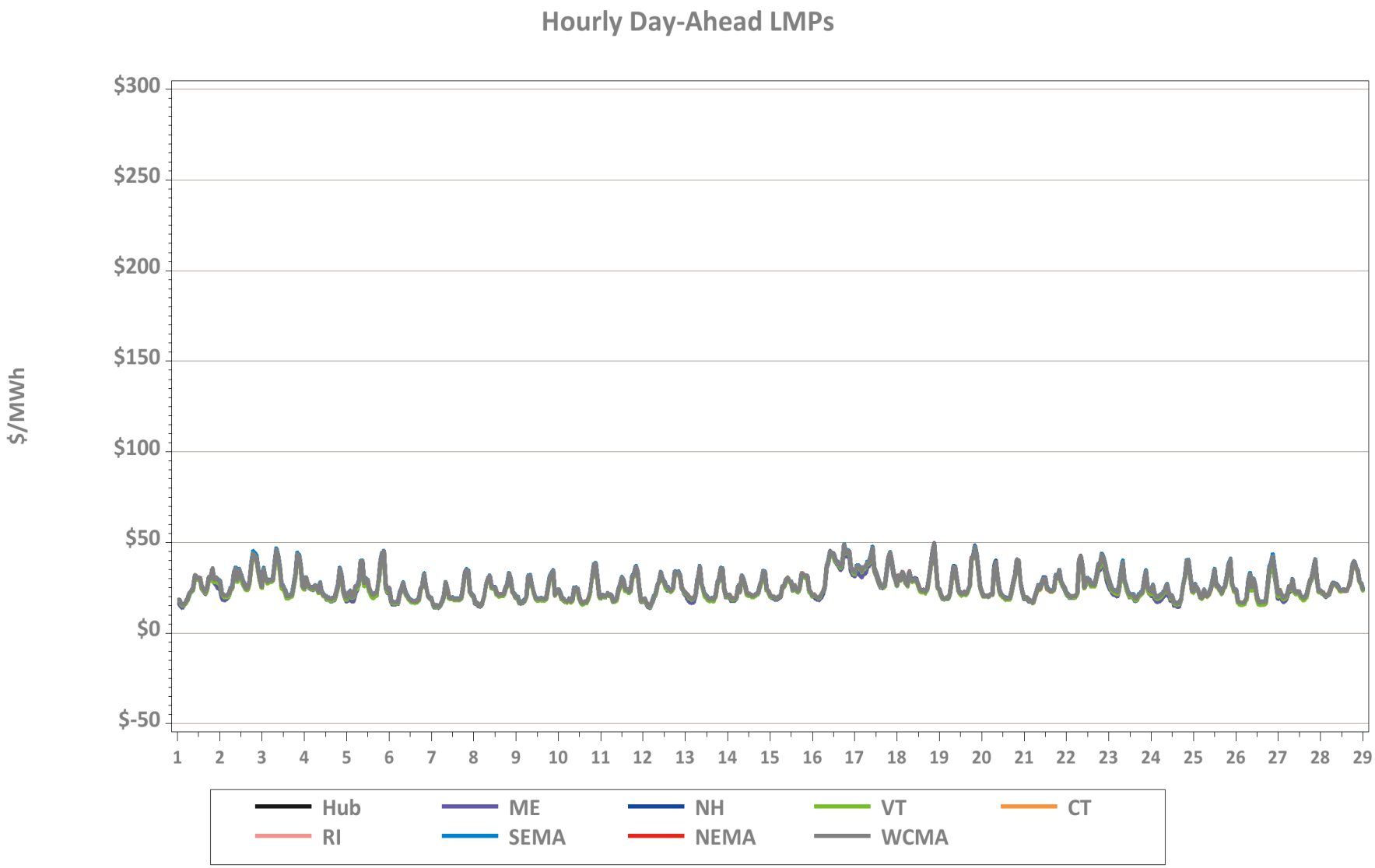


Underlying natural gas data furnished by:

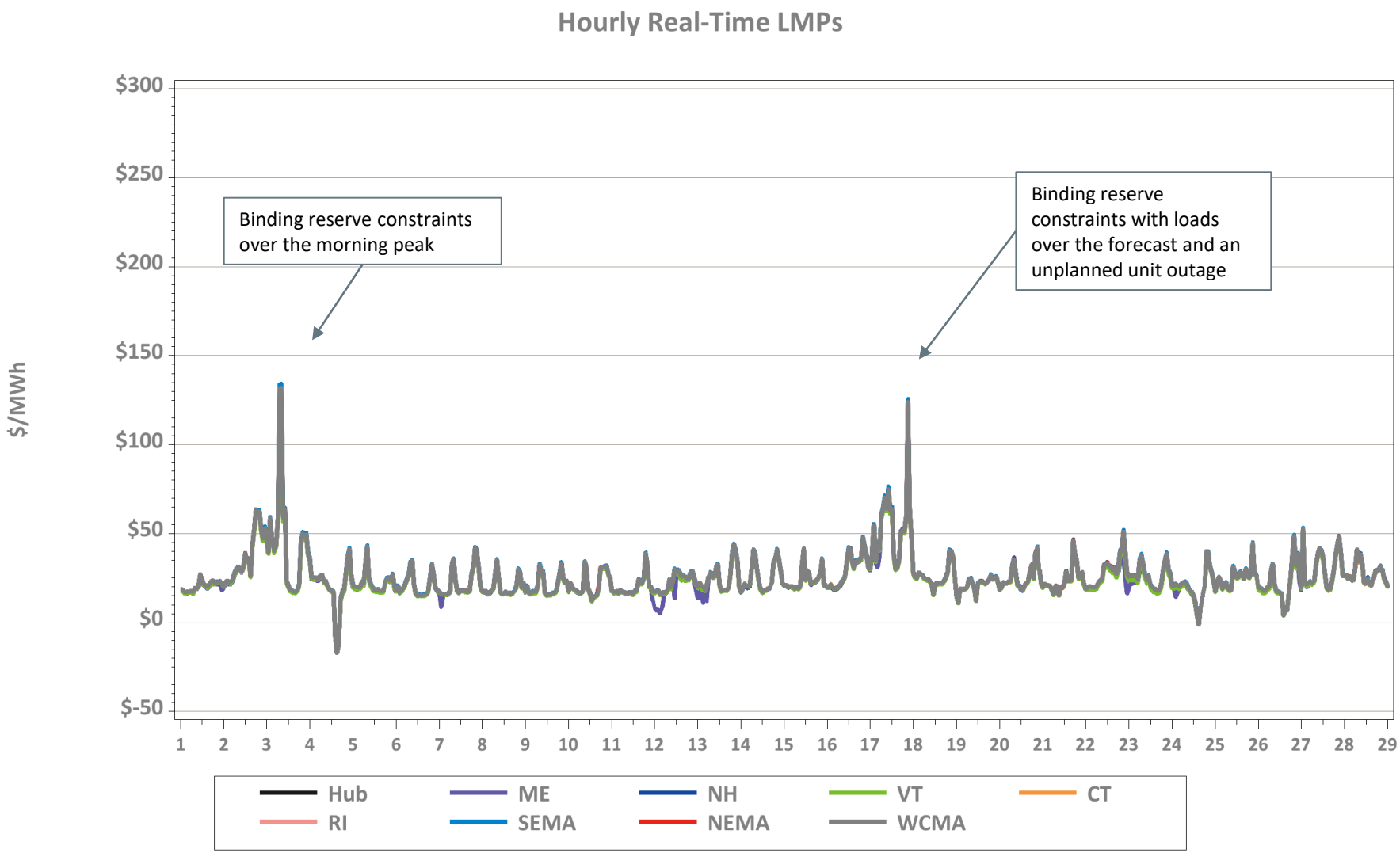
ICE Global markets in clear view

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

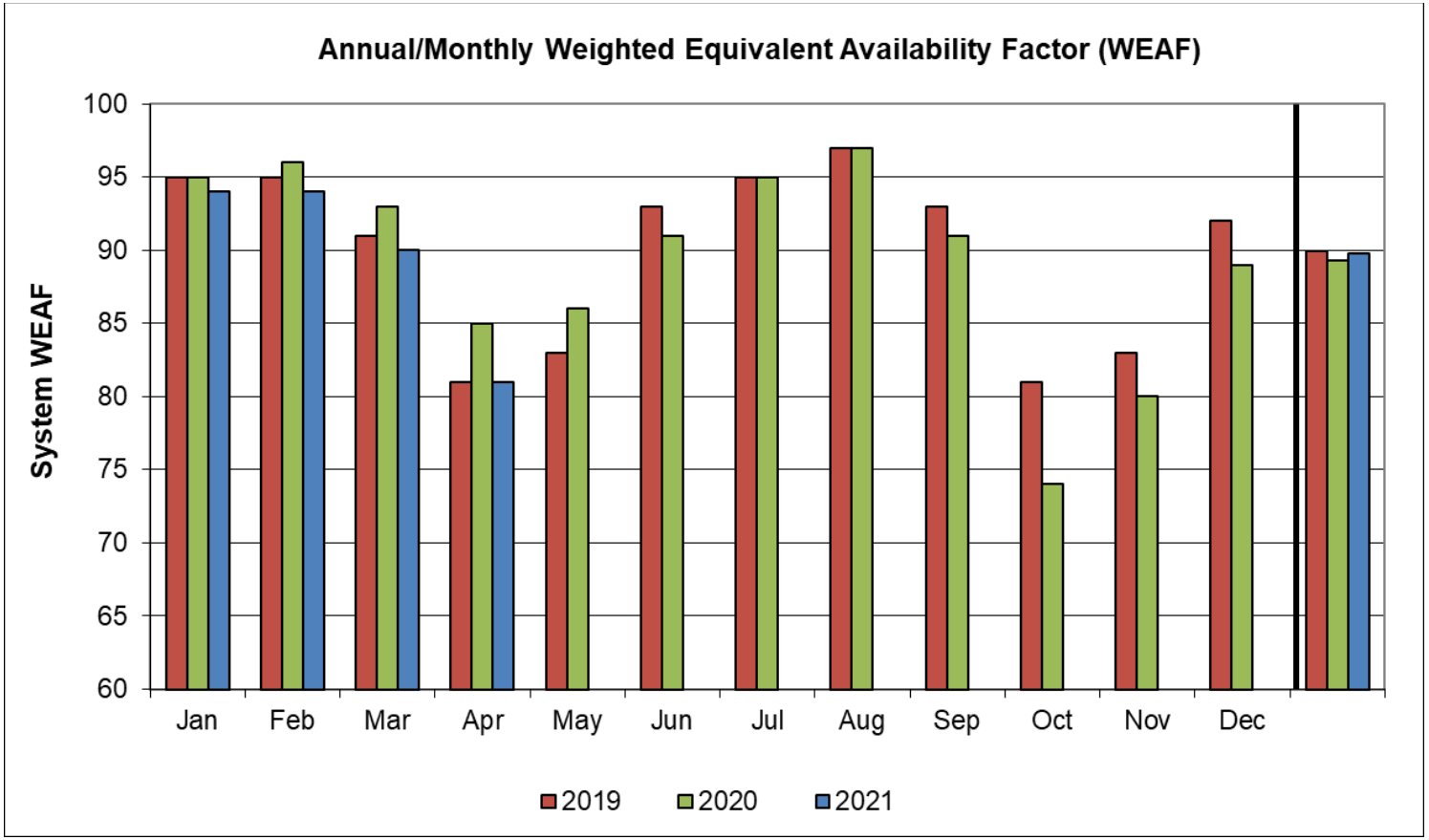
Hourly DA LMPs, April 1-28, 2021



Hourly RT LMPs, April 1-28, 2021



System Unit Availability



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

Data as of 4/26/2021

BACK-UP DETAIL

DEMAND RESPONSE

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

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	77.4	184.4	0.0	261.8
NH	33.6	149.2	0.0	182.7
VT	31.8	103.4	0.0	135.2
CT	103.3	165.3	549.2	817.8
RI	36.3	270.6	0.0	306.9
SEMA	43.4	445.0	0.0	488.4
WCMA	76.5	469.5	45.3	591.3
NEMA	60.8	815.0	0.0	875.8
Total	**463.1**	**2,602.4**	**594.5**	**3,660.0**

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

NEW GENERATION

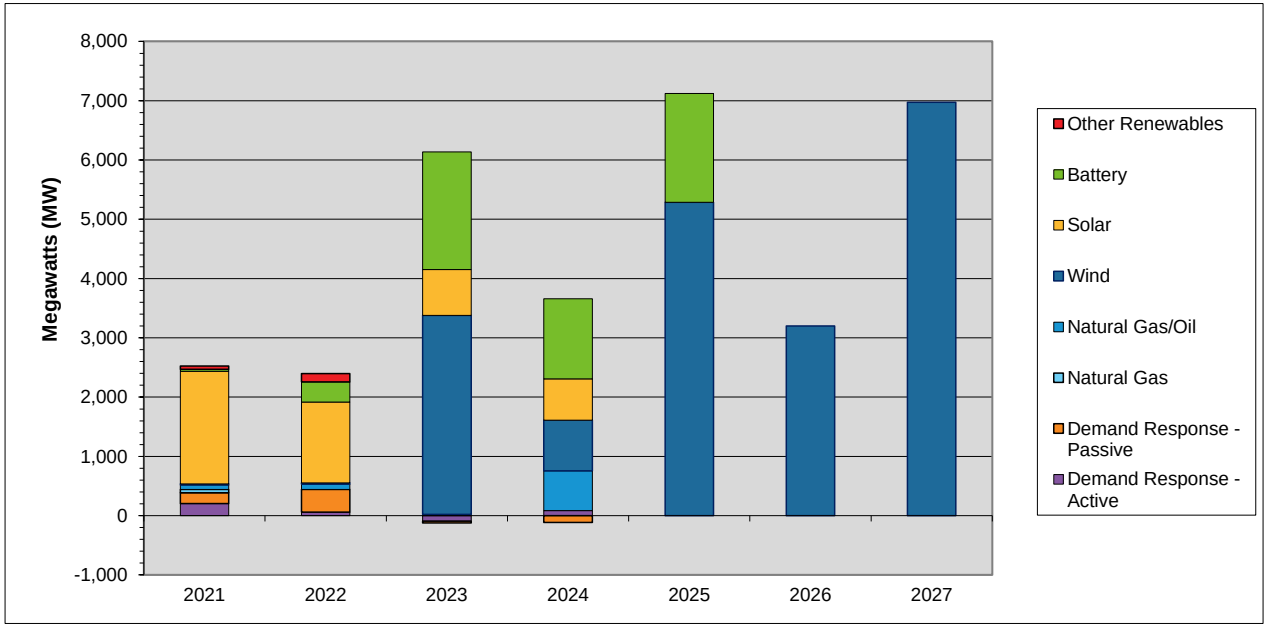
New Generation Update

Based on Queue as of 4/30/21

- Seventeen new projects totaling 5,283 MW applied for interconnection study since the last update
  - They consist of five new battery storage projects, seven battery and solar co-location projects, one solar project and four offshore wind projects with in-service dates ranging from 2021 to 2027
- No projects went commercial and one project was withdrawn
- In total, 288 generation projects are currently being tracked by the ISO, totaling approximately 31,102 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



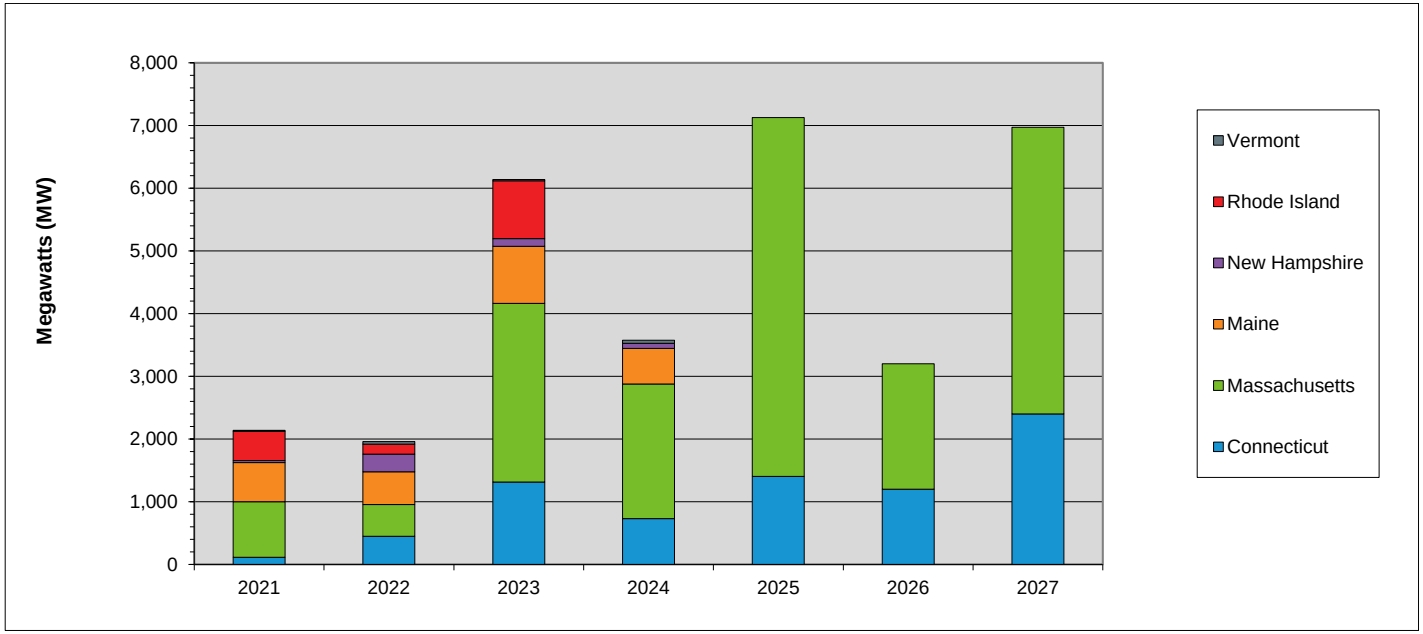
	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Other Renewables	56	142	0	0	0	0	0	198	0.6
Battery	34	340	1,988	1,354	1,837	0	0	5,553	17.5
Solar[2]	1,899	1,366	772	696	0	0	0	4,733	14.9
Wind	19	20	3,355	852	5,287	3,200	6,972	19,705	62.0
Natural Gas/Oil[3]	76	89	23	672	0	0	0	860	2.7
Natural Gas	53	0	0	0	0	0	0	53	0.2
Demand Response - Passive	184	380	-28	-114	0	0	0	422	1.3
Demand Response - Active	204	62	-94	86	0	0	0	258	0.8
Totals	**2,525**	**2,399**	**6,016**	**3,546**	**7,124**	**3,200**	**6,972**	**31,782**	**100.0**

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

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

Actual and Projected Annual Generator Capacity Additions

By State



	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Vermont	15	40	20	50	0	0	0	125	0.4
Rhode Island	466	160	921	0	0	0	0	1,547	5.0
New Hampshire	30	281	126	80	0	0	0	517	1.7
Maine	625	523	907	567	0	0	0	2,622	8.4
Massachusetts	888	505	2,852	2,145	5,719	2,000	4,572	18,681	60.1
Connecticut	113	448	1,312	732	1,405	1,200	2,400	7,610	24.5
Totals	**2,137**	**1,957**	**6,138**	**3,574**	**7,124**	**3,200**	**6,972**	**31,102**	**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	1	8	1	8	0	0
Battery Storage	34	5,553	0	0	34	5,553
Fuel Cell	4	54	1	10	3	44
Hydro	3	99	2	71	1	28
Natural Gas	5	53	0	0	5	53
Natural Gas/Oil	7	860	1	14	6	846
Nuclear	1	37	0	0	1	37
Solar	205	4,733	21	343	184	4,390
Wind	27	19,705	1	15	26	19,690
Total	287	31,102	27	461	260	30,641

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

New Generation Projection

By Operating Type

Operating Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	8	132	3	23	5	109
Intermediate	9	822	1	14	8	808
Peaker	243	10,443	22	409	221	10,034
Wind Turbine	27	19,705	1	15	26	19,690
Total	287	31,102	27	461	260	30,641

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

New Generation Projection

By Operating Type and Fuel Type

Unit Type	Total		Baseload		Intermediate		Peaker		Wind Turbine	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	1	8	1	8	0	0	0	0	0	0
Battery Storage	34	5,553	0	0	0	0	34	5,553	0	0
Fuel Cell	4	54	4	54	0	0	0	0	0	0
Hydro	3	99	2	33	0	0	1	66	0	0
Natural Gas	5	53	0	0	4	47	1	6	0	0
Natural Gas/Oil	7	860	0	0	5	775	2	85	0	0
Nuclear	1	37	1	37	0	0	0	0	0	0
Solar	205	4,733	0	0	0	0	205	4,733	0	0
Wind	27	19,705	0	0	0	0	0	0	27	19,705
Total	287	31,102	8	132	9	822	243	10,443	27	19,705

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation (CSO) FCA 12

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

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

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

ARA – Annual Reconfiguration Auction
FCA – Forward Capacity Auction
ICR – Installed Capacity Requirement

Capacity Supply Obligation FCA 13

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	685.554	683.116	-2.438				
	Passive Demand	3,354.69	3,407.507	52.817				
Demand Total		**4,040.244**	**4,090.623**	**50.38**				
Generator	*Non-Intermittent*	28,586.498	27,868.341	-718.157				
	Intermittent	1,024.792	901.672	-123.12				
Generator Total		**2,9611.29**	**28,770.013**	**-841.28**				
Import Total		**1,187.69**	**1,292.41**	**104.72**				
Grand Total*		**34,839.224**	**34,153.046**	**-686.18**				
Net ICR (NICR)		**33,750**	**32,465**	**-1,285**				

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

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

Capacity Supply Obligation FCA 14

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	592.043						
	Passive Demand	3,327.071						
Demand Total		**3,919.114**						
Generator	*Non-Intermittent*	27,816.902						
	Intermittent	1,160.916						
Generator Total		**28,977.818**						
Import Total		**1,058.72**						
Grand Total*		**33,955.652**						
Net ICR (NICR)		**32,490**						

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

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

Capacity Supply Obligation FCA 15

Resource Type	Resource Type	FCA	ARA 1		ARA 2		ARA 3	
		CSO	CSO	Change	CSO	Change	CSO	Change
		MW	MW	MW	MW	MW	MW	MW
Demand	*Active Demand*	677.673						
	Passive Demand	3,212.865						
Demand Total		**3,890.538**						
Generator	*Non-Intermittent*	28,154.203						
	Intermittent	1,089.265						
Generator Total		**29,243.468**						
Import Total		**1,487.059**						
Grand Total*		**34,621.065**						
Net ICR (NICR)		**33,270**						

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

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

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/Passive	Existing	New	Grand Total
2019-20	Active	357.221	20.304	377.525
	Passive	2,018.20	350.43	2,368.63
	Grand Total	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

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

What are Daily NCPC Payments?

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

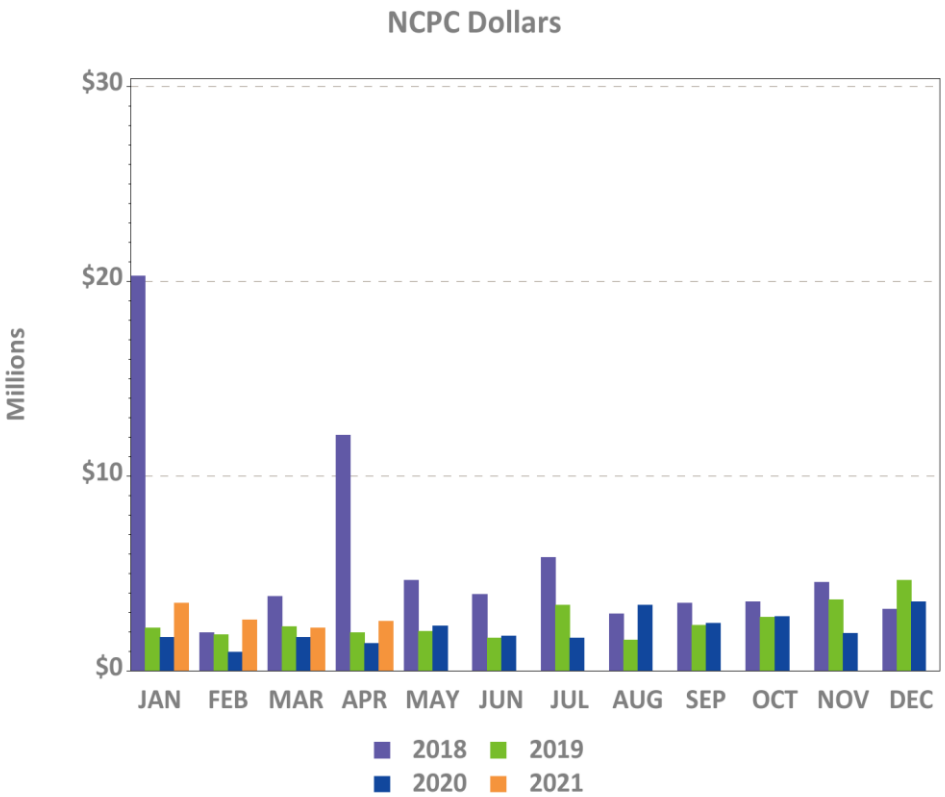
Definitions

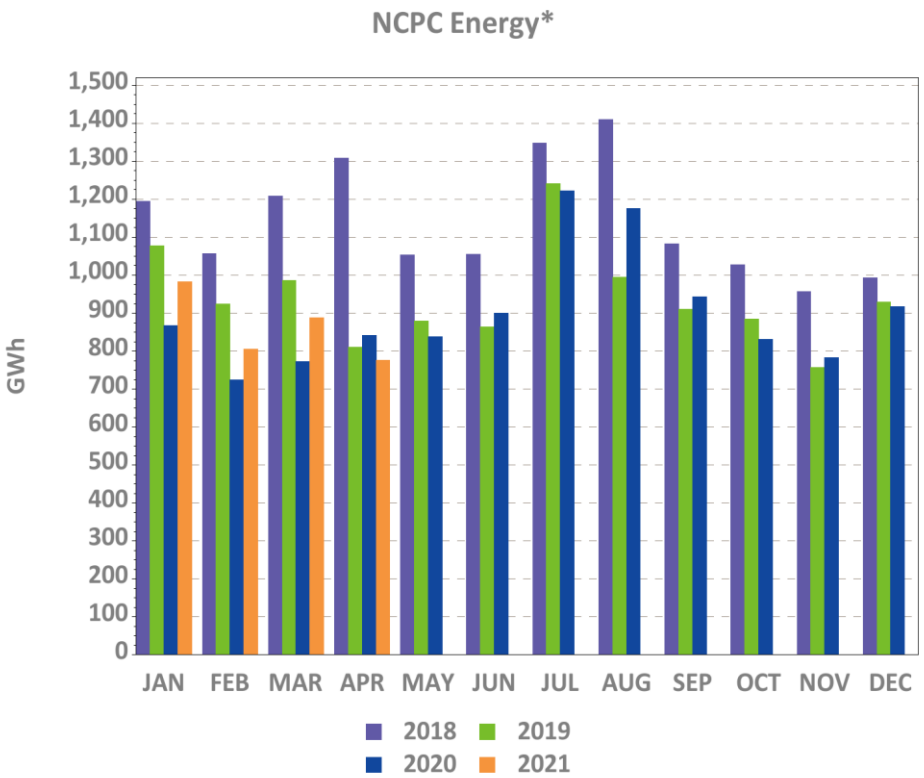
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

Charge Allocation Key

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

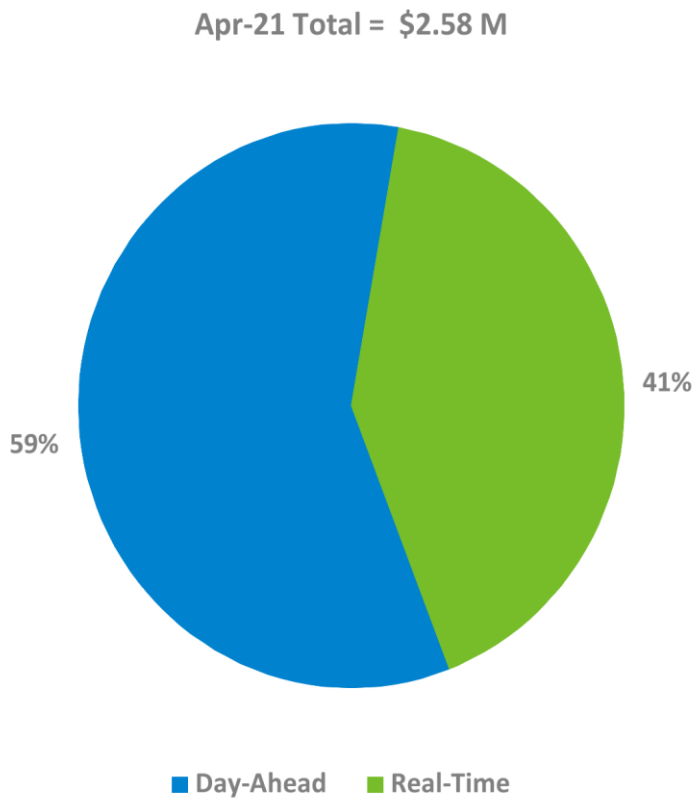
Year-Over-Year Total NCPC Dollars and Energy

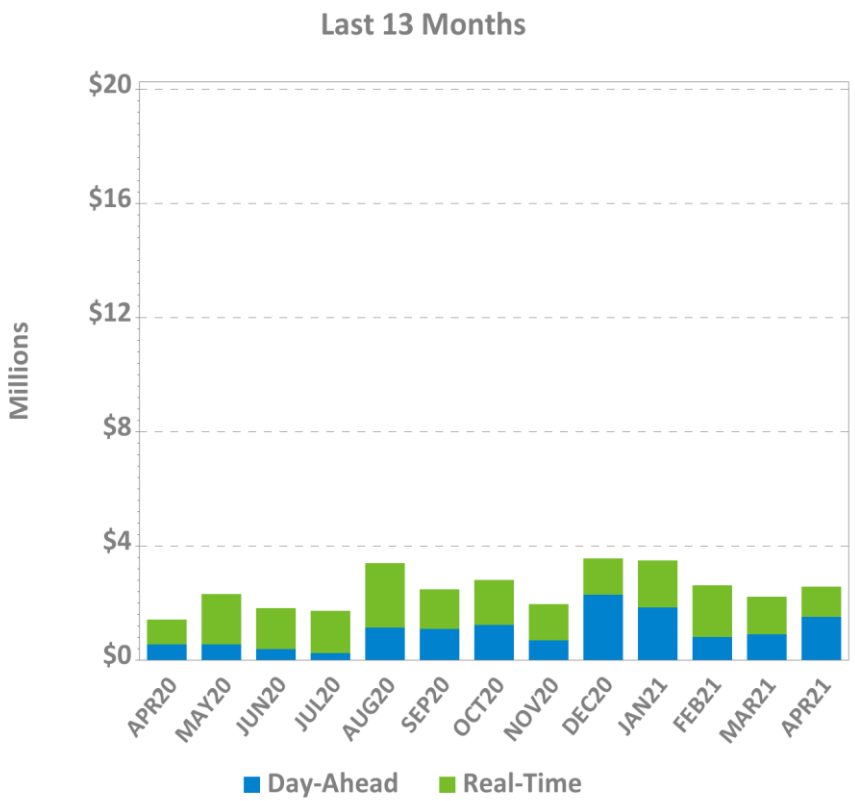




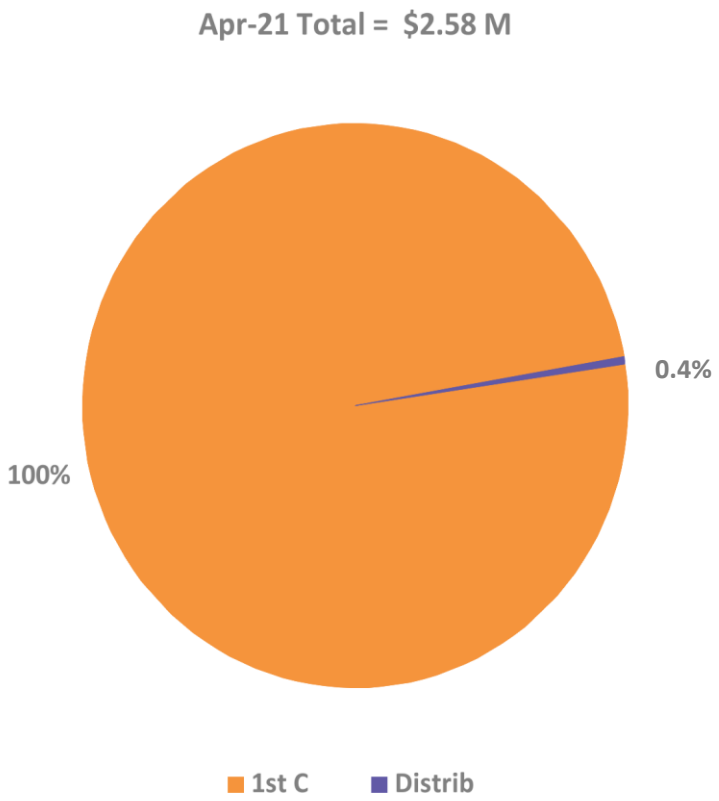
*** NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

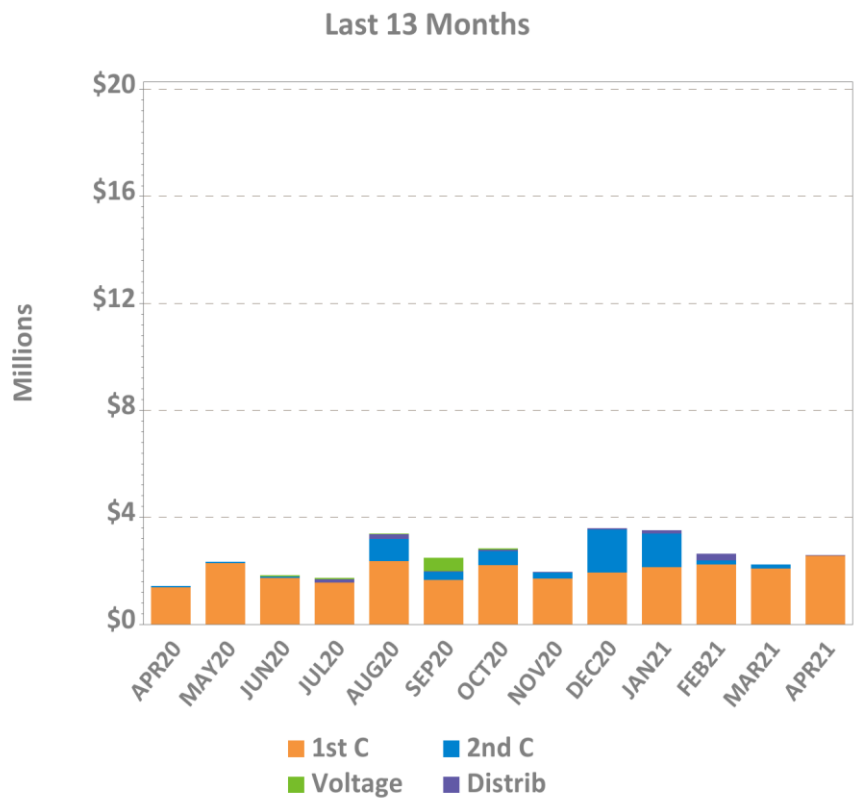
DA and RT NCPC Charges





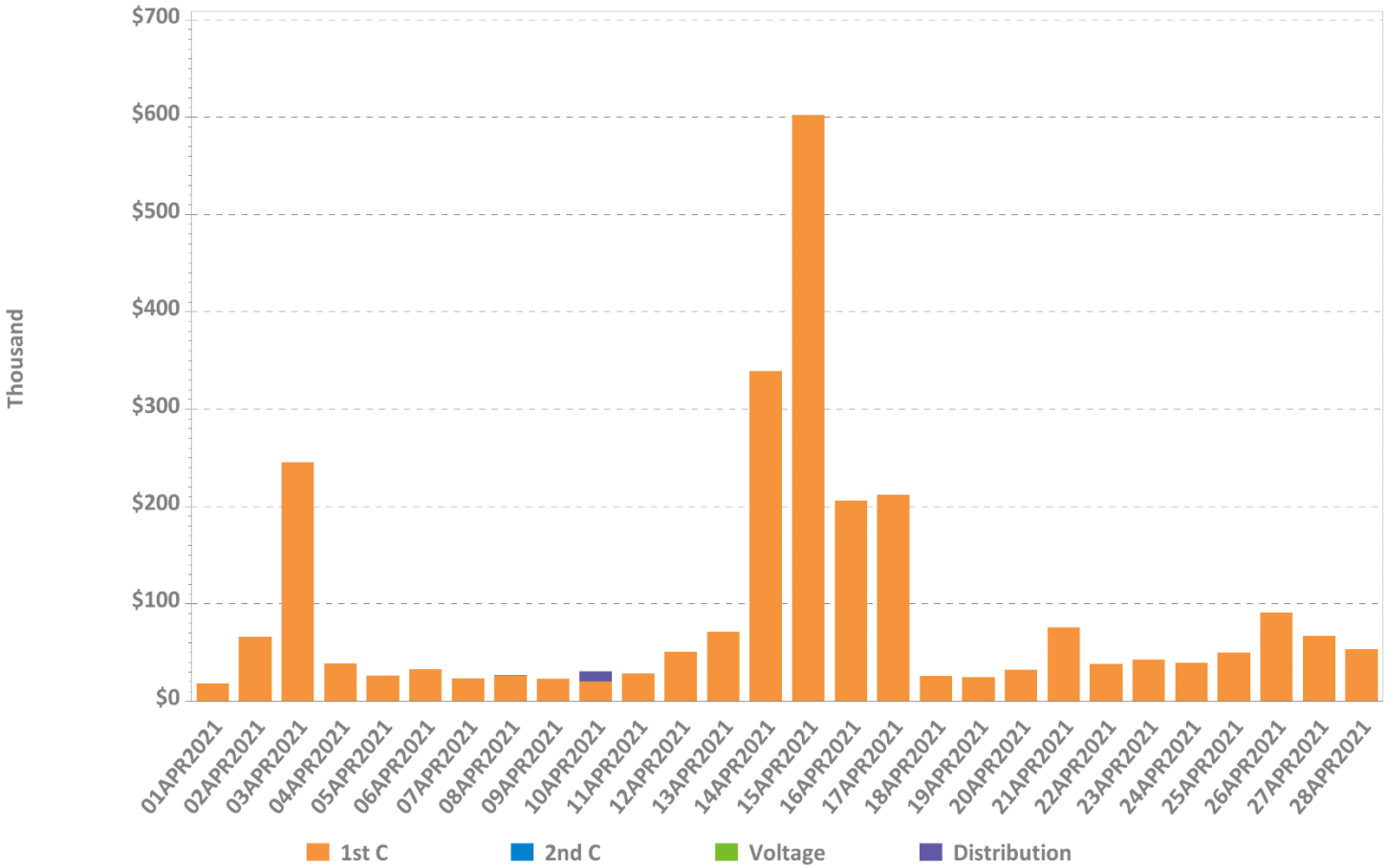
NCPC Charges by Type



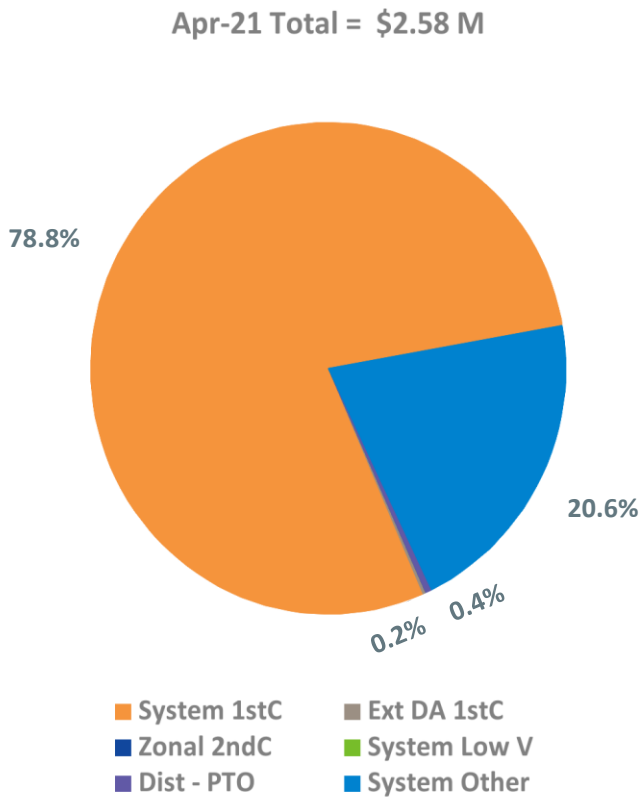


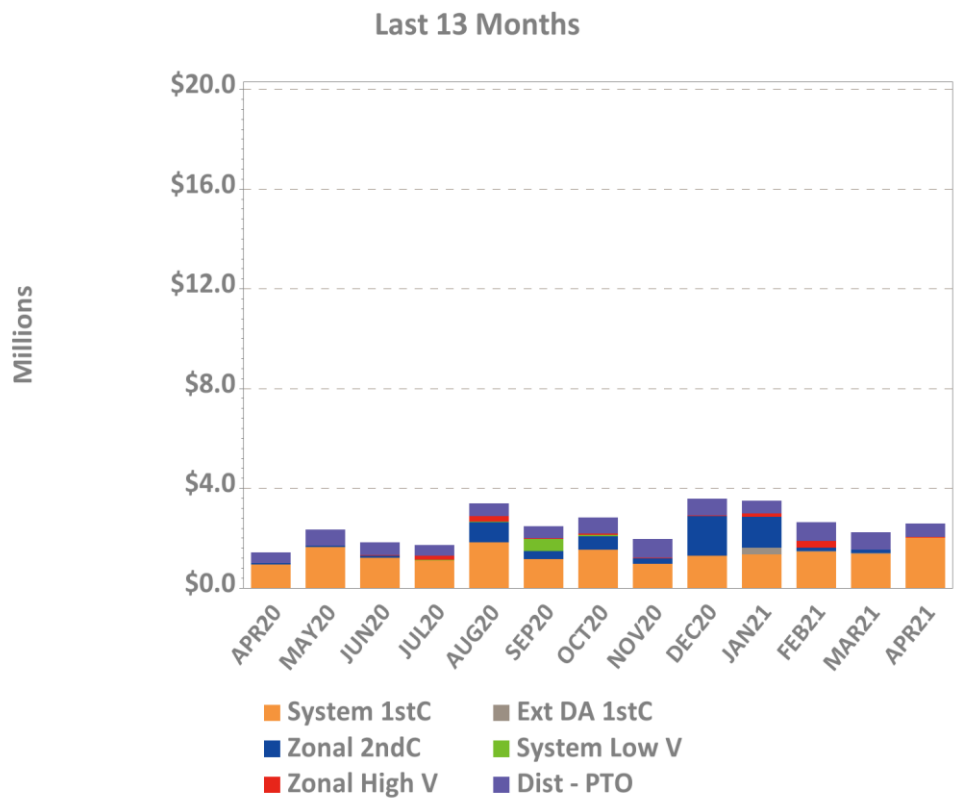
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



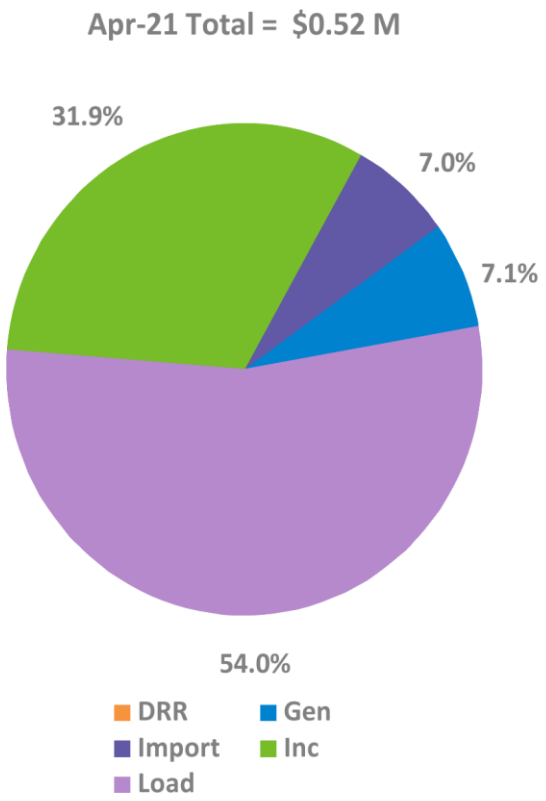
NCPC Charges by Allocation

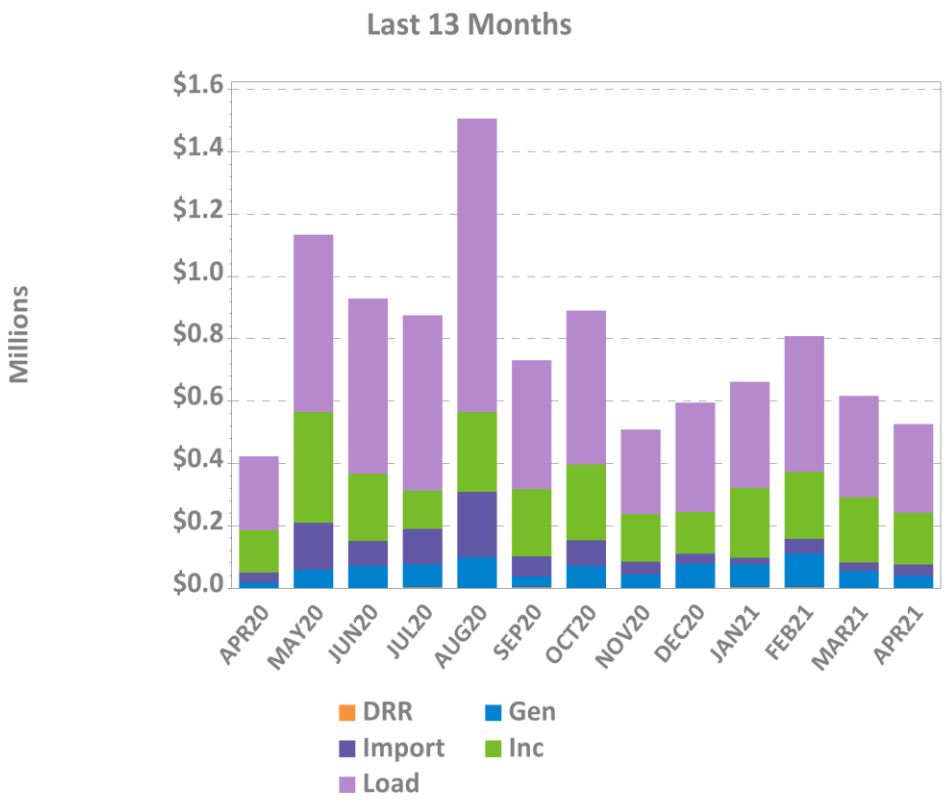




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

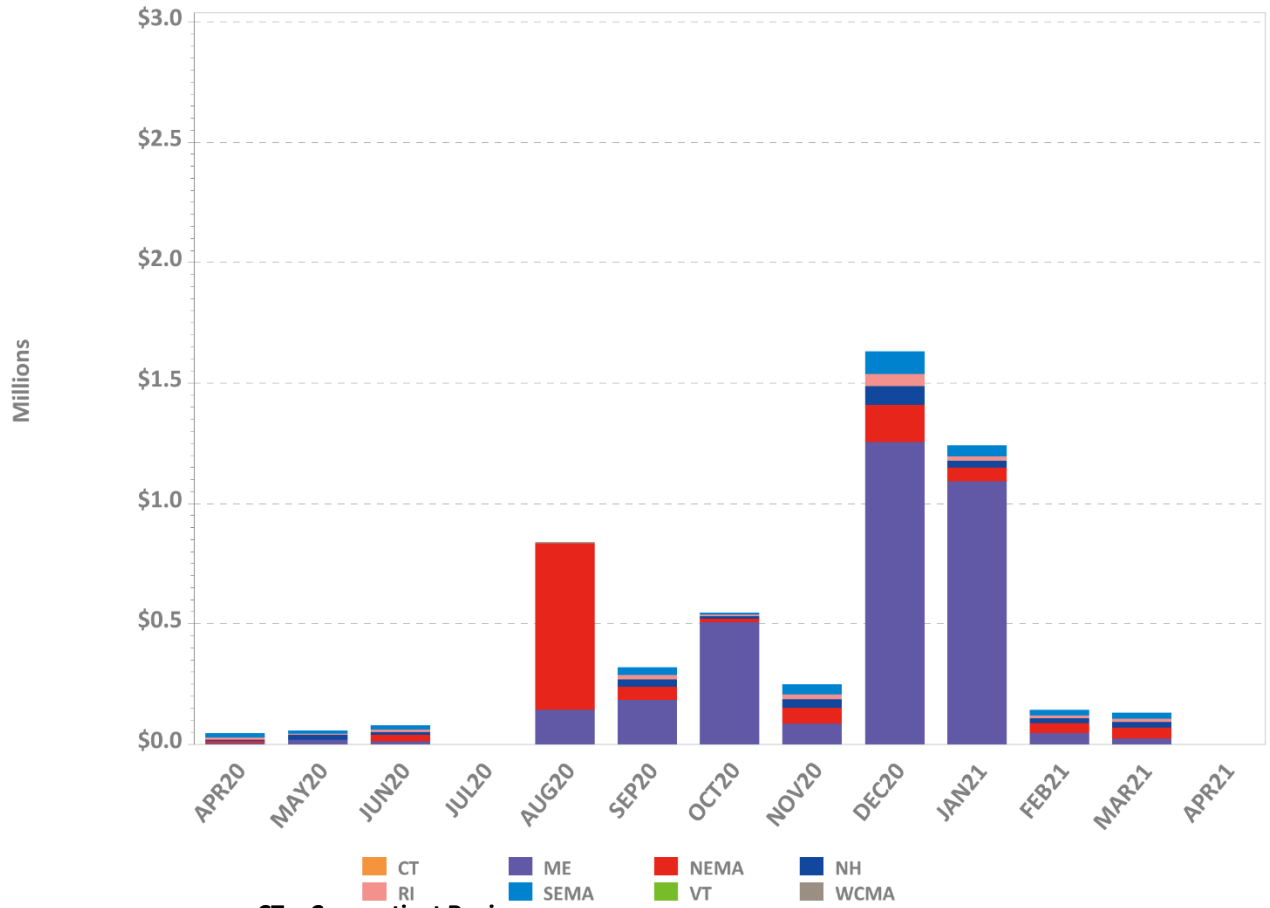
RT First Contingency Charges by Deviation Type





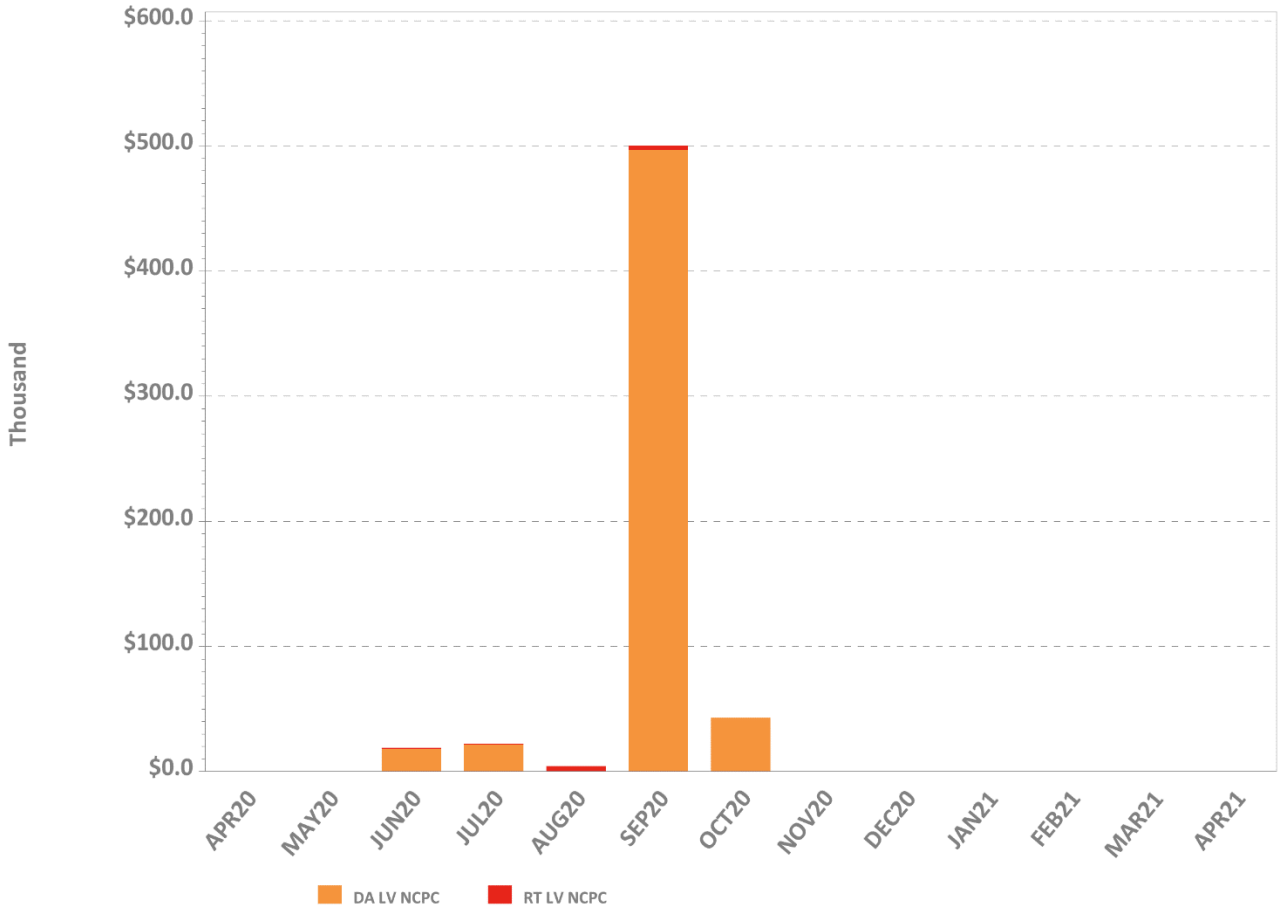
DRR – Demand Response Resource deviations
Gen – Generator deviations
Inc – Increment Offer deviations
Import – Import deviations
Load – Load obligation deviations

LSCPR Charges by Reliability Region

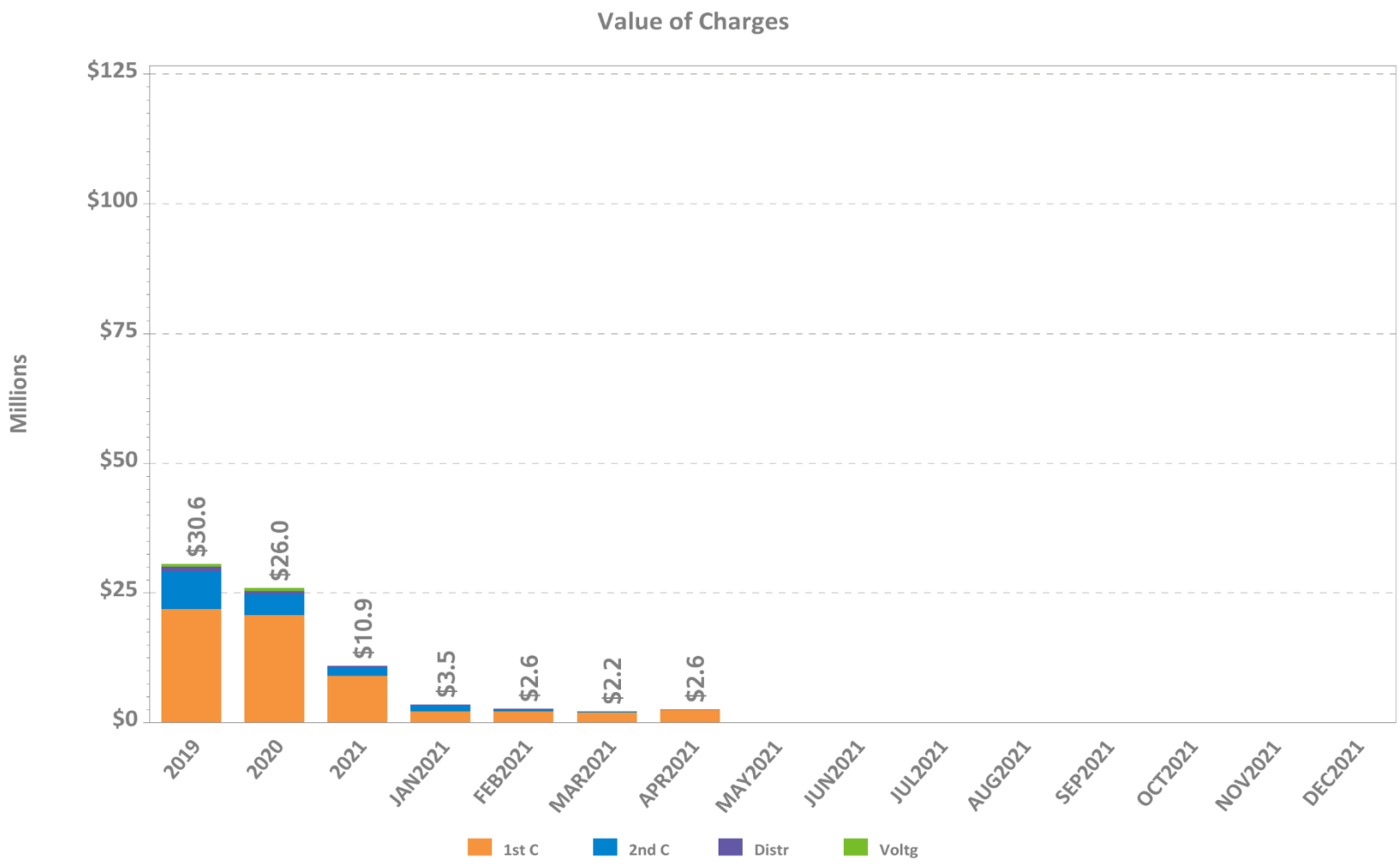


CT – Connecticut Region
ME – Maine Region
NH – New Hampshire Region
RI – Rhode Island Region
VT – Vermont Region
SEMA – Southeast Massachusetts Region
WCMA – Western/Central Massachusetts Region
NEMA – Northeast Massachusetts Region

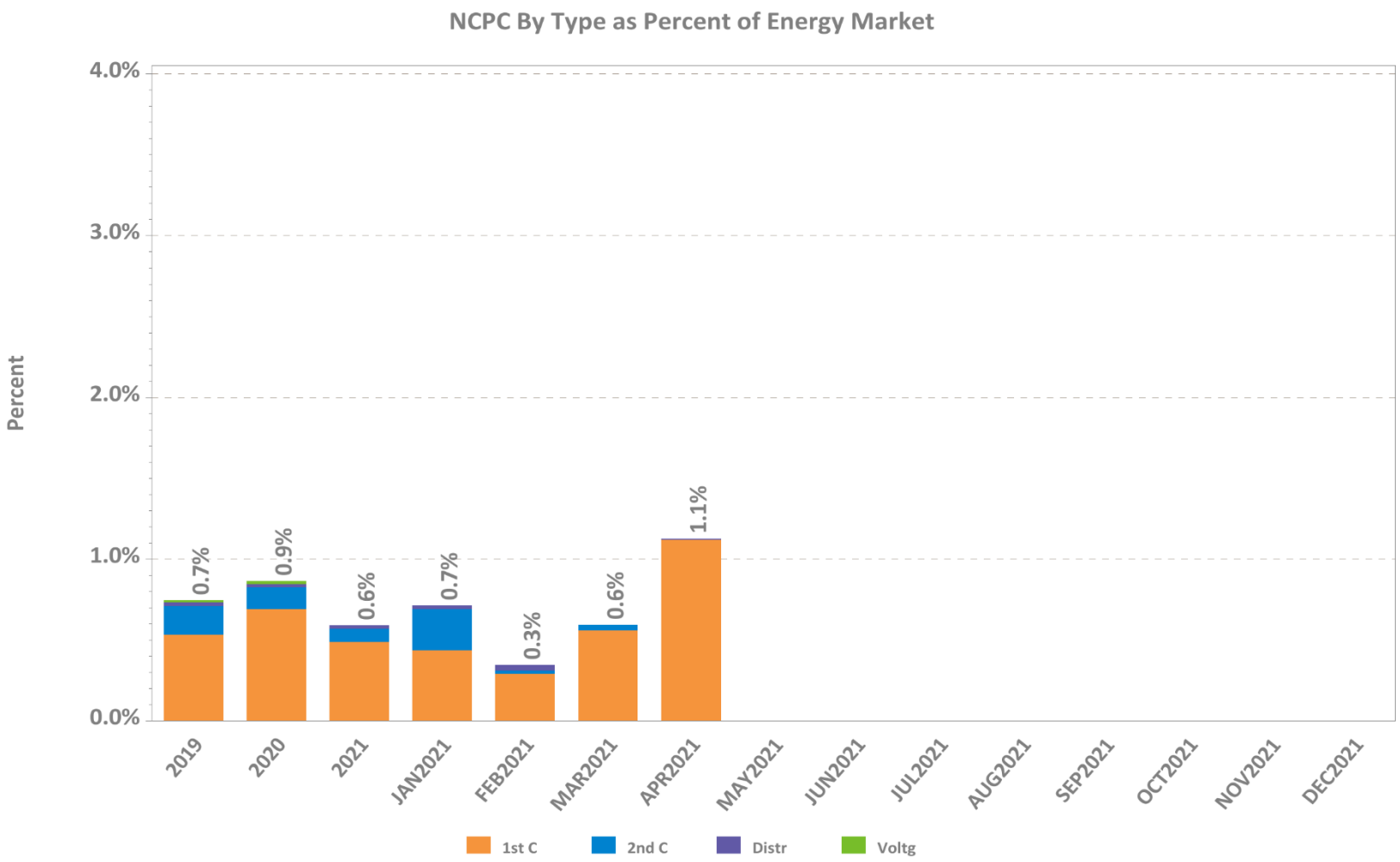
NCPC Charges for Voltage Support and High Voltage Control



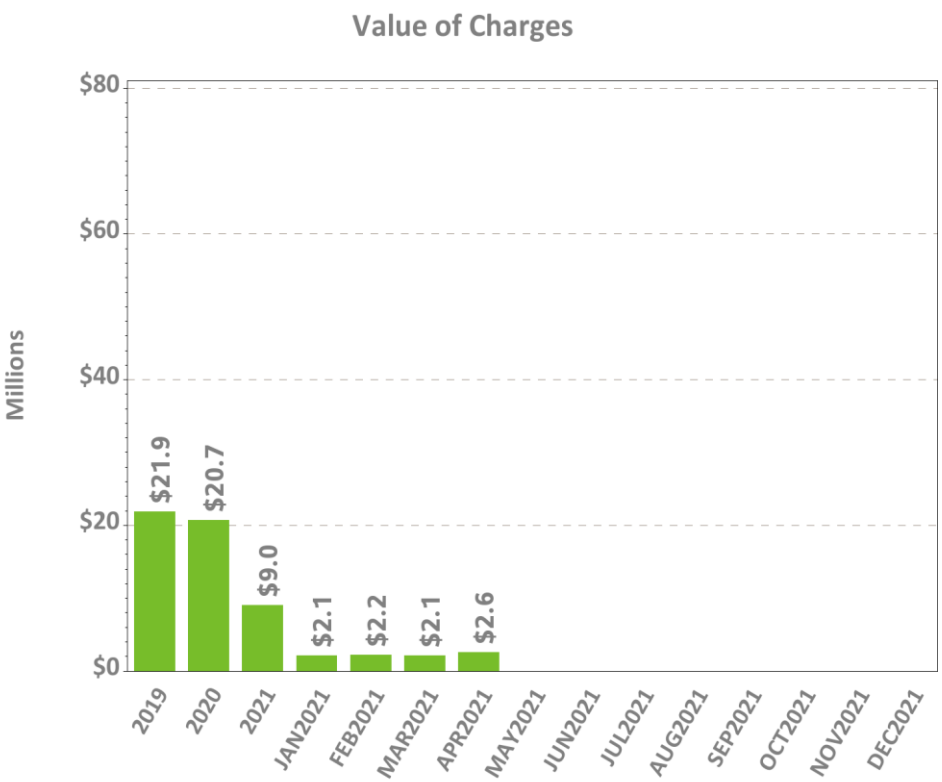
NCPC Charges by Type

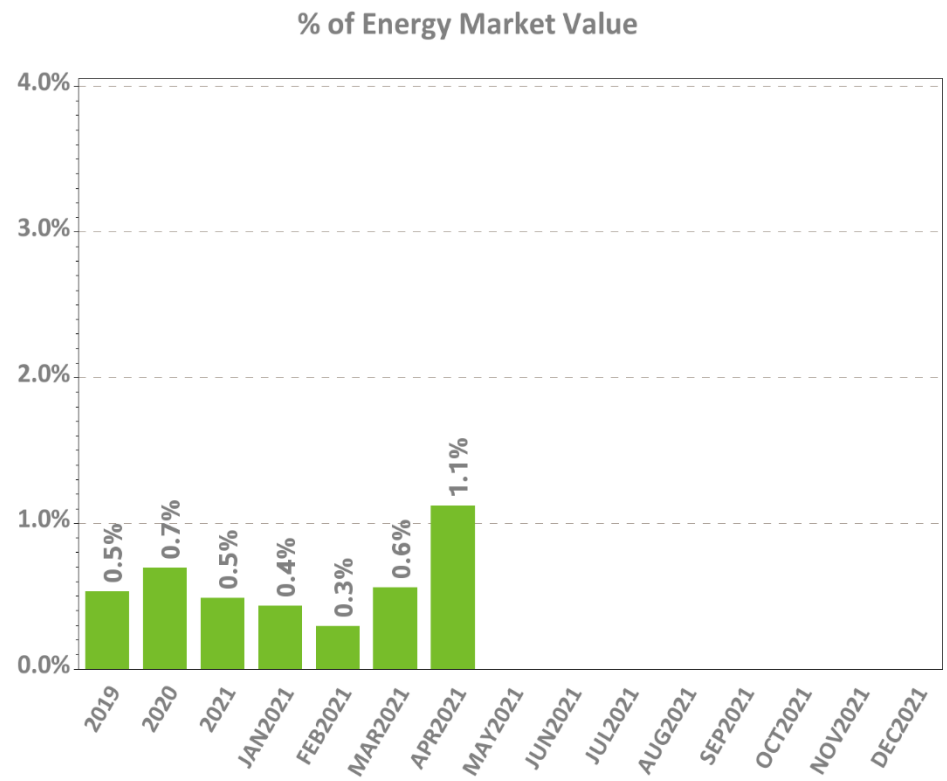


NCPC Charges as Percent of Energy Market



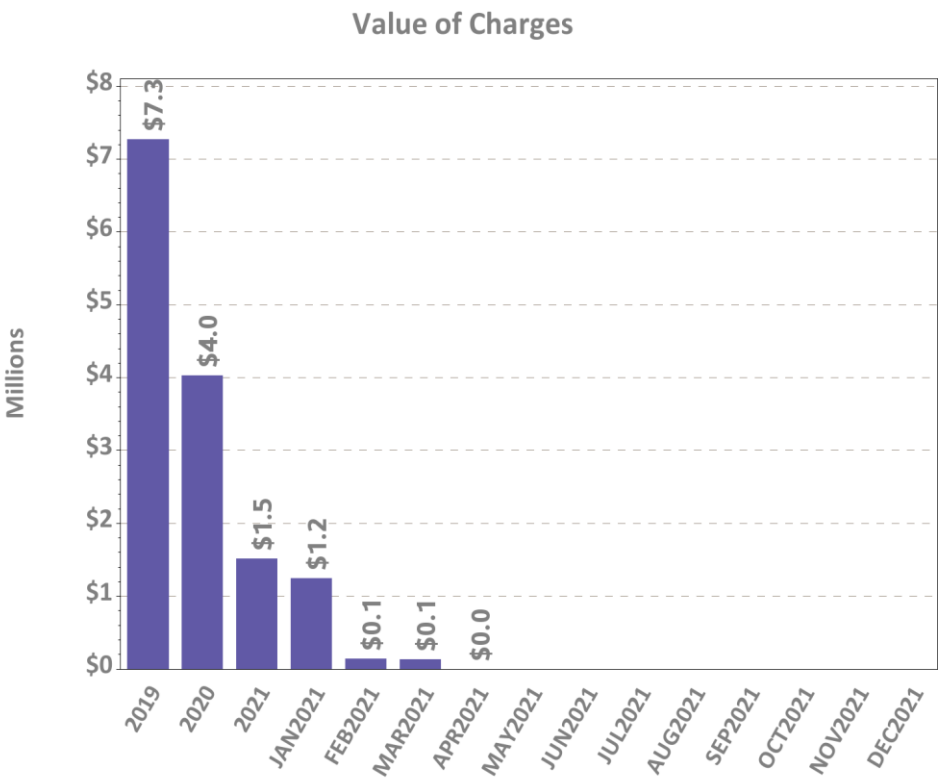
First Contingency NCPC Charges

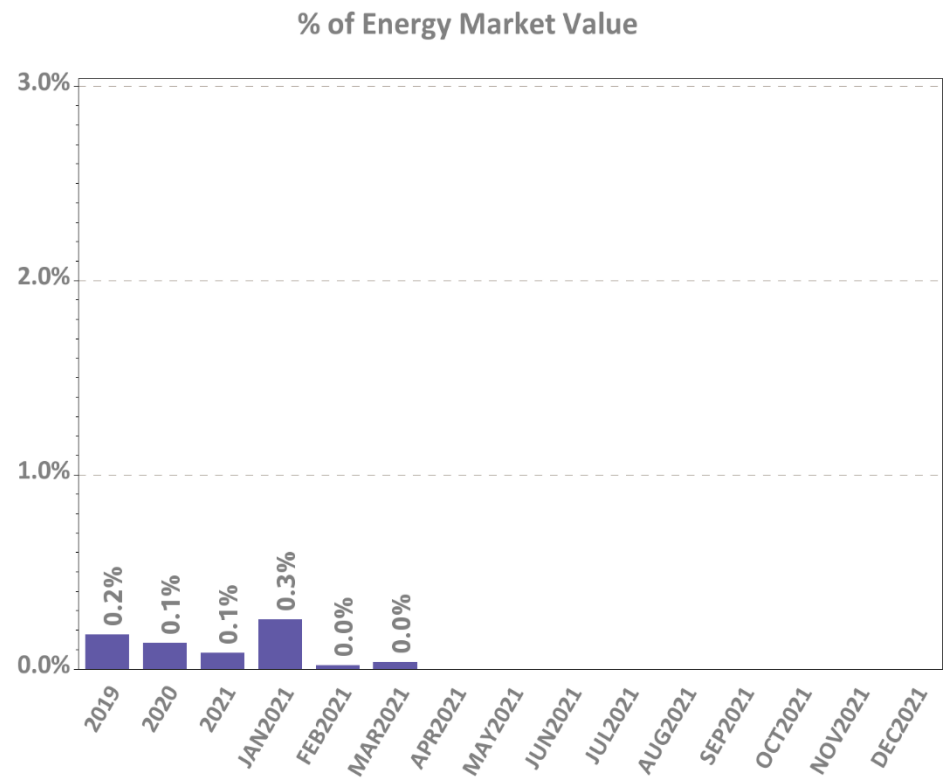




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

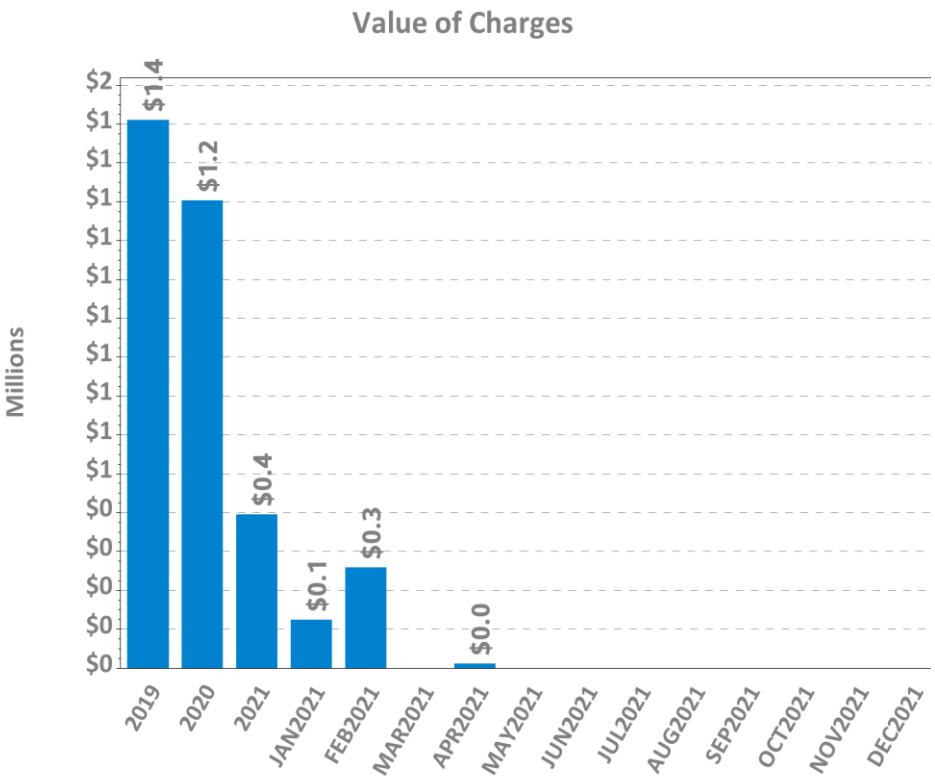
Second Contingency NCPC Charges

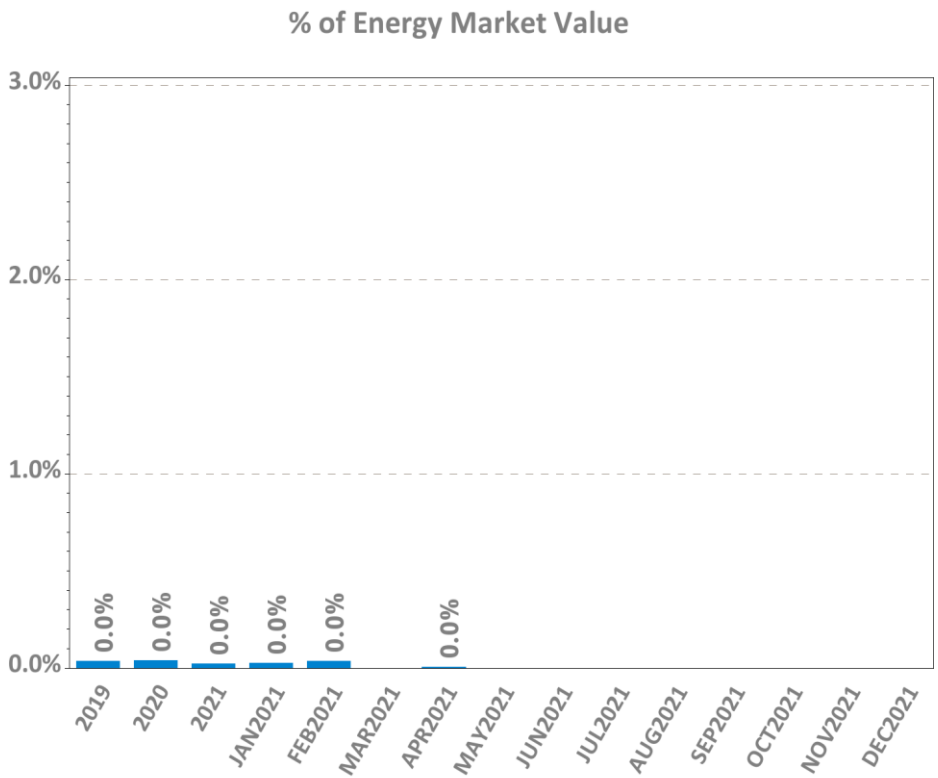




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution NCPC Charges





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

DA vs. RT Pricing

The following slides outline:

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

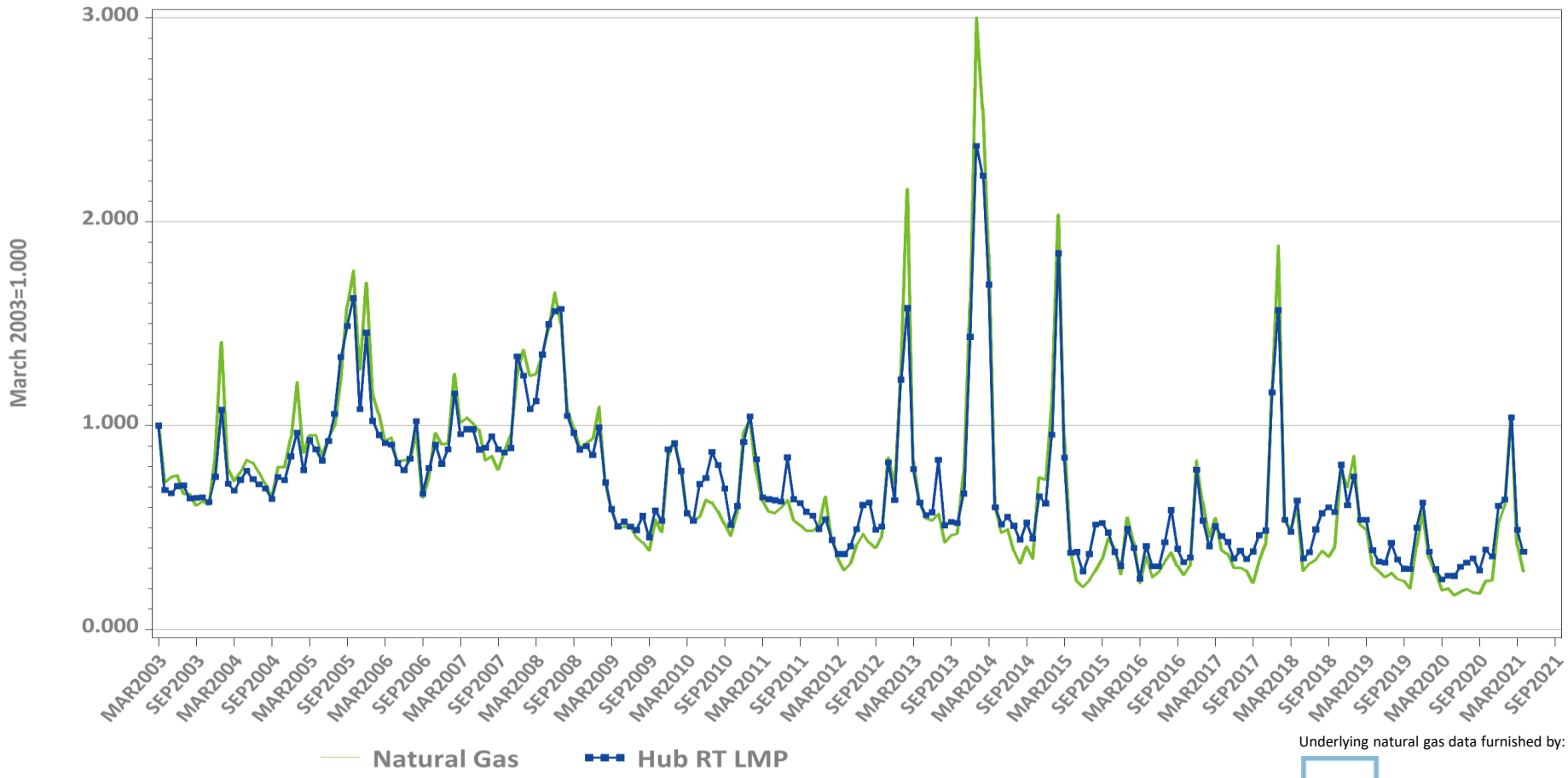
DA vs. RT LMPs ($/MWh)

Arithmetic Average

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

April-20	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$18.65	$17.70	$18.01	$18.42	$17.61	$18.33	$18.64	$18.32	$18.36
Real-Time	$18.35	$17.63	$17.47	$18.08	$17.30	$18.03	$18.32	$18.04	$18.09
RT Delta %	-1.6%	-0.4%	-3.0%	-1.8%	-1.8%	-1.6%	-1.7%	-1.5%	-1.5%
April-21	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Day-Ahead	$26.21	$25.73	$25.14	$25.92	$25.24	$26.06	$26.27	$26.07	$26.07
Real-Time	$26.38	$25.92	$25.34	$26.09	$25.39	$26.18	$26.41	$26.20	$26.19
RT Delta %	0.6%	0.7%	0.8%	0.7%	0.6%	0.5%	0.5%	0.5%	0.5%
Annual Diff.	**NEMA**	**CT**	**ME**	**NH**	**VT**	**RI**	**SEMA**	**WCMA**	**Hub**
Yr over Yr DA	40.6%	45.4%	39.6%	40.7%	43.3%	42.2%	41.0%	42.3%	42.0%
Yr over Yr RT	43.8%	47.0%	45.0%	44.3%	46.8%	45.2%	44.2%	45.2%	44.8%

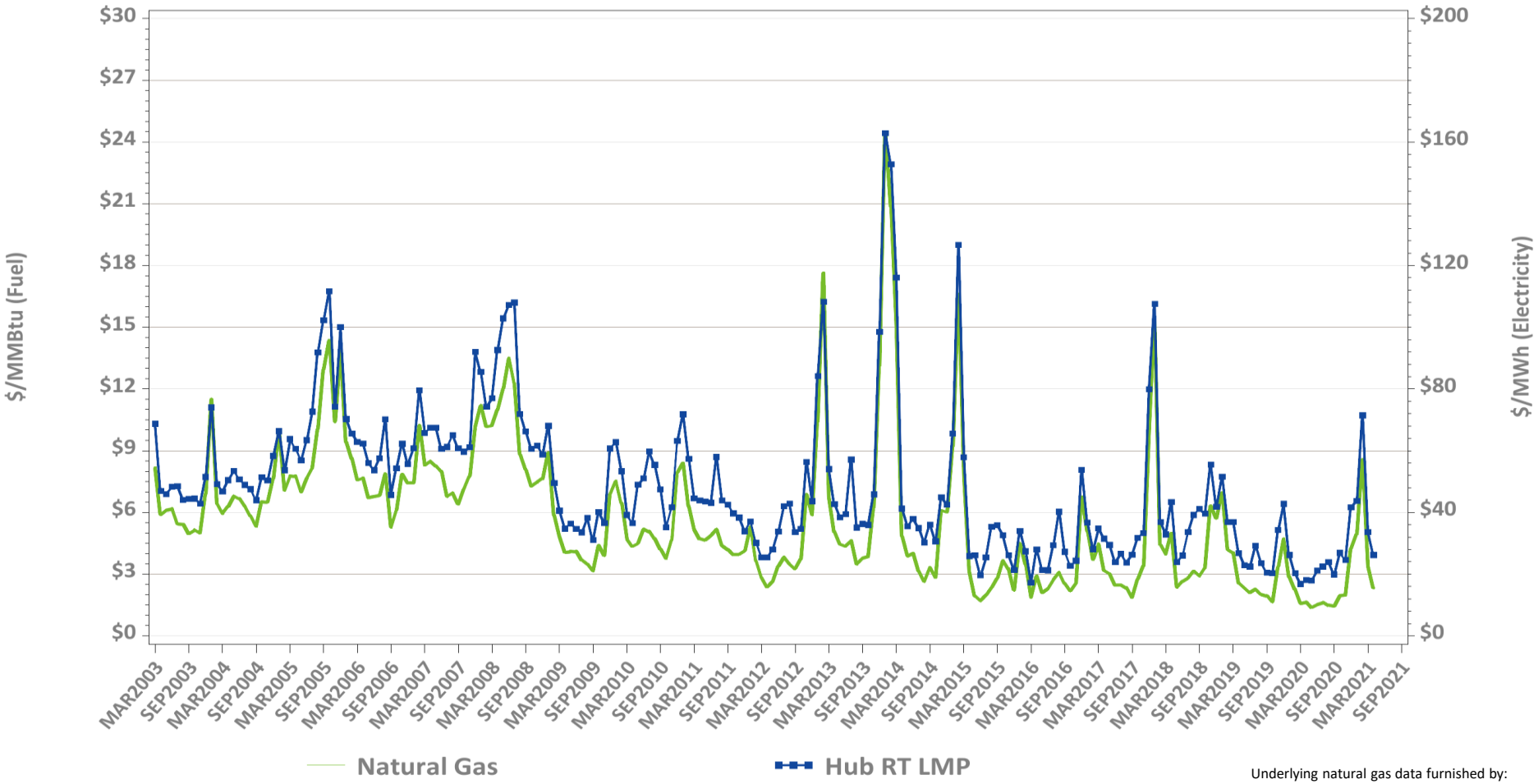
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ICE Global markets in clear view

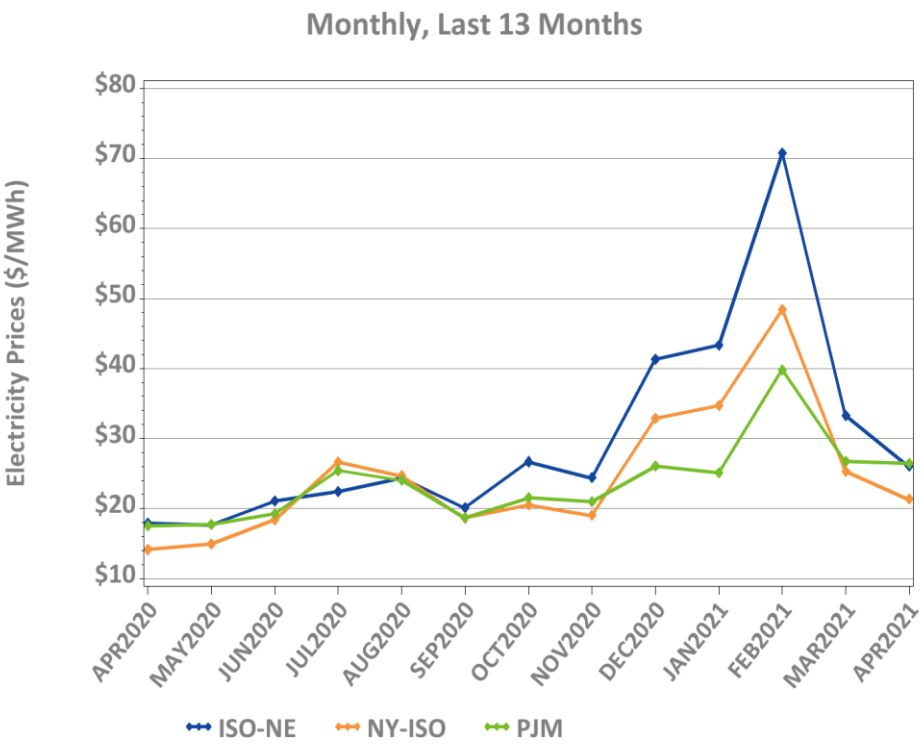
Monthly Average Fuel Price and RT Hub LMP



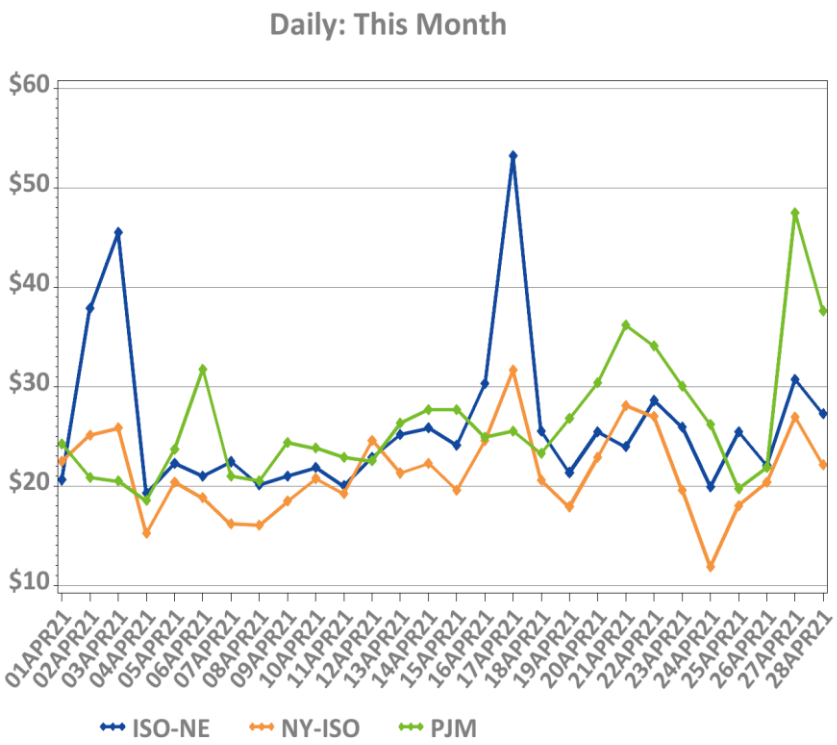
Underlying natural gas data furnished by:

ICE Global markets in clear view

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

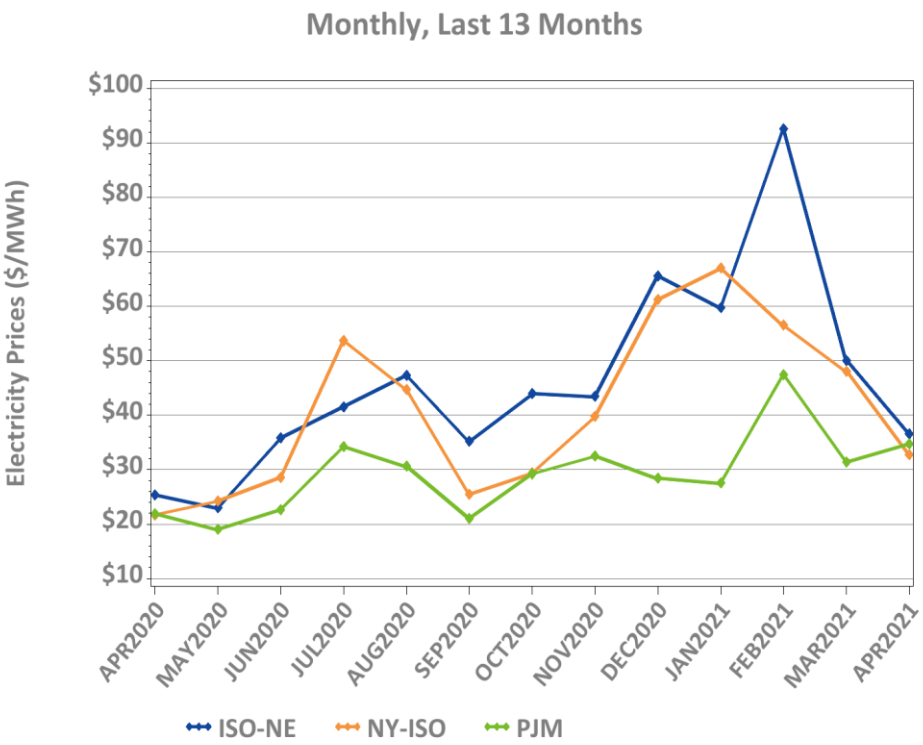


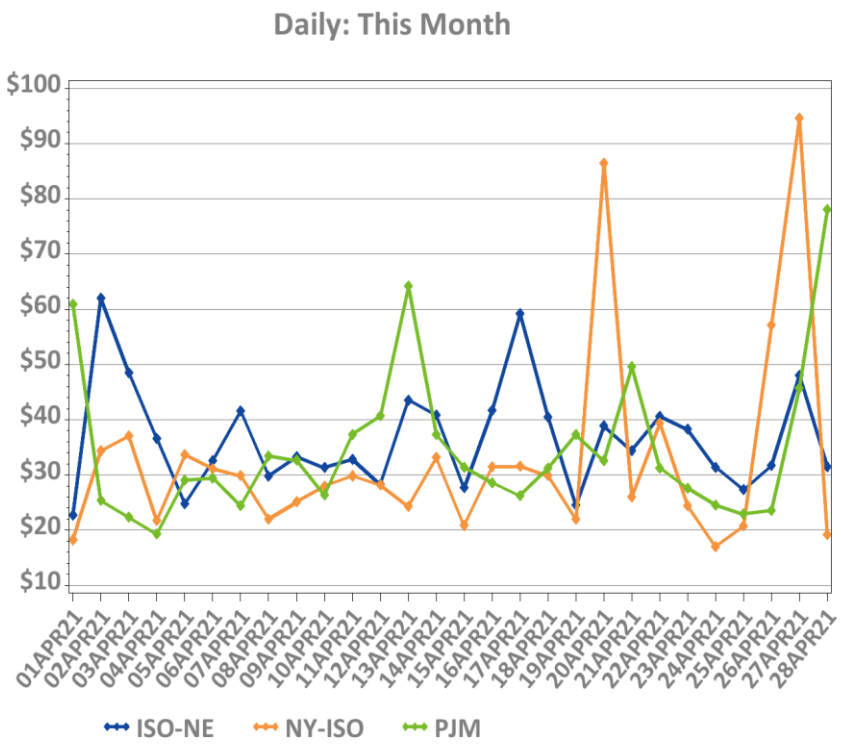
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





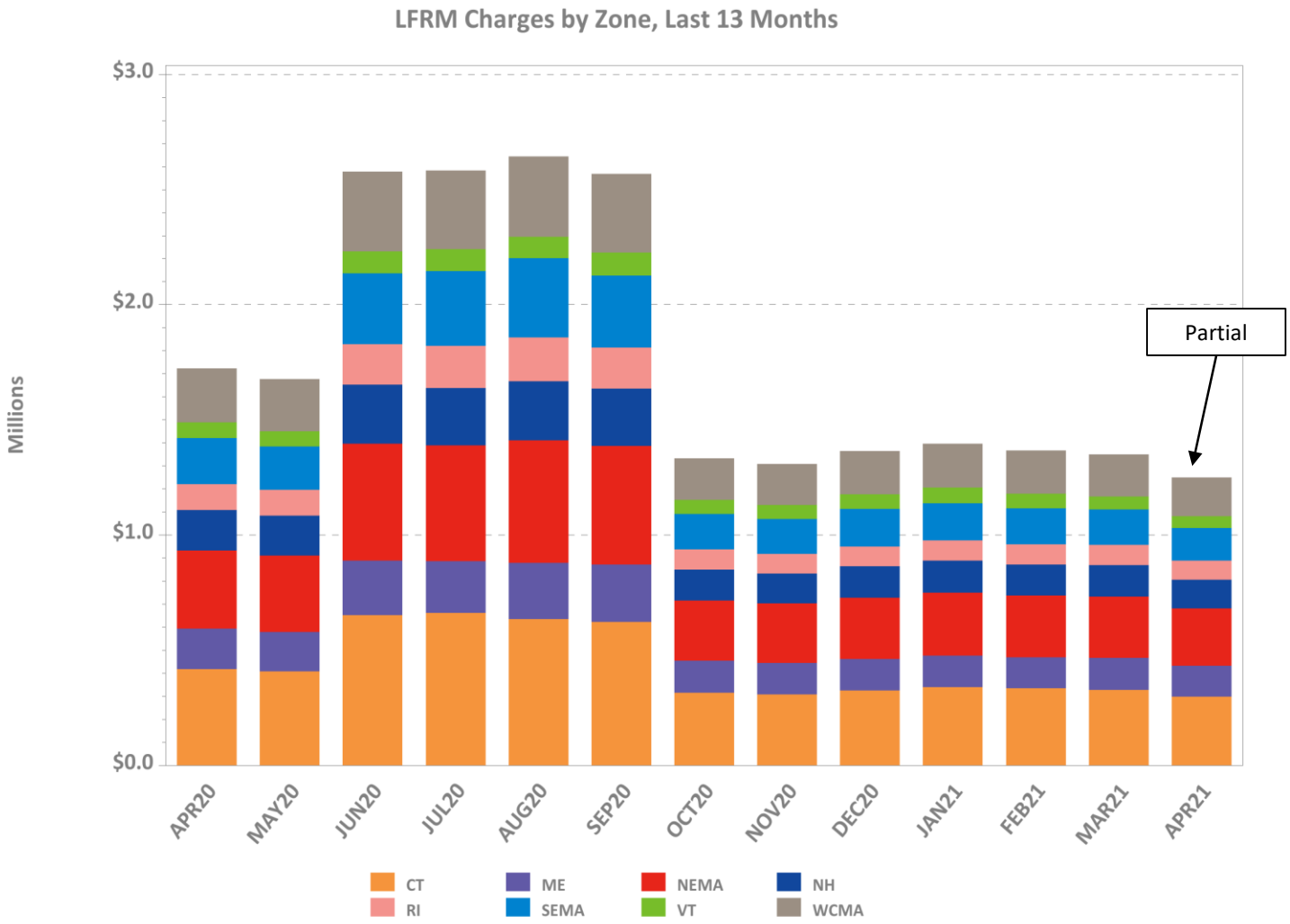
***Forecasted New England daily peak hours reflected**

Reserve Market Results – April 2021

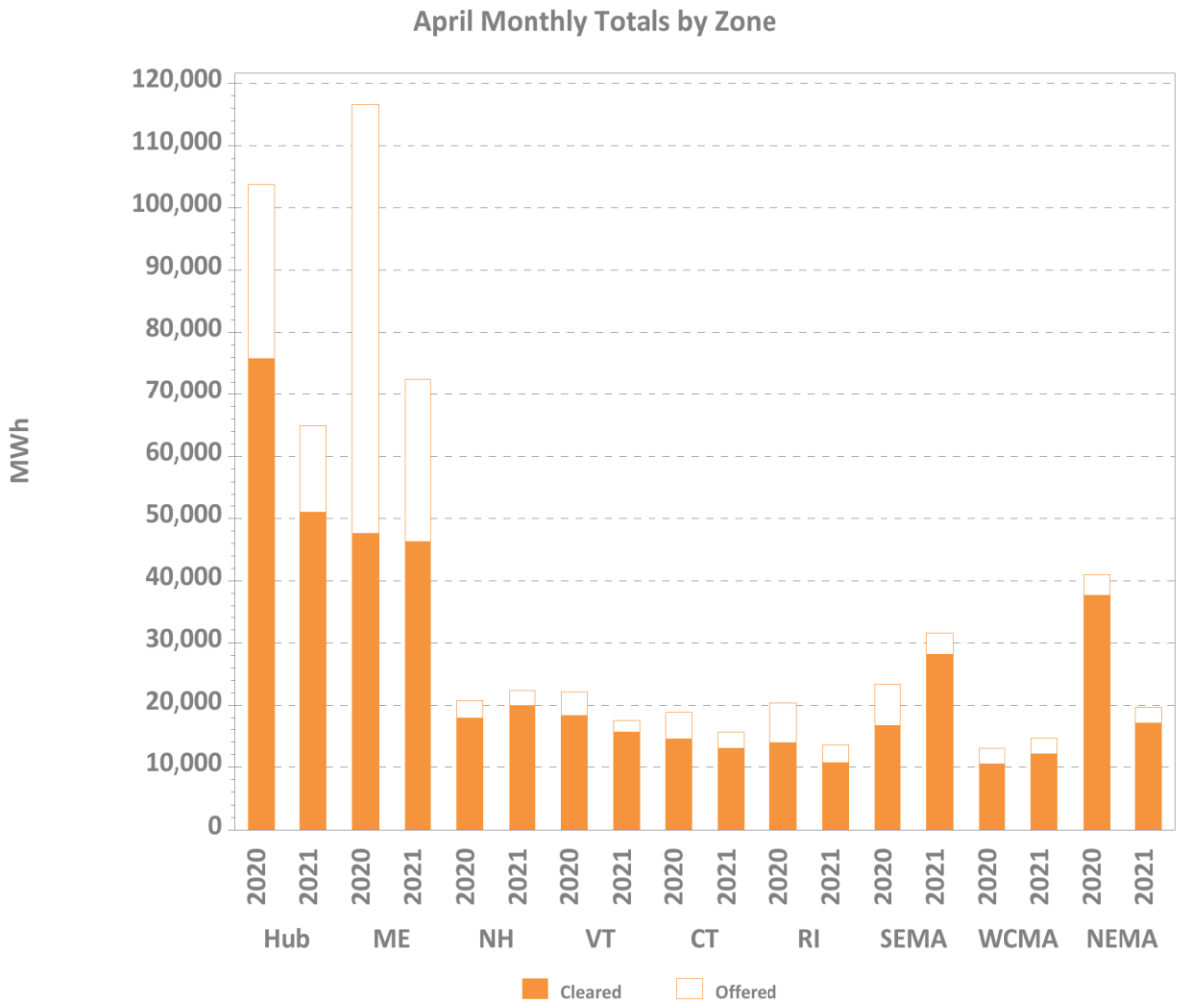
- Maximum potential Forward Reserve Market payments of $1.3M were reduced by credit reductions of $18K, failure-to-reserve penalties of $27K and no failure-to-activate penalties, resulting in a net payout of $1.1M or 96% of maximum
  - Rest of System: $0.97M/1.01M (97%)
  - Southwest Connecticut: $0.04M/0.04M (100%)
  - Connecticut: $0.24M/0.25M (95%)
- $659K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of $659K in Real-Time Reserve payments
  - Rest of System: 243 hours, $454K
  - Southwest Connecticut: 243 hours, $118K
  - Connecticut: 243 hours, $71K
  - NEMA: 243 hours, $17K

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.

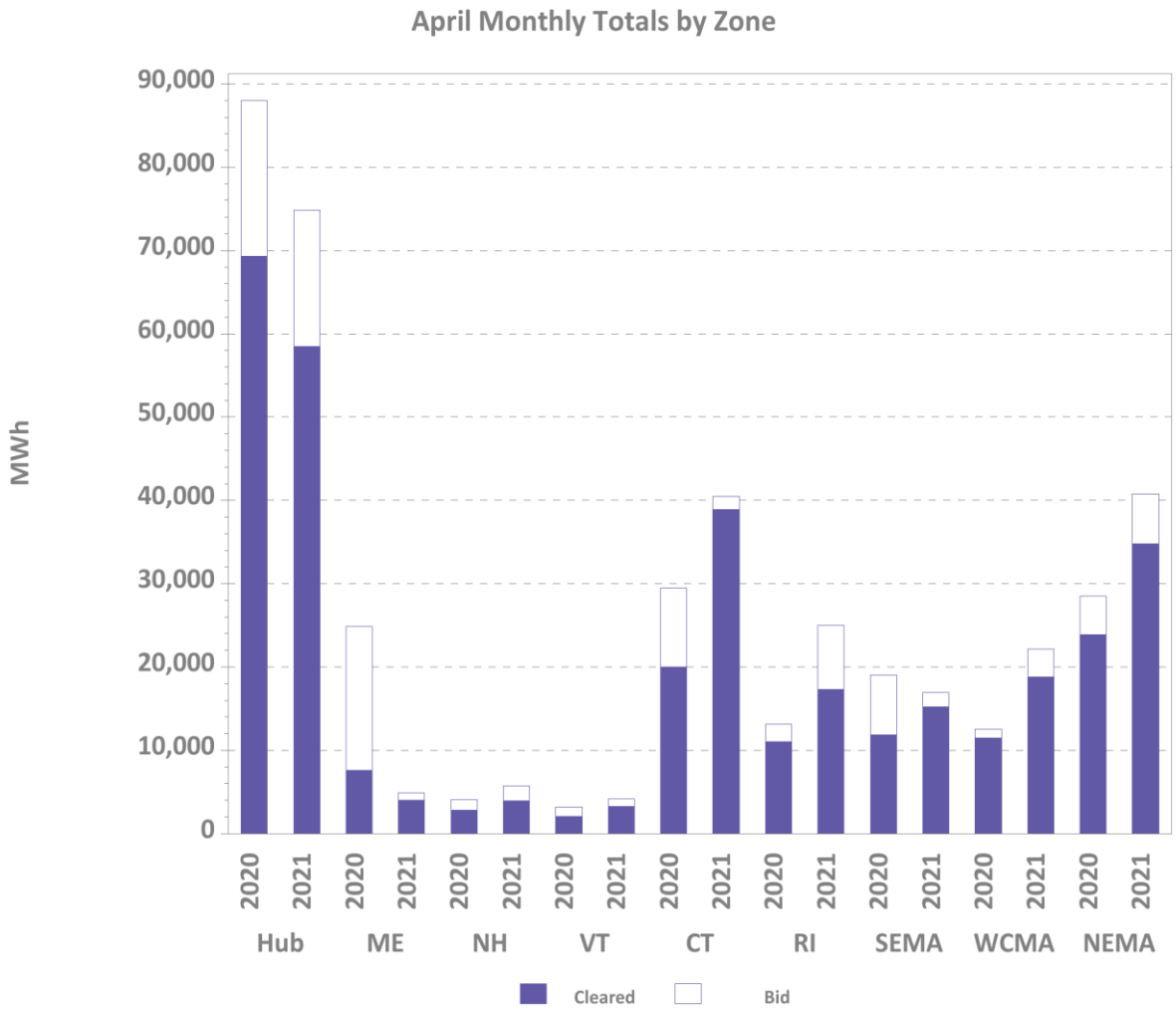
LFRM Charges to Load by Load Zone ($)



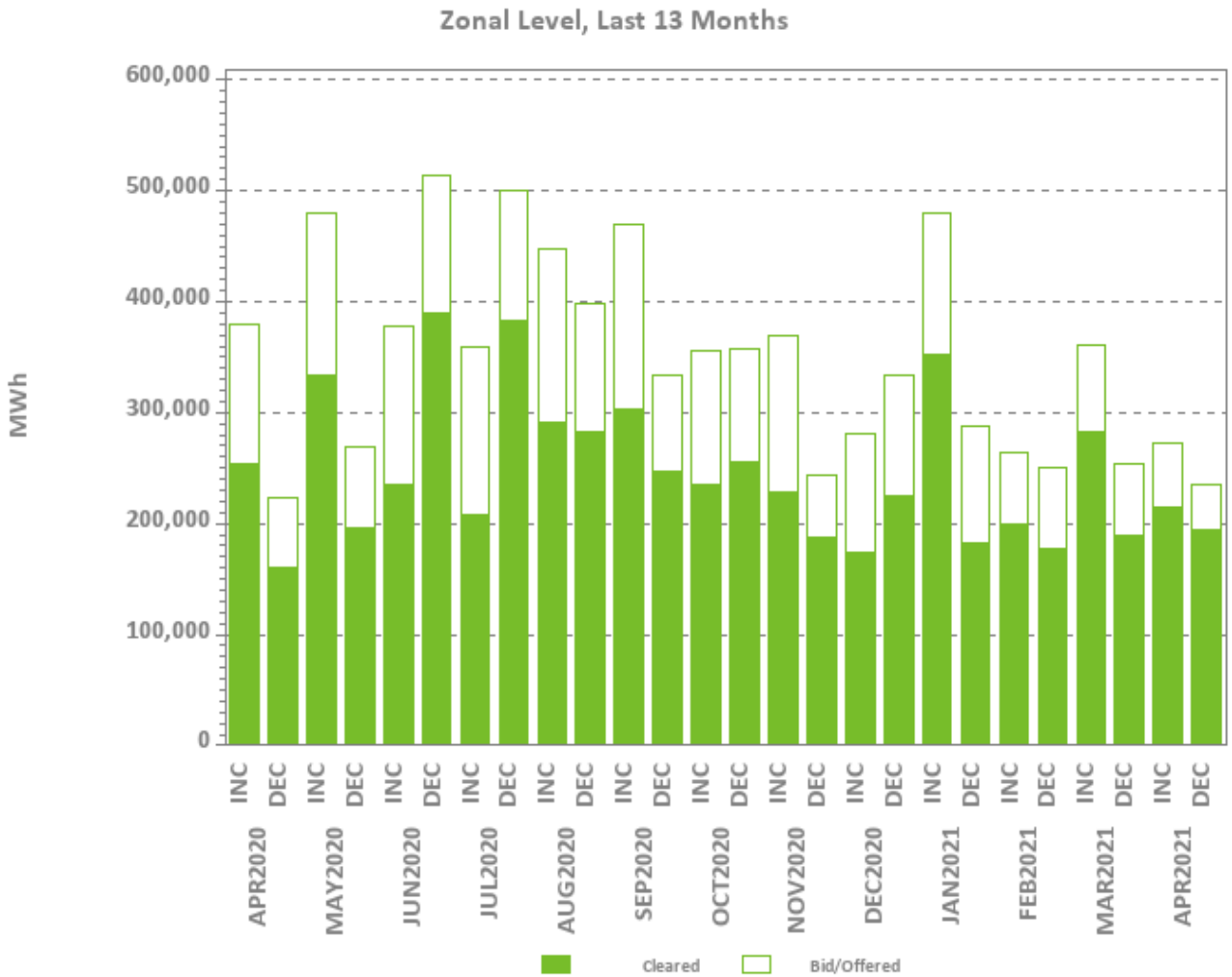
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

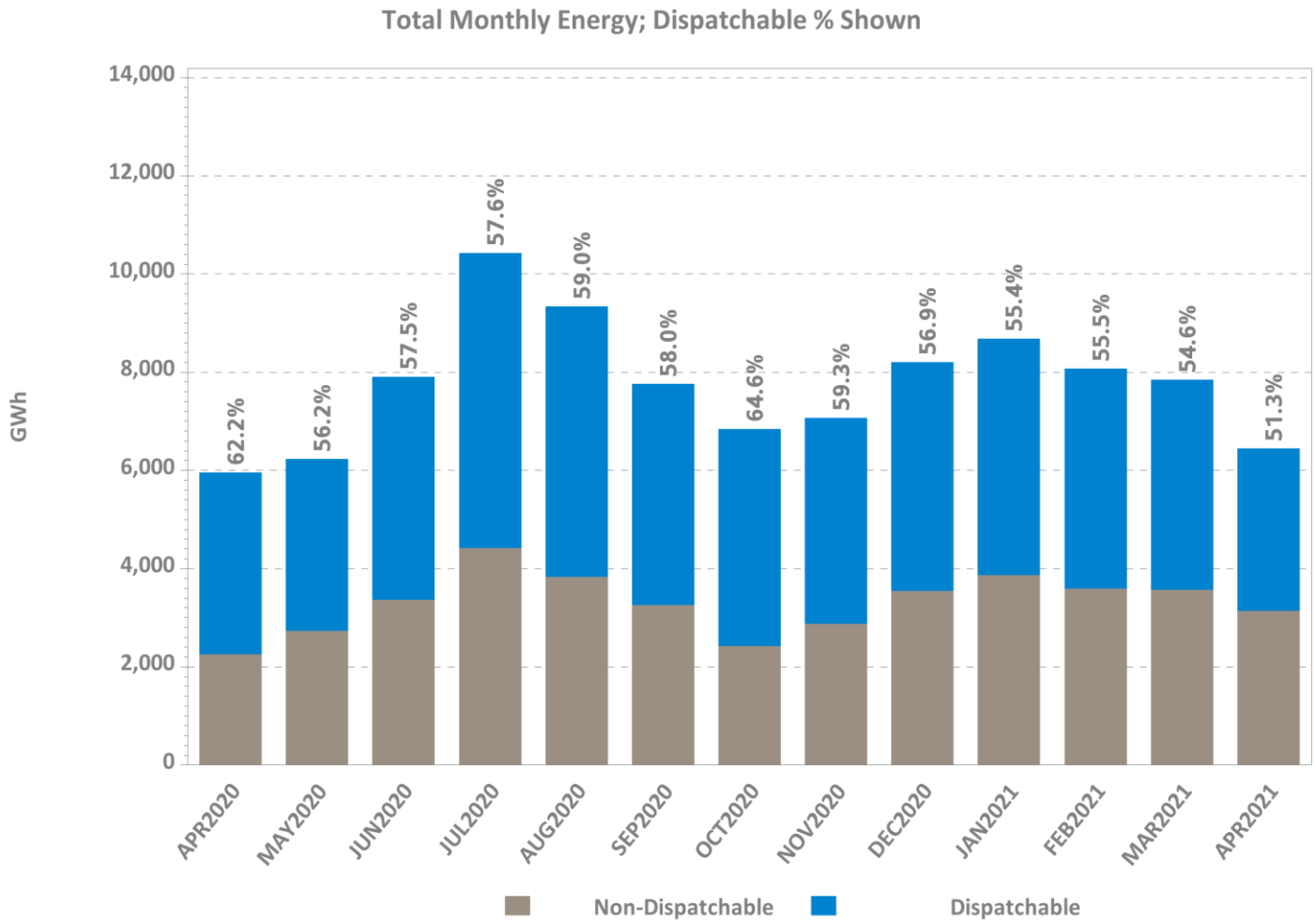


Total Increment Offers and Decrement Bids



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 (not offered 'must run') by the customer.**

REGIONAL SYSTEM PLAN (RSP)

Regional System Plan (RSP)

- 2021 is an RSP publication year (RSP21)
- Over the next few months, supporting presentations will be made at the PAC
- The report will be much shorter and the Executive Summary will be more comprehensive
  - Static information found in the RSP to be moved to the ISO-NE website
  - Dynamic information found in the RSP to be included in the report but at a high level
- RSP21 Public Meeting date is set for October 6
  - Venue and format have yet to be decided

Planning Advisory Committee (PAC)

- May 19 PAC Meeting Agenda Topics*
  - Millbury #2 - Asset Condition Replacement
  - C-129N 115kV Line (Millbury #2 - Beaver Pond) Fiber Installation
  - X-176 115kV Line (Ludlow – Palmer) Asset Condition Project
  - Cape Cod Resource Integration Study
  - 2021 Economic Study Request Assumptions – Part 2 of 2

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

Transmission Planning for the Clean-Energy Transition

- On 9/24/20 the ISO initiated discussions with the PAC about proposed refinements to study assumptions that better reflect long-term trends, such as increased amounts of distributed-energy resources (primarily solar PV), offshore wind generation, and battery energy storage
- A follow-up presentation at the 11/19/20 PAC meeting outlined a proposal for a pilot study, with the following goals:
  - Explore transmission reliability concerns that may result from various system conditions possible by 2030
  - Quantify trade-offs necessary between transmission system reliability/flexibility and transmission investment cost
  - Inform future discussions on transmission planning study assumptions
- An overview of the system conditions and dispatch assumptions for the pilot study was discussed at the 12/16/20 and 1/21/21 PAC meetings
- Study work is in progress, with results expected in Q2 or Q3

Economic Studies

- 2020 Economic Study Request
  - Study proponent is National Grid
  - Study simulations are complete, and results have been presented to PAC
    - Ancillary Services simulations will not be performed
    - Report to be completed by June 1
- 2021 Economic Study Request
  - Submitted in accordance with Attachment K, Section 4.1(b) of the Tariff
  - FGRS Phase 1 Study will be the only 2021 economic study, which was submitted by NEPOOL
    - Assumptions and results presentations will go to the PAC monthly, with periodic updates to the MC/RC

Future Grid Reliability Study (FGRS)

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

Environmental Matters – Reset on Federal Environmental Priorities

U.S. Paris Agreement Goal Updated, No Specific Power Sector Target Yet

- U.S. proposes reducing greenhouse gas (GHG) emissions 50% below 2005 levels (7,423 million metric tons (MMT)) by 2030:
  - In 2020, preliminary estimates indicate U.S. GHG emissions fell to 5,160 MMT, 21% below 2005 levels; U.S. power sector GHG emissions were 1,488 MMT
    - New England power sector – 21.4 MMT GHG emissions in 2020
  - In 2019, U.S. GHG emissions were 6,558 MMT; U.S. power sector GHG emissions were 1,648 MMT
    - New England power sector – 20.8 MMT GHG emissions in 2019
- EPA expected to outline approach on power sector GHG emissions standards by summer

Upcoming Rulemakings and Anticipated Regulatory Actions

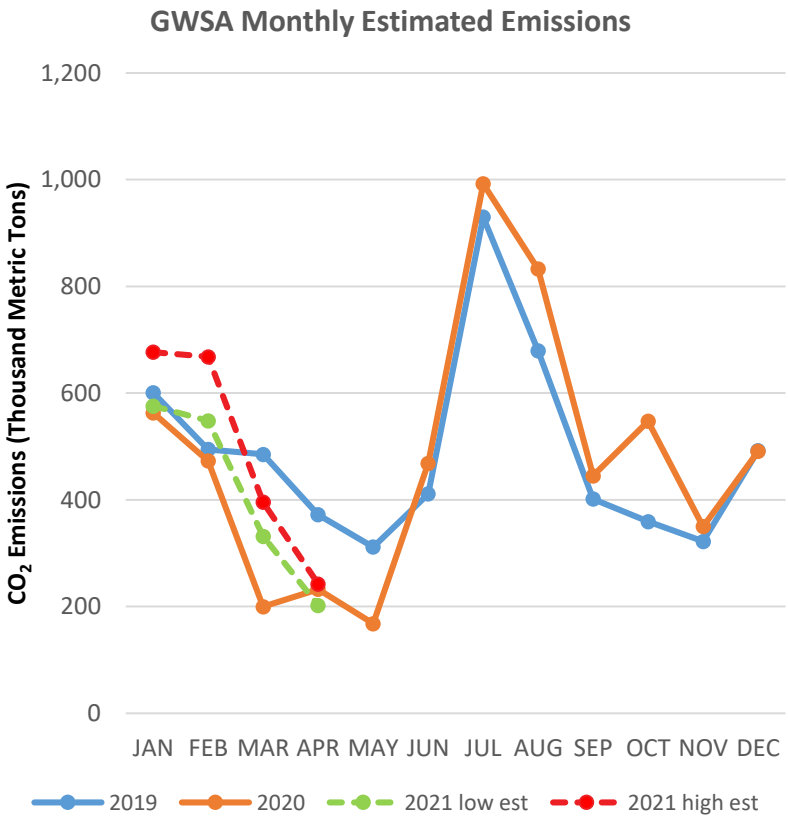
- Ozone & particulate air quality standards: EPA currently evaluating whether to strengthen existing standards
  - Could require additional controls on emitting generators across southern New England
- EPA reviewing changes to air permitting requirements; may revoke flexibility, weaker limits
- Other updates to regional haze, upwind air pollution rules may also impact emitting generators

Environmental Matters – Massachusetts CO_2 Generator Emissions Cap

2021 CO_2 Emissions Trending Higher Than Past 1st Quarters

- As of 4/25/21, 2021 estimated CO_2 emissions range between 1.45 and 1.75 MMT:
  - 1.9 MMT in 2019; 1.5 MMT in 2020
  - 18% to 21% of the 8.23 MMT 2021 cap
- 3/11/21: GWSA auction clearing price was $6.50 per metric ton
  - GWSA allowances valued below RGGI allowances (RGGI allowances $7.21 per metric ton (direct comparison to GWSA metric ton allowance) or $7.95 per short ton)
- 12/16/20: GWSA auction clearing price was $7.25 per metric ton

2019-2021 Estimated Monthly Emissions (Thousand Metric Tons)



GWSA - Global Warming Solutions Act

RSP Project Stage Descriptions

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

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

Greater Boston Projects

Status as of 4/28/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install new 345 kV line from Scobie to Tewksbury	Dec-17	4
Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Apr-17	4
Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-19	4
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-22	3*
Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	4
Reconductor W-23W 69 kV line from Woodside to Northboro Road	Jun-19	4

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

Greater Boston Projects, cont.

Status as of 4/28/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Separate X-24 and E-157W DCT	Dec-18	4
Separate Q-169 and F-158N DCT	Dec-15	4
Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Sep-20	4
Install third 115 kV line from West Walpole to Holbrook	Sep-20	4
Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
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
Install a new 115 kV line from Sudbury to Hudson	Dec-23	2

Greater Boston Projects, cont.

Status as of 4/28/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-19	4
Install a 345 kV breaker in series with breaker 104 at Woburn	May-17	4
Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	4
Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	4
Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	4
Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	May-19	4
Install a 115 kV breaker on the East bus at K Street	Jun-16	4
Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	May-21	3*
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	May-21	3

*Mystic to Chelsea line portion of the project is a present stage 4 as of October 2020.

Greater Boston Projects, cont.

Status as of 4/28/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	May-22	3
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
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	4
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 4/28/2021

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

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

SEMA/RI Reliability Projects

Status as of 4/28/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
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
Conduct remote terminal station work at the Wampanoag and Pawtucket substations for the new Grand Army GIS switching station	Oct-20	4
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
Increase clearances on E-183E & F-184 lines between Brayton Point and Grand Army substations	Nov-19	4
Separate the X3/W4 DCT and reconductor the X3 and W4 lines between Somerset and Grand Army substations; reconfigure Y2 and Z1 lines	Nov-19	4

SEMA/RI Reliability Projects, cont.

Status as of 4/28/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Dec-21	3
Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	May-25	2
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	Jun-23	2
Extend the Line 114 from the Dartmouth town line (Eversource-NGRID border) to Bell Rock substation	Dec-23	2
Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Cancelled*	N/A

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

SEMA/RI Reliability Projects, cont.

Status as of 4/28/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	Dec-23	1
Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	3
Retire the Barnstable SPS	Dec-21	3
Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Dec-22	1
Install a new bay position at Kingston substation to accommodate new 115 kV line	Dec-22	1
Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-23	1

SEMA/RI Reliability Projects, cont.

Status as of 4/28/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	3
Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Jan-23	2
Separate the 325/344 DCT lines from West Medway to West Walpole substations	Cancelled**	N/A
Reconductor and upgrade the 112 Line from the Tremont substation to the Industrial Tap	Jun-18	4
Reconductor the 108 line from Bourne substation to Horse Pond Tap*	Oct-18	4
Replace disconnect switches on 323 line at West Medway substation and replace 8 line structures	Aug-20	4

* Does not include the reconductoring work over the Cape Cod canal
** Cancelled per ISO-NE PAC presentation on August 27, 2020

SEMA/RI Reliability Projects, cont.

Status as of 4/28/2021

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

Upgrade	Expected/ Actual In-Service	Present Stage
Rebuild the Middleborough Gas and Electric portion of the E1 line from Bridgewater to Middleborough	Apr-19	4
Reconductor the J16S line	Jun-22	2
Replace the Kent County 345/115 kV transformer	Mar-22	2
West Medway 345 kV circuit breaker upgrades	Dec-21	3
Medway 115 kV circuit breaker replacements	Nov-20	4

Eastern CT Reliability Projects

Status as of 4/28/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

Upgrade	Expected/ Actual In-Service	Present Stage
Reconductor the L190-4 and L190-5 line sections	Dec-26	1
Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation	Mar-23	2
Upgrade Card 115 kV to BPS standards	Mar-23	2
Install one 115 kV circuit breaker in series with Card substation 4T	Mar-23	2
Convert Gales Ferry substation from 69 kV to 115 kV	Dec-23	1
Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Dec-21	1

Eastern CT Reliability Projects, cont.

Status as of 4/28/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

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

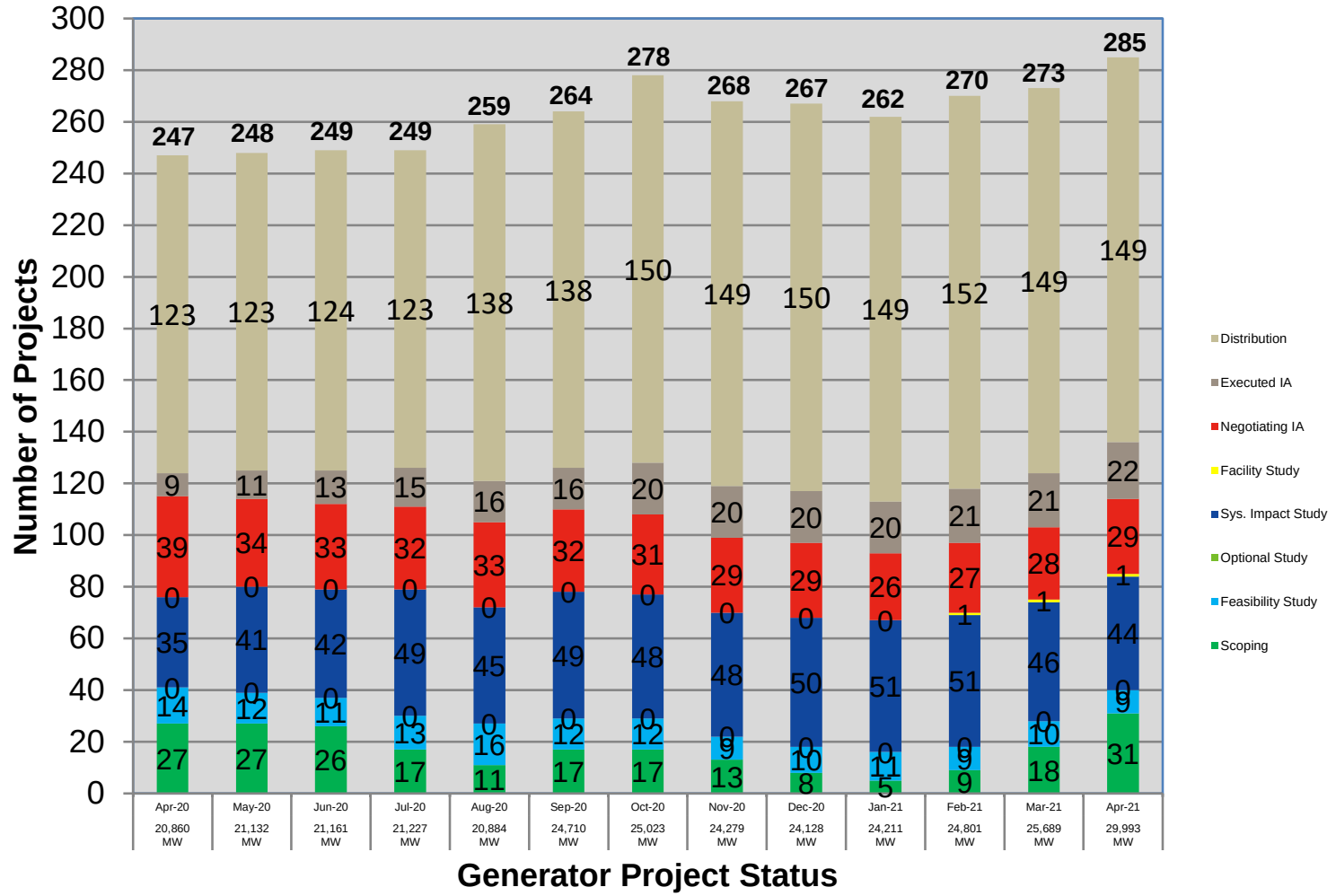
Eastern CT Reliability Projects, cont.

Status as of 4/28/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

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

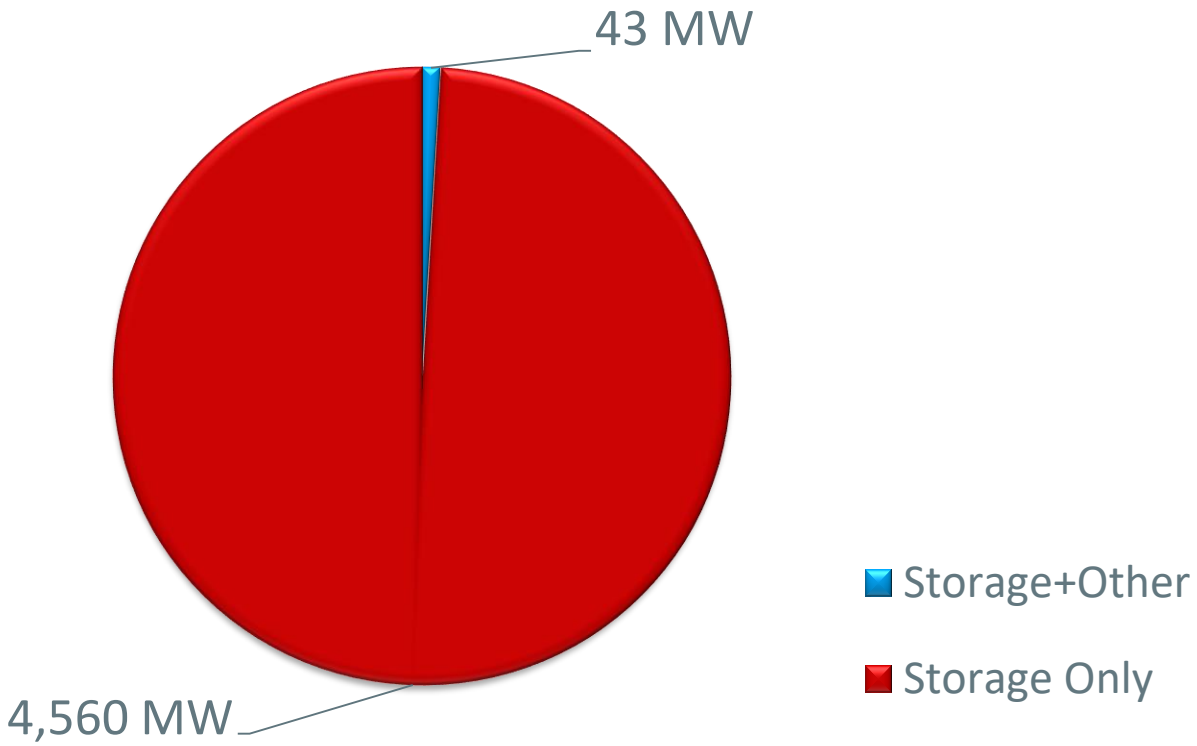
Status of Tariff Studies



Note: April 2021 is based on partial data.
As of April 2021, there is 1 ETU in Scoping, 0 in FS, 3 in SIS, 0 in OIS, 0 in FAC, 0 Negotiating IA, and 2 with Executed IA.
https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of April 26, 2021)

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



OPERABLE CAPACITY ANALYSIS

Spring 2021 Analysis

Spring 2021 Operable Capacity Analysis

50/50 Load Forecast (Reference)	May - 2021[2] CSO (MW)	May - 2021[2] SCC (MW)
Operable Capacity MW [1]	30,304	33,393
Active Demand Capacity Resource (+) [5]	429	405
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,183	1,183
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outage MW (-)	2,505	3,196
Gas Generator Outages MW (-)	1,885	2,293
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)	24,126	26,092
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	18,063	18,063
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	20,368	20,368
Operable Capacity Margin	3,758	5,723

[1]Operable Capacity is based on data as of **April 27, 2021** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **April 27, 2021.**

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

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

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

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

Spring 2021 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	May - 2021[2] CSO (MW)	May - 2021[2] SCC (MW)
Operable Capacity MW [1]	30,304	33,393
Active Demand Capacity Resource (+) [5]	429	405
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,183	1,183
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outage MW (-)	2,505	3,196
Gas Generator Outages MW (-)	1,885	2,293
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)	24,126	26,092
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	19,500	19,500
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	21,805	21,805
Operable Capacity Margin	2,321	4,286

[1]Operable Capacity is based on data as of **April 27, 2021** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **April 27, 2021.**

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

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

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

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

Spring 2021 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

April 30, 2021 - 50-50 FORECAST using CSO MW

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

Report created: 4/27/2021

Study Week (Week Begining , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	CSO Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
5/8/2021	30304	429	1183	0	2505	1885	3400	0	24126	18063	2305	20368	3758	Y	Spring 2021
5/15/2021	30304	429	1183	0	1676	1632	3400	0	25208	19057	2305	21362	3846	N	Spring 2021
5/22/2021	30304	429	1183	0	1225	982	3400	0	26309	19981	2305	22286	4023	N	Spring 2021

Column Definitions

1. **CSO Supply Resource Capacity MW:** Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. **CSO Demand Resource Capacity MW:** Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. **External Node Capacity MW:** Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. **Non-Commercial capacity MW:** New resources and generator improvements that have acquired a CSO but have not become commercial.
5. **CSO Non Gas-Only Generator Planned Outages MW:** All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. **CSO Gas-Only Generator Planned Outages MW:** All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. **Unplanned Outage Allowance MW:** Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. **CSO Generation at Risk Due to Gas Supply Mw:** Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. **CSO Net Available Capacity MW:** the summation of columns (1+2+3+4-5-6-7-8=9)
10. **Peak Load Forecast MW:** Provided in the annual 2021 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. **Operating Reserve Requirement MW:** 120% of first largest contingency plus 50% of the second largest contingency.
12. **CSO Net Required Capacity MW:** (Net Load Obligation) (10+11=12)
13. **CSO Operable Capacity Margin MW:** CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. **Operable Capacity Season Label:** Applicable season and year.
15. **Season Minimum Operable Capacity Flag:** this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Spring 2021 Operable Capacity Analysis
90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

April 30, 2021 - 90-10 FORECAST using CSO MW

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

Report created: 4/27/2021

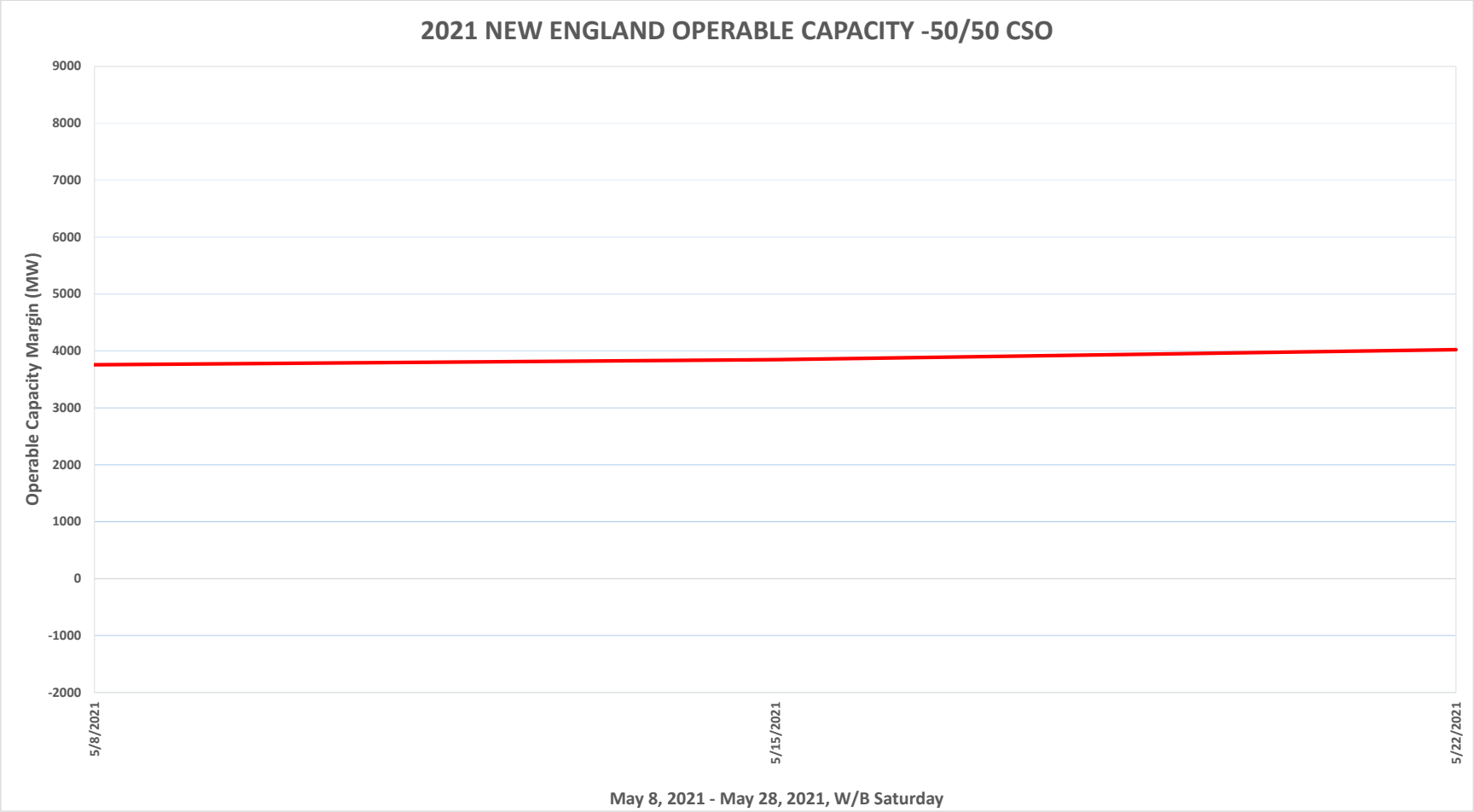
Study Week (Week Begining , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	CSO Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
5/8/2021	30304	429	1183	0	2505	1885	3400	0	24126	19500	2305	21805	2321	Y	Spring 2021
5/15/2021	30304	429	1183	0	1676	1632	3400	0	25208	20560	2305	22865	2343	N	Spring 2021
5/22/2021	30304	429	1183	0	1225	982	3400	0	26309	21546	2305	23851	2458	N	Spring 2021

Column Definitions

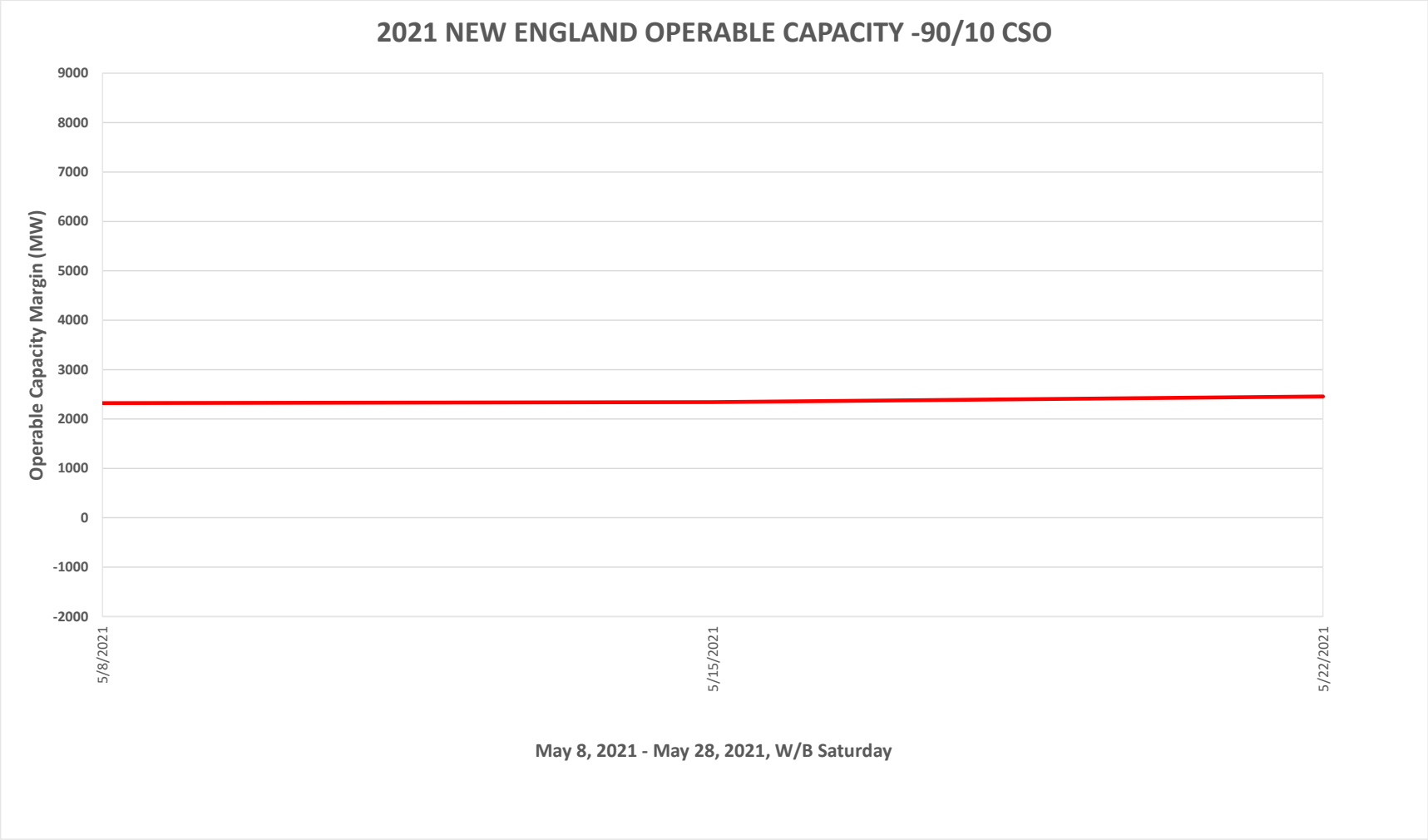
1. **CSO Supply Resource Capacity MW:** Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. **CSO Demand Resource Capacity MW:** Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. **External Node Capacity MW:** Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. **Non-Commercial capacity MW:** New resources and generator improvements that have acquired a CSO but have not become commercial.
5. **CSO Non Gas-Only Generator Planned Outages MW:** All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. **CSO Gas-Only Generator Planned Outages MW:** All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. **Unplanned Outage Allowance MW:** Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. **CSO Generation at Risk Due to Gas Supply Mw:** Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. **CSO Net Available Capacity MW:** the summation of columns (1+2+3+4-5-6-7-8=9)
10. **Peak Load Forecast MW:** Provided in the annual 2021 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. **Operating Reserve Requirement MW:** 120% of first largest contingency plus 50% of the second largest contingency.
12. **CSO Net Required Capacity MW:** (Net Load Obligation) (10+11=12)
13. **CSO Operable Capacity Margin MW:** CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. **Operable Capacity Season Label:** Applicable season and year.
15. **Season Minimum Operable Capacity Flag:** this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

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



Spring 2021 Operable Capacity Analysis
90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Summer 2021 Analysis

Summer 2021 Operable Capacity Analysis

50/50 Load Forecast (Reference)	September - 2021[2] CSO (MW)	September - 2021[2] SCC (MW)
Operable Capacity MW [1]	29,380	30,056
Active Demand Capacity Resource (+) [5]	505	431
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,208	1,208
Non Commercial Capacity (+)	50	50
Non Gas-fired Planned Outage MW (-)	2,414	2,617
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	26,629	27,029
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	24,810	24,810
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	27,115	27,115
Operable Capacity Margin	-486	-86

[1]Operable Capacity is based on data as of **April 27, 2021** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **April 27, 2021.**

[2] Load forecast that is based on the 2021 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **September 11, 2021.**

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

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

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

Summer 2021 Operable Capacity Analysis

90/10 Load Forecast (Extreme)	September - 2021[2] CSO (MW)	September - 2021[2] SCC (MW)
Operable Capacity MW [1]	29,380	30,056
Active Demand Capacity Resource (+) [5]	505	431
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,208	1,208
Non Commercial Capacity (+)	50	50
Non Gas-fired Planned Outage MW (-)	2,414	2,617
Gas Generator Outages MW (-)	0	0
Allowance for Unplanned Outages (-) [4]	2,100	2,100
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	26,629	27,029
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	26,711	26,711
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	29,016	29,016
Operable Capacity Margin	-2,387	-1,987

[1]Operable Capacity is based on data as of **April 27, 2021** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **April 27, 2021.**

[2] Load forecast that is based on the 2021 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **September 11, 2021.**

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

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

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

Summer 2021 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

April 30, 2021 - 50-50 FORECAST using CSO MW

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

Report created: 4/27/2021

Study Week (Week Begining , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	CSO Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
5/29/2021	29369	505	1208	50	202	506	2800	0	27624	24810	2305	27115	509	N	Summer 2021
6/5/2021	29369	505	1208	50	52	0	2800	0	28280	24810	2305	27115	1165	N	Summer 2021
6/12/2021	29369	505	1208	50	103	0	2800	0	28229	24810	2305	27115	1114	N	Summer 2021
6/19/2021	29369	505	1208	50	21	0	2800	0	28311	24810	2305	27115	1195	N	Summer 2021
6/26/2021	29369	505	1208	50	82	133	2800	0	28116	24810	2305	27115	1001	N	Summer 2021
7/3/2021	29380	505	1208	50	31	0	2100	0	29012	24810	2305	27115	1897	N	Summer 2021
7/10/2021	29380	505	1208	50	96	0	2100	0	28947	24810	2305	27115	1832	N	Summer 2021
7/17/2021	29380	505	1208	50	92	0	2100	0	28951	24810	2305	27115	1836	N	Summer 2021
7/24/2021	29380	505	1208	50	34	0	2100	0	29009	24810	2305	27115	1894	N	Summer 2021
7/31/2021	29380	505	1208	50	37	0	2100	0	29006	24810	2305	27115	1891	N	Summer 2021
8/7/2021	29380	505	1208	50	34	0	2100	0	29009	24810	2305	27115	1894	N	Summer 2021
8/14/2021	29380	505	1208	50	28	0	2100	0	29015	24810	2305	27115	1900	N	Summer 2021
8/21/2021	29380	505	1208	50	41	0	2100	0	29002	24810	2305	27115	1887	N	Summer 2021
8/28/2021	29380	505	1208	50	18	0	2100	0	29025	24810	2305	27115	1910	N	Summer 2021
9/4/2021	29380	505	1208	50	1321	0	2100	0	27722	24810	2305	27115	607	N	Summer 2021
9/11/2021	29380	505	1208	50	2414	0	2100	0	26629	24810	2305	27115	-486	Y	Summer 2021

Column Definitions

1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2021 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

Summer 2021 Operable Capacity Analysis

90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

April 30, 2021 - 90/10 FORECAST using CSO MW

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

Report created: 4/27/2021

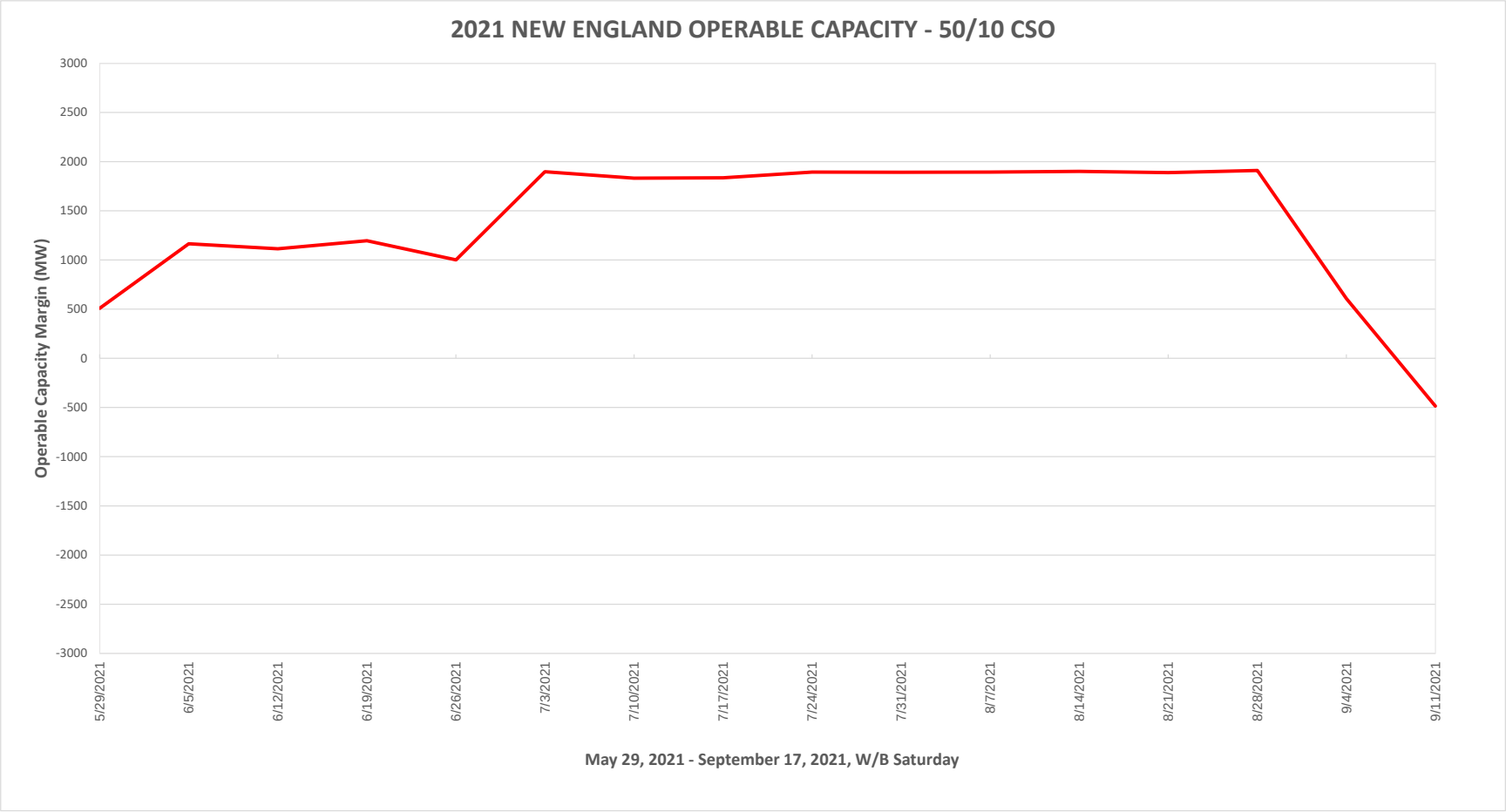
Study Week (Week Begining , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	CSO Non-Commerical Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
5/29/2021	29369	505	1208	50	202	506	2800	0	27624	26711	2305	29016	-1392	N	Summer 2021
6/5/2021	29369	505	1208	50	52	0	2800	0	28280	26711	2305	29016	-736	N	Summer 2021
6/12/2021	29369	505	1208	50	103	0	2800	0	28229	26711	2305	29016	-787	N	Summer 2021
6/19/2021	29369	505	1208	50	21	0	2800	0	28311	26711	2305	29016	-706	N	Summer 2021
6/26/2021	29369	505	1208	50	82	133	2800	0	28116	26711	2305	29016	-900	N	Summer 2021
7/3/2021	29380	505	1208	50	31	0	2100	0	29012	26711	2305	29016	-4	N	Summer 2021
7/10/2021	29380	505	1208	50	96	0	2100	0	28947	26711	2305	29016	-69	N	Summer 2021
7/17/2021	29380	505	1208	50	92	0	2100	0	28951	26711	2305	29016	-65	N	Summer 2021
7/24/2021	29380	505	1208	50	34	0	2100	0	29009	26711	2305	29016	-7	N	Summer 2021
7/31/2021	29380	505	1208	50	37	0	2100	0	29006	26711	2305	29016	-10	N	Summer 2021
8/7/2021	29380	505	1208	50	34	0	2100	0	29009	26711	2305	29016	-7	N	Summer 2021
8/14/2021	29380	505	1208	50	28	0	2100	0	29015	26711	2305	29016	-1	N	Summer 2021
8/21/2021	29380	505	1208	50	41	0	2100	0	29002	26711	2305	29016	-14	N	Summer 2021
8/28/2021	29380	505	1208	50	18	0	2100	0	29025	26711	2305	29016	9	N	Summer 2021
9/4/2021	29380	505	1208	50	1321	0	2100	0	27722	26711	2305	29016	-1294	N	Summer 2021
9/11/2021	29380	505	1208	50	2414	0	2100	0	26629	26711	2305	29016	-2387	Y	Summer 2021

Column Definitions

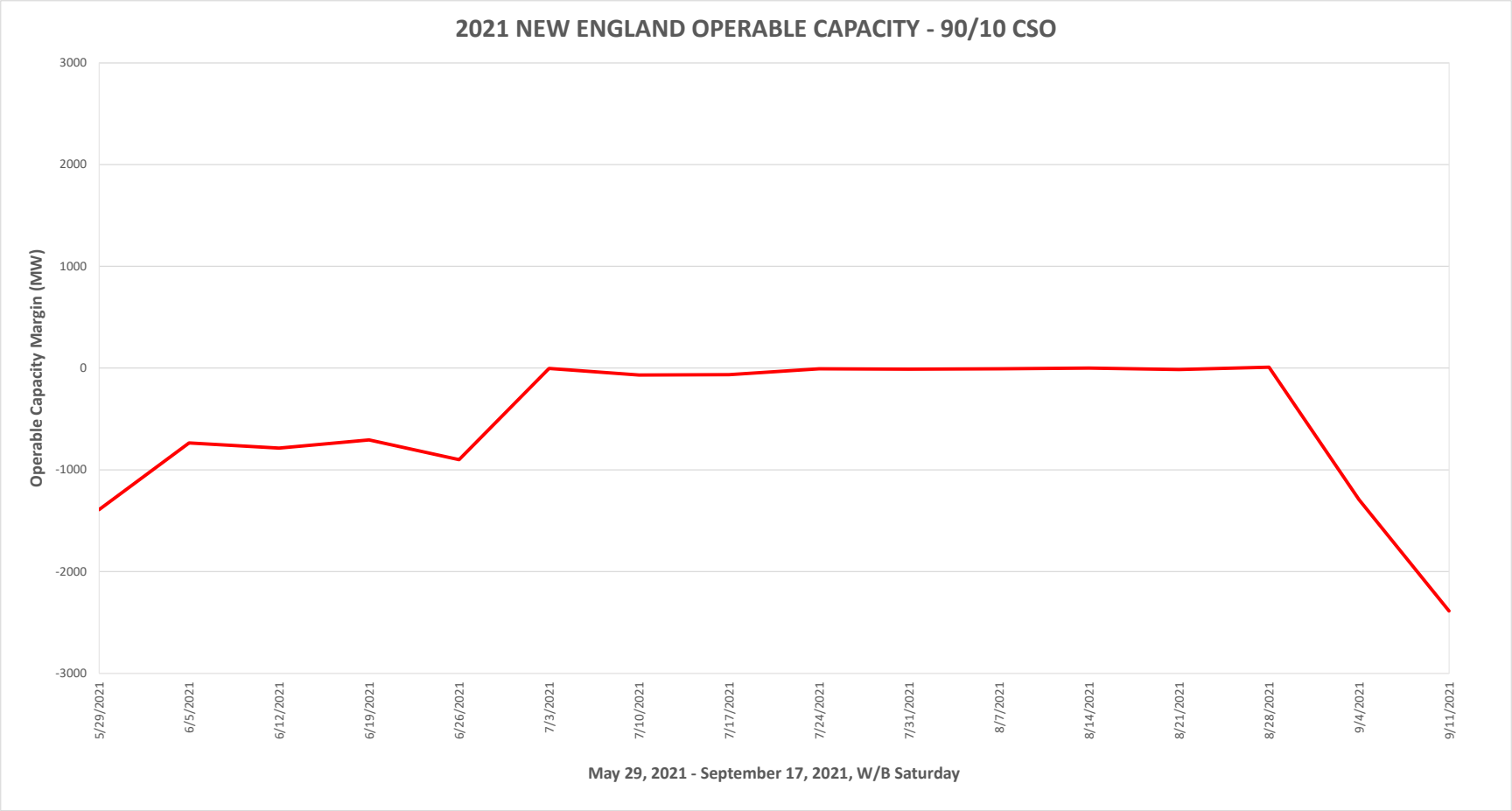
1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can participate in the Forward Capacity market (FCM).
These resources will have the ability to obtain a CSO and also particpate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Capacity MW: Sum of external Capacity Supply Obligations (CSO) imports and exports.
4. Non-Commercial capacity MW: New resources and generator improvements that have acquired a CSO but have not become commercial.
5. CSO Non Gas-Only Generator Planned Outages MW: All Non-Gas Planned Outages is the total of Non Gas-fired Generator/DARD Outages for the period. This value would also include any known long-term Non Gas-fired Forced Outages.Outages.
6. CSO Gas-Only Generator Planned Outages MW: All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Unplanned Outage Allowance MW: Forced Outages and Maintenance Outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. CSO Generation at Risk Due to Gas Supply Mw: Gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. CSO Net Available Capacity MW: the summation of columns (1+2+3+4-5-6-7-8=9)
10. Peak Load Forecast MW: Provided in the annual 2021 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).
11. Operating Reserve Requirement MW: 120% of first largest contingency plus 50% of the second largest contingency.
12. CSO Net Required Capacity MW: (Net Load Obligation) (10+11=12)
13. CSO Operable Capacity Margin MW: CSO Net Available Capacity MW minus CSO Net Required Capacity MW (9-12=13)
14. Operable Capacity Season Label: Applicable season and year.
15. Season Minimum Operable Capacity Flag: this column indicates whether or not a week has the lowest capacity margin for its applicable season.

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

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



Summer 2021 Operable Capacity Analysis
90/10 Forecast (Extreme)



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

Updated 2021 Annual Work Plan

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

2021 Notable Highlights

This update summarizes changes to the 2021 Annual Work Plan since its release in September 2020

- The updated plan reflects the ISO's continued focus on innovation in support of the region's efforts to transition to a clean energy future while also working with the states and stakeholders to ensure that the power system is reliable throughout this transition; it includes:
  - Updates on the large-scale study commitments by the ISO that assess the future grid and the supporting tools it is developing
  - Addition of a project to address the Minimum Offer Price Rule
  - Addition of 2050 Transmission Study request from New England states
  - Updates on assessment of Resource Capacity Contributions to Resource Adequacy/ELCC
  - Addition of assessment related to operational impacts of extreme weather events
  - Addition of FERC Order No. 2222 Compliance
- The ISO will be able to perform the added work, remain dedicated to meeting its planning and operational commitments, and ensure business continuity during its pandemic posture; however, the organization is fully committed and new priorities would require further resource and budget considerations
- In Q3, the ISO begins full cycle again with *2022 Annual Work Plan*

New England's Future Grid Initiative

Updates on high-priority studies the ISO has committed to in 2021 that assess a reliable, clean-energy future grid

- **Future Grid Reliability Study (FGRS) Phase 1** (NEPOOL initiated): For its 2021 Economic Study, the ISO is conducting a series of engineering and economic analyses that use stakeholder-defined scenarios to identify grid reliability challenges that could occur in the year 2040 in light of state energy policies; the ISO will issue a report in **Q1 2022**
  - A second phase that would assess revenue sufficiency and system security in a gap analysis is paused; results of and issues resolved through Phase 1 and other future-grid-related studies will be critical inputs to and create efficiencies in how the Phase 2 analyses may be shaped
- **Pathways to the Future Grid**: The ISO is evaluating the effectiveness and efficiency of two potential market frameworks in facilitating the evolution of New England's power grid that reflects state energy policies; the ISO will issue a report in **Q1 2022**
  - **Study 1** (NEPOOL/NESCOE initiated): Evaluate a forward clean-energy market
  - **Study 2** (ISO initiated)**:** Evaluate net carbon pricing

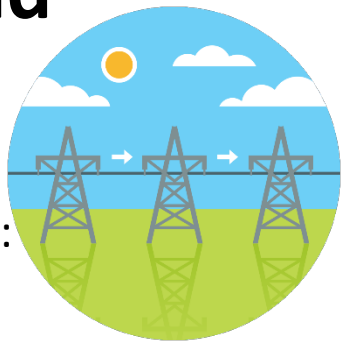
MOPR Proposal

Additional project to develop a proposal to address the removal of this capacity market component

- The Minimum Offer Price Rule (MOPR) requires a minimum price for new resources entering the Forward Capacity Market (FCM)
- Significant concerns have been raised at both the regional and federal level that the application of the MOPR precludes resources sponsored by the states from clearing in the FCM
  - The FERC has identified this matter as a priority
- Elimination of the MOPR must be consistent with maintaining reliability, which is the primary goal of FCM; therefore, the ISO intends to develop a proposal with input from stakeholders to address the dual objectives of allowing sponsored resources to clear and maintaining competitive capacity pricing
- This will be a top initiative for the ISO, which is expected to ramp up in the second half of 2021
- The ISO anticipates the need to file a proposal by Q1 2022, which will require targeted efforts by the ISO and all stakeholders

Transmission Planning for the Future Grid

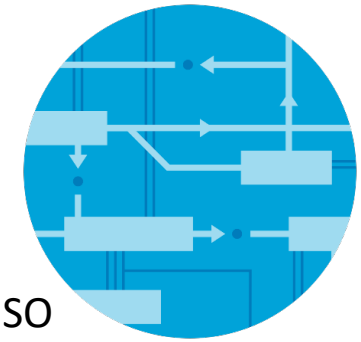
Updates on high-priority studies the ISO has committed to in 2021 that assess a reliable, clean-energy future grid



- **Transmission Planning for the Clean-Energy Transition** (ISO initiated): The ISO seeks to update the assumptions used in its transmission planning studies to reflect future-grid trends
  - In **Q1-3**, the ISO will complete a pilot study via PAC process to test a variety of assumptions for 2030 (typical 10-year planning horizon); in **Q3**, based on study results and input from the PAC, the ISO will select the updated assumptions to use going forward in its planning studies (e.g., Needs Assessments)
- **New: 2050 Transmission Study** (Initiated via New England States' Energy Vision): The ISO will conduct a high-level transmission study for the year 2050 that informs the region of the amount and type of transmission infrastructure needed to cost-effectively incorporate clean-energy and distributed-energy resources and to meet energy policy goals, including economywide decarbonization
  - The study looks well beyond the ISO's 10-year requirement for transmission planning to meet reliability needs so states can prepare in the nearer term for that future outlook
  - It is not a plan to build specific projects unless states choose to move forward
  - The states and the ISO are actively discussing their request; the ISO anticipates sharing the scope, assumptions, and inputs at the PAC before beginning the study
  - Discussions are targeted to start in Q3 regarding potential tariff changes that would allow the ISO to routinely perform this type of long-range transmission planning

Models and Tools to Support Future Grid Studies

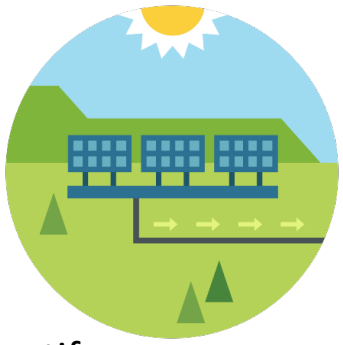
Updates include project description and timeframes



- Models, simulators, and other tools that are adaptive to new technologies and changes are needed to support future-grid studies under evolving conditions
- **Inverter-Based Resource Integration and Modeling Assessment**: The ISO has begun a multi-year project (2021-2023) to assess and adopt advanced, innovative analysis techniques that capture the unique performance characteristics of inverter-based resources (e.g., solar and wind), critical to studies beyond the 10-year horizon
  - By the end of 2021, the ISO expects to deliver a report that evaluates options for and recommends deployment of Electromagnetic Transient power system software and analytical methods that will enable efficient and reliable integration and modeling of rapidly-evolving inverter-based resources
- **Day-Ahead Market Simulator Development**: This is the first step in a multi-year project (2021-2023) to develop an Integrated Market Simulator of the ISO's energy markets that consolidates the capabilities of multiple tools into one simulator; the new platform will produce highly accurate, timely long-term market simulation results through which the ISO can better compare and contrast future energy market designs, impacts of evolving resource mixes, market operations risks, and other important outcomes and impacts
  - The ISO anticipates completing the development of the day-ahead market simulator in 2021

Resource Capacity Contributions to Resource Adequacy

Work-scope emerging from the previously listed "Evaluate Impacts of Shifting Peak Loads"



- In 2021, the ISO is assessing possible modifications to the methodologies used to attribute resource contributions to resource adequacy
  - This work supports a reliable, clean-energy transition by seeking to identify methodologies that more appropriately credit resource contributions to resource adequacy as the resource mix evolves over time (e.g., as renewable generation and energy storage resources become more prevalent)
  - It is critical to both system planning and sound market design that the methodologies reflect the reliability capabilities of all resources and how those capabilities contribute differently to resource adequacy
  - This work will also consider how **Effective Load Carrying Capability (ELCC)** techniques could be used in quantifying resource contributions to regional resource adequacy
- The ISO will begin discussing the scope of this work with stakeholders in Q2 2021
  - Once these analyses are more fully developed, the ISO plans to discuss the findings with stakeholders, allowing for a more informed discussion regarding next steps, including possible market design modifications, which would extend into 2022

FERC Order No. 2222: Participation of DER Aggregations in Wholesale Markets

New major project for 2021 that will allow more integrated participation by DERs in wholesale markets

- FERC issued Order No. 2222 on September 17, 2020, which requires ISOs/RTOs to allow distributed energy resources (DERs) to provide all wholesale services that they are technically capable of providing through an aggregation of resources
- The ISO is dedicating significant resources to this important initiative in 2021 and beyond to create a responsive market design, develop the compliance proposal through an extensive and comprehensive stakeholder process, and implement changes in ISO systems
- The compliance filing of proposed tariff revisions is due July 19, 2021; the ISO, like other RTOs, has requested an extension until February 2, 2022

Operational Impacts of Extreme Weather and Contingency Events

New initiative will consider how to study New England's reliability risks from severe weather events

- The 2021 events in Texas have caused the ISO to further evaluate whether the region is adequately assessing and preparing for its low-probability, high-impact reliability risks
- The ISO plans to initiate a process in Q3 or Q4 for discussing approaches to modeling tail risks related to extreme weather events and contingencies
- This process will:
  - Initially focus on understanding the modeling approaches to quantify such risks
  - Subsequently focus on understanding if and how the region should protect against the risks

Energy Security Initiative (ESI)

Updates on next steps

- The ISO's planned work in 2021 to advance energy security improvements was contingent on FERC's response to the ISO's ESI filing, which FERC rejected on October 30, 2020
- The ISO understands FERC's rejection of ESI was a result of several concerns, compounded by the region's inability to discuss and address these concerns under the restrictions of a Section 206 order
  - Primary concerns: (a) lack of clear continuing evidence of fuel-based reliability risks (esp. in the Impact Analysis); (b) high potential total costs, relative to the benefits; (c) absence of a mitigation proposal and analysis; and (d) absence of a forward procurement component
- Consequently, ESI is on hold and discussion is needed on how best to reconsider it
  - ESI's other potential benefits (e.g., price formation, incorporating reliability requirements into markets, etc.) were not properly before the commission in this 206 proceeding
  - Some of the elements of ESI could be reformulated in the context of improved price formation, but the ISO suggests that the timing and scope correlate to the re-evaluation of the energy security risks discussed on the previous slide
- Beyond ESI, the ISO will continue to engage with stakeholders on how best to improve the ancillary services market design
  - New products and services in the evolving power system may be needed to address reliability needs as varied as inertia, ramping, load following, or duration capability

	Q2 2021	Q3 2021	Q4 2021
Markets Related	Pathways to the Future Grid Studies: FCEM and Net Carbon Pricing		
	MOPR Proposal		
	FERC Order No. 2222 Compliance		
	Resource Capacity Contributions to Resource Adequacy (Peak-Hour Assessments)		
	Submission of FTRs for Clearing		
Operations/ Planning	Future Grid Reliability Study Phase 1 (2021 Economic Study)		
	2050 Transmission Study		
	Transmission Planning for the Clean-Energy Transition		
	Order 1000 Lessons Learned		
	2021 Regional System Plan		
		Operational Impacts of Extreme Weather and Contingency Events	
	Forecasting Enhancements		
	Continuing Business		
Capital Project Priorities	nGEM Day-Ahead Market Clearing Engine Implementation		
	Cybersecurity Projects		
	Application and Database Enhancements		
	IT Infrastructure Enhancements		

NESCOE
New England States Committee on Electricity

To: **Vamsi Chadalavada, ISO-NE**
From: **NESCOE**
Date: **May 4, 2021**
Subject: **2021 Draft Updated Work Plan: Questions on Minimum Offer Price Rule (MOPR) Reforms and Timing**

We understand you'll discuss the 2021 Annual Work Plan (Updated 2021 Work Plan) at the May 6, 2021 NEPOOL Participants Committee meeting.[1]

We appreciate that the Updated 2021 Work Plan prioritizes resources to assessing continued power system reliability, integrating clean energy and distributed energy resources, and potential wholesale market design changes. This is consistent with our 2019 Work Plan Request in July 2019 on wholesale markets and the requirements of state law, and the directional needs expressed in the 2020 Vision Statement. We're appreciative of the chance to focus, with you and NEPOOL, on these key issues in 2021.

We also thank you for responsiveness to our April 13, 2021 request by revising the draft Updated 2021 Work Plan to include commencement of work this year on potential tariff changes to implement a new scenario-based transmission planning tool referenced in the 2020 Vision Statement.[2]

The Updated 2021 Work Plan prioritizes a new matter: "to develop a proposal to address the removal of" the MOPR from the capacity market rules.[3] It states that ISO-NE "intends to develop a proposal with input from stakeholders to address the dual objectives of allowing sponsored resources to clear and maintaining competitive capacity pricing."[4] This is "a top initiative" for ISO-NE that "is expected to ramp up in the second half of 2021[,]" with an expected FERC filing by April 2022.[5]

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1 ISO-NE, Updated 2021 Annual Work Plan, NEPOOL Participants Committee, May 6, 2021, available at https://www.iso-ne.com/static-assets/documents/2021/04/2021_awp_update_05_06_21_pc.pdf.

2 *See id.* at Slide 5. *See also* NESCOE, *New England States' Vision for a Clean, Affordable, and Reliable 21st Century Regional Electric Grid* (Oct. 2020), available at http://nescoe.com/resource-center/vision-stmt-oct2020/.

3 Updated 2021 Work Plan at Slide 4.

4 *Id.*

5 *Id.*

Last week, PJM and NYISO announced the timing of their anticipated filings with FERC to reform their MOPR provisions.

On April 6, 2021, the PJM Board of Managers requested use of an "accelerated stakeholder process mechanism to try and achieve stakeholder consensus that would inform a PJM Board decision on a potential filing with FERC by late July."[6] PJM presented an initial proposal to stakeholders last week regarding changes to the MOPR.[7] It set out a work plan that provides for a stakeholder vote on proposed tariff changes on June 30, 2021 and a FERC filing on July 15, 2021.[8]

Similarly, on April 20, 2021, NYISO discussed with stakeholders its plan for reforming buyer-side market mitigation rules and other market rule changes.[9] That plan outlines an expected FERC filing on MOPR-related rules in October 2021, with other capacity market changes on separate tracks.[10]

ISO-NE, along with other RTOs/ISOs, of course prioritize reliable system operations. Consistent with your primary functions, it's fair to say that no RTO/ISO would recommend to FERC changes to your respective market rules if their implementation would put system reliability at risk.

As part of the discussion of the 2021 Updated Work Plan at the May 6th Participants Committee meeting, we'd like to hear your reactions to the accelerated efforts that PJM and NYISO announced on MOPR-related changes. For example, it would be helpful to understand any work ISO-NE has done to date on this issue and any particular impediments that lead to a six-to-ten month lag here relative to the other eastern RTOs/ISOs, especially if it could result in an additional capacity auction under the current rules. Given the expiration of the Renewable Technology Resource Exemption, and CASPR's functionality, the next auction is of heightened concern. We encourage ISO-NE to communicate and work with states and stakeholders early in the development of the range of potential near-term approaches.

We look forward to the discussion and working with you and NEPOOL toward a timely resolution on this important issue for the New England states.

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6 *See* https://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20210406-board-letter-regarding-capacity-market-minimum-offer-price-rule-and-initiation-of-the-critical-issue-fast-path-process.ashx.

7 PJM's Initial Proposal: Minimum Offer Price Rule, MOPR CIFP Meeting, April 28, 2021.

8 *Id.* at Slide 2.

9 *See* NYISO, Preparing the Capacity Market for the Grid in Transition, ICAPWG Meeting, April 20, 2021, available at https://www.nyiso.com/documents/20142/20839079/20210420%20NYISO%20-%20Preparing%20the%20Capacity%20Market%20for%20the%20Grid%20in%20Transition.pdf/92f68a4b-8c2a-0c5a-10e0-5ca75229aaf9.

10 *See id.* at Slides 8 and 12.

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval, NEPOOL Counsel

DATE: April 29, 2021

RE: Changes to ISO-NE Financial Assurance Policy - Non-Commercial Capacity Financial Assurance

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At its May 6, 2021 meeting, the Participants Committee will be asked to consider changes to the "NCC Trading FA" component of the Non-Commercial Capacity Financial Assurance Amount calculation in the ISO New England Financial Assurance Policy ("FAP"). NCC Trading FA was added to the FAP in 2020 to ensure that potential trading profits do not undermine incentives to deliver a Non-Commercial Capacity ("NCC") project. The current changes further refine the calculation of NCC Trading FA for Capacity Supply Obligation ("CSO") Bilaterals and add a calculation of NCC Trading FA for Annual Reconfiguration Transactions ("ARTs"). The proposed changes are included in Attachment 1 to this memorandum, and this memorandum summarizes those changes.

Under the current design, NCC Trading FA for CSO Bilaterals is based on the applicable monthly reconfiguration auction clearing price. Under the proposed changes, NCC Trading FA for CSO Bilaterals will instead be determined based on whether the Designated FCM Participant certifies to the ISO that is has not entered into a transaction regarding the pricing of the CSO Bilateral that is not settled by the ISO, as follows:

- If the Designated FCM Participant does not provide such a certification, the NCC Trading FA will be based on the lower of the applicable monthly reconfiguration auction price and the CSO Bilateral price;
- If the Designated FCM Participant provides such a certification and is the Capacity Transferring Resource and is an Affiliate of the Capacity Acquiring Resource, then the NCC Trading FA will be based on the lower of the CSO Bilateral price and the applicable Capacity Clearing Price (adjusted as appropriate); and
- If neither of the two preceding scenarios applies, the NCC Trading FA will be based on the CSO Bilateral price.

In addition, the calculation of NCC Trading FA will now include a component based on the ARTs associated with the NCC for the relevant Capacity Commitment Period in which the Designated FCM Participant is the Capacity Transferring Resource. The additional component of the NCC Trading FA for ARTs will be based on whether the Designated FCM Participant certifies to the ISO that is has not entered into a transaction regarding the pricing of the ART that is not settled by the ISO, as follows:

- If the Designated FCM Participant does not provide such a certification, the NCC Trading FA will be based on the lower of the applicable annual reconfiguration auction price and the ART price;
- If the Designated FCM Participant provides such a certification and is the Capacity Transferring Resource and is an Affiliate of the Capacity Acquiring Resource, then the NCC Trading FA will be based on the lower of the ART price and the applicable Capacity Clearing Price (adjusted as appropriate); and
- If neither of the two preceding scenarios applies, the NCC Trading FA will be based on the ART price.

The NCC Trading FA changes to the FAP were discussed by the Budget and Finance Subcommittee (the "Subcommittee") at its October 5, 2020, January 28, 2021, March 25, 2021 and April 22, 2021 teleconferences. The ISO made several adjustments to the proposed changes in response to comments made by NEPOOL Participants on those teleconferences. None of the NEPOOL Participants attending the April 22, 2021 teleconference objected to the changes included with this memorandum, and several of those Participants thanked the ISO for being responsive to their comments on prior iterations of the changes.

The following form of resolution may be used for Participants Committee action on the FAP changes:

> RESOLVED, that the Participants Committee supports the NCC Trading FA revisions to the ISO New England Financial Assurance Policy, as proposed by the ISO and as circulated to this Committee with the April 29, 2021 supplemental notice, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair of the Budget and Finance Subcommittee.

EXHIBIT IA

ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

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Non-Commercial Capacity equal to three (3) times the Non-Commercial Capacity FA Amount.

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

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

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

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

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

For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the thirteenth Forward Capacity Auction, NCCFCA$ = the Capacity Clearing Price from the first run of the auction-clearing process of the Forward Capacity Auction in which the Capacity Supply Obligation was awarded. For Capacity Supply Obligations acquired in the fourteenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCCFCA$ = the Net CONE associated with the Forward Capacity Auction in

which the Capacity Supply Obligation was awarded (adjusted as described in Section III.13.2.4).

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

In the case of Non-Commercial Capacity that fails to become commercial by the commencement of the Capacity Commitment Period associated with the Forward Capacity Auction in which it was awarded a Capacity Supply Obligation, the Non-Commercial Capacity Financial Assurance Amount shall be recalculated as follows: beginning at 8 a.m. (Eastern Time) on the first Business Day of the second month of the Capacity Commitment Period associated with the Forward Capacity Auction in which the Capacity Supply Obligation was awarded, the Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance Amount shall be four. The Multiplier in the recalculation of the Non-Commercial Capacity Financial Assurance Amount shall increase by one every six months thereafter until the Non-Commercial Capacity becomes commercial or the Capacity Supply Obligation is terminated.

For Capacity Supply Obligations acquired in Forward Capacity Auctions up to and including the twelfth Forward Capacity Auction, NCC Trading FA = zero. For Capacity Supply Obligations acquired in the thirteenth Forward Capacity Auction and all Forward Capacity Auctions thereafter, NCC Trading FA shall be zero until the start of the applicable Capacity Commitment Period, at which time NCC Trading FA shall be calculated as described below, except that in no case shall NCC Trading FA be less than zero: =

(a) the total amount of NCC that has been shed (whether before or after the start of the Capacity Commitment Period) in any reconfiguration auctions or Capacity Supply Obligation Bilaterals or that is subject to a failure to cover

charge pursuant to Section III.13.3.4(b) (but this total amount shall not be greater than NCC); multiplied by

(b) the difference ~~(but not less than zero)~~ between: (~~i~~x) the weighted average price at which the Capacity Supply Obligation was acquired in the Forward Capacity Auction (adjusted, where appropriate, in accordance with the Handy-Whitman Index of Public Utility Construction Costs); and (~~ii~~y) the weighted average price or failure to cover charge rate at which the Capacity Supply Obligation was shed or assessed, as applicable, ~~(~~except that for monthly Capacity Supply Obligation Bilaterals, ~~the applicable monthly reconfiguration auction clearing price will be used instead of the Capacity Supply Obligation Bilateral price).~~one of the following prices will be used:

(i) If the Designated FCM Participant does not certify to the ISO that it has not entered into ~~and will not enter into~~ any contract or other transaction with another party regarding the pricing of such Capacity Supply Obligation Bilateral (other than those ~~approved~~ to be settled by the ISO) ~~for the purpose of, or with the~~ that has the effect of deflating its NCC Trading FA, then the lower of: (1) the applicable monthly reconfiguration auction price, and (2) the Capacity Supply Obligation Bilateral price shall be used;

(ii) If the Designated FCM Participant provides the certification described in subsection (i) above, is the Capacity Transferring Resource, and is an Affiliate of the Capacity Acquiring Resource, then the lower of: (1) the Capacity Supply Obligation Bilateral price, and (2) the applicable Capacity Clearing Price (adjusted, where appropriate, in accordance with the Handy-Whitman Index of Public Utility Construction Costs) shall be used; or

(iii) If neither subsection (i) nor (ii) applies, then the Capacity Supply Obligation Bilateral price shall be used.

plus

(c) the quantity of any Annual Reconfiguration Transactions associated with NCC for the relevant Capacity Commitment Period in which the Designated FCM Participant is the Capacity Transferring Resource (but this amount shall not be greater than NCC) multiplied by the difference between: (x) the

applicable annual reconfiguration auction clearing price, and (y) the transaction price, which shall equal one of the following:

(i) If the Designated FCM Participant does not certify to the ISO that it has not entered into ~~and will not enter into~~ any contract or other transaction with another party regarding the pricing of such Annual Reconfiguration Transaction (other than those ~~approved~~ to be settled by the ISO) ~~for the purpose of or with the~~ that has the effect of deflating its NCC Trading FA, the transaction price shall be equal to the lower of: (1) the applicable annual reconfiguration auction clearing price, and (2) applicable Annual Reconfiguration Transaction price;

(ii) If the Designated FCM Participant provides the certification described in subsection (i) above, is the Capacity Transferring Resource, and is an Affiliate of the Capacity Acquiring Resource, then the transaction price shall be equal to the lower of: (1) the applicable Annual Reconfiguration Transaction price, and (2) the applicable Capacity Clearing Price (adjusted, where appropriate, in accordance with the Handy-Whitman Index of Public Utility Construction Costs); or

~~(i)~~(iii) If neither subsection (i) nor (ii) applies, then applicable Annual Reconfiguration Transaction price shall be used.

c. Non-Commercial Capacity Deferral

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

3. Return of Non-Commercial Capacity Financial Assurance

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of May 4, 2021

The following activity, as more fully described in the attached litigation report, has occurred since the report dated March 30, 2021 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

COVID-19

No Activity to Report

I. Complaints/Section 206 Proceedings

	2	Green Development DAF Charges Complaint Against National Grid (EL21-47)	Apr 9	National Grid answers Mar 23 Green Development and SEIA answers
	3	NECEC/Avangrid Complaint Against NextEra/Seabrook (EL21-6)	Apr 15 Apr 30	NextEra answers amended complaint Avangrid answers NextEra's Apr 15 answer
	4	New England Generators' Exelon Complaint (EL20-67)	Apr 15	FERC dismisses Complaint

II. Rate, ICR, FCA, Cost Recovery Filings

	7	FCA15 Results Filing (ER21-1226)	Apr 12 Mar 31-Apr 13 Apr 27	MA AG, NEPGA file comments Private citizens submit comments ISO-NE answers comments by MA AG, NEPGA and private citizens
	8	Essential Power Newington CIP IROL (Schedule 17) Cost Recovery Period Filing (ER21-1171)	Mar 31	FERC accepts filing, eff. Feb 18, 2021
	8	Mystic 8/9 Cost of Service Agreement (ER18-1639)	Apr 2 Apr 19 Apr 26	Mystic answers Mar 18 protests of third compliance filing by CT Parties, ENECOS and Public Systems CT Parties answer Mystic's Apr 2 answer FERC accepts in part, and rejects in part, Mystic's second, and rejects Mystic's third, compliance filing; a fourth compliance filing is due ***Jun 25, 2021***

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

*	11	eTariff § III.13.1 Corrections (ER21-1766)	Apr 26 Apr 29	ISO-NE files conforming changes to eTariff § III.13.1 to ensure that the eTariff Viewer reflects in all appropriate versions the rejection of the June 11, 2018 Economic Life Revisions and includes the corresponding, since-accepted compliance revisions; comment date ***May 17, 2021*** NEPOOL intervenes
*	11	Waiver Request: FCA16 Qual. Req. (CMEEC, MMWEC, Pascoag, VT DPS) (ER21-1726)	Apr 21 Apr 29	CMEEC, MMWEC, Pascoag, VT DPS jointly request waiver; comment date ***May 12, 2021*** NEPOOL intervenes
*	11	ISO-NE IMM Ethical Standards Changes (ER21-1666)	Apr 13 Apr 14-May 4	ISO-NE and NEPOOL submit changes to include directly in § 18 of Appendix A to MR1 the remaining minimum ethical standards for the IMM Unit and its employees Brookfield, Calpine, Eversource (out-of-time), National Grid, NESCOE, NRG intervene

*	11	FCA16 ORTP Jump Ball Filing (ER21-1637)	Apr 7	ISO-NE and NEPOOL submit filing
			Apr 8-28	Avangrid, Brookfield, CLF, CPV Towantic, Dominion, ENE, Exelon, EPSA, National Grid, NESCOE, NRDC, NRG, Vineyard Wind, Public Citizen intervene, Sierra Club, MOPA, Eversource (out-of-time)
			Apr 13	NEPOOL moves for protective order
			Apr 16	ISO-NE opposes, PJM answers, NEPOOL's motion for protective order
			Apr 20	NEPOOL answers ISO-NE's Apr 16 answer
			Apr 21	ISO-NE answers NEPOOL's Apr 20 answer
			Apr 27-28	Comments and Protests filed by: NEPOOL, ISO-NE IMM; Acadia, Calpine/Vistra, ENECOS, Enel X/ENGIE/Borrego/AEE/SEIA/ACPA, FirstLight, MMWEC/NHEC, MA AG/NH OCA/CT OCC, NEPGA, North East Offshore, New England for Off Shore Wind, RENEW, CT AG, CT DEEP, EPSA, National Hydropower Assoc.
	12	Elimination of Price Lock and Zero-Price Offer Rule for New Entrants Starting in FCA16 (ER21-1010)	Apr 13	FERC accepts Tariff revisions, eff. Apr 2, 2021
	12	EER Exemption from PFP Settlement (ER21-943)	Mar 31	FERC accepts Tariff revisions, eff. Apr 1, 2021
	13	Updated CONE, Net Cone and PPR Values (eff. FCA16) (ER21-787)	Apr 20	Comments and protests on ISO-NE's deficiency letter response filed by: NEPOOL, NESCOE, NEPGA, CPV Towantic, New England Generators
			Apr 19-26	NextEra, Marco DM Holdings and ENE (out-of-time) intervene

V. OATT Amendments / TOAs / Coordination Agreements

	14	ISO-NE/NYISO Coordination Agreement (ER21-1278)	Apr 15	FERC accepts amended Agreement, eff. May 4, 2021

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

	14	Schedule 20A NEP-Vitol Phase I/II HVDC-TF Service Agreement (ER21-1180)	Apr 19	FERC accepts Agreement, eff. Nov 1, 2020
	14	Schedule 21-VP: 2019 Annual Update Settlement Agreement (ER15-1434-004)	Apr 26	FERC approves settlement agreement
*	15	Schedule 21-VEC and 20-VEC: Annual Informational Filing (ER10-1181)	Apr 30	VEC submits its annual update to its Schedule 21-VEC and 20-VEC formula rates covering the Jul 1, 2021 – Jun 30, 2022 period

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

	16	Capital Projects Report - 2020 Q4 (ER21-1109)	Apr 7	FERC accepts Q4 Report, eff. Jan 1, 2021
*	16	Reserve Market Compliance (30th) Semi-Annual Report (ER06-613)	Apr 1	ISO-NE submits 30th semi-annual report

*	16	IMM Quarterly Markets Reports - 2021 Winter (ZZ21-4)	Apr 28	IMM files Winter 2021 Report
*	17	ISO-NE FERC Form 3Q (2020/Q4) (not docketed)	Apr 15	ISO-NE submits its 2020 Q4 FERC Form 3Q
*	17	ISO-NE FERC Reporting Req. 582 (not docketed)	Apr 19	ISO-NE submits 2020 annual report of total MWh of transmission service (approx. 1.24 million MWhs) (roughly 2.6 MWh less than 2019)

IX. Membership Filings

*	17	May 2021 Membership Filing (ER21-1804)	Apr 30	NEPOOL requests that the FERC accept (i) the membership of Protor Energy and Voltus Inc.; (ii) the termination of Great Bay Power Marketing; comment date ***May 21, 2021***
*	17	April 2021 Membership Filing (ER21-1570)	Mar 31	NEPOOL requests that the FERC accept the membership of Ocean State BTM LLC and Transgrid Midwest LLC
	17	March 2021 Membership Filing (ER21-1228)	Apr 26	FERC accepts (i) the membership of Trafigura Trading LLC; (ii) the termination of Axon Energy and Springfield Power; and (iii) Titan Gas LLC's d/b/a (CleanSky Energy)
	17	February 2021 Membership Filing (ER21-1008)	Apr 1	FERC accepts (i) the memberships of: Axpo U.S.; Palm Energy; Madison ESS; Rumford ESS; Vineyard Reliability; West Medway II; and Dick Brooks; (ii) the termination of the Participant status of: EFI; Great American Power; Oasis Power; Praxair; Rubicon NYP; and Verde Group; and (iii) the name change of Utility Services of Vermont
*	18	Suspension Notice – Manchester Methane, LLC (not docketed)	Apr 16 May 3	ISO-NE files notice of suspension of Manchester Methane, LLC from the New England Markets Manchester Methane FAP Default cured, suspension lifted

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

	18	Revised Reliability Standard: FAC-008-5 (RD21-4)	Apr 7	FERC approves revised Standard, which will become eff. Oct 1, 2021
	20	Report on Research Results Under NERC's Final GMD Research Work Plan (RM15-11)	Apr 30 May 3	NERC files informational report providing further technical justification and support for the currently effective GMD planning standard, TPL-007-4 (Transmission System Planned Performance for GMD Events) EPRI submits technical reports
	20	Amended and Restated NERC Bylaws (RR21-1)	Apr 5	FERC accepts amended and restated Bylaws
*	20	Notice of Penalty: VTransco (NP21-14)	Apr 29	NERC files a Notice of Penalty regarding VTransco's violation of FAC-003-4 R2 and R6, including a Settlement Agreement requiring VTransco to pay a ***$100,000 penalty***

XI. Misc. - of Regional Interest

*	21	203 Application: Seneca/Rice et al. (EC21-84)	Apr 28	Seneca, among others, requests authorization for a transaction pursuant to which its ultimate upstream ownership will change to include, in addition to Ares Management, a publicly listed company and Aria Energy; comment date ***May 19, 2021***
*	21	203 Application: ReEnergy/Ember (EC21-83)	Apr 28	ReEnergy requests authorization for a transaction pursuant to which its ultimate upstream ownership will change to include a joint venture holding company that adds Ember to ReEnergy Stratton's Related Persons; comment date ***May 19, 2021***

	21	203 Application: Exelon Generation (EC21-57)	Apr 2 Apr 16 Apr 29	Exelon answers PJM Joint Consumer Advocates protest FERC issues a deficiency letter, directing Exelon to provide additional information on or before May 17 Exelon submits response to Apr 16 deficiency letter; comment date **May 13, 2021**
*	21	D&E Agreement Cancellation: CL&P / Gravel Pit Solar (ER21-1740)	Apr 23	CL&P submits notice of cancellation of D&E Agreement; comment date ***May 14, 2021***
	22	D&E Agreement: NSTAR/Vineyard Wind (ER21-1285)	Apr 16	FERC accepts D&E Agreement, eff. Mar 6, 2021
	22	Related Facilities Agreement: PSNH / NECEC (ER21-1151)	Apr 15	FERC accepts RFA, eff. Feb 16, 2021
	22	D&E Agreement: PSNH/NECEC (ER21-1147)	Apr 15	FERC accepts D&E Agreement, eff. Feb 16, 2021
	23	*Orders 864/864-A* (Public Util. Trans. ADIT Rate Changes): New England Compliance Filings (various)	Apr 2 Apr 9 Apr 16 Apr 16 Apr 19 May 4	*ER20-2133 (Versant Power)*. MPUC submits comments protesting elements of Versant's deficiency letter response *ER21-1650 (NSTAR)*. NSTAR submits revisions to Appendix A of the Sched. 1 Implementation Rule with respect to NSTAR (East)'s local control center revenue calculation *ER21-1694 (GMP)*. GMP supplements an *Order 864* compliance filing *ER21-1702 (CMP)*. CMP submits proposed revisions to Appendix B of the Schedule 1 Implementation Rule to reflect changes to CMP's Local Control Center revenue requirement *ER21-1709 (VTransco)*. VTransco supplements an *Order 864* compliance filing *ER20-2429 (CMP)*. FERC issues deficiency letter; responses due on or before ***Jun 3, 2021***

XII. Misc. - Administrative & Rulemaking Proceedings

	24	Climate Change, Extreme Weather, and Electric Sys. Reliability: Jun 1-2 Tech. Conf. (AD21-13)	Apr 6-19	Pre-Jun 1-2, 2021 tech. conf. comments submitted by, among others, ISO-NE, AEE, Dominion, EDF, Eversource, Exelon, LS Power, National Grid, PSEG, Vistra, APPA, Capital Power, EEI, NARUC, NEI, NERC, NRECA, R Street Institute
	24	Electrification and the Grid of the Future: Apr 29 Technical Conference (AD21-12)	Apr 14 Apr 28 Apr 29	FERC issues supplemental notice of tech conf FERC issues second supplemental notice of tech conf FERC holds tech conf
	25	Resource Adequacy - Modernizing Electricity Mkt Design (AD21-10)	Apr 5 Apr 26	FERC issues notice that initial comments due on or before Apr 26; reply comments, ***May 10, 2021*** 40 sets of initial comments filed, including by: AEE, Calpine, Cogentrix, Dominion, Exelon, FirstLight, LS Power, NESCOE, NEPGA, NRG, PSEG, Shell, Vistra, CT DEEP, EEI, EPSA, NRECA/APPA
		May 25 New England Tech Conf	Apr 22 May 3	FERC issues notice of tech conf regarding ISO-NE-administered wholesale markets FERC issues supplemental notice of, including an agenda for, the May 25 tech conf.
	25	The Office of Public Participation (AD21-9)	Apr 16 Mar 31-Apr 30	FERC holds tech conf More than 80 sets of comments received
	25	ISO/RTO Credit Principles and Practices (AD21-6)	Apr 19 Apr 21	Tech conf transcripts posted in eLibrary FERC issues notice inviting post-tech conf comments; comments due on or before ***Jun 7, 2021***

	26	Offshore Wind Integration in RTOs/ISOs (AD20-18)		Post-tech comments due ***May 10, 2021***
	27	NOPR: Cybersecurity Incentives (RM21-3)	Apr 6	Over 20 sets of comments on NOPR filed including by: NECPUC, APPA, EEI, EPSA, LPPC, NERC, NRECA; reply comments due ***May 6, 2021***
	28	NOPR: Managing Transmission Line Ratings (RM20-16)	Apr 15-23	Organization of MISO States, Potomac Economics, and ITC Holdings Corp. submit reply comments
	28	NOPR: Electric Transmission Incentives Policy (RM20-10)	Apr 15	FERC issues *Supplemental NOPR* and notice of Sep 10, 2021 workshop; Comments on *Supplemental NOPR* due ***May 26, 2021***
			May 3	MISO TOs, IRC request 30-day extension of time to submit comments
			May 4	EEI, WIRES support requests for extension of time
	29	*Order 2222/2222-A*: DER Participation in ISO/RTO Markets (RM18-9)	Apr 9	FERC grants extensions of time to comply requested by MISO, PJM, SPP
			Apr 16	ISO-NE requests extension of time, to Feb 2, 2022 (2/2/222) to comply with *Order 2222*
			Apr 21, 28	AEE, MA DPU submit comments supporting the ISO-NE request
			Apr 19	AEE/AEMA, EEI, NARUC, LPSC/MPSC, NC Utilities Comm., MISO TOs, Voltus request rehearing of *Order 2222-A*
			Apr 30	MISO files comments supporting NARUC, LPSC/MPSC and MISO TOs' rehearing requests
			May 4	ISO-NE answers AEE/AEMA request for clarification of *Order 2222*
	31	*Order 860/860-A*: Data Collection for Analytics & Surveillance and MBR Purposes (RM16-17)	Apr 22	FERC holds a technical workshop to discuss the functionality and features of the MBR Database
	35	NOI: Certification of New Interstate Natural Gas Facilities (PL18-1)	Apr 12-30	Comments filed by: the MIT Energy Initiative, Competitive Enterprise Institute, Laborers' International Union of North America, Ohio Envir. Council, Americans for Prosperity – HQ, several private citizens, and jointly be the AGs of 22 states (none from New England)

XIII. FERC Enforcement Proceedings

*	35	PacifiCorp (IN21-6)	Apr 15	FERC issues show cause order directing PacifiCorp to show cause why it should not (i) be found to have violated NERC's reliability standards and (ii) be assessed civil penalties in the amount of ***$42 million***
			Apr 21	PacifiCorp requests 60-day extension, to ***Jul 15, 2021***, to respond
			Apr 22	FERC Staff comments on request for extension of time
			May 4	FERC extends PacifiCorp's answer period and OE's reply period by 60 days each; PacifiCorp's answer due on or before ***July 16, 2021***
	36	Rover Pipeline, LLC and Energy Transfer Partners, L.P. (IN19-4)	Apr 5	FERC grants Rover/ETP a 60-day extension of time, to ***Jun 18, 2021***, to respond to show cause order

XIV. Natural Gas Proceedings

	37	Iroquois ExC Project (CP20-48)	Apr 9, 20	National Grid, ConEd submit comments supporting Iroquois' application and request for action
	37	Atlantic Bridge Project (CP16-9)	Apr 1-12	Nearly 50 sets of initial briefs and comments filed; Reply briefs due on or before ***May 5, 2021***

XV. State Proceedings & Federal Legislative Proceedings

	40	New England States' Vision Statement / On-Line Technical Forums	Apr 23	Deadline for written comments on equity and environmental justice topics extended to and including ***May 13, 2021***

XVI. Federal Courts

41	ISO-NE Implementation of *Order 1000* Exemptions for Immediate Need Reliability Projects (20-1422)	Apr 5 Apr 12	LS Power files Petitioner's Brief MMWEC files "Intervenor in Support of Petitioners" Brief
41	CIP IROL Cost Recovery Rules (20-1389)	Apr 30	FERC files Respondent's Brief
41	Mystic 8/9 Cost of Service Agreement (20-1343; 20-1361, 20-1362; 20-1365, 20-1368) (consolidated)	Apr 16	Court orders parties to submit by ***May 17, 2021*** proposed formats for the briefing of these cases
42	CASPR (20-1333, 20-1331) (consolidated)	Apr 7	Court grants motion to hold cases in abeyance pending further order of the Court; motions to govern future proceedings to be filed on or before ***Oct 22, 2021***
42	Opinion 531-A Compliance Filing Undo (20-1329)	Apr 21 May 4	FERC files unopposed motion for continued abeyance of this case Court orders that this case remain in abeyance pending further order of the court, subject to 120-day status reports
43	2013/14 Winter Reliability Program Order on Compliance and Remand (20-1289, 20-1366)	Apr 9 Apr 16 Apr 30	TransCanada files Petitioner's Reply Brief TransCanada files Deferred Appendix TransCanada files Final Brief
43	ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224) (consol.)	Apr 20-21 May 4	Petitioners file corrected Joint Appendix Parties file Final Briefs

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: May 4, 2021

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

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"),[1] state regulatory commissions, and the Federal Courts and legislatures through May 4, 2021. If you have questions, please contact us.

COVID-19

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

All hearings before Administrative Law Judges ("ALJs") are being held remotely through video conference software (WebEx and SharePoint) until further notice.[2] The Presiding Judge in each remote hearing will ensure that the participants have access to an "IT Day" prior to the hearing to allow all participants, witnesses, and the public who will attend the hearing to learn more about the remote hearing software and to get their technical questions answered by the appropriate FERC staff. Uniform Hearing Rules for all Office of the ALJ hearings were adopted effective September 15, 2020.[3] The "Remote Hearing Guidance for Participants" was revised on September 23, 2020 to make three changes.[4] The Uniform Hearing Rules and Remote Hearing Guidance for Participants are publicly available in this proceeding in eLibrary and on the FERC's Administrative Litigation webpage.

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

On January 22, 2021, the wavier of FERC regulations that require that filings with the FERC be notarized or supported by sworn declarations was further ***extended through July 30, 2021***.[5] The January 25 notice extended the waiver first noticed in May[6] and extended on August 20, 2020.[7] As previously reported, Entities may also seek waiver of FERC orders, regulations, tariffs and rate schedules, including motions for

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

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

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

[4] *Chief Administrative Law Judge's Notices to the Public*, Docket No. AD20-12 (Sep. 23, 2020) (removing law clerk requirement to share screen when moving exhibits, revising procedures for requesting Live Litigation, and revising witness communication guidance to require that "[c]ommunications with a witness through concealed channels of communications are prohibited while the witness is providing testimony on the witness stand. Communications with a witness are allowed during breaks and when they are not on the witness stand.")

[5] See *Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (Jan. 25, 2021).

[6] *Extension of Non-Statutory Deadlines*, Docket No. AD20-11-000 (May 8, 2020).

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

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

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

On January 25, 2021, the extension of the blanket waivers of ISO/RTO Tariff *in-person*[9] meeting and notarization requirements was further ***extended through July 30, 2021***.[10] The January 25 order extended the blanket waivers first granted in the FERC's April 2, 2020 order and extended in an August 20, 2020 order.[11]

I. Complaints/Section 206 Proceedings

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

As previously reported, Green Development, LLC ("Green Development") filed on February 10, 2021 a Complaint against New England Power Company and Narragansett Electric Company (together, "National Grid" or "Grid") requesting a finding that Grid's assessment of Direct Assignment Facility ("DAF") charges for Green Development's projects is unauthorized under the ISO-NE Tariff. Green Development asserts that the upgrades associated with the interconnection of its distribution-level, state jurisdictional projects are not DAF as defined in the ISO-NE Tariff. National Grid filed its answer on March 2, 2021. Solar Energy Industries Association ("SEIA") and Dry Bridge Solar submitted comments supporting the Complaint. Doc-less interventions were filed by Avangrid, Energy Development Partners and New York Transmission Owners ("NY TOs"). On March 23, Green Development and SEIA answered National Grid's March 2 answer. On April 9, National Grid answered those answers. This matter remains pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **NEPGA Net CONE Complaint (EL21-26)**

Still pending before the FERC is NEPGA's December 11, 2020 complaint against ISO-NE. The Complaint alleged that ISO-NE violated its Tariff and the filed-rate doctrine by recalculating and reviewing with NEPOOL a Net CONE value methodology demonstrably inconsistent with the Tariff and prior practice. NEPGA sought an order directing ISO-NE to recalculate, review with NEPOOL stakeholders, and file with the FERC a Net CONE value consistent with the existing Tariff definition. Should its requested relief be granted, NEPGA asked the FERC to find unjust and unreasonable the Net CONE value for FCAs 16-18 (filed on December 31, *see* ER21-787 in Section III below) and, should there not be sufficient time to allow for completion of stakeholder review before the beginning of the FCA16 calendar (March 2021), NEPGA asked that ISO-NE be directed to apply the Tariff-defined annual adjustment factors to the FCA15 Net CONE value to be used for the FCA16 Net CONE value.

ISO-NE's answer, comments and interventions with respect to the Net CONE Complaint were due December 31, 2020. In its answer, ***ISO-NE*** explained why it acted legally and consistent with its Tariff, and requested a FERC order summarily dismissing or denying NEPGA's Complaint. ***NEPOOL*** filed comments explaining why the Complaint was premature and should be rejected so that NEPGA's arguments could be properly addressed in response to ISO-NE's filing of its proposed updates to CONE, Net CONE and the PPR values. NEPOOL's comments, alternatively, suggested that the Complaint proceeding be held in abeyance pending the outcome of ISO-NE's December 31 Updated CONE, Net CONE and PPR Values filing. Protests were also filed by

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

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

[10] *Temporary Action to Facilitate Social Distancing*, 174 FERC ¶ 61,047 (Jan. 25, 2021).

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

NESCOE, ***NECOS/ENE***[12] and ***CT State Agencies***.[13] ***EPSA*** filed comments supporting NEPGA's Complaint. Doc-less interventions only were filed by Avangrid, Calpine, Dominion, Eversource, FirstLight, LS Power, Massachusetts Attorney General ("MA AG"), MMWEC, National Grid, NHEC, NRG, MA DPU, RI PUC, and Public Citizen. On January 8, 2021, NEPGA answered ISO-NE's Answer and the comments and protests filed in response to its Complaint. ISO-NE answered NEPGA's answer on January 25, 2021. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

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

As previously reported, NECEC Transmission LLC ("NECEC") and Avangrid Inc. (together, "Avangrid") filed a complaint (the "Complaint") on October 13, 2020 requesting FERC action "to stop NextEra from unlawfully interfering with the interconnection of the New England Clean Energy Connect transmission project ("NECEC Project")" and seeking, among other things, an initial, expedited order that would grant certain relief[14] 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. Avangrid amended the Complaint on March 26, 2021 to reflect that aspects of the relief originally requested in the Complaint are no longer feasible within the timeline previously sought. Avangrid continues to seek expeditious FERC action, requesting in its March 26 filing a FERC order on or before May 7, 2021.

NextEra submitted an answer to the October 13 Complaint (requesting the FERC dismiss or deny the Complaint) and National Grid filed comments. Doc-less interventions were filed by Dominion, Eversource, Calpine, Exelon, HQ US, MA AG, MMWEC National Grid, NESCOE, NRG, and Public Citizen. Avangrid answered NextEra's answer and NextEra answered Avangrid's November 17 answer ("supplemental answer"), repeating its request that the FERC dismiss or deny the Complaint. Avangrid also answered the supplemental answer.

Since the last Report, on April 15, NextEra answered the amended Complaint. On April 20, 2021, Avangrid answered NextEra's April 15 answer. 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 Energy Seabrook Declaratory Order Petition re: NECEC Elective Upgrade Costs Dispute (EL21-3)**

In a related matter, initiated a week earlier than the Avangrid Complaint, NextEra Energy Seabrook, LLC ("Seabrook") filed a Petition for a Declaratory Order ("Petition") "by which it seeks to understand the scope of its FERC-jurisdictional regulatory obligations with respect to the project ("NECEC Elective Upgrade"), and to resolve its dispute with NECEC". Specifically, Seabrook asked the FERC to declare that: (1) Seabrook is not required to incur a financial loss to upgrade, for NECEC's sole benefit, a 24.5 kV generator circuit breaker and ancillary equipment ("Generation Breaker") at Seabrook Station; (2) "Good Utility Practice" for replacement of the nuclear plant Generation Breaker is defined in terms of the practices of the nuclear power industry, such that Seabrook's proposed definition of that term is appropriate for use in a facilities agreement with NECEC; and (3) Seabrook will

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[12] "NECOS/ENE" are: Belmont Municipal Light Department, Block Island Utility District, Braintree Electric Light Department, Georgetown Municipal Light Department, Groveland Electric Light Department, Hingham Municipal Lighting Plant, Littleton Electric Light Department, Merrimac Municipal Light Department, Middleborough Gas & Electric Department, Middleton Electric Light Department, North Attleborough Electric Department, Norwood Light & Broadband Department, Reading Municipal Light Department, Rowley Municipal Lighting Plant, Stowe Electric Department, Taunton Municipal Lighting Plant, and Wallingford Department of Public Utilities Electric Division (collectively, "NECOS"); and Energy New England, LLC ("ENE").

[13] "CT Agencies" are: the Connecticut Department of Energy and Environmental Protection ("CT DEEP"), William Tong, Attorney General for the State of Connecticut ("CT AG"), the Connecticut Public Utilities Regulatory Authority ("CT PURA") and the Connecticut Office of Consumer Counsel ("CT OCC")

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

not be liable for consequential damages for the service it provides to NECEC under a facilities agreement (collectively, the "Requested Declarations"). Alternatively, Seabrook asked that the FERC declare that nothing in ISO-NE's Tariff requires Seabrook to enter into an agreement to replace the Generation Breaker, and therefore, Seabrook and the Joint Owners are entitled to bargain for appropriate terms and conditions to recover their costs, to define Good Utility Practice, and to limit liability associated with providing the service ("Alternative Declaration").

Comments on Seabrook's Petition were filed by Eversource, MMWEC and NEPGA. Avangrid and NECEC Transmission ("Avangrid") protested the Declaratory Order. Doc-less interventions were filed by Avangrid, Dominion, Eversource, Calpine, Exelon, HQ US, National Grid, NESCOE, NRG, and Public Citizen. NextEra answered Avangrid's protest and Avangrid answered NextEra's answer. This matter also remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **New England Generators' Exelon Complaint (EL20-67)**

On April 15, 2021, the FERC dismissed[15] the New England Generators'[16] August 25, 2020 complaint against Exelon[17] (the Complaint").[18] In dismissing the Complaint, the FERC found that the first two of the Generator's three requests for relief had become moot (Exelon having withdrawn the two new interconnection queue requests at issue[19] and the FERC having directed that objectionable language in the COS Agreement's clawback provision be removed[20]), and that, with respect to their third request (the application of the clawback mechanism to Everett), the Generators had failed to support a departure from prior FERC orders on that issue (which found that the clawback mechanism does not apply to capital expenditures to Everett).[21] Challenges, if any, to the April 15 order are due on or before May 17, 2021. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@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.

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[15] *Vistra Corp. et al.*, 175 FERC ¶ 61,027 (Apr. 15, 2021).

[16] For purposes of this summary, "New England Generators" or "Generators" are Vistra, Dynegy Marketing and Trade, NextEra Energy Resources, NRG Power Marketing, LS Power Associates, FirstLight Power, and Cogentrix Energy Power Management.

[17] For purposes of this Complaint, "Exelon" is short for Constellation Mystic Power, LLC ("Mystic"), Exelon Generation Company, LLC ("Exelon Generation") and Exelon Corporation ("Exelon Corp.").

[18] As previously reported, the Complaint requested that, if and to the extent the FERC did not grant all relief requested by the New England Generators in its August 27, 2020 request for clarification and/or rehearing of the July 17 Orders in the Mystic 8/9 Cost of Service Agreement ("COS Agreement") proceeding (*see* ER18-1639 below), the FERC should find that the new information about Exelon's two new queue positions and Exelon's intention to continue to operate Everett beyond the term of the Mystic Agreement makes the existing rate in the Mystic Agreement unjust and unreasonable. Specifically, the New England Generators requested that the FERC change the Mystic Agreement to: (i) apply the clawback mechanisms to Exelon's two new interconnection queue positions (to prevent Exelon from using interconnection queue positions for "new" or "repowered" units to skirt restrictions imposed on Mystic's recovery of costs pursuant to the COS Agreement); (ii) delete or give no meaning to the words "that were expensed" (in order to prevent Exelon from shielding costs paid for by captive ratepayers from the application of the COS Agreement's clawback provision); and (iii) require that Mystic return any of the undepreciated Everett repair and capital expenditure costs in the event that Mystic 8 or 9 return to the market after the end of the COS Agreement.

[19] *Id.* at P 21. The FERC also noted that the clawback mechanism would apply to Mystic 8 and 9 "if for any reason Mystic 8 and/or 9 do not retire immediately following their retention for fuel security and/or transmission reliability and if Mystic 8 and/or 9 re-enter the market as either a New Generating Capacity Resource or Existing Generating Capacity Resource." *Id.* at P 22.

[20] *Id.* at P 27.

[21] *Id.* at PP 32-33.

- ***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,[22] 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*).[23] However, the FERC's orders were challenged, and in *Emera Maine,*[24] the DC Circuit vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the FERC remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.

- ***Base ROE Complaints II & III (EL13-33 and EL14-86) (consolidated)***. The second (EL13-33)[25] and third (EL14-86)[26] ROE complaint proceedings were consolidated for purposes of hearing and decision, though the parties were permitted to litigate a separate ROE for each refund period. After hearings were completed, ALJ Sterner issued a 939-paragraph, 371-page *Initial Decision*, which lowered the base ROEs for the EL13-33 and EL14-86 refund periods from 11.14% to 9.59% and 10.90%, respectively.[27] 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[28] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[29] The *Base ROE IV Initial Decision* concluded that the currently-filed base ROE of 10.57%, which may reach a

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[22] 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*")).

[23] *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*").

[24] *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).

[25] 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%.

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

[27] *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*").

[28] 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 XV below, have been appealed to, and are pending before, the DC Circuit.

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

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.[30] 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.[31] 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*[32] (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.[33]

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

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

The FERC provided preliminary analysis of how it would apply the proposed methodology in the Base ROE I Complaint, suggesting that it would affirm its holding that an 11.14% Base ROE is unjust and unreasonable. The FERC suggested that it would adopt a 10.41% Base ROE and cap any preexisting incentive-based total ROE at 13.08%.[34] 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

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

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

[32] *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*.

[33] *Id.* at P 19.

[34] *Id.* at P 59.

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[35] for an extension of time to submit briefs, the latest date for filing initial and reply briefs was extended to January 11 and March 8, 2019, respectively. On January 11, initial briefs were filed by EMCOS, Complainant-Aligned Parties, TOs, EEI, Louisiana PSC, Southern California Edison, and AEP. As part of their initial briefs, each of the Louisiana PSC, SEC and AEP also moved to intervene out-of-time. Those interventions were opposed by the TOs on January 24, 2019. The Louisiana PSC answered the TOs' January 24 motion on February 12. Reply briefs were due March 8, 2019 and were submitted by the TOs, Complainant-Aligned Parties, EMCOS, 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*[36] and requested that the FERC re-open the record to permit that additional testimony on the impacts of the *MISO ROE Order*'s changes. On January 21, 2020, EMCOS and CAPs opposed the TOs' request and brief.

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

II. Rate, ICR, FCA, Cost Recovery Filings

- **FCA15 Results Filing (ER21-1226)**

On February 26, 2021, ISO-NE filed the results of the fifteenth FCA ("FCA15") held February 8, 2021. ISO-NE reported the following highlights:

- FCA15 Capacity Zones were the Southeastern New England ("SENE") Capacity Zone (the Northeastern Massachusetts ("NEMA")/Boston, Southeastern Massachusetts, and Rhode Island Load Zones), the Northern New England ("NNE") Capacity Zone (the Maine, New Hampshire and Vermont Load Zones), the Maine Capacity Zone (the Maine Load Zone) and the Rest-of-Pool ("ROP") Capacity Zone (the Connecticut and Western/Central Massachusetts Load Zones). NNE was modeled as an export-constrained Capacity Zone. The Maine Load Zone was modeled as a separate nested export-constrained Capacity Zone within NNE.
- FCA15 commenced with a starting price of $13.932/kW-mo. and concluded for all Capacity Zones after five rounds.
- Capacity Clearing Prices were as follows (prices expressed per kw-mo.): SENE - $3.980; NNE and Maine - $2.477; ROP - $2.611; imports over the NY AC Ties (684 MW) and the Phase I/II HQ Excess external interface (517 MW) - $2.611; imports over Highgate (60 MW) and New Brunswick (226 MW) - $2.477.
- There were no active demand bids for the substitution auction and, accordingly, the substitution auction was not conducted.

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

[36] *Ass'n of Buss. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569, 169 FERC ¶ 61,129 (2019) ("*MISO ROE Order*"), *order on reh'g*, Opinion No. 569-A, 171 FERC ¶ 61,154 (May 21, 2020).

- No resources cleared as Conditional Qualified New Generating Capacity Resources.
- No Long Lead Time Generating Facilities secured a Queue Position to participate as a New Generating Capacity Resource.
- No de-list bids were rejected for reliability reasons.

ISO-NE asked the FERC to accept the FCA15 rates and results, effective June 26, 2021.

Comments on this filing were due on or before April 12, 2021 and were filed by MA AG and NEPGA. NEPOOL, NESCOE, Calpine, Dominion, Exelon, MA AG, National Grid, NRG, MA DPU, and Public Citizen filed doc-less interventions. Comments from more than 30 individual citizens have also been filed, largely focused on environmental issues, and the Merrimack Generating Station in particular. On April 27, ISO-NE answered the comments by MA AG, NEPGA and the individual citizens. 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 Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Essential Power Newington CIP IROL (Schedule 17) Cost Recovery Period Filing (ER21-1171)**

On March 31, 2021, the FERC accepted Essential Power Newington, LLC's ("EP Newington's") rate schedule that will allow EP Newington to begin the recovery period for certain Interconnection Reliability Operating Limits Critical Infrastructure Protection costs under Schedule 17 of the ISO-NE Tariff ("CIP-IROL Costs").[37] EP Newington's rate schedule was accepted effective as of February 18, 2021, as requested. The March 31 order was not challenged and is final and unappealable. Accordingly, this proceeding is concluded. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Amended and Restated IRH Support and Use Agreements (ER21-712)**

On December 18, 2020, New England Hydro-Transmission Electric Company, Inc.; New England Hydro-Transmission Corporation; New England Electric Transmission Corporation; and Vermont Electric Transmission Company (collectively the "Asset Owners") and the IRH Management Committee ("IMC") on behalf of the renewing Interconnection Rights Holders ("IRH") submitted for approval an Offer of Settlement that amends and restates four Support Agreements and an Agreement with Respect to Use of Québec Interconnection ("Use Agreement")[38] to provide for ongoing financial support of, and related rights and obligations with respect to, the United States portion of the 2,000 MW high-voltage, direct current ("HVDC") transmission facilities interconnecting New England and Québec. The initial term of the existing Support Agreements was scheduled to end on October 31, 2020, and the Use Agreement by its own terms will remain in effect though the term of the last Support Agreement to expire. The filing extends the term of those Support Agreements (and thereby the Use Agreement) another 20 years, until October 31, 2040. A January 1, 2021 effective date was requested. Comments on this filing were due on or before January 8, 2021; none were filed. Avangrid, Energy New England ("ENE"), NESCOE, and Eversource (out-of-time) filed doc-less interventions. This matter is still pending before the FERC. If you have any questions concerning these matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

As previously reported, the FERC issued four orders in this proceeding in July 2020 (three on July 17 (together, the "*July 17 Orders*"); one on July 28, 2020). Each of the orders addressed in part or in whole the

[37] *Essential Power Newington, LLC*, Docket No. ER21-1171 (Mar. 31, 2021) (unpublished letter order).

[38] The Support Agreements are separate contracts between the IRH and each of the Asset Owners under which the IRH agree to financially support the elements of the Phase I/II HVDC-TF owned by each Asset Owner in exchange for rights to use the transmission capacity of the Phase I/II HVDC-TF to transmit power to and from the HQ system ("Use Rights"). The Use Agreement is a contract among the IRH that provides the rules for the exercise of the Use Rights, for making the Use Rights available to others, and for the collective management of those individual contractual rights through the IRH Management Committee.

Cost-of-Service Agreement ("COS Agreement")[39] among Constellation Mystic Power ("Mystic"), Exelon Generation Company ("ExGen") and ISO-NE, which is to provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024. As noted in Section XV below, each of the *July 17 Orders*[40] (and the earlier, underlying orders) have been appealed to the DC Circuit. Three aspects of this proceeding are pending before the FERC:

ROE Paper Hearings (-000). The *Dec 2018 Order* established a paper hearing to determine the just and reasonable ROE to be used in setting charges under Mystic's COS Agreement. On April 19, 2019, Mystic, CT Parties,[41] ENECOS,[42] MA AG, and FERC Trial Staff filed initial briefs. On July 18, 2019, Constellation Mystic Power, CT Parties, ENECOS, MA AG, National Grid, FERC Trial Staff filed reply briefs. In a July 28, 2020 order,[43] the FERC reopened the record to allow parties an opportunity to present written evidence applying the FERC's *Opinion 569-A* ROE methodology to the facts of this proceeding. CT Parties, EMCOS, MA AG, and FERC Trial Staff filed their initial "Opinion 569-A" briefs on September 28, 2020. Responses to those initial briefs were due October 28, 2020 and were filed by Mystic, CT Parties, ENECOS, and FERC Trial Staff. The ROE issue is now pending before the Commission.

Sep 2020 Compliance Filing (-007). On September 15, 2020, Mystic filed a revised COS Agreement in response to the requirements of the *July 17 Compliance Order*. Also included were typographical edits proposed by NESCOE in its protest of the First Compliance Filing. Mystic also filed revisions to the Fuel Security Agreement ("FSA") for informational purposes because some of the compliance directives required changes to the FSA. Comments on the Sep 2020 Compliance Filing were due on or before October 6, 2020. CT Parties and ENECOS protested the compliance filing. On October 21, 2021, Mystic answered the CT Parties' and ENECOS' protests. On April 26, 2021, the FERC accepted in part, and rejected in part, the Sep 2020 Compliance Filing.[44] The FERC found that Mystic had partially complied with its directive "to reflect the transfer in lieu of foreclosure in its original cost study."[45] Agreeing with CT Parties, the FERC found that Mystic improperly applied the difference between the purchase price and net original cost to reduce the plant's gross book value, thereby unreasonably increasing Mystic's rate base. Accordingly, the FERC directed Mystic to submit, on or before June 25, 2021, a compliance filing "adopting the accounting treatment that Mystic submitted in Attachment A of its answer for instructional

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[39] The COS Agreement, submitted on May 16, 2018, is between Mystic, Exelon Generation Company, LLC ("ExGen") and ISO-NE. The COS Agreement is to provide cost-of-service compensation to Mystic for continued operation of Mystic 8 & 9, which ISO-NE has requested be retained to ensure fuel security for the New England region, for the period of June 1, 2022 to May 31, 2024. The COS Agreement provides for recovery of Mystic's fixed and variable costs of operating Mystic 8 & 9 over the 2-year term of the Agreement, which is based on the pro forma cost-of-service agreement contained in Appendix I to Market Rule 1, modified and updated to address Mystic's unique circumstances, including the value placed on continued sourcing of fuel from the Distrigas liquefied natural gas ("LNG") facility, and on the continued provision of surplus LNG from Distrigas to third parties.

[40] The "*July 17 Orders*" are the *July 2018 Rehearing Order, Dec 2018* Rehearing *Order* and the *July 17 Compliance Order*. *Constellation Mystic Power, LLC,* 164 FERC ¶ 61,022 (July 13, 2018) ("*July 2018 Order*"), *clarif. granted in part and denied in part, reh'g denied*, 172 FERC ¶ 61,043 (July 17, 2020) ("*July 2018 Rehearing Order*"); *Constellation Mystic Power, LLC*, 165 FERC ¶ 61,267 (Dec. 20, 2018) ("*Dec 2018 Order*"), *set aside in part, clarification granted in part and clarification denied in part*, 172 FERC ¶ 61,044 (July 17, 2020) ("*Dec 2018* Rehearing *Order*"); *Constellation Mystic Power, LLC*, 172 FERC ¶ 61,045 (July 17, 2020) ("*July 17 Compliance Order*") (order on compliance and directing further compliance).

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

[42] "ENECOS" are: Braintree, Concord, Georgetown, Hingham, Littleton, Middleborough, Middleton, Norwood, Pascoag, Reading, Taunton, and Wellesley.

[43] *Constellation Mystic Power, LLC*, 172 FERC ¶ 61,093 (July 28, 2020), *order addressing arguments on reh'g*, 173 FERC ¶ 61,261 (Dec. 21, 2020).

[44] *Constellation Mystic Power, LLC*, 175 FERC ¶ 61,069 (Apr. 26, 2021) ("*April 26 Order*").

[45] *Id.* at PP 23-24. Mystic was directed to reflect the fact that a group of creditors acquired Mystic 8 and 9 from the then-owner (Boston Generating, LLC) in exchange for extinguishing a debt in accordance with the FERC's original cost test.

purposes, which adds to accumulated depreciation the difference between the purchase price and net original cost (and not to the plant's *gross* book value)".[46]

Feb 2021 Compliance Filing (-008). On February 25, 2021, Mystic filed a revised COS Agreement in a third compliance filing, this time in response to the requirements of the FERC's *Dec 21, 2020 Third Compliance Order*.[47] The Feb 2021 Compliance Filing proposed changes to section 2.4 of the COS Agreement to align that section with the FERC's direction that the Agreement's clawback mechanism apply to costs "that are incurred" rather than those that "that were expensed." Comments on the third compliance filing were due on or before March 18, 2021. CT Parties, ENECOS and Public Systems[48] filed protests of the third compliance filing, and Mystic answered those protests on April 2, 2021. In the *April 26 Order*, the FERC rejected the Feb 2021 Compliance Filing.[49] The FERC found that, while Mystic removed the phrase "that were expensed", Mystic also proposed other revisions to the language of section 2.4 of the COS Agreement that went beyond the directives of the *Dec 21, 2020 Third Compliance Order*. Under FERC precedent, filers may not include a rate change in a compliance filing that is not directed or otherwise authorized by the FERC.[50] Therefore, the FERC rejected Mystic's proposed changes to section 2.4 of the COS Agreement and directed Mystic to submit in its 60-day (June 25, 2021) compliance filing, a change to section 2.4 that simply removes the phrase "that were expensed."

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).

- **MPD OATT 2019 Annual Informational Filing Settlement Agreement (ER15-1429-014)**

On December 28, 2020, Versant Power submitted an uncontested Joint Offer of Settlement between itself, MPUC, MOPA, and the MCG to resolve certain issues raised by the MPUC and the MCG with regards to Versant Power's annual charges update under the Open Access Transmission Tariff for Maine Public District ("MPD OATT"), as filed in Docket No. ER15-1429-000 on May 1, 2019, and revised on May 16, 2019 (together, the "2019 Annual Update").[51] Initial comments and reply comments were due January 18 and 27, 2021, respectively; none were filed. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **ISO Securities: Authorization for Future Drawdowns (ES21-34)**

On March 26, 2021, ISO-NE requested the necessary FERC authorization for drawdowns under a new $20 million Revolving Credit Line and a new $4 million line of credit supporting the Payment Default Shortfall Fund, each of which are with TD Bank, are for a term of three years ending June 30, 2024, and replace similar arrangements that will expire June 30, 2021.[52] Comments on this filing were due on or before April 18; none

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[46] *Id.* at P 24.

[47] *Constellation Mystic Power, LLC*, 173 FERC ¶ 61,261 (Dec. 21, 2020) ("*Dec 21, 2020 Third Compliance Order*")

[48] "Public Systems" are Mass. Mun. Wholesale Electric Co. ("MMWEC") and New Hampshire Elec. Coop. ("NHEC").

[49] *April 26 Order* at P 30.

[50] *See Ind. & Mich. Mun. Distribs. Ass'n v. Ind. Mich. Power Co.,* 61 FERC ¶ 61,351, at 62,373 (1992).

[51] As previously reported, MCG moved to strike the true-up to actuals portion of the 2019 Annual Update to the extent that the true-up proposed a change in the formula rate from a direct assignment of Maine Public District ("MPD") post-retirement benefits other than pensions ("PBOPs") to an allocation of company-wide PBOPs (which MCG argued would be a retroactive change to the formula rate, otherwise required to effect only prospectively).

[52] *See ISO New England Inc.*, 139 FERC ¶ 62,248 (June 22, 2012) (initially authorizing borrowings through June 30, 2014); *ISO New England Inc.*, 147 FERC ¶ 62,091 (May 6, 2014) (continuing authorization through June 30, 2015); *ISO New England Inc.*, 151 FERC ¶ 62,185 (June 15, 2015) (continuing authorization through June 30, 2017); *ISO New England Inc.*, 159 FERC ¶ 62,143 (May 9, 2017) (continuing authorization through June 30, 2019); *ISO New England Inc.*, 163 FERC ¶ 62,144 (June 1, 2018) (continuing authorization through May 31, 2020); *ISO New England Inc.*, 172 FERC ¶ 62,017 (July 13, 2020) (continuing authorization through July 12, 2022).

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).

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

- **eTariff § III.13.1 Corrections (ER21-1766)**

On April 26, 2021, ISO-NE filed changes to Section III.13.1 of its eTariff to ensure that the eTariff Viewer reflects in all appropriate versions the rejection of the June 11, 2018 Economic Life Revisions and includes the corresponding, since-accepted compliance revisions. Comments on this filing are due on or before May 17, 2021. Thus far, NEPOOL has intervened doc-lessly. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Waiver Request: FCA16 Qualification Requirement (CMEEC, MMWEC, Pascoag, VT DPS) (ER21-1726)**

On April 21, 2021, CMEEC, MMWEC, Pascoag, and VTDPS (together, "Movants") petitioned the FERC for a one-time waiver of the requirement to submit, by the deadline contained in ISO-NE Tariff Section III.13.1.10(e), the required copies of executed versions of its New York Power Authority ("NYPA") contracts in connection with the FCA16 New Capacity Imports qualification process. Movants explained that the waiver is necessary because, while the contracts with NYPA have been completed and have received initial approval from NYPA's Board of Trustees, the contracts will not have been signed prior to the close of the submission because of the duration of the state approval process. Comments on Movants' waiver request are due on or before May 12. Thus far, NEPOOL has filed a doc-less intervention. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **ISO-NE IMM Ethical Standards Changes (ER21-1666)**

On April 13, 2021, ISO-NE and NEPOOL filed revisions to Market Rule 1 to include directly in Section 18 of Appendix A to Market Rule 1 the remaining minimum ethical standards for the IMM Unit and its employees that, pursuant to *Order 719*, must be included in the ISO-NE Tariff. While two of those ethical standard are already set forth directly in Appendix A Section 18, the revisions add the remaining five to Section 18 and delete Exhibit 5 to Appendix A (ISO-NE's Code of Conduct) which had been until now relied on for including those five standards. The changes were supported by the Participants Committee (by way of the March 4 Consent Agenda - Item No. 5). Comments on this filing were due on or before May 4, 2021; none were filed. Brookfield, Calpine, Eversource (out-of-time), National Grid, NESCOE, and NRG filed doc-less interventions. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **FCA16 ORTP Jump Ball Filing (ER21-1637)**

On April 7, 2021, ISO-NE and NEPOOL filed alternative Tariff changes to establish Offer Review Trigger Prices (ORTPs) for the sixteenth Forward Capacity Auction (FCA16). The primary differences between the alternative proposals were the ORTPs for Off-Shore Wind, Energy Storage Devices (Lithium Ion Batteries), and Photovoltaic Solar, where NEPOOL proposed lower ORTPs,[53] as well as NEPOOL's Proposals regarding Economic Life determination, unit-specific offer review, the use of tax credits, and the ORTP for Combined Resources. The Participants Committee supported the NEPOOL alternative with a 72.5% vote in favor; the ISO-NE alternative, with a 19.04% in favor. ISO-NE and NEPOOL jointly requested that the FERC issue an order on or before Tuesday, June 8, 2021.

Motion for Protective Order. On April 13, 2021, NEPOOL requested the adoption of a Protective Order to allow for prompt access to the complete set of data relied on by ISO-NE for its alternative, particularly confidential cost information from Mott MacDonald's database. Access to that information would help the parities and the

[53] For Off-Shore Wind, Lithium Ion Batteries and Photovoltaic Solar, ISO-NE proposed ORTPs of the FCA Starting Price, $2.912, and $1.381, respectively; NEPOOL, $0.000, $2.601, and $0.000, respectively.

FERC to understand and assess the ISO's calculation for its proposed offshore wind ORTP. ISO-NE opposed NEPOOL's motion. PJM, concerned that "the risk of public disclosure – even subject to a protective order – may hinder PJM's ability to engage with independent consultants" who may be unwilling to disclose confidential and proprietary project specific costs given the non-disclosure agreements with their respective clients, urged the FERC to limit the scope of its order in this docket. NEPOOL answered points made in the ISO-NE protest and PJM comments. ISO-NE answered NEPOOL's answer. The FERC has not, as of the date of this Report, taken any action on the motion for protective order.

Comments, Protests, Answers. Comments were due on or before April 28 and were filed by: NEPOOL, ISO-NE IMM; Acadia, Calpine/Vistra, ENECOS, Enel X/ENGIE/Borrego/AEE/SEIA/ACPA, FirstLight, MMWEC/NHEC, MA AG/NH OCA/CT OCC, NEPGA, North East Offshore, New England for Off Shore Wind, RENEW, CT AG, CT DEEP, EPSA, National Hydropower Assoc. Interventions only were filed by a number of parties, including by: Avangrid, Brookfield, CLF, CPV Towantic, Dominion, ENE, Eversource, Exelon, EPSA, National Grid, NESCOE, NRDC, NRG, Vineyard Wind, Public Citizen intervene, Sierra Club, and the Maine Office of Public Advocate. A round of pleadings in response to the April 28 comments can be expected to be filed on or before May 13, 2021.

This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Dave Doot (dtdoot@daypitney.com; 860-275-0102), Sebastian Lombardi (860-275-0663; slombardi@daypitney.com), Joe Fagan (202-218-3901; jfagan@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **eTariff § I.2 Corrections (ER21-1513)**

On March 25, 2021, ISO-NE filed corrections to its eTariff to remove from Section I.2 previously-rejected changes (proposed in the April 15, 2020 Energy Security ("ESI") Initiatives filing (ER20-1567)) that were also included as part of an April 16, 2020 filing accepted by the FERC that extended the implementation date of the Settlement-Only Generator Dispatchability Changes (ER20-1582). Comments on this filing were due on or before April 15, 2021; none were filed. NEPOOL filed a doc-less intervention. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Elimination of Price Lock and Zero-Price Offer Rule for New Entrants Starting in FCA16 (ER21-1010)**

On April 13, 2021, the FERC accepted Tariff revisions eliminating the price lock and associated zero-price offer rule for new entrants starting in FCA16.[54] As previously reported, ISO-NE proposed the changes in response to the requirements of the *December 2 Order.*[55] The changes were supported by the Participants Committee (by way of the February 4 Consent Agenda - Item No. 4) following the required February 1, 2021 filing. Unless the April 13 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **EER Exemption from PFP Settlement (ER21-943)**

On March 31, 2021, the FERC accepted Tariff revisions filed by ISO-NE (including related revisions to the FAP) to exclude energy efficiency resources ("EERs") from Pay-for-Performance ("PFP") obligations and settlement in all hours.[56] EER capacity base payments are unaffected. In accepting the revisions, the FERC disagreed with arguments made by AEE, finding that "it is not *unduly discriminatory* to exclude [EERs] from [PFP] rewards or

[54] *ISO New England Inc.*, Docket No. ER21-1010 (Apr. 12, 2021) (unpublished letter order).

[55] *ISO New England Inc.*, 173 FERC ¶ 61,198 (Dec. 2, 2020) ("*December 2 Order*") (finding the price-lock mechanism and zero-price offer rule ("New Entrant Rules") no longer just and reasonable and directing ISO-NE to remove the New Entrant Rules from the Tariff).

[56] *ISO New England Inc.*, 174 FERC ¶ 61,252 (Mar. 21, 2021).

penalties during energy efficiency measure hours."[57] The revisions were accepted effective as of April 1, 2021. The March 31 order was not challenged and this proceeding is now concluded. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Updated CONE, Net Cone and PPR Values (eff. FCA16) (ER21-787)**

On December 31, 2020, ISO-NE filed changes to update the Cost of New Entry ("CONE"), Net CONE, and Payment Performance Rate ("PPR") values beginning with FCA16. The values in this filing are the same CONE, Net CONE and PPR values that the NPC approved at its December 5 meeting as part of a broader FCM updates package; however, this filing did not include the updated Offer Review Trigger Prices ("ORTPs"), which were part of the broader package, and on which NEPOOL and ISO-NE will propose alternative values in a jump ball filing to be submitted later this month. ISO-NE explained in its filing that, if the schedule for FCA16 is to be maintained, the updated CONE, Net CONE and PPR values need to be acted on by the FERC and become effective by early March, 2010 (a March 2, 2021 effective date was requested). ISO-NE stated that the revised ORTPs and related Tariff changes, however, do not need to be effective until slightly later in the FCA16 qualification process (thereby permitting a slightly later submission of, and FERC action on, the various ORTPs and related Tariff changes). Because NEPOOL did not vote on the CONE, Net CONE and PPR values separately, but rather as part of a broader package with the alternative ORTP provisions, NEPOOL did not join this ISO-NE filing but will provide comments in response to the filing explaining the December 5 NEPOOL vote on the package of proposed FCM parameters.

Comments on this ISO-NE filing were due on or before January 21, 2021. Comments were filed by NEPOOL, MMWEC, NESCOE, and CT Agencies. Protests were filed by CPV Towantic, Dominion, FirstLight, NEPGA, and NEI. Doc-less interventions were filed by Avangrid, Brookfield, BSW Project Co, Calpine, Cogentrix, Dominion, Eversource, CT AG, CT OCC, CT DEEP, CT PURA, LS Power, MA AG, National Grid (out-of-time), NESCOE, NHEC, NRG, Vistra, EPSA, and MA DPU (out-of-time). On February 12, ISO-NE answered the protests filed. On February 16 and 17, answers to ISO-NE's February 12 answer were filed by EPSA, NEPGA and CPV Towantic.

March 1, 2021 Deficiency Letter. On March 1, 2021, the FERC issued a deficiency letter, directing ISO-NE to provide within 30 days additional information, including the following: (i) an example of a potential site for the reference unit (in or near New London County, CT) that is two miles from both a main natural gas transmission line and the point of interconnection to the electric grid; (ii) an estimate of NOx emissions limit and whether those limits affect the reference unit's revenues; and (iii) additional support for the assumption that the reference unit always runs on natural gas rather than oil in the dispatch model. The responses to the Deficiency Letter were due on or before March 31, 2021 and were filed by ISO-NE on March 30, 2021. ISO-NE's submission of the additional information re-set the 60-day deadline for FERC action on this filing.

Comments on ISO-NE's deficiency letter responses were due on or before April 20, 2021 and were filed by NEPOOL,[58] NESCOE, NEPGA, CPV Towantic, and New England Generators. Additional doc-less interventions were filed by NextEra, Marco DM Holdings and ENE (out-of-time).

This matter is again pending before the FERC. If you have any questions concerning this proceeding, please contact Dave Doot (dtdoot@daypitney.com; 860-275-0102), Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

[57] *Id.* at PP 27-32.

[58] NEPOOL's limited comments (i) provided a more fulsome report on the stakeholders' consideration of ISO-NE's proposed revised CONE/Net CONE/PPR Values; (ii) corrected the record regarding the NEPOOL vote outcome; and (iii) noted NEPOOL's unanimous support for Tariff revisions, included with ISO-NE's deficiency letter response, that provide additional flexibility for FCA16 De-List Bids

IV. OATT Amendments / TOAs / Coordination Agreements

- **ISO-NE/NYISO Coordination Agreement (ER21-1278)**

On April 15, 2021, the FERC accepted changes jointly filed by ISO-NE and NEPOOL to the ISO-NE/NYISO Coordination Agreement.[59] The changes move the ISO-NE/NYISO Interconnection Facilities List, including associated descriptions of the Interties and common metering points, from Schedule A of the ISO-NE/NYISO Coordination Agreement to ISO-NE's public website. The changes were accepted effective May 4, 2021 as requested. Unless the April 15 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).

- ***Order 676-I* Compliance Filing (ER21-941)**

On January 26, 2021, ISO-NE and NEPOOL, in response to *Order 676-I*, jointly filed changes to incorporate by reference in Schedule 24 of the OATT the latest version (Version 003.2) of certain Standards for Business Practices and Communication Protocols for Public Utilities adopted by the Wholesale Electric Quadrant ("WEQ") of the North American Energy Standards Board ("NAESB"). The Participants Committee unanimously supported the *Order 676-I* revisions at its May 7, 2020 meeting. Comments on this filing were due on or before February 16, 2021; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

- **Schedule 20A NEP-Vitol Phase I/II HVDC-TF Service Agreement (ER21-1180)**

On April 19, 2021, the FERC accepted the new Phase I/II HVDC-TF Service Agreement between New England Power Company ("NEP") and Vitol Inc. ("Vitol").[60] As previously reported, the Service Agreement, based on the *pro forma* Phase I/II HVDC-TF Service Agreement set forth in Schedule 20A-Common Attachment A, provides for firm point-to-point transmission service over the Phase I/II HVDC transmission facilities ("Phase I/II HVDC-TF") for the November 1, 2020 to November 1, 2025 period. The Agreement was filed separately because it contains potentially non-conforming terms that provide Vitol a right to terminate the Agreement if it finds unacceptable the terms and conditions of the Amended and Restated IRH Support and Use Agreements pending in ER21-712 (*see* Section II above). The Agreement was accepted effective as of November 1, 2020, as requested. Unless the April 19 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Schedule 21-VP: 2019 Annual Update Settlement Agreement (ER15-1434-004)**

On April 26, 2021, the FERC approved Emera Maine's (now Versant Power) joint offer of settlement, filed March 19, 2020, between itself and the MPUC to resolve all issues raised by the MPUC in response to Emera Maine's 2019 annual charges update filed, as previously reported, on June 10, 2019 (the "Emera 2019 Annual Update Settlement Agreement").[61] As previously reported, under Part V of Attachment P, "Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the [Attachment P] Rate Formula. . . ." and follow a dispute resolution procedure set forth there. In accordance with those provisions, the MPUC identified certain disputes with the 2019 Annual Update, all of

[59] *ISO New England Inc.*, Docket No. ER21-1278 (Apr. 15, 2021) (unpublished letter order).

[60] *New England Power Co.*, Docket No. ER21-1180 (Apr. 19, 2021) (unpublished letter order).

[61] *ISO New England Inc. and Emera Maine*, 175 FERC ¶ 61,067 (Apr. 26, 2021).

which were resolved by the Emera 2019 Annual Update Settlement Agreement. Unless the April 26 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-VP: Recovery of Bangor Hydro/Maine Public Service Merger-Related Costs (ER15-1434-001 *et al.*)**

The MPS Merger Cost Recovery Settlement, filed by Emera Maine on May 8, 2018 to resolve all issues pending before the FERC in the consolidated proceedings set for hearing in the *MPS Merger-Related Costs Order,*[62] and certified by Settlement Judge Dring[63] to the Commission,[64] remains pending before the FERC. As previously reported, under the Settlement, permitted cost recovery over a period from June 1, 2018 to May 31, 2021 will be $390,000 under Attachment P of the BHD OATT and $260,000 under the MPD OATT. If you have any questions concerning these matters, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

On April 30, 2021, VEC submitted its 18th annual update to the formula rates contained in Schedules 21-VEC and 20-VEC covering the July 1, 2021 – June 30, 2022 period. VEC indicated that it was not proposing any changes to the underlying formulas. The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

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

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

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

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

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

- ***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*[65] *and 531-B*[66] 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 - 2020 Q4 (ER21-1109)**

On April 7, 2021, the FERC accepted ISO-NE's Capital Projects Report and Unamortized Cost Schedule covering the fourth quarter ("Q4") of calendar year 2020 (the "Report").[67] As previously reported, Report highlights included the following new projects: (i) nGEM software development part II ($4.79 million); (ii) Integrated Market Simulator Phase 1 ($1.6 million); (iii) FCM Qualification Enhancements ($1.2 million); (iv) CIP Electronic Security Perimeter Redesign ($1.1 million); (v) Sub-accounts for FTR Market ($0.98 million); (vi) Enterprise Phone System Upgrade ($701,300); (vii) Wireless Infrastructure Upgrade ($548,900); (viii) Time Entry System Upgrade ($398,200); (ix) Ownership Transfer & External Registration ($382,700); (x) PI Historian for Short-term PMU Data Repository ($368,800); (xi) Annual Maintenance Schedule Automation ($315,800); and (xii) FERC Form 1, 3-Q and 714 Project ($162,400). There were no significant changes for Chartered Projects in 2020 Q4. Unless the April 7 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **Reserve Market Compliance (30th) Semi-Annual Report (ER06-613)**

As directed by the original ASM II Order,[68] as modified,[69] ISO-NE submitted its 30th semi-annual reserve market compliance report on April 1, 2021. In the 30th report, ISO-NE explained that it is focused on efforts to address energy security, and is engaged in regional discussions with stakeholders to evaluate wholesale market responses to the region's focus on rapid decarbonization. ISO-NE committed to address in future reports how the objectives of a forward TMSR market might be achieved or impacted by those efforts. The April 1 report was not noticed for public comment. If there are questions on this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com).

- **IMM Quarterly Markets Reports – Winter 2021 (ZZ21-4)**

On April 28, 2021, the IMM filed with the FERC its Winter 2021 report of "market data regularly collected by [the IMM] in the course of carrying out its functions under … Appendix A and analysis of such market data," as required pursuant to Section 12.2.2 of Appendix A to Market Rule 1. These filings are not noticed for public

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

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

[67] *ISO New England Inc.*, Docket No. ER21-1109 (Apr. 7, 2021) (unpublished letter order).

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

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

comment by the FERC. The Winter 2021 Report will be discussed with the Markets Committee at its May 11 meeting.

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

On March 29, 2021, ISO-NE submitted its 2020 Annual Transmission Planning and Evaluation Report. These filings are not noticed for public comment.

- **ISO-NE FERC Form 3Q (2020/Q4) (not docketed)**

On April 15, 2021, ISO-NE submitted its 2020/Q4 FERC Form 3Q (Quarterly financial report of electric utilities, licensees, and natural gas companies). FERC Form 3-Q is a quarterly regulatory requirement which supplements the annual FERC Form 1 financial reporting requirement. These filings are not noticed for comment.

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

On April 19, 2021, ISO-NE submitted a report of its total MWh of transmission service during 2020. ISO-NE reported that 124,105,168 MWh of transmission service in interstate commerce was provided during 2020 (roughly 2.6 MWh less than 2019 (126,676,919 MWh)). These filings are not noticed for comment.

IX. Membership Filings

- **May 2021 Membership Filing (ER21-1804)**

On April 30, 2021, NEPOOL requested that the FERC accept (i) the memberships of Protor Energy, LLC [Related Person to Darby Energy, LLC (Supplier Sector)]; and Voltus Inc. (AR Sector, Load Response Sub-Sector); and (ii) the termination of the Participant status of Great Bay Power Marketing (AR Sector, Small RG Group Member). Comments on this filing are due on or before May 21, 2021.

- **April 2021 Membership Filing (ER21-1570)**

On March 31, 2021, NEPOOL requested that the FERC accept the membership of Ocean State BTM LLC [Related Person to Madison BTM, Madison ESS, Rumford ESS, and New England Battery Storage (Generation Group Seat)]; and Transgrid Midwest LLC (Supplier Sector). Comments on this filing were due on or before April 21, 2021; none were filed. This matter is pending before the FERC.

- **March 2021 Membership Filing (ER21-1228)**

On February 26, 2021, the FERC accepted:[70] (i) the membership of Trafigura Trading LLC (Supplier Sector); (ii) the termination of Axon Energy (Supplier Sector) and Springfield Power [Related Person to Stored Solar J&WE, LLC (AR Sector)]; and (iii) the inclusion of Titan Gas LLC's d/b/a (as CleanSky Energy) in the list of Participants. Unless the April 26 order is challenged, this proceeding will be concluded.

- **February 2021 Membership Filing (ER21-1008)**

On April 1, the FERC accepted:[71] (i) the memberships of: Axpo U.S. LLC (Supplier Sector); Catalyst Power & Gas, LLC (Supplier Sector); Palm Energy LLC (Provisional Member); Madison ESS, LLC and Rumford ESS, LLC [each a Related Person to Madison BTM and New England Battery Storage (Generation Group Seat)]; Vineyard Reliability LLC (Generation Group Seat); West Medway II, LLC [Related Person to Exelon Generation Company and Constellation NewEnergy, Inc. (Supplier Sector)]; and Dick Brooks (End User Sector, Governance Only Member); (ii) the termination of the Participant status of: Energy Federation Inc. ("EFI") (AR Sector, LR Sub-Sector, Small LR Group Seat); Great American Power, LLC (Supplier Sector); Oasis Power, LLC d/b/a Oasis Energy [Related Person to Spark Energy et al., (Supplier Sector)]; Praxair, Inc. (End User Sector); Rubicon NYP Corp. (Supplier Sector); and

[70] *New England Power Pool Participants Comm.*, Docket No. ER21-1228 (Apr. 26, 2021) (unpublished letter order).

[71] *New England Power Pool Participants Comm.*, Docket No. ER21-1008 (Apr. 1, 2021) (unpublished letter order).

Verde Group, LLC (Provisional Member); and (iii) the Name change of Utility Services of Vermont (f/k/a Utility Services, Inc.). Unless the April 1 order is challenged, this proceeding will be concluded.

- **Invenia Additional Conditions Informational Filing (ER20-2001)**

Still pending before the FERC is the June 5, 2020 informational filing submitted by ISO-NE pursuant to Section II.A.1(b) of the FAP identifying the additional condition (supplemental financial assurance) required of Invenia for participation in the New England Markets. The additional condition was supported, and made a condition of Invenia's membership, by the Participants Committee at its June 4, 2020 meeting. A doc-less intervention was submitted by Public Citizen. This informational filing is still pending before the FERC.

- **Suspension Notice (not docketed)**

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

Date of Suspension/ FERC Notice	*Participant Name*	*Default Type*	*Date Reinstated*
Apr 14/16	Manchester Methane, LLC	Financial Assurance	May 3

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

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

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

- **Revised Reliability Standard: FAC-008-5 (RD21-4)**

On April 7, 2021, the FERC approved NERC's proposed changes to Reliability Standard FAC-008-5 (Facility Ratings). FAC-008-5 reflects the retirement of Requirement R7, recommended as part of NERC's Standards Efficiency Review because of its redundancy with requirements in other Reliability Standards. FAC-008-5 will become effective (and the currently effective versions be retired) on October 1, 2021 (the first day of the first calendar quarter that is three months following FERC approval). Unless the April 7 order is challenged, this proceeding will be concluded.

- **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 (resulting from Projects 2016-02 (Modifications to CIP Standards) and 2019-02 (BES Cyber System Information Access Management)). NERC filed its fifth informational filing on March 15, 2021, reporting no change in schedule for either project from that reported in its supplemental November 2020 filing -- filing of proposed Reliability Standards in December 2021 for both Projects (2019-02 and 2016-02).

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

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

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

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

On February 20, 2020, the FERC issued a NOI seeking comments on (i) the potential benefits and risks associated with the use of virtualization and cloud computing services in association with bulk electric system ("BES") operations; and (ii) whether the CIP Reliability Standards impede the voluntary adoption of virtualization or cloud computing services.[72] On March 25, 2020, Joint Associations[73] requested an extension of time to submit comments and reply comments. On April 2, the FERC granted Joint Associations' request and extended the deadline for initial comments on the NOI to July 1, 2020; the deadline for reply comments, July 31, 2020. Comments were filed by NERC, the IRC, Accenture, Amazon Web Services ("Amazon"), Bonneville, the Bureau of Reclamation, Barry Jones, Georgia System Operations, GridBright, Idaho Power, Microsoft, MISO, MISO Transmission Owners, Siemens Energy Management, Tri-State Generation and Transmission Association, VMware, Inc., AEE, American Association for Laboratory Accreditation ("A2LA"), APPA, Canadian Electricity Assoc., EEI, NRECA, and Waterfall Security Solutions. Reply comments were due on or before July 31, 2020, and were filed by AEE, Amazon and Microsoft.

In part in response the comments filed, the FERC, in a December 17, 2020 order,[74] directed NERC to begin a formal process to assess, and to make an informational filing in a little over one year (January 1, 2022) that addresses, the feasibility of voluntarily conducting BES operations in the cloud in a secure manner, as well as the status and schedule for any plans to modify the standards.

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

On September 17, 2020, the FERC approved the retirement of the 18 Reliability Standard requirements through the retirement of four Reliability Standards and the modification of five Reliability Standards,[75] concluding that the 18 requirements "(1) provide little or no reliability benefit; (2) are administrative in nature or relate expressly to commercial or business practices; or (3) are redundant with other Reliability Standards."[76] The FERC also approved the associated violation risk factors, violation severity levels, implementation plan, and effective dates proposed by NERC. Because it was not persuaded by NERC's justification for the retirement of FAC-008-4 requirement R8, the FERC remanded the retirement of requirements R7 and R8 to NERC for further consideration.[77]

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

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

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

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

[76] *Order 873* at P 2.

[77] *Order 873* at P 5. Pursuant to FPA section 215(d)(4), if the FERC disapproves a modification to a Reliability Standard in whole or in part, it must remand the entire Reliability Standard to NERC for further consideration. Accordingly, although it was satisfied here with

The FERC left for another day its final action on the remaining 56 requirements for which the FERC proposed to approve retirement in the *Retirements NOPR*[78] (the "MOD A Reliability Standards"). The FERC intends to coordinate the effective dates for the retirement of the MOD A Reliability Standards with successor North American Energy Standards Board ("NAESB") business practice standards (v. 003.3) that include Modeling business practices pending in the *NAESB WEQ v. 003.3 Standards NOPR* (*see* Section XII below).[79]

- **Report on Research Results Under NERC's Final GMD Research Work Plan (RM15-11)**

On April 30, 2021, NERC filed an informational report, pursuant to P 77 of *Order 830*, that provides further technical justification and support for the currently effective geomagnetic disturbances ("GMD") planning standard, TPL-007-4 (Transmission System Planned Performance for GMD Events). The outcomes from this research project affirm the efficacy of the TPL-007 Reliability Standard and provide tools and insights for the ERO, industry, and research partners to use in accurately performing GMD Vulnerability Assessments. NERC committed, as part of the required periodic review of the TPL-007 Reliability Standard, to consider these research findings, as well as any new developments in space weather research and other insights that are gained during the implementation of the standard, to determine whether further improvements and refinements to the standard are necessary. This Report was not noticed for public comment.

- **Amended and Restated NERC Bylaws (RR21-1)**

On April 5, 2021, the FERC accepted NERC's October 14, 2020 petition for approval of its amended and restated Bylaws.[80] As previously reported, NERC stated that the amendments (i) address governance matters relating to the composition of NERC's membership Sectors, certain rules relating to the Member Representatives Committee, as well as the qualification of independent trustees for the Board; (ii) update certain provisions to conform with applicable state law; and (iii) improve internal consistency and introduce ministerial changes within the Bylaws with respect to capitalizing defined terms consistently and removing inoperative provisions. Unless the April 5 order is challenged, this proceeding will be concluded.

- **Notice of Penalty: VTransco (NP21-14)**

On April 29, 2021, NERC filed a Notice of Penalty regarding VTransco's violation of Reliability Standards FAC-003-4 (Transmission Vegetation Management) Requirements 2 and 6. Specifically, NPCC, NERC's Regional Entity for the Northeast, determined VTransco violated FAC-003-4 R2, from June 6-8, 2020, when a tree encroached into the Minimum Vegetation Clearance Distance and contacted a 345kV transmission line, causing the line to trip and lock out of service as designed. NPCC determined VTransco violated FAC-003-4 R6, from May 17, 2020-June 17, 2020, by failing to include the same two 345kV transmission lines in its database used for its Vegetation Management Program, thereby failing to perform a Vegetation Inspection on these two transmission lines at least once per calendar year with no more than 18 calendar months between inspections on the same Right-of-Way, as required. NPCC determined that these violations posed a moderate risk to the reliability of the Bulk Power System ("BPS").

To resolve all outstanding issues arising from NPCC's determinations and findings, NPCC and VTransco entered into a Settlement Agreement in which VTransco admits to the violations and agrees to a ***$100,000***

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the justification for the retirement of R7, the FERC was required to remand both R7 and R8 so that its concerns with the retirement of Requirement R8 could be addressed.

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

[79] *Standards for Bus. Practices and Communication Protocols for Pub. Utils.*, 85 Fed. Reg. 55201 (Sep. 4, 2020).

[80] *N. Am. Elec. Rel. Corp.*, Docket No. RR21-1 (Apr. 5, 2021) (unpublished letter order).

penalty, in addition to other activities outlined in the Settlement Agreement. Pursuant to 18 CFR § 39.7(e), the penalty will be effective May 29, 2021, or, if the FERC decides to review the penalty, upon a final determination by the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

XI. Misc. - of Regional Interest

- **203 Application: Seneca/Rice et al. (EC21-84)**

On April 28, 2021, Seneca Energy II ("Seneca"), among others, requested authorization for a transaction pursuant to which its ultimate upstream ownership will change to include a publicly listed company (Rice Acquisition Corp. ("Rice")) and both Aria Energy LLC ("Aria"), which is wholly-owned by funds managed by Ares Management Corporation ("Ares Management"), and Archaea Energy, LLC ("Archaea"). After the closing, Aria affiliates will hold approximately 20% of the expected outstanding voting shares; Archaea and its members, 29%; Rice and its shareholders, the remaining shares. Seneca will remain, fir the time being, a Related Person to Generation Sector member Kleen Energy. Comments on the 203 application are due on or before May 19, 2021. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: ReEnergy/Ember (EC21-83)**

Also on April 28, 2021, ReEnergy Livermore Falls LLC and ReEnergy Stratton LLC ("ReEnergy") requested authorization for the sale of 55% of their membership interests to a new joint venture holding company to be owned by ReEnergy Biomass and Ember RGE Holdings, LLC ("Ember"). Upon consummation, ReEnergy Biomass and Ember will ultimately hold 15-30% and 70-85%, respectively, of the voting interests in the joint venture holding company. Comments on the 203 application are due on or before May 19, 2021. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

As previously reported, Exelon Generation Company, LLC ("ExGen"), on behalf of its public utility subsidiaries, requested on February 25, 2021 authorization for a "spin" transaction in which, after completion of an internal reorganization, the ownership of Applicants' intermediate holding company owner, HoldCo, will be distributed to the shareholders of Applicants' current ultimate upstream owner, Exelon Corporation (the "Transaction"). Following the Transaction, Exelon Corporation and its remaining subsidiaries will retain no interest in or affiliation with ExGen or the ExGen Utility Subsidiaries; Exelon Corporation and HoldCo will be separate publicly-traded companies. Comments on this filing were due on or before March 18, 2021. Joint PJM Consumer Advocates[81] filed a protest requesting, among other things, that the FERC direct Applicants to file supplemental materials that include a market power analysis and addresses the vertical market power concerns that Joint PJM Consumer Advocates raised in its comments. Doc-less interventions only were filed by PJM, PJM IMM, EDF, Old Dominion, and Public Citizen. Since the last Report, Exelon answered Joint PJM Consumer Advocates on April 2, 2021. On April 16, the FERC issued a deficiency letter requiring a response from Exelon within 30 days. On April 29, 2021, Exelon submitted its responses to the April 16 deficiency letter. Comments on the April 29 deficiency letter response are due on or before May 13, 2021. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement Cancellation: CL&P / Gravel Pit Solar (ER21-1740)**

On April 23, 2021, CL&P filed a notice of cancellation of a Design and Engineering Agreement ("D&E Agreement") with Gravel Pit Solar LLC. The D&E Agreement set forth the terms and conditions under which Gravel Pit Solar would reimburse CL&P for the costs associated with performing preliminary engineering and

[81] "Joint PJM Consumer Advocates" are: the Office of the People's Counsel for the District of Columbia, Citizens Utility Board, the Delaware Division of the Public Advocate, Maryland Office of the People's Counsel, New Jersey Division of Rate Counsel, and the Pennsylvania Office of Consumer Advocate.

design activities of the line work and switching station that is required to interconnect the project to the transmission system, prior to execution of an LGIA. By its terms, the Agreement terminated upon execution of the LGIA, which occurred on April 20, 2021. An April 23, 2021 effective date was requested for this notice of cancellation. Comments on this filing are due on or before May 14, 2021. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **LGIA Cancellation: CMP / Rumford (ER21-1457)**

On March 16, 2021, CMP filed a notice of cancellation of an Interconnection Agreement between CMP and Rumford Power that expired by its own terms on October 31, 2020 and was replaced by a new, three-party Large Generator Interconnection Agreement ("Renewed LGIA") between ISO-NE, CMP and Rumford Power. An October 22, 2020 effective date was requested. Comments on this filing were due on or before April 6, 2021; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement: NSTAR/Vineyard Wind (ER21-1285)**

On April 16, 2021, the FERC accepted the Preliminary Agreement for Design, Engineering and Construction services (the "D&E Agreement") filed by NSTAR between itself and Vineyard Wind LLC ("Vineyard Wind").[82] The D&E Agreement sets forth the terms and conditions under which NSTAR would advance certain design, engineering and cost estimating activities of the civil and below-grade and above-grade electrical substation work at NSTAR's new proposed Bourne 345 kV substation plus the associated line work and substation upgrades at West Barnstable Station to interconnect two new underground 345 kV lines at West Barnstable Station. The D&E Agreement was accepted for filing as of March 6, 2021, as requested. Unless the April 16 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Related Facilities Agreement: PSNH / NECEC (ER21-1151)**

On April 15, 2021, the FERC accepted the Related Facilities[83] Agreement ("RFA") between Public Service Company of New Hampshire ("PSNH") and NECEC that provides the terms and conditions governing PSNH's activities, and NECEC's associated cost responsibility, in completing the Related Facilities.[84] The RFA was accepted effective February 16, 2021, as requested. Unless the April 15 order is challenged, this proceeding will be concluded. If there are questions on this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement: PSNH/NECEC (ER21-1147)**

On April 15, 2021, the FERC accepted a Preliminary Agreement for Design, Engineering and Construction services (the "D&E Agreement") between PSNH and NECEC.[85] The D&E Agreement sets forth the terms and conditions under which PSNH will undertake certain design, engineering and procurement activities for the mitigation of violations identified in the preliminary initial interconnection analysis summary for Queue Position #979, and other services as may be requested in writing by NECEC to support engineering, design, and procurement activities related to Affected System upgrades needed on the PSNH system for reliable interconnection of the Project. The Agreement was accepted for filing as of February 16, 2021, as requested.

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[82] *NSTAR Electric Co.*, Docket No. ER21-1285 (Apr. 16, 2021).

[83] The "Related Facilities" are certain upgrades of facilities on PSNH's electric transmission system needed to support the construction by NECEC of a 1,200 MW unidirectional +/- 320 kV, symmetrical monopole High Voltage Direct Current line from the 735 kV Appalaches Substation in Quebec to CMP's 345 kV Larrabee Road Substation in Lewiston, ME.

[84] *Public Service Co. of New Hampshire*, Docket No. ER21-1151 (Apr. 15, 2021) (unpublished letter order).

[85] *Public Service Co. of New Hampshire*, Docket No. ER21-1147 (Apr. 15, 2021) (unpublished letter order).

Unless the April 15 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- ***Orders 864/864-A* (Public Util. Trans. ADIT Rate Changes): *New England Compliance Filings* (various)**

In accordance with *Order 864*[86] and *Order 864-A,*[87] and extensions of time granted, New England's public utilities with transmission have submitted their *Order 864* compliance filings, with the specific dockets and filing dates identified in the following table (all remain pending):

Date Filed	Docket	Transmission Provider	Date Accepted
Mar 11, 2021	ER21-1325	NHT	pending
Mar 8, 2021	ER21-1295	Eversource (CL&P, PSNH, NSTAR)	pending
Feb 16, 2021	ER21-1154	Fitchburg Gas & Electric ("FG&E")	pending
Oct 30, 2020 Apr 16, 2021	ER21-311 ER21-1694	Green Mountain Power	pending pending
Aug 5, 2020	ER20-2614	New England Power Support Agreement	pending
Aug 5, 2020	ER20-2610	CL&P	pending
Aug 5, 2020	ER20-2609 ER21-1650	NSTAR	pending pending
Aug 5, 2020	ER20-2608	PSNH	pending
Aug 4, 2020	ER20-2607	NEP – Seabrook Transmission Support Agreement	pending
Jul 31, 2020	ER20-2594 ER21-1709	VTransco	pending pending
Jul 30, 2020	ER20-2551	New England Power	pending
Jul 30, 2020	ER20-2553	NEP – LSA with MECO/Nantucket	pending
Jul 30, 2020	ER20-2572 ER21-1130	New England TOs	pending
Jul 15, 2020	ER20-2429 ER21-1702	CMP	pending pending
Jun 29, 2020	ER20-2219	New England Power	pending
Jun 23, 2020 Mar 22, 2021	ER20-2133 -001	Versant Power	pending
May 18, 2020 Jan 7, 2021	ER20-1839	VETCO	pending
Feb 26, 2020 Dec 11, 2020	ER20-1089	New England Elec. Trans. Corp.	pending
Feb 26, 2020 Dec 11, 2020	ER20-1088	New England Hydro Trans. Elec. Co.	pending
Feb 26, 2020 Dec 11, 2020	ER20-1087	New England Hydro Trans. Corp.	pending

[86] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, Order No. 864, 169 FERC ¶ 61,139 (Nov. 21, 2019), *reh'g denied and clarification granted in part,* 171 FERC ¶ 61,033 (Apr. 16, 2020) ("*Order 864*"). *Order 864* requires all public utility transmission providers with transmission rates under an OATT, a transmission owner tariff, or a rate schedule to revise those rates to account for changes caused by the 2017 Tax Cuts and Jobs Act ("2017 Tax Law"). Specifically, for transmission formula rates, *Order 864* requires public utilities (i) to deduct excess ADIT from or add deficient ADIT to their rate bases and adjust their income ta x allowances by amortized excess or deficient ADIT; and (ii) to incorporate a new permanent worksheet into their transmission formula rates that will annually track ADIT information.

[87] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, 171 FERC ¶ 61,033, Order No. 864-A (Apr. 16, 2020) ("*Order 864-A*").

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

- ***ER20-2133 (Versant Power).*** On April 2, 2021, MPUC submitted comments protesting Versant Power's deficiency letter response.
- ***ER21-1709 (VTransco).*** On April 19, 2021, VTransco supplemented its *Order 864* compliance filing to bring its currently effective local transmission formula rate under Schedule 21-VTransco Attachment D-1 into compliance for the Jan 1, 2020 through Dec 31, 2021 period (the Interim Period) until the rate is superseded and replaced by the settled formula rate approved in ER20-2054, which becomes effective on Jan 1, 2022.
- ***ER21-1702 (CMP).*** CMP submitted proposed revisions to Appendix B of the Schedule 1 Implementation Rule to reflect changes to CMP's Local Control Center revenue requirement.
- ***ER20-2429 (CMP)***. On May 4, 2021, the FERC issued a deficiency letter requiring responses/additional information from CMP on or before June 3, 2021.
- ***ER21-1694 (GMP).*** On April 15, 2021, Green Mountain Power ("GMP") supplemented its Order 864 compliance filing to bring its currently effective local transmission formula rate under Schedule 21-GMP Attachment D-1 into compliance for the Jan 1, 2020 through Dec 31, 2021 period (the Interim Period) until the rate is superseded and replaced by the settled formula rate approved in ER20-2054, which becomes effective on Jan 1, 2022. In addition, GMP revised its permanent ADIT worksheet.
- ***ER21-1650 (NSTAR).*** On April 9, 2021, NSTAR submitted revisions to Appendix A of the ISO-NE Sched. 1 Implementation Rule with respect to NSTAR (East)'s local control center revenue calculation.

XII. Misc. - Administrative & Rulemaking Proceedings

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

On March 5, 2021, the FERC issued a notice that FERC staff will convene on June 1-2, 2021, a technical conference to discuss issues surrounding the threat to electric system reliability posed by climate change and extreme weather events. This technical conference will address (i) concerns that, because extreme weather events are increasing in frequency, intensity, geographic expanse, and duration, the number and severity of weather-induced events in the electric power industry may also increase; and (ii) specific challenges posed to electric system reliability by climate change and extreme weather, which may vary by region. The FERC seeks to understand the near, medium and long-term challenges facing the regions of the country; how decision makers in the regions are evaluating and addressing those challenges; and whether further FERC action is needed to help achieve an electric system that can withstand, respond to, and recover from extreme weather events. A supplemental notice will be issued prior to the conference with further details regarding the agenda and organization.

Pre-technical conference comments were due on or before April 15, 2021 and were filed by, among others, ISO-NE, AEE, Dominion, EDF, Eversource, Exelon, LS Power, National Grid, PSEG, Vistra, APPA, Capital Power, EEI, NARUC, NEI, NERC, NRECA, and the R Street Institute.

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

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

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

March 23 Tech Conf (PJM). The FERC convened a Commissioner-led technical conference was on March 23, 2021 to provide input to the Commission on resource adequacy in the evolving electricity sector. Speaker materials from the March 23 technical conference have been posted to eLibrary. On March 29, Ohio PUC Commission Dan Conway submitted written comments. On April 5, the FERC issued a notice inviting post-technical conference comments on specific PJM-specific questions. Initial comments were due on or before April 26, 2021; reply comments must be submitted on or before May 10, 2021. More than 45 sets of comments were filed, including by: AEE, Calpine, Cogentrix, Dominion, Exelon, FirstLight, LS Power, NESCOE, NEPGA, NRG, PSEG, Shell, Vistra, CT DEEP, EEI, EPSA, and NRECA/APPA, some of which addressed issues to be discussed in the May 25 New England technical conference (identified immediately below).

May 25 Tech Conf (New England). On April 22, 2021, the FERC issued a notice that it will convene a remotely-held, Commissioner-led technical conference regarding the wholesale markets administered by ISO New England Inc. On May 3, the FERC issued a supplemental notice of the technical conference, which included an agenda and topics/questions for discussion for the technical conference. The technical conference will include the following three panel discussions: (1) Commissioner-led discussion of the relationship between state policies and the New England Markets; (2) Staff-led discussion of short-term options and complementary potential market changes to accommodate state policies in New England; and (3) Staff-led discussion of long-term options and centralized procurement of clean energy. Panelists have yet to be announced. A copy of the supplemental notice of the technical conference is included with this Report.

- **Office of Public Participation: Apr 16 Workshop (AD21-9)**

On April 16, 2021, the FERC convened a workshop to allow for input to the Commission on the creation of the Office of Public Participation ("OPP"). As previously reported, the Commission intends to establish and operate the Office of Public Participation to "coordinate assistance to the public with respect to authorities exercised by the Commission," including assistance to those seeking to intervene in Commission proceedings, pursuant to FPA section 319. At the workshop, the Commission heard input on the following considerations in forming the OPP, including: (1) the office's function and scope as authorized by FPA section 319; (2) the office's organizational structure and approach, including the use of equity assessment tools; (3) participation by tribes, environmental justice communities, and other affected individuals and communities, including those who have not historically participated before the Commission; and (4) intervenor compensation.

In addition, the FERC held a series of virtual listening sessions, between March 17, 2021 to March 25, 2021, to similarly solicit public input on how the Commission should establish and operate the OPP with the following groups: (1) landowners and communities affected by infrastructure development (March 17): (2) environmental justice communities and tribal interests (March 22); (3) tribal governments (March 24); and (4) energy consumers and consumer advocates (March 25). Written comments were due by April 23, 2021, and nearly 100 sets of comments were filed. This matter is pending before the Commission.

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

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

On April 21, 2021, the FERC issued a notice inviting post-technical conference comments on the issues raised during the technical conference, including the questions listed in the February 24, 2021 supplemental

notice of the technical conference and in the attachment to the April 21 notice. Post-technical conference comments are due on or before June 7, 2021.

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

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

On March 11, 2021, the FERC issued a notice inviting interested persons to file, on or before May 10, 2021, post-technical conference comments on the questions listed in the attachment to its Notice or to the questions outlined in the October 22, 2020 supplemental notice of technical conference.

- **Carbon Pricing in RTO/ISO Markets Policy Statement (AD20-14)**

On April 15, 2021, the FERC issued a Policy Statement[88] to explain how it will approach FPA section 205 filings that propose RTO/ISO market rules that incorporate a state-determined carbon price. Without indicating a preference for a state-determined carbon pricing approach over other state policies, and noting "whether and how a state chooses to address [greenhouse gas] emissions is a matter exclusively within that state's jurisdiction", the FERC expressly stated that "it is the policy of this Commission to encourage efforts of RTOs/ISOs and their stakeholders—including States, market participants, and consumers—to explore and consider the value of incorporating state-determined carbon prices into RTO/ISO markets."[89]

The *Carbon Pricing Policy Statement* explained the FERC's jurisdiction to review, and identified the following non-binding list of potential considerations that the FERC may use to evaluate, a filing to establish market rules for incorporating a state determined carbon price into an RTO/ISO market:

a. How, if at all, do the relevant market design considerations change depending on the manner in which the state or states determine the carbon price (e.g., price-based or quantity-based methods)? How would state determined carbon prices, including any changes to these prices, be reflected in RTO/ISO tariffs or market designs?

b. How would the FPA section 205 proposal provide adequate price transparency and enhance price formation?

c. How would the carbon price or prices be reflected in locational marginal prices ("LMP")?

d. How would the incorporation of the state-determined carbon price into the RTO/ISO market affect dispatch? Would the state-determined carbon price affect how the RTO/ISO co-optimizes energy and

[88] *Carbon Pricing in Organized Wholesale Electricity Markets*, 175 FERC ¶ 61,036 (Apr. 15, 2021) ("*Carbon Pricing Policy Statement*"). A policy statement provides only a general expression of FERC policy. It does not establish any binding rule, regulation, or other precedent. When applied in specific cases, parties can challenge or support the application of the Policy Statement in those proceedings.

[89] *Id.* at P 19.

ancillary services? Would any reforms to RTO/ISO co-optimization rules be necessary in light of the state determined carbon price? Would any reforms to other market design elements be necessary, such as to market power mitigation rules or other rules that affect whether the market produces just and reasonable rates?

e. Would the filer's proposal result in economic or environmental leakage? If so, how might the proposal address any such leakage?

f. What elements of the proposal affect the wholesale rates paid by customers? How does the proposal consider this impact and the impact on consumers overall?

The *Carbon Pricing Policy Statement* makes clear that the FERC will determine whether the filing meets the FPA section 205 standard based on the particular facts and circumstances presented in that proceeding. The *Carbon Pricing Policy Statement* follows a September 30, 2020 technical conference and October 15, 2020 Notice of Proposed Policy Statement[90] summarized in previous Reports.

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

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

On January 19, 2021, the FERC issued an order directing each ISO/RTO to submit, within 6 months (or before July 19, 2021), a report that provides: (a) a description of its current practices related to each of the following four hybrid resource issues: (1) terminology; (2) interconnection; (3) market participation; and (4) capacity valuation (collectively, the "Issues"); (b) an update on the status of any ongoing efforts to develop reforms related to each of the Issues; and (c) responses to the specific requests for information contained in the order. Public comments in response to the RTO/ISO reports may be submitted within 30 days of the filing of the reports. The FERC will use the reports and comments to determine whether further action is appropriate.

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

On December 17, 2020, the FERC issued a NOPR[91] proposing to establish rules for incentive-based rate treatment for voluntary cybersecurity investments by a public utility for or in connection with the transmission or sale of electric energy subject to FERC jurisdiction, and rates or practices affecting or pertaining to such rates for the purpose of ensuring the reliability of the BPS.

Comments on the *Cyber security Incentives NOPR* were due on or before April 6, 2021. Comments were filed by: NECPUC, APPA, EEI, EPSA, LPPC, NERC, NRECA, TAPS, Accenture, aDolus Inc. et al.,[92] Alliant, Anterix, Bureau of Reclamation, CA Dept of Water Resources State Water Project/CPUC, George Cotter, FRS, Hitachi ABB Power Grids, IECA, ITC, Joint Consumer Advocates, MI PUC, Org of MISO States, MISO TOs, PJM TOs, and Public Citizen. Reply comments are due May 6, 2021.[93]

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[90] *Carbon Pricing in Organized Wholesale Electricity Markets*, 173 FERC ¶ 61,062 (Oct. 15, 2020) ("*Proposed Policy Statement*").

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

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

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

- **NOPR: Managing Transmission Line Ratings (RM20-16)**

On November 19, 2020, the FERC issued a NOPR[94] proposing to reform both the *pro forma* OATT and its regulations to improve the accuracy and transparency of transmission line ratings. Specifically, the NOPR proposes to require: transmission providers to implement ambient-adjusted ratings on the transmission lines over which they provide transmission service; ISO/RTOSs to establish and implement the systems and procedures necessary to allow transmission owners to electronically update transmission line ratings at least hourly; and transmission owners to share transmission line ratings and transmission line rating methodologies with their respective transmission provider(s) and, in ISO/RTOs, with their respective market monitor(s). Comments on the *Managing Transmission Line Ratings NOPR* were due on or before March 22, 2021.[95] Comments were submitted by over 50 parties, including by ISO-NE, DC Energy, Dominion, EDF, ENEL/EnerNOC, Eversource, Exelon, NRDC, Vistra, EEI, EPRI, EPSA, New England State Agencies,[96] NRECA/LPPC, and Potomac Economics. Reply comments were submitted by the Organization of MISO States, Potomac Economics, and ITC Holdings Corp. This matter is pending before the FERC.

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

In two developments since the last Report, the FERC issued on April 15, 2021 (i) a supplemental notice of proposed rulemaking;[97] and (ii) a notice of a September 10, 2021 workshop.[98]

Supplemental NOPR. In light of comments already received in this proceeding,[99] the FERC issued the *Supplemental NOPR* to propose and seek comment on a revised incentive for transmitting and electric utilities that join Transmission Organizations ("Transmission Organization Incentive"). The incentive would be reduced from 100 to 50 basis points and would be available only for three years. The FERC seeks comment on whether voluntary participation should be a requirement, and if so, how "voluntary" should be determined. In addition, the FERC now proposes to require each utility that has received a Transmission Organization Incentive for three or more years to submit a compliance filing revising its tariff to remove the incentive from its transmission tariff. The *Supplemental NOPR* did not address the other proposals contained in the *March NOPR*.[100] A more detailed

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

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

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

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

[98] Notice of Workshop, *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, Docket Nos. RM20-10 and AD19-19 (Apr. 15, 2021).

[99] Over 80 sets of comments on the *March NOPR* were filed on or before the July 1, 2020 comment date, including comments by: Avangrid, EDF Renewables, EMCOS, Eversource, Exelon, LS Power, MMWEC/NHEC/CMEEC, National Grid, NESOCE, NextEra, UCS, CT PURA, and Potomac Economics. Reply comments were filed by AEP, ITC Holding, the N. California Transmission Agency, and WIRES.

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

- A shift from risks and challenges to a ***consumers'' benefits test*** that focuses on ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.
- ***ROEs incentive for Economic Benefits***. A 50-basis-point adder for transmission projects that meet an economic benefit-to-cost ratio in the top 75th percentile of transmission projects examined over a sample period <u>and</u> an additional 50-basis-point adder for transmission projects that demonstrate *ex post* cost savings that fall in the 90th percentile of transmission projects studied over the same sample period, as measured at the end of construction.
- ***ROE for Reliability Benefits***. A 50-basis-point adder for transmission projects that can demonstrate potential reliability benefits by providing quantitative analysis, where possible, as well as qualitative analysis.
- ***Abandoned Plant Incentive***. 100 percent of prudently incurred costs of transmission facilities selected in a regional transmission planning process that are cancelled or abandoned due to factors that are beyond the control of the applicant. Recovery from the date that the project is selected in the regional transmission planning process.

summary of the NOPR was distributed to the Transmission Committee and discussed at the TC's March 25, 2020 meeting.

Comments on the *Supplemental NOPR* are currently due on or before May 26, 2021; reply comments, June 10, 2021.[101] Please note, however, that, requests for a 30-day extension of time to submit comments on the *Supplemental NOPR* have been filed by the MISO Transmission Owners (April 20) and the ISO/RTO Council ("IRC") (May 3). Those requests were supported by EEI and Wires (on May 4). The requests for an extension of time are currently pending before the FERC.

September 10, 2021 Workshop. The FERC will convene a workshop on September 10, 2021 to discuss certain performance-based ratemaking approaches, particularly shared savings, that may foster deployment of transmission technologies. The notice states that the workshop will explore: the maturity of the modeling approaches for various transmission technologies; the data needed to study the benefits/costs of such technologies; issues pertaining to access to or confidentiality of this data; the time horizons that should be considered for such studies; and other issues related to verifying forecasted benefits. The workshop may also discuss whether and how to account for circumstances in which benefits do not materialize as anticipated and may explore other performance-based ratemaking approaches for transmission technologies seeking incentives under FPA section 219, particularly market-based incentives. Self-nomination emails from individuals interested in participating as panelists are due on or before May 21, 2021.

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

- ***Order 2222/2222-A*: DER Participation in RTO/ISO Markets (RM18-9)**

On September 17, 2020, the FERC issued a final rule ("*Order 2222*")[102] adopting reforms to remove what it found were barriers to the participation of distributed energy resource ("DER")[103] aggregations in the RTO/ISO markets. *Order 2222* requires each RTO/ISO to revise its tariff to ensure that its market rules facilitate the participation of DER aggregations. Specifically, the tariff provisions addressing DER aggregations must:

(1) allow DER aggregations to participate directly in RTO/ISO markets and establish DER aggregators as a type of market participant;

(2) allow DER aggregators to register DER aggregations under one or more participation models that accommodate the physical and operational characteristics of the DER aggregations;

(3) establish a minimum size requirement for DER aggregations that does not exceed 100 kW;

- ***Eliminate Transco Incentives***.
- ***Transmission Organization Incentive.*** A *50-basis-point increase* for transmitting utilities that turn over their wholesale facilities to a Transmission Organization and *only for the first three years after transferring operational control of its facilities.* The FERC seeks comment as to whether participation must be voluntary to receive the incentive, and if so, how the CFERC should determine whether the decision to join is voluntary.
- ***Transmission Technologies Incentives***. Eligible for both a stand-alone, 100-basis-point ROE incentive on the costs of the specified transmission technology project and specialized regulatory asset treatment. Pilot programs presumptively eligible (though rebuttable).
- ***250-Basis-Point Cap***. Total ROE incentives capped at 250 basis points in place of current "zone of reasonableness" limit.
- ***Updated Date Reporting Processes***. Information to be obtained on a project-by-project basis, information collection expanded, updated reporting process.

[101] The *Supplemental NOPR* was published in the *Fed. Reg.* on Apr. 26, 2021 (Vol. 86, No. 78) pp. 21,972-21,984.

[102] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 172 FERC ¶ 61,247 (Sep. 17, 2020).

[103] The FERC defined a DER as "any resource located on the distribution system, any subsystem thereof or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment."

(4) address locational requirements for DER aggregations;

(5) address distribution factors and bidding parameters for DER aggregations;

(6) address information and data requirements for DER aggregations;

(7) address metering and telemetry requirements for DER aggregations;

(8) address coordination between the RTO/ISO, the DER aggregator, the distribution utility, and the relevant electric retail regulatory authorities;

(9) address modifications to the list of resources in a DER aggregation;

(10) address market participation agreements for DER aggregators; and

(11) Accept bids from a DER aggregator if its aggregation includes DERs that are customers of utilities that distributed more than 4 million MWh in the previous fiscal year. An RTO/ISO must not accept bids from a DER aggregator if its aggregation includes DERs that are customers of utilities that distributed 4 million MWhs or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers to be bid into RTO/ISO markets by a DER aggregator.

Compliance Deadline Extensions. On April 16, 2021, ISO-NE requested an extension of time to February 2, 2022 (2/2/222) to comply with *Order 2222*. AEE and MA DPU submitted comments supporting the ISO-NE request, which is pending before the FERC.

Requests for extension of time to comply with *Order 2222* filed by MISO, SPP and PJM were granted by the FERC on April 9, 2021,[104] so that they are now due on April 18, 2022, April 28, 2022, and February 1, 2022, respectively. In granting the extensions of time, the FEC required that each of the RTOs submit an informational filing containing a detailed stakeholder process schedule on or before May 9, 2021, and to submit status reports every 90 days thereafter until its compliance filing is submitted.

Order 2222-A. On March 18, 2021, the FERC issued *Order 2222-A*,[105] which addressed arguments on rehearing and set aside and clarified *Order 2222* in part. Specifically, as is its right under *Allegheny*, the FERC modified the discussion in *Order 2222* and set aside *Order 2222*, in part, by finding that the participation of demand response in DER aggregations is subject to the opt-out and opt-in requirements of *Orders 719* and *719-A,* providing further clarification on the FERC's interconnection policies pertaining to Qualifying Facilities ("QFs"), and modifying § 35.28(g)(12)(i) to make a non-substantive ministerial correction. Requests for rehearing and/or clarification of *Order 2222-A* were due on or before April 19, 2021 and were filed by: AEE/AEMA (Advanced Energy Management Alliance), EEI, National Association of Regulatory Utility Commissioners ("NARUC"), Louisiana Public Service Commission ("LPSC") and the Mississippi Public Service Commission ("MPSC"), North Carolina Utilities Commission, the MISO Transmission Owners ("MISO TOs"), and Voltus. On April 30, MISO filed comments supporting the rehearing requests filed by NARUC, LPSC/MPSC and the MISO TOs. On May 4, ISO-NE answered the AEE/AEMA request for clarification and/or rehearing of *Order 2222*. The requests for rehearing are pending, with FERC action required on or before May 19, 2021, or the requests will be deemed denied by operation of law.

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[104] Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, 175 FERC ¶ 61,013 (Apr. 9, 2021).

[105] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Indep. Sys. Operators*, Order No. 2222-A, 174 FERC ¶ 61,197 (Mar. 18, 2021).

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

As previously reported, *Order 860,*[106] issued three years after the FERC's *Data Collection NOPR,*[107] (i) revises the FERC's MBR regulations by establishing a relational database of ownership and affiliate information for MBR Sellers (which, among other uses, will be used to create asset appendices and indicative screens), (ii) reduces the scope of information that must be provided in MBR filings, modifies the information required in, and format of, a MBR Seller's asset appendix, (iii) changes the process and timing of the requirements to advise the FERC of changes in status and affiliate information, and (iv) eliminates the requirement adopted in *Order 816* that MBR Sellers submit corporate organization charts. In addition, the FERC stated that it will *not* adopt the *Data Collection NOPR* proposal to collect Connected Entity data from MBR Sellers and entities trading virtuals or holding FTRs. The FERC has posted on its website high-level instructions that describe the mechanics of the relational database submission process and how to prepare filings that incorporate information that is submitted to the relational database. As recently extended (*see* below), *Order 860* will become effective July 1, 2021, and submitters will have until close of business on November 2, 2021 to make their initial baseline submissions. Submitters will be required to obtain FERC-generated IDs for reportable entities that do not have CIDs or LEIs, as well as Asset IDs for reportable generation assets without an EIA code so that every ultimate upstream affiliate or other reportable entity has a FERC-assigned company identifiers ("CID"), Legal Entity Identifier,[108] or FERC-generated ID and that all reportable generation assets have an code from the Energy Information Agency ("EIA") Form EIA-860 database or a FERC-assigned Asset ID. Requests for rehearing and/or clarification of *Order 860* were denied,[109] other than TAPS' request that the FERC clarify that the public will be able to access the relational database. On that point, the FERC clarified "that we will make available services through which the public will be able to access organizational charts, asset appendices, and other reports, as well as have access to the same historical data as Sellers, including all market-based rate information submitted into the database. We also clarify that the database will retain information submitted by Sellers and that historical data can be accessed by the public."

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

Notice Seeking Comments on Change to MBR Database. On March 18, 2021, the FERC issued a notice seeking comments on proposed changes to the MBR Data Dictionary to reflect the affiliations, or lack of affiliation, among Sellers for which their ultimate upstream affiliate is an institutional investor who acquired their securities pursuant to a section 203(a)(2) blanket authorization.[110] Specifically, the FERC proposes to update the MBR Data Dictionary and add the following three new attributes to the Entities table: the blanket authorization docket number, and the utility ID types and the utility IDs of the utilities whose securities were purchased under the corresponding blanket authorization docket number. Appropriate Sellers would be required to submit the docket number of the proceeding in which the FERC granted the section 203(a)(2) blanket authorization and the upstream affiliate whose securities were acquired pursuant to the section 203(a)(2) blanket authorization. Comments on the Notice are due on or before June 7, 2021.[111] In light of the

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

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

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

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

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

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

proposed changes, the FERC deferred by three months the effective date of *Order 860* and its associated deadlines.

Effective Date Extended a Second Time by 3 Months. On March 18, 2021, the FERC issued a notice extending the effective and associated implementation dates of *Order 860* by an additional *three* months. The new *Order 860* effective date will be July 1, 2021, and the deadline for baseline submissions to and including November 2, 2021. First change in status filings under these new timelines will be due November 30, 2021.

April 22, 2021 Technical Workshop. On April 22, 2021, the FERC held a technical workshop to discuss the functionality and features of the MBR Database.

- **NOPR: NAESB WEQ Standards v. 003.3 - Incorporation by Reference into FERC Regs (RM05-5-029, -030)**

On July 16, 2020, the FERC issued a NOPR proposing to incorporate by reference, with certain enumerated exceptions, the latest version (Version 003.3) of certain Standards for Business Practices and Communication Protocols for Public Utilities adopted by the NAESB Wholesale Electric Quadrant ("WEQ").[112] Despite having only recently incorporated Version 003.2 in its regulations, the FERC proposed to move forward on Version 003.3 because this Version contains a number of major initiatives whose incorporation by reference "will improve the security and the efficiency of business transactions. These include enhanced cybersecurity standards resulting from an assessment by Sandia, improved methodologies for resolving transmission loading relief, and standards for determining available transfer capacity."[113] Comments on the *NAESB WEQ v. 003.3 Standards NOPR* were due on or before November 3, 2020[114] and were filed by Bonneville Power Administration ("BPA"), EEI, the IRC, and Open Access Technology International. The *NAESB WEQ v. 003.3 Standards NOPR* is pending before the FERC.

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

On May 21, 2020, the FERC issued a Proposed Policy Statement that would clarify its policy regarding requests for waiver of tariff provisions.[115] The *Proposed Policy Statement* sets forth the approach the FERC would take going forward to ensure compliance with the filed rate doctrine and the rule against retroactive making. The proposed policy will both clarify and modify waiver standards, and in some instances, make it harder to obtain waivers.

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

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

[112] *Standards for Business Practices and Communication Protocols for Public Utilities*, 172 FERC ¶ 61,047 (July 16, 2020) ("*NAESB WEQ v. 003.3 Standards NOPR*").

[113] The *NAESB WEQ v. 003.3 NOPR* at P .

[114] The *NAESB WEQ v. 003.3 NOPR* was published in the *Fed. Reg.* on Sep. 4, 2020 (Vol. 85, No. 173) pp. 55,201-55,219.

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

expressly authorizes regulated entities to seek a remedial waiver from the FERC for past non-compliance with the filed tariff.

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

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

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

The FERC proposed to incorporate its current four-part analysis[116] in considering both requests for prospective waiver and petitions for remedial relief, but cautioned that it would apply that analysis only in those limited circumstances where the request for remedial relief would not violate the filed rate doctrine or the rule against retroactive ratemaking due to adequate prior notice, or the requested relief is within the FERC's authority to grant under FPA section 309 or NGA section 16.

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

With respect to prospective requests to waive the 60-day prior notice requirement under FPA section 205(d) (or the 30-day prior notice requirement under NGA section 4(d)), which the FERC has discretion to waive "for good cause shown," the FERC proposes to leave in effect its policy of generally granting such waivers,[117] to the extent that entities seek an effective date no earlier than the day *after* the date a rate change is submitted to the FERC.

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

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

Comments on the Proposed Policy Statement were due on or before June 18, 2020 and were filed by the IRC, AEE, APPA, AWEA/SEIA, EEI, EPSA, Indicated Generators,[118] INGAA, Kansas Electric Power Coop. ("KEPC"), NGA, NGSA, NRECA, Public Citizen, Sunflower Electric Power, and TAPS. Reply comments were filed by APPA, Joint Trade Associations,[119] KEPC, and the Sustainable FERC Project. The proposed Policy Statement is pending before the FERC.

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

On May 21, 2020, the FERC issued a Policy Statement that applies to natural gas and oil pipelines, with certain exceptions to account for the statutory, operational, organizational and competitive differences among the electric, natural gas and oil pipeline industries, the FERC's ROE methodology adopted in *Opinion No. 569-A*.[120] Specifically, the FFERC revised its policy and will determine natural gas and oil pipeline ROEs by averaging the results of the DCF and CAPM, but will not use the risk premium model discussed in *Opinion 569/569-A* ("Risk Premium").[121] In addition, the FERC clarified its policies governing the formation of proxy groups and the treatment of outliers in proceedings addressing natural gas and oil pipeline ROEs. Finally, the FERC encouraged oil pipelines to file revised FERC Form No. 6, page 700s for 2019 reflecting the revised ROE policy. This Policy Statement became effective May 27, 2020.[122] On July 7, the FERC issued a notice that pipelines choosing to file updated FERC Form No. 6, page 700 data consistent with the ROE Policy Statement should file such data on or before July 21, 2020.

Complainant-Aligned Parties[123] answered the New England TO's May 10 supplemental comments. On June 15, 2020, Joint Parties[124] submitted supplemental comments arguing that the FERC should use the midpoint, rather than the median, as the measure of central tendency for public utilities that file individually to establish a ROE. Joint Parties' comments were opposed by Six Cities.[125] WIRES submitted supplemental comments on June 18, 2020 requesting that the FERC take further action in this proceeding to "resolve the uncertainty surrounding its base ROE methodology and establish a policy consistent with the recommendations made in these comments" (recommending a framework that employs all four of the previously proposed ROE models, including the Expected Earnings model, along with certain modifications, to ensure that ROEs attract capital investment in needed transmission infrastructure). On June 24, EEI and WIRES requested the FERC issue a NOI regarding the FERC's policy for determining base ROE applicable to the electric industry as a whole. Six Cities answered Joint Parties on June 30. APPA answered EEI and WIRES' June 24 motion.

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

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

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

[121] As previously reported, the FERC issued a notice of inquiry on March 21, 2019 seeking information and views to help the FERC explore whether, and if so how, it should modify its policies concerning the determination of ROE to be used in designing jurisdictional rates charged by public utilities.[121] The FERC also sought comment on whether any changes to its policies concerning public utility ROEs should be applied to interstate natural gas and oil pipelines. This NOI followed *Emera Maine*, which reversed *Opinion 531*, and seeks to engage interests beyond those represented in the *Emera Maine* proceeding (see EL11-66 *et al.* in Section I above).

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

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

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

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

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

Since the last Report, on March 31, 2021, the FERC extended by 30 days the time for comments on its February 18, 2021 notice of inquiry ("*2021 NOI*"). As previously reported, the NOI sought new information and additional stakeholder perspectives to help the FERC explore whether it should revise its approach under the currently effective policy statement on the certification of new natural gas transportation facilities to determine whether a proposed natural gas project is or will be required by the public convenience and necessity, as that standard is established in NGA section 7.[126] The 2021 NOI is to provide an opportunity for stakeholders to refresh the record and provide updated information and additional viewpoints to help the FERC assess its policy.[127] The FERC strongly urged stakeholders to not resubmit previously filed comments, which remain in the record of this proceeding.[128] Comments on the *2021 NOI*, which previously were due on or before April 26, 2021,[129] are now due May 26, 2021. Comments on the 2021 NOI have been filed by the MIT Energy Initiative, Competitive Enterprise Institute, Laborers' International Union of North America, Ohio Environmental Council, Americans for Prosperity – HQ, several private citizens, and jointly be the Attorneys General of 22 States (none from any of the New England states).

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- **PacifiCorp (IN21-6)**

On April 15, 2021, in the FERC's first-ever Show Cause Order addressing alleged violations of NERC Reliability Standards,[130] the FERC directed PacifiCorp to show cause why it should not be found to have violated FPA section 215(b)(1) and section 39.2 of the FERC's regulations by failing to comply with Reliability Standard FAC 009-1 (Establish and Communicate Facility Ratings), Requirement R1, and the successor Reliability Standard FAC-008-3 (Facility Ratings), Requirement R6 (collectively, "FAC-009-1 R1"), which requires a transmission owner to establish and have facility ratings that are consistent with its Facility Ratings Methodology ("FRM"). An Enforcement investigation found that clearance measurements on a majority of PacifiCorp's transmission lines were incorrect under the National Electric Safety Code, which were used to calculate PacifiCorp's facility ratings, thus making PacifiCorp's facility ratings inconsistent with its FRM. Enforcement alleges that PacifiCorp was aware of incorrect clearances on its system since at least 2007 when FAC-009-1 R1 became mandatory, but failed to identify and remedy them in a timely manner, and PacifiCorp's violations began on August 31, 2009, when it implemented its FRM policy, and at least some of the violations continued until August 2017 when PacifiCorp completed remediation of all of its incorrect clearances to make them consistent with its FRM. Enforcement also pointed to the role of the violations in the Wood Hollow, Utah wildfire that lasted from June 23 to July 1, 2012. In light of these alleged violations, the FERC directed PacifiCorp to show cause why it should not be assessed civil penalties in the amount of ***$42 million***.

On April 21, PacifiCorp asked for a 60-day extension of time, to July 15, 2021, to file its answer. On April 22, FERC staff responded to Respondent's motion, not opposing the extension of time, but asking that, for scheduling conflict reasons, its deadline to reply also be extended by 30 days. On May 4, 2021, the FERC extended PacifiCorp's answer period by 60 days, to and including July 16, 2021, and Enforcement's reply

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

[127] *Id.* at P 3.

[128] The 2021 NOI follows an April 19, 2018 NOI that sought comments on four broad issue categories: (1) project need, including whether precedent agreements are still the best demonstration of need; (2) exercise of eminent domain; (3) environmental impact evaluation (including climate change and upstream and downstream greenhouse gas emissions); and (4) the efficiency and effectiveness of the FERC certificate process. Literally thousands of individual and mass-mailed comments were filed on the 2018 NOI.

[129] The 2021 NOI was published in the *Fed. Reg.* on Feb. 24, 2021 (Vol. 86, No. 35) pp. 11,268-11,274.

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

period, 60 days from the filing of PacifiCorp's answer. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

Natural Gas-Related Enforcement Actions

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

On March 18, 2021, the FERC issued a show cause order[131] in which it directed Rover Pipeline, LLC ("Rover") and Energy Transfer Partners, L.P. ("ETP" and together with Rover, "Respondents") to show cause why they should not be found to have violated Section 157.5 of the FERC's regulations by misleading the FERC in its Application for Certificate of Public Convenience and Necessity under NGA section 7(c).[132] The FERC directed Respondents to show cause why they should not be assessed civil penalties in the amount of ***$20.16 million***. On April 5, 2021, the FERC extended by 60 days, to June 18, 2021, the deadline for Respondents' answer.

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

On December 17, 2020, the FERC issued *Opinion 549-A*,[133] a 159-page decision addressing arguments raised on rehearing requested of *Opinion 549.*[134] *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.[135] 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.[136]

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*.

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

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

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

[134] *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 Ene rgy 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*")).

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

[136] *Id*. at P 319.

- ***Total Gas & Power North America, Inc. et al. (IN12-17)***

On April 28, 2016, the FERC issued a show cause order[137] 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.[138]

The FERC also directed TGPNA to show cause why it should not be required to disgorge unjust profits of ***$9.18 million***, plus interest; TGPNA, Tran and Hall to show cause why they should not be assessed civil penalties (TGPNA - ***$213.6 million***; Hall - ***$1 million*** (jointly and severally with TGPNA); and Tran - ***$2 million*** (jointly and severally with TGPNA)). In addition, the FERC directed TGPNA's parent company, Total, S.A. ("Total"), and TGPNA's affiliate, Total Gas & Power, Ltd. ("TGPL"), to show cause why they should not be held liable for TGPNA's, Hall's, and Tran's conduct, and be held jointly and severally liable for their disgorgement and civil penalties based on Total's and TGPL's significant control and authority over TGPNA's daily operations. Respondents filed their answer on July 12, 2016. OE Staff replied to Respondents' answer on September 23, 2016. Respondents answered OE's September 23 answer on January 17, 2017, and OE Staff responded to that answer on January 27, 2017. This matter remains pending before the FERC.

XIV. Natural Gas Proceedings

For further information on any of the natural gas proceedings, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com).

New England Pipeline Proceedings

The following New England pipeline projects are currently under construction or before the FERC:

- ***Iroquois ExC Project (CP20-48)***
  - 125,000 Dth/d of incremental firm transportation service to ConEd and KeySpan by building and operating new natural gas compression and cooling facilities at the sites of four existing Iroquois compressor stations in Connecticut (Brookfield and Milford) and New York (Athens and Dover).
  - Three-year construction project; service request by November 1, 2023.
  - February 2, 2020 application for a certificate of public convenience and necessity pending; Iroquois requests on January 26, 2021 that the FERC act promptly and issue the certificate; National Grid and ConEd submit comments supporting Iroquois'' application and request for action.

- ***Atlantic Bridge Project (CP16-9)***
  - On February 24, 2020, the FERC authorized Algonquin Gas Transmission, LLC ("Algonquin") and Maritimes & Northeast Pipeline, LLC ("Maritimes") to place facilities associated with the Atlantic Bridge Project into service.[139] Rehearing of the Authorization Order was timely requested, but denied by operation of law.

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

[138] 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.

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

- In a fairly unprecedented order issued February 18, 2021,[140] the FERC, expressing concerns regarding operation of the project, established briefing on the following matters:
  - In light of the concerns expressed regarding public safety, is it consistent with the FERC's responsibilities under the NGA to allow the Weymouth Compressor Station to enter and remain in service?
  - Should the Commission reconsider the current operation of the Weymouth Compressor Station in light of any changed circumstances since the project was authorized? For example, are there changes in the Weymouth Compressor Station's projected air emissions impacts or public safety impacts the Commission should consider? We encourage parties to address how any such changes affect the surrounding communities, including environmental justice communities.
  - Are there any additional mitigation measures the Commission should impose in response to air emissions or public safety concerns?
  - What would the consequences be if the Commission were to stay or reverse the Authorization Order?
- Requests for rehearing of the Briefing Order were filed by Algonquin, NGSA and Center for Liquefied Natural Gas, and by America and Energy Infrastructure Council. Cheniere Energy submitted comments in support of the requests for rehearing. On April 19, 2021, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration".[141] The Notice confirmed that the 60-day period during which a petition for review of its *Briefing Order* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of the *Briefing Order*. The Notice also indicated that the FERC would address, as is its right, the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper."
- Initial briefs in response to the *Briefing Order* were due April 5, 2021. Nearly 50 sets of initial briefs and comments were filed. Reply briefs are due on or before May 5, 2021.
- The FERC noted that the facilities placed in service pursuant to the Authorization Order may remain in service while it considers the issues set for briefing.

Non-New England Pipeline Proceedings

The following pipeline projects could affect ongoing pipeline proceedings in New England and elsewhere:

- **Northern Access Project (CP15-115)**
  - The New York State Department of Environmental Conservation ("NY DEC") and the Sierra Club requested rehearing of the *Northern Access Certificate Rehearing Order* on August 14 and September 5, 2018, respectively. On August 29, National Fuel Gas Supply Corporation and Empire Pipeline ("Applicants") answered the NY DEC's August 14 rehearing request and request for stay. On April 2, 2019, the FERC denied the NY DEC and Sierra Club requests for rehearing.[142] Those orders have been challenged on appeal to the US Court of Appeals for the Second Circuit (19-1610).
  - As previously reported, the August 6, 2018 *Northern Access Certificate Rehearing Order* dismissed or denied the requests for rehearing of the *Northern Access Certificate Order*.[143] Further, in an interesting twist, the FERC found that a December 5, 2017 "Renewed Motion for Expedited Action"

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

[141] *Algonquin Gas Transmission, LLC and Maritimes & Northeast Pipeline, LLC*, 175 FERC ¶ 62,022 (Apr. 19, 2021).

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

[143] *Nat'l Fuel Gas Supply Corp. and Empire Pipeline, Inc.*, 164 FERC ¶ 61,084 (Aug. 6, 2018) ("*Northern Access Rehearing & Waiver Determination Order*"), *reh'g denied*, 167 FERC ¶ 61,007 (Apr. 2, 2019).

filed by National Fuel Gas Supply Corporation and Empire Pipeline, Inc. (the "Companies"), in which the Companies asserted a separate basis for their claim that the NY DEC waived its authority under section 401 of the Clean Water Act ("CWA") to issue or deny a water quality certification for the Northern Access Project, served as a motion requesting a waiver determination by the FERC,[144] and proceeded to find that the NY DEC was obligated to act on the application within one year, failed to do so, and so waived its authority under section 401 of the CWA.

- The FERC authorized the Companies to construct and operate pipeline, compression, and ancillary facilities in McKean County, Pennsylvania, and Allegany, Cattaraugus, Erie, and Niagara Counties, New York ("Northern Access Project") in an order issued February 3, 2017.[145] The Allegheny Defense Project and Sierra Club (collectively, "Allegheny") requested rehearing of the *Northern Access Certificate Order*.
- Despite the FERC's *Northern Access Certificate Order*, the project remained halted pending the outcome of National Fuel's fight with the NY DEC's April denial of a Clean Water Act permit. NY DEC found National Fuel's application for a water quality certification under Section 401 of the Clean Water Act, as well as for stream and wetlands disturbance permits, failed to comply with water regulations aimed at protecting wetlands and wildlife and that the pipeline failed to explore construction alternatives. National Fuel appealed the NY DEC's decision to the 2nd Circuit on the grounds that the denial was improper.[146] On February 2, 2019, the 2nd Circuit vacated the decision of the NY DEC and remanded the case with instructions for the NY DEC to more clearly articulate its basis for the denial and how that basis is connected to information in the existing administrative record. The matter is again before the NY DEC.
- On November 26, 2018, the Applicants filed a request at FERC for a 3-year extension of time, until February 3, 2022, to complete construction and to place the certificated facilities into service. The Applicants cited the fact that they "do not anticipate commencement of Project construction until early 2021 due to New York's continued legal actions and to time lines required for procurement of necessary pipe and compressor facility materials." The extension request was granted on January 31, 2019.
- On August 8, 2019, the NY DEC again denied Applicants request for a Water Quality Certification, and as directed by the Second Circuit,[147] provided a "more clearly articulate[d] basis for denial."
- On August 27, 2019, Applicants requested an additional order finding on additional grounds that the NY DEC waived its authority over the Northern Access 2016 Project under Section 401 of the CWA, even if the NY DEC and Sierra Club prevail in their currently pending court petitions challenging the basis for the Commission's Waiver Order.[148]
- On October 16, 2020, Applicants requested, due to ongoing legal and regulatory delays, an additional 2-year extension of time, until December 1, 2024, to complete construction of the Project and enter service. More than 50 sets of comments on the requested extension were filed and on December1, 2020, the FERC dismissed, without prejudice, Applicants' request for an extension of time, [149] finding

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[144] The DC Circuit has indicated that project applicants who believe that a state certifying agency has waived its authority under CWA section 401 to act on an application for a water quality certification must present evidence of waiver to the FERC. *Millennium Pipeline Co., L.L.C. v. Seggos*, 860 F.3d 696, 701 (D.C. Cir. 2017).

[145] *Nat'l Fuel Gas Supply Corp.*, 158 FERC ¶ 61,145 (2017) ("*Northern Access Certificate Order*"), *reh'g denied*, 164 FERC ¶ 61,084 (Aug 6, 2018) ("*Northern Access Certificate Rehearing Order*").

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

[147] Summary Order, *Nat'l Fuel Gas Supply Corp. v. N.Y. State Dep't of Envtl. Conservation*, Case 17-1164 (2d Cir, issued Feb. 5, 2019).

[148] *See Sierra Club v. FERC*, No. 19-01618 (2d Cir. filed May 30, 2019); *NYSDEC v. FERC*, No. 19-1610 (2d. Cir. filed May 28, 2019) (consolidated).

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

the request premature. The FERC reiterated its encouragement that pipeline applicants requesting extensions "file their requests no more than 120 days before the deadline to complete construction", so that the FERC has the relevant information available to determine whether good cause exists to grant an extension of time and whether the FERC's prior findings remain valid.[150]

XV. State Proceedings & Federal Legislative Proceedings

- **New England States' Vision Statement**

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

Jan 13, 2021	Wholesale Market Reform
Jan 25, 2021	Wholesale Market Reform
Feb 2, 2021	Transmission Planning
Feb 25, 2021	Governance Reform
Mar 18, 2021	Equity and Environmental Justice

Written comments on the topics and discussions addressed in the on the equity and environmental justice topics and discussions are, following an extension, due by May 13, 2021 and may be submitted to claire.sickinger@ct.gov. Comments will be publicly posted on **WholesaleEnergy@NewEnglandEnergyVision.com.**

Recordings of the technical forums, as well as draft notices, agendas, and additional information on these sessions, are available on the New England States' Vision Statement website (https://newenglandenergyvision.com/).

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). 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).

[150] *Id.* at P 10.

- **ISO-NE Implementation of Order 1000 Exemptions for Immediate Need Reliability Projects (20-1422)**
  Underlying FERC Proceeding: EL19-90[151]
  Petitioner: LS Power
  Status: Briefing Underway

On October 16, 2020, LSP Transmission Holdings II, LLC ("LS Power") petitioned the DC Circuit Court of Appeals for review of the FERC's orders addressing ISO-NE's implementation of the Order 1000 exemptions for immediate need reliability projects. On March 2, 2021, the Court, at FERC's request, issued an amended briefing schedule to apply in this case, adding roughly one month to each deadline previously identified. In accordance with that amended schedule, LS Power filed Petitioner's Brief on April 5, 2021 and MMWEC filed an "Intervenor in Support of Petitioners" Brief on April 12, 2021. Next up is the FERC's brief due on June 11, 2021. Remaining deadlines after that include: Intervenors in Support of FERC due July 9, 2021; Petitioner's Reply Brief, July 9, 2021; Intervenors in Support of Petitioner Reply Brief, July 9, 2021; Deferred Appendix, July 16, 2021; and Final Briefs July 30, 2021.

- **CIP IROL Cost Recovery Rules (20-1389)**
  Underlying FERC Proceeding: ER20-739[152]
  Petitioner: Cogentrix, Vistra
  Status: Briefing Underway

On September 25, 2020, Cogentrix and Vistra petitioned the DC Circuit Court of Appeals for review of the FERC's orders allowing for recovery of expenditures to comply with the IROL-CIP requirements, but only those costs incurred on or after the effective date of the relevant individual FPA section 205 filing, including undepreciated costs of any such past capital expenditures to comply with the IROL-CIP requirements. On December 22, 2020, the Court adopted a proposed *revised* briefing schedule that added roughly 45 days to each procedural deadline previously established. On March 1, 2021, Cogentrix and Vistra filed Petitioners' Brief (which it corrected on March 8 to remove the use of the acronym "NERC" to identify the "North American Electric Reliability Corporation). FERC filed Respondent's Brief on April 30, 2021. Next up are Intervenor for Respondent Brief (June 1, 2021); Petitioners' Reply Briefs (June 28, 2021); Deferred Appendix (July 16, 2021); and Final Briefs (July 26, 2021).

- **Mystic 8/9 Cost of Service Agreement (20-1343; 20-1361, 20-1362; 20-1365, 20-1368; 21-1067; 21-1070)(consolidated)**
  Underlying FERC Proceeding: EL18-1639[153]
  Petitioners: Mystic (20-1343), NESCOE (20-1361, 21-1067), MA AG (20-1362), CT Parties (20-1365, 20-1368, 21-1070)
  Status: Briefing Not Yet Begun

Mystic, NESCOE, MA AG, and CT Parties have separately petitioned the DC Circuit Court of Appeals for review of the FERC's orders addressing the COS Agreement among Mystic, ExGen and ISO-NE.[154] The cases have been consolidated into Case No. 20-1343. On February 17 and 24, 2021, the Court consolidated with 20-1343 the

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[151] *ISO New England Inc., 171 FERC ¶ 61,211 (June 18, 2020) ("Order Terminating Proceeding")* (finding (i) "insufficient evidencein the record to find under FPA section 206 that [ISO-NE's] implementation of the exemption for immediate need reliability projects is unjust, unreasonable, or unduly discriminatory or preferential; (ii) "insufficient evidence in the record to find that ISO-NE implemented the immediate need reliability project exemption in a manner that is inconsistent with or more expansive than [the FERC] directed"; and (iii) that ISO-NE complies with the five criteria established for the immediate need reliability project exemption); and *ISO New England Inc.,* 172 FERC ¶ 61,293 (Sep. 29, 2020) *("Order 1000 Exemptions Allegheny Order")* (addressing arguments raised by request for rehearing denied by operation of law, modifying discussion in *Order Terminating Proceeding,* but reaching same result).

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

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

[154] The COS Agreement is to provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024.

most recent appeals in cases 21-1067 (NESCOE) and 21-1070 (CT Parties), respectively. On March 25, 2021, the Court issued an order returning this case to its active docket. On March 26, the Court granted the interventions by MMWEC/NHEC, NESCOE, and ENECOS. On April 16, 2021, the Court ordered the parties to file, by May 17, 2021, proposed formats for the briefing of these cases.

- ***CASPR* (20-1333, 20-1331) (consolidated)****
  Underlying FERC Proceeding: ER18-619[155]
  Petitioners: Sierra Club, NRDC, RENEW Northeast, and CLF
  Status: Being Held in Abeyance

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

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

On April 7, 2021, the Court granted Petitioners' motion to hold this matter in abeyance, pending further order of the Court. The parties were directed to file motions to govern future proceedings in these cases on or before October 22, 2021.

- ***Opinion 531-A* Compliance Filing Undo (20-1329)**
  Underlying FERC Proceeding: ER15-414[156]
  Petitioners: TOs' (CMP et al.)

On August 28, 2020, the TOs[157] 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*[158] 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

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

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

[157] 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.

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

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

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

- **2013/14 Winter Reliability Program Order on Compliance and Remand (20-1289, 20-1366) (consol.)**
  Underlying FERC Proceeding: ER13-2266[159]
  Petitioner: TransCanada
  Status: Briefing Complete

On July 30, 2020, TransCanada Power Marketing ("Petitioner" or "TransCanada") again petitioned the DC Circuit Court of Appeals for review of the FERC's action on the 2013/2014 Winter Reliability Program, this time in the FERC's April 1, 2020 *2013/14 Winter Reliability Program Order on Compliance and Remand*.[160] NEPGA intervened on October 15, 2020 (and its intervention granted on October 28). On October 16, TransCanada filed a docketing statement and statement of issues. On October 29, the FERC filed a certified index to the record and an unopposed motion for a 60-day briefing period. On December 2, 2020, the Court granted the FERC's October 29 motion On January 11, 2021, TransCanada submitted its initial brief. On March 12, FERC filed its Respondent Brief. Since the last Report, TransCanada filed Petitioner's Reply Brief on April 9, 2021 and the Deferred Appendix on April 16. TransCanada filed its Final Brief on April 30, 2021. Briefing is now complete and this matter is before the Court.

- **ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224***; 19-1247; 19-1252; 19-1253)(consolidated); Underlying FERC Proceeding: ER19-1428**[161]
  Petitioners: ENECOS (Belmont et al.) (19-1224); MA AG (19-1247); NH PUC/NH OCA (19-1252); Sierra Club/UCS (19-1253)
  Status: Briefing Complete

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

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[159] 171 FERC ¶ 61,003 (Apr. 1, 2020) ("*2013/14 Winter Reliability Program Order on Compliance and Remand*") (accepting ISO-NE's January 23, 2017 compliance filing, finding that the bid results from the 2013/14 Winter Reliability Program were just and reasonable, and providing for this finding the further reasoning requested by the DC Circuit in *TransCanada Power Mktg. Ltd. v. FERC*, 811 F.3d 1 (DC Cir. 2015) ("*TransCanada*").)

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

[161] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

on February 9. Intervenor for Respondent Briefs were filed on February 16 by ISO-NE and NEPGA. On February 24, the FERC filed an amended certified index to the record. Petitioners' Reply Brief was filed on March 30, 2021. The Deferred Appendix was filed on April 20, 2021. Final Briefs were filed on May 4, 2021. With briefing complete, this matter is now before the Court.

Other Federal Court Activity of Interest

- ***Order 872* (20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[162]
  Petitioners: SEIA et al.
  Status: Briefing Again Underway

On September 17, 2020, SEIA petitioned the 9th Circuit Court of Appeals for review of *Order 872*.[163] On October 9, the FERC filed an unopposed motion for the Court to hold this appeal in abeyance, suspend filing of the certified index to the record, and issue a new briefing schedule after January 4, 2021. The abeyance will permit the FERC to address the pending rehearing requests in a future order. On October 26, 2020, the Court granted the FERC's motion. On January 29, 2021, SEIA requested that this case be consolidated with the others, and that the abeyance period be extended to give the parties additional time to coordinate and develop a unified, efficient briefing schedule.

On March 25, 2021, the Court granted SEIA's unopposed March 5, 2021 motion to lift the stay in this proceeding. Briefing will resume as follows: Petitioners' briefs (May 27, 2021); joint brief of petitioner-intervenors (June 28, 2021); motions and associated briefs by amici curiae in support of petitioners (June 28, 2021); Respondent's brief (September 27, 2021); joint brief of respondent-intervenors (October 27, 2021); motions and associated briefs by amici curiae in support of respondent (October 27, 2021); and any optional reply briefs (December 13, 2021).

- **PennEast Project (18-1128)**
  Underlying FERC Proceeding: CP15-558[164]
  Petitioners: NJ DEP, DE and Raritan Canal Commission, NJ Div. of Rate Counsel
  Status: Being Held in Abeyance

Abeyance continues of the appeal before the DC Circuit of the FERC's orders granting certificates of public convenience and necessity to PennEast Pipeline Company, LLC ("PennEast")[165] for the construction and operation of a new 116-mile natural gas pipeline from Luzerne County, Pennsylvania, to Mercer County, New Jersey, along with three laterals extending off the mainline, a compression station, and appurtenant above ground facilities ("PennEast Project"). The cases are being held in abeyance "pending final disposition of any post-dispositional proceedings [ ] before the United States Supreme Court resulting from the Third Circuit's decision in No. 19-1191 (In re: PennEast Pipeline Company, LLC (3rd Cir. Sep. 10, 2019)), or other action that resolves the obstacle PennEast poses". That decision held that the Eleventh Amendment barred condemnation cases brought by PennEast in federal district court in New Jersey to gain access to property owned by the State or its agencies, thus calling into question the viability of PennEast's proposed project route, and the certificates issued in the underlying case. Until the Third Circuit case is resolved, which is in the midst of proceedings before the Supreme

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[162] *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).

[163] *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.

[164] *PennEast Pipeline Co., LLC*, 162 FERC ¶ 61,053 (Jan. 19, 2018), *reh'g denied*, 163 FERC ¶ 61,159 (May 30, 2018).

[165] PennEast is a joint venture owned by Red Oak Enterprise Holdings, Inc., a subsidiary of AGL Resources Inc.; NJR Pipeline Company, a subsidiary of New Jersey Resources; SJI Midstream, LLC, a subsidiary of South Jersey Industries; UGI PennEast, LLC, a subsidiary of UGI Energy Services, LLC; and Spectra Energy Partners, LP.

Court, the DC Circuit will not take up this case. The last Joint Status Report was filed on March 23, 2021, noting developments since the December 23, 2020 Status Report, and reporting that none of the events "constitute any of the conditions that [the DC Circuit] enumerated in its October 1, 2019 Order as triggering an obligation to file a motion governing future proceedings."

- **Opinion 569/569-A: FERC's Base ROE Methodology (16-1325, 20-1182, 20-1240, 20-1241, 20-1248, 20-1251, 20-1267, 20-1513)**
  Underlying FERC Proceeding: EL14-12; EL15-45[166]
  Petitioners: MISO TOs, Transource Energy, Dec 23 Petitioners et al.
  Status: Briefing Underway

The MISO Transmission Owners (TOs), Transource and "Dec 23 Petitioners",[167] among others, have appealed *Opinion 569/569-A*. The MISO TOs' case has been consolidated with previous appeals that had been held in abeyance, with the lead case number assigned as 16-1325. The FERC filed a certified Index to the Record on December 3, 2020, the Parties filed a joint unopposed briefing schedule on December 23, 2020. Statements of issues were filed on February 8, 2021. Since the last Report, Petitioners' Briefs were filed on March 10. On March 17, 2021, a motion to participate as amicus curiae was jointly filed by NEP, CPM, Eversource, Fitchburg and Unitil, NHT, VTransco, Versant Power, and UI ("New England Parties") (that motion was granted on April 30, 2021). On March 18, New England Parties submitted an amicus brief in support of Transmission Owning Petitioners. On March 24, 2021, Intervenors in Support of Petitioners[168] filed their Brief. The following deadlines remain: FERC's brief, June 8, 2021; Intervenors in Support of FERC, June 22, 2021; Petitioners Reply Briefs, July 8, 2021; Intervenors in Support of Petitioners Reply Briefs, July 22, 2021; Joint Deferred Appendix, August 6, 2021; and Final Briefs, August 19, 2021.

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

[167] "Dec 23 Petitioners" are: Assoc. of Bus. Advocating Tariff Equity; Coalition of MISO Transmission Customers: IL Industrial Energy Consumers; IN Industrial Energy Consumers, Inc.; MN Large Industrial Group; WI Industrial Energy Group; AMP; Cooperative Energy; Hoosier Energy Rural Elec. Coop.; MS Public Service Comm.; MO Public Service Comm.; MO Joint Municipal Electric Utility Comm. ; Organization of MISO States, Inc.; Southwestern Elec. Coop., Inc.; and Wabash Valley Power Assoc.

[168] The Intervenors for Petitioners Brief was filed by Citizens Utility Board of Wisconsin, Illinois Citizens Utility Board, Indiana Office of Utility Consumer Counselor, Iowa Office of Consumer Advocate, Louisiana Public Service Commission, Michigan Citizens Against Rate Excess, Minnesota Department of Commerce, and Missouri Office of Public Council.

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Modernizing Electricity Market Design Docket No. AD21-10-000

SUPPLEMENTAL NOTICE OF TECHNICAL CONFERENCE
ON RESOURCE ADEQUACY IN THE EVOLVING ELECTRICITY SECTOR:
ISO NEW ENGLAND INC.

(May 3, 2021)

As first announced in the Notice of Technical Conference issued in this proceeding on April 22, 2021, the Federal Energy Regulatory Commission (Commission) will convene a Commissioner-led technical conference in the above-referenced proceeding on May 25, 2021, from approximately 9:00 a.m. to 4:15 p.m. Eastern time. The conference will be held remotely. Attached to this Supplemental Notice is an agenda for the technical conference. Commissioners may attend and participate in the technical conference.

Discussions at the conference may involve issues raised in proceedings that are currently pending before the Commission. These proceedings include, but are not limited to:

ISO New England Inc.	Docket No. ER21-787-000
ISO New England Inc.	Docket No. ER21-943-000
New England Power Generators Ass'n, Inc. v. ISO New England Inc.	Docket No. EL21-26-000
ISO New England Inc.	Docket No. ER21-1226-000
ISO New England Inc., New England Power Pool Participants Committee	Docket No. ER21-1637-000
Independent Market Monitor for PJM v. PJM Interconnection, L.L.C., Docket No.	Docket No. EL19-47-000
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New York Independent System Operator, Inc.	Docket No. ER20-1718-002
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New York Independent System Operator, Inc.	Docket Nos. ER21-502-000 and ER21-502-001
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Cricket Valley Energy Center LLC and Empire Generating Company, LLC v. New York Independent System Operator, Inc.	Docket No. EL21-7-000

The conference will be open for the public to attend remotely. There is no fee for attendance. Information on this technical conference, including a link to the webcast, will be posted on the conference's event page on the Commission's website (https://www.ferc.gov/news-events/events/technical-conference-regarding-wholesale-markets-administered-iso-new-england) prior to the event.

The conference will be transcribed. Transcripts will be available for a fee from Ace Reporting at (202) 347-3700.

Commission conferences are accessible under section 508 of the Rehabilitation Act of 1973. For accessibility accommodations, please send an email to accessibility@ferc.gov or call toll free (866) 208-3372 (voice) or (202) 208-8659 (TTY), or send a fax to (202) 208-2106 with the required accommodations.

For more information about this technical conference, please contact David Rosner at david.rosner@ferc.gov or (202) 502-8479 or Emma Nicholson at emma.nicholson@ferc.gov or (202) 502-8741. For legal information, please contact Meghan O'Brien at meghan.o'brien@ferc.gov or (202) 502-6137. For information related to logistics, please contact Sarah McKinley at sarah.mckinley@ferc.gov or (202) 502-8368.

Kimberly D. Bose,
Secretary.

Technical Conference on Modernizing Electricity Market Design: Resource Adequacy in the Evolving Electricity Sector: ISO New England Inc.

Docket No. AD21-10-000
May 25, 2021

Agenda

9:00 am – 9:45 am: **Welcome and Opening Remarks**

9:45 am – 11:45 am: **Panel 1: Commissioner-Led Discussion of the Relationship between State Policies and ISO New England Inc.'s Markets**

The Chairman and Commissioners will lead a discussion about the interaction between state policies and ISO New England Inc.'s (ISO-NE) markets. The panel will include a discussion of the following topics and questions:

1. In October 2020, the New England States Council on Electricity (NESCOE) released a vision statement that called for ISO-NE to provide an appropriate level of state involvement in wholesale market design and implementation.[1] Please provide an update on the discussions in the region since the vision statement was released.

2. Please explain how states are currently involved in market design and implementation processes. How are states' perspectives considered in these processes? How is information shared with states related to these processes? What is the appropriate role for New England states with respect to ISO-NE capacity market reforms?

3. New England Power Pool (NEPOOL), in coordination with NESCOE and ISO-NE representatives, launched the "New England's Future Grid Initiative" in two parallel processes to (1) define and assess the future state of the region's power system; and (2) explore and evaluate potential market frameworks that could be pursued to accommodate state policies focused on decarbonization.[2]

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[1] NESCOE, New England States' Vision for a Clean, Affordable, and Reliable 21st Century Regional Electric Grid, http://nescoe.com/resource-center/vision-stmt-oct2020/.

[2] ISO-NE, New England's Future Grid Initiative Key Project, https://www.iso-ne.com/committees/key-projects/new-englands-future-grid-initiative-key-project/. *See also* Dr. Frank Felder, *NEPOOL's Pathways to the Future Grid Process Project Report*

What is the current status of each of these stakeholder processes?

4. Many New England states have established long-term policy goals and/or statutory requirements to reduce greenhouse gas emissions and increase clean energy generation. Consistent with these goals, several states have instituted programs to promote the development of renewable energy resources and to retain existing zero-emitting generation resources. How do the current ISO-NE market rules affect implementation of existing or proposed state policies? If states have differing policy goals, how should these be accommodated in the ISO-NE capacity market? How do one state's actions to shape the resource mix affect other states? Should such effects be addressed, and if so, how?

5. Is ISO-NE's existing capacity market design, including the Competitive Auctions with Sponsored Policy Resources (CASPR) framework effective in ensuring resource adequacy at just and reasonable rates? Why or why not? Is it compatible with achieving New England states' policies? Given the small quantity of capacity cleared through the substitution auction, is CASPR achieving its goals? Is CASPR's current design durable? Why, or why not?

11:45 am – 12:45 pm: **Lunch**

12:45 pm – 2:15 pm: **Panel 2: Staff-Led Discussion of Short-Term Options and Complementary Potential Market Changes to Accommodate State Policies in ISO-NE**

Taking into consideration New England states' policies, this panel will consider whether short-term and long-term changes may be required for ISO-NE's capacity market. The panel will include a discussion of the following topics and questions:

1. Should ISO-NE's capacity market design, including the CASPR framework, change to better accommodate state policies? If so, how?

2. As the resource mix in ISO-NE continues to evolve, what new challenges are presented? Are the needs of the evolving resource mix better addressed in the capacity market or the energy and ancillary services markets, or are changes needed in both? Please explain.

3. At the March 23, 2021 technical conference,[3] panelists suggested that both

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n.1 (Jan. 2021), https://nepool.com/wp-content/uploads/2021/01/NPC_20210107_Felder_Report_on_Pathways_rev1.pdf.

[3] *See Supplemental Notice of Technical Conference on Resource Adequacy in the*

short-term and long-term reforms to aspects of ISO-NE's capacity, energy, and ancillary services markets could be needed if CASPR and the Offer Review Trigger Prices (ORTPs) are modified or eliminated.

a. What, if any, are the short-term and long-term challenges of removing CASPR and the ORTPs from ISO-NE's capacity market? What market design changes, if any, would be necessary to preserve the capacity market's ability to ensure resource adequacy? If changes are necessary, how quickly would ISO-NE need to implement short-term changes following the removal of CASPR and ORTP?

b. What other specific modifications to ISO-NE's capacity market rules may be necessary? For example, should capacity accreditation rules for various resource types, the shape of the capacity market demand curve, the net cost of new entry estimates, or mechanisms to ensure fuel security, among others, be revised and if so why, and how? Approximately how long would it take ISO-NE and stakeholders to develop and implement each additional needed reform? Assuming any such modifications are necessary, which should be prioritized in the short-term, and which should be pursued in the long-term?

c. Some panelists expressed concerns that ORTPs are necessary to prevent cost shifts between New England states. Please explain whether and if so, how these cost shifts would occur if CASPR and the ORTPs were eliminated. Is there a way to mitigate such an effect? Please explain. Additionally, please discuss the extent to which certain impacts are unavoidable in a regional market where participating resources are located in multiple states.

2:15 pm – 2:30 pm: **Break**

2:30 pm – 4:00 pm: **Panel 3: Staff-Led Discussion of Long-Term Options and Centralized Procurement of Clean Energy**

The New England's Future Grid Initiative contemplates a new, regionally-based market framework that delivers reliable service, but also accounts for and supports state policies in an efficient and affordable manner. This panel will explore potential new constructs being discussed as part of the initiative that would enable states to achieve a portion of their clean energy public policy goals within an ISO-NE-administered capacity

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Evolving Electricity Sector, Docket No. AD21-10-000 (March 16, 2021), https://www.ferc.gov/sites/default/files/2021-03/AD21-10-000supp.pdf.

and/or energy market. The panel will include a discussion of the foundational questions associated with developing and implementing a centralized clean procurement mechanism in ISO-NE.

1. What benefits would a centralized clean procurement mechanism in ISO-NE provide to the ISO-NE states and the ISO-NE markets? What would be the goals of such approaches and what are important design considerations in developing any potential market mechanism? What are the downsides of pursuing such constructs? What concerns regarding potential undue discrimination may arise from implementing such new market constructs, if any?

2. What are potential challenges to developing the new market constructs discussed in this panel (e.g., would interstate compacts be required)? How could those challenges be overcome? For example, New England states have policies that support different types of resources (e.g., offshore wind). Could a standard product be developed and centrally procured in ISO-NE-administered markets to meet these diverse state policy goals? Given the differences in state policies, is it possible to define products that resources could provide (e.g., zero-emission generation) and incorporate the procurement of those products into Commission-jurisdictional markets?

3. Stakeholder discussions to date have focused on the Forward Clean Energy Market and Integrated Clean Capacity Market as potential frameworks. What are the key design features of these proposals? What are the advantages and disadvantages of these approaches?

4. Given that many state policy goals target electricity generation (e.g., Renewable Portfolio Standards that target a percentage of electric loads), would it be more effective to develop such a construct within the energy and ancillary services markets?

4:00 pm – 4:15 pm: **Closing Remarks**

Summary of April 8, 9 and 16, 2021 Joint Nominating Committee Meetings

- On April 8, 9 and 16, the JNC met for the purpose of interviewing nine candidates selected for the two ISO-NE director positions which will open on October 1, 2021 following Kathleen Abernathy's and Phil Shapiro's retirements from the Board.

- Before commencing the interviews, Ms. Abernathy, in her role as ISO Board Chair, raised the topic of Mr. Curran's eligibility for reelection to a second full term, relaying that the Board fully endorses his reelection, citing his prior Board experience, relevant expertise, chairmanship of the Audit and Finance Committee, participation in other Board committees and his commitment to the ISO Board. NEPOOL representatives indicated that they had not received any objections since the February NPC meeting at which Mr. Curran presented. Mr. Nelson, as representative of the New England Conference of Public Utilities Commissioners, also indicated his support for Mr. Curran's reelection.

- The Committee then commenced its interviews with the candidates whose backgrounds reflected a mix of transmission, markets and more general executive/Board level expertise.

- Following the second day of interviews, the Committee discussed the absence from the Committee this year of Vickie VanZandt, noting that her input would be helpful in assessing the technical skills of the transmission candidates. Ms. Dickstein offered to consult with Maria Gulluni, ISO General Counsel, to see if Ms. VanZandt could join the Committee in a non-voting capacity to interview the transmission candidates during the second round. Ms. Gulluni agreed and Ms. Dickstein relayed this to the Committee at its April 16 meeting.

- At the conclusion of all nine interviews, Committee members fully discussed each candidate, expressing a variety of views and opinions. Members then voted and five individuals were selected for second round interviews to take place in the mid-May timeframe. The candidates selected were:

  - A part-time advisor for a utility infrastructure consulting company and former interim CEO of an electric utility company
  - An advisor to the CEO of a technology services company and former utility innovation strategist
  - An independent consultant focusing on policy studies and analysis for a range of institutions
  - A managing director of a financial services leadership coaching firm and former banking executive
  - A former transitional utility CEO with a varied energy background

- Next steps center around firming up mid-May second round interview dates and scheduling candidates accordingly