David T. Doot
Secretary

July 29, 2021

VIA ELECTRONIC MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of August 5, 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 August meeting of the Participants Committee will be held **via teleconference on *Thursday*, August 5, 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 August 5 meeting will be recorded. NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, consumer advocates that are not members, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those participating in the meeting are required to identify themselves and their affiliation during the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the draft minutes of the June 24, 2021 Participants Committee meeting. The draft preliminary minutes of that meeting, marked to show changes from the draft 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 Committee 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. Summaries of ISO Board and Board Committee meetings that occurred since the June 3 Participants Committee meeting are included with this supplemental notice and posted with the meeting materials.

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

5. To receive a brief overview and comments from various NESCOE Managers on their June 29, 2021 Report to the New England Governors, entitled "*Advancing the Vision*". A copy of that Report was included with the initial notice, is posted with the composite materials for this meeting and is also available at https://nescoe.com/resource-center/advancing_the_vision/.

6. To receive an ISO Internal Market Monitor Report by Dr. Jeffrey McDonald, Vice President, Market Monitoring. A presentation with highlights of the IMM's 2020 Annual Report on the ISO New England Markets will be circulated and posted with the meeting materials when received. The IMM's 2020 Annual Markets Report is available on-line at https://www.iso-ne.com/static-assets/documents/2021/06/2020-annual-markets-report.pdf.

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

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

9. Administrative matters.

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

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, June 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.

APPROVAL OF JUNE 3, 2021 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the June 3, 2021 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of that meeting were unanimously approved as circulated, with an abstention by Mr. Michael Kuser's alternate noted.

ISO CFO REPORT: 2022 ISO BUDGETS

Mr. Robert Ludlow, the ISO's Chief Financial Officer (CFO), referred the Committee to a presentation of the ISO's 2022 Preliminary Operating and Capital Budgets included with the materials posted in advance of the meeting. He reported that he had also shared this information with state officials in early June and had answered clarifying questions and committed to provide further detail/information in future meetings.

He began by noting that the 2022 preliminary operating budget supported~~s~~ the ISO's vision to harness the power of competition and advanced technologies to reliably plan and operate the grid as the region transitions to clean energy. He indicated that, to achieve this vision, the ISO anticipated the need for approximately 21 full-time equivalent (FTE) additions between 2022 and 2023. To meet that anticipated need, the 2022 preliminary budget included funding for 9 FTE additions. Those 2022 additions would be primarily to address the growing volume and workload for the integration of clean energy and distributed resources, which had impacted the market development, transmission planning, power system modeling, and legal areas, and for cyber security and information technology (IT) support. The 2023 preliminary budget included funding for 12 more FTE additions which, similarly, would be primarily to address the growing volume and workload for the integration of clean energy and distributed resources. The increased resources represented projected year-over-year increases, before depreciation, of $10,605,000 or 5.9% for 2022 and $9,161,900 or 4.8% for 2023. The projected increases, including depreciation, would be $9,057,100 or 4.4% and $7,181,900 or 3.4%, in 2022 and 2023, respectively.

Turning to the capital budget, Mr. Ludlow reported that the ISO anticipated that the annual capital budget would need to increase by up to $7 million over the next 5 years, from $28 million to $35 million. The ISO proposed, preliminarily, to have $4 million of that increase to occur in 2022, which would reflect a $32 million annual capital budget. Four primary drivers necessitated the projected increase: (i) nGEM platform replacement; (ii) cyber security; (iii) major capital projects to enable the clean energy transition and improve reliability; and (iv) IT asset and infrastructure replacement. Mr. Ludlow reported that the ISO planned to discuss the 2022 and 2023 budgets with the NEPOOL Budget & Finance Subcommittee in August.

In response to a question about the projected 2021 year-end actuals, Mr. Ludlow noted that the ISO anticipated being on budget at year's end.

ISO COO UPDATE

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by addressing the concerns raised about Minimum Offer Price Rule (MOPR) reform plans. He noted that the current work plan had changed substantially from the 2021 work plan that was shared with stakeholders eight months before, primarily due to intervening FERC orders and new priorities. He then highlighted that the ISO prioritized the project to eliminate MOPR in response to the strong message sent from the FERC ~~chair~~ Chair and the preference for a FERC proceeding initiated by a Federal Power Act (FPA) section 205 filing rather than an order from the FERC pursuant to FPA section 206.

He noted the ISO's operational concerns with a complete elimination of MOPR. He reported that the ISO had asked Dr. David Patton, Ph.D., President of Potomac Economics, the ISO's External Market Monitor (EMM), for assistance in quantifying the uncertainty of the market without MOPR. He explained that the ISO already had a standing contract in place with Potomac Economics so it did not separately document a statement of work. The ISO expected to receive more guidance from the FERC in late July or early August and would continue to engage with stakeholders to understand, discuss and refine what could be included in the MOPR filing (expected in early 2022). He noted the intent to provide early reports on status for feedback but noted possible limitation on the ability to do so with the need to think through implementation ahead of finalizing the analysis. He acknowledged work on resource electric load carrying capabilities (ELCC) was a critical companion to the elimination of MOPR. He said that the ISO planneds~~s~~ to advance that project as soon as possible. He reiterated the ISO's objective to balance many competing factors that help to achieve reliability through the markets, rather than outside the markets, while maintaining a priority on elimination of MOPR. He expected that the stakeholder process would help to ensure informed and robust discussions amongst stakeholders.

Dr. Chadalavada responded to a number of questions about the scope of Dr. Patton's review to provide an assessment and quantification of a market without MOPR. He said the plans were for the EMM to share its core recommendations with stakeholders in late July or August, and to provide later a sequence of additional recommendations relative to ELCC and the Energy Security Initiative (ESI). When pressed with numerous additional questions about the work required by the ISO to support the filing, Ms. Maria Gulluni, the ISO's General Counsel, noted that the ISO would ensure that it completes the work it believes will be required for the ISO filing to include all the information necessary to demonstrate that the filed changes are just, reasonable and supportable.

EMM 2020 ANNUAL MARKETS REPORT

MOPR Reform

Following Dr. Chadalavada's presentation, the Chair introduced Dr. Patton ~~was introduced~~ to present his annual report on the state of the markets. Having listened to the earlier discussions about the EMM's scope of work in response to ISO's request relating to the elimination of MOPR, he volunteered to address some of those questions from the EMM's perspective and the Chair agreed.

~~He~~ Dr. Patton began by acknowledging the concerns with MOPR and the need for the Forward Capacity Market (FCM), as well as the markets holistically, to continue to work and serve their purpose. He shared two priorities the EMM had identified relating to this topic. The first priority he discussed was the need to improve resource ~~the~~ capacity accreditation ~~of resources~~. Dr. Patton opined that resources, particularly newer technologies, were often given too much capacity credit and that their contribution to resource adequacy was dependent on the penetration of that type of resource in the resource mix. Thus, he stressed the importance of getting a resource's accreditation correct to prevent collateral issues in the market. Dr. Patton noted that, while accreditation was a high priority, the immediate scope of work did not encompass that issue but Potomac Economics would offer feedback.

The EMM considered the second priority to be ensuring that markets support resources' investment decisions were reasonably based on the expectation of market revenues over the life of the resource. Dr. Patton explained that eliminating MOPR would likely increase revenue risk and would reduce the expected future revenues for non-sponsored resources. The scope of work, as viewed by the EMM, was to quantify the adjustments to the demand curve that would be necessary to account for the increased price uncertainty in the market so that the expectation of future revenues ~~due to~~in light of the elimination of MOPR would continue to support investments by non-sponsored resources.

After describing the EMM's plans for the work to be performed, numerous members sought further understanding on how those efforts might unfold. One line of questions sought Dr. Patton's views on whether the EMM in its scope of work would take into account the possibility that FCA17 would not have a new method to accredit resources. A colleague of Dr. Patton, who was on the team planning and performing the work, responded that the EMM was working to construct an analysis of multiple scenarios with and without MOPR to determine a range of outcomes. The EMM was planning to focus on a variety of inputs that would change if MOPR was eliminated. The analysis, he continued, was still being designed with the intention of answering the basic question of what impacts could reasonably be expected with the elimination of the MOPR. The next line of questions sought Dr. Patton's opinion on whether adjusting the inputs into the FCM would produce competitively determined auction prices. Dr. Patton responded that EMM intended to analyze whether and how the region might offset the detrimental effects of eliminating the MOPR and prevent out-of-market actions, with the desire that the markets would result in efficient decision making by ~~market~~ Market ~~participants~~ Participants to satisfy resource adequacy.

Following approximately 30 minutes of the Committee's time with Dr. Patton on this topic, and while there remained other Market Participants that had expressed an interest in continuing to question the EMM as to its expectations and predictions of where its future work might take it in response to the ISO's request relating to elimination of MOPR, the Chair halted further questions. He expressed concern with the extended time discussion on this topic, which had not been noticed, was taking. He suggested that the Markets Committee would be a better forum for addressing such questions and that a Markets Committee meeting for that discussion was planned. He requested that Dr. Patton, in the remaining time he was available for the Committee during this meeting, move to the presentation of the highlights of the EMM's assessment of the markets in 2020, which was the topic that had been noticed for the meeting.

2020 EMM Annual Report Overview

In response to the Chair's request, Dr. Patton referred to the EMM's 2020 Markets Report (EMM Annual Report) and a presentation with highlights from that report, each of which had been circulated and posted in advance of the meeting. He explained that the role of the EMM was (i) to evaluate and report on the competitive performance and operation of New England's wholesale markets, (ii) to identify and recommend necessary changes to improve existing and proposed market rules, tariff provisions and market design elements, and (iii) to evaluate the mitigation by the ISO's Internal Market Monitor (IMM). He stated that the EMM

Annual Report focused on and summarized the following key market areas: cross-market comparison of several key market outcomes and metrics; competitive performance of the markets; market issues related to reliability commitments and uplift costs; long-term investment signals; energy efficiency participation in the FCM; and capacity accreditation in the FCM. He then highlighted three high priority recommendations that he expected would improve the performance of the markets and facilitate large-scale entry of intermittent resources. The first was a recommendation to introduce co-optimized Operating Reserves in the Day-Ahead Energy Market to account for and price all system needs, such as had been proposed in ESI. The second recommendation was to ensure that the FCM accreditation of resources be based on the resources' marginal reliability value. The third recommendation was to modify the pay-for-performance rate to vary with the size of the Operating Reserve shortage.

Cross-Market Comparisons

Next, Dr. Patton reviewed the portion of the presentation that showed cross-market comparisons and highlighted key differences between the New England and other markets. Comparatively, New England generally had the highest all-in prices, driven largely by high capacity costs and higher natural gas prices than other regions of the country. Focusing next on congestion costs, Dr. Patton noted that New England had congestion costs that were only 10-20% of the relative congestion costs of other ISO/RTOs. He attributed the results to the large transmission investments made in New England. He observed that the resulting transmission rates in New England, however, were more than double the average rates in other ISO/RTO markets. When comparing uplift as a percent of load in different markets, he noted that New England appeared to be in line with other markets, but had much lower uplift per megawatt hours

(MWh) of load than other markets. He attributed this uplift difference from the other markets to the absence of Day-Ahead reserve markets and low levels of virtual trading.

Discussing Coordinated Transaction Scheduling (CTS), Dr. Patton highlighted that the ISO was more accurate in its load forecasts than other ISO/RTOs and that CTS' positive performance was partly due to the decision not to impose administrative charges on CTS transactions. In other regions where such fees were not waived, the benefits of interregional trading were reduced. He noted the forecast errors, and encouraged that the impact of those errors be reduced through Real-Time price quotes rather than the current process of future estimating.

Market Competitiveness

Transitioning to discussion of market competitiveness, Dr. Patton opined that the New England Market had been performing competitively. He said market competitiveness had improved because of 1.5 gigawatts of new combined cycle units (CCs) in import-constrained areas, transmission upgrades in Boston, and falling load levels because of mild weather, continued growth of energy efficiency and behind-the-meter solar resources, and the effects of COVID-19.

Reliability Commitments and NCPC Charges

He then talked about the impacts of Day-Ahead commitments for local second contingency protection and system level reserve requirements, including on overall Net Commitment Period Compensation (NCPC) costs. With respect to local second contingency protection, he highlighted that Maine was seeing more frequent commitments and higher costs to address local transmission constraints, which would be mitigated if the EMM's recommendation to allow firm imports to satisfy local reserve requirements were to be implemented. He estimated that local second contingency protection commitments accounted for roughly 41% of Day-Ahead NCPC. With respect to system-level operating reserve requirements, Dr. Patton explained that additional generating capacity was being committed Day-Ahead to satisfy expected Real-Time system-level Ten-Minute Spinning Reserve requirements in roughly 45% of all hours. Without those reserve requirements being reflected in the Day-Ahead market dispatch or pricing software, clearing prices for energy (and reserves) were understated and incentives for resources to be made available at the lowest cost were being undermined. He estimated that the commitments for system-level operating reserve requirements accounted for roughly 41% of Day-Ahead NCPC.

He observed that the ISO satisfies a large share of the region's operating reserve requirements using resources that receive no Day-Ahead schedules or compensation (latent reserves), citing many days where the actual reserve requirements exceeded what had been procured. Latent reserves were protecting the region from reliability issues but increasing amounts of resources were being required to manage uncertainty. Dr. Patton opined that the issue of latent resources would become a more pressing issue with higher renewable penetration, reaffirming the need for additional reserve products in the Day-Ahead markets.

Following a short recess for lunch, Dr. Patton shared and explained his reasoning for the EMM's recommendation to reduce inflated costs associated with supplemental commitments by having the ISO use the lowest-cost fuel and/or configuration model for multi-unit generators committed for local reliability and by permitting firm imports to satisfy local reserve requirements.

Long-Term Investment Signals

Turning to the EMM's assessment of the ability of the New England Markets to support long-term investments, Dr. Patton presented a table showing the net revenue comparison across markets. He noted a new combustion turbine was not economic in most markets. He also noted the impact of COVID-19 on the change in load. He observed that 2020 revenues were high enough to motivate development of new resources other than wind. He referred to a table in his presentation that provided the following three recommendations to improve long-term investment signals: (i) improve accreditation rules; (ii) procure operating reserves in a co-optimized Day-Ahead market; and (iii) improve the pay-for-performance penalty rate. He explained that these recommendations would increase compensation for flexible resources, especially batteries.

Reviewing slides illustrating average prices in 2030 offshore wind scenarios, Dr. Patton explained that the impact of various technologies on energy prices depended on the level of penetration of each technology. High penetration of offshore wind, for example, could negatively affect renewable developers and land-based wind. He opined that implementation of technology-neutral strategies to advance State policy goals would lessen the effects of revenue erosion from excess penetration.

Members raised a number of questions about the EMM modeling assumptions for estimating long-term investment signals. Dr. Patton acknowledged that power purchase agreements (PPAs) with fixed prices insulate ~~the~~ a supplier from market changes over time, and that the economic life of such resources under long-term PPAs might be equal to the term of the contract. He explained that reliability requires that the system be able to respond to both short-lived, transitory events and longer-duration events. Transitory events produce temporarily high prices that resources such as two-hour batteries would receive for a short time only. He indicated planning models needed to reflect both shorter and longer duration events to produce more accurate economic projections for each type of technology. He explained why the Report encouraged States to compensate public policy resources based on their contribution to the State's policy goal, regardless of entry date or technology. He opined that changes in State policies affect future contracts through additional entry and more attractive terms, which may push down prices to levels below those that earlier resources were relying on for their economic viability. He noted that the resource mix used in each of the EMM cases studied was the mix reflected the 2019 ISO Economic Studies. He explained that supporting certain technologies through contracting schemes, like bundled PPAs, make some ~~market~~ Market ~~participants~~ Participants less sensitive to the efficiency of the investments and can shift investment risks to other ~~market~~ Market ~~participation~~ Participants who may not have the same contractual protections.

Capacity Accreditation

Dr. Patton noted that resource adequacy accreditation should be designed to reflect how each type of resource impacts the loss-of-load expectation. He noted the following concerns with over-accreditation for certain resources: (i) intermittent resources we~~a~~re accredited based on median output in certain hours each day, defined seasonally, which effectively measures intermittent resources' average contribution to reliability; (ii) the marginal reliability value of intermittent resources falls as penetration grows because output is correlated; and (iii) by ignoring the correlation in output, the current approach could~~an~~ over-value the reliability provided by intermittent resources. He then shared a table reflecting average intermittent output during the top five annual net load hours as the penetration of those resources rise. He expressed the importance of tracking diminishing contribution of those resources to reliability. Applying this concept to the value of batteries, as the penetration of storage on the system increases, the marginal value of those resources falls. Batteries with longer duration of potential discharge, though, have a larger contribution to reliability than shorter duration batteries. The market should incentivize longer duration batteries. The marginal accreditation approach would compensate each resource based on its incremental reliability value to the system at each point in time. This would recognize correlations/synergies as the resource mix changes, would provide efficient incentives to invest in diverse resources and would reduce the risk of oversaturated technologies. It would also help defining efficient pairing of storage with intermittent resources, selecting the most advantageous storage durations and/or augment duration over time, and maintaining flexible conventional resources while they are needed. He recommended to improve capacity accreditation rules through the accreditation of all resources based their marginal reliability value. He commented on the shortcomings of the current resource adequacy modeling used because it failed to reflect the more dynamic output potentials and availabilities of specific technologies such as intermittent resources, resources that all depend on the availability of a particular pipeline, and resources with different flexibilities in responding to changes on the system.

There was considerable discussion about the EMM's accreditation suggestions and modeling. Some members suggested that the scenarios driving the EMM analysis should reflect more storage coupled with intermittent resources. Others suggested that accreditation changes should be more urgently pursued and potentially addressed as part of the MOPR reforms. The EMM acknowledged the importance of instituting many of the changes as soon as possible. There was also discussion of the importance of updating modeling for resource adequacy in connection with implementing the accreditation reforms. There was discussion of moving from an audit-based system for assessing capacity credits to one based on historical performance during times of the lowest Operating Reserve margin on the system. The EMM noted a key takeaway from the report was that the current process for translating the megawatts of a non-conventional resource into a generic qualified capacity number, assuming it had the same reliability value as other megawatts of qualified capacity, was not correct and leads to inaccurate compensation and inefficient investment. He encouraged future discussions of changes to accreditation in order to correct the overstatement in supply contribution of individual technology and changes to installed capacity modeling to avoid the underestimate in demand.

Energy Efficiency in the FCM

The EMM expressed concern with the treatment of energy efficiency as supply side rather than demand side. Doing so, he noted, would artificially increase demand, which would in turn inflate capacity prices. The EMM recommended that changes be made to account for energy efficiency as a reduction in load instead of as supply, which would lower administrative costs, address manipulation concerns and would not prevent load serving entities from benefiting from energy efficiency.

EMM Recommendations

The discussion ended with a review of the complete list of the EMM's recommendations, and highlighted the following four as recommendations of particular importance: (i) introduce co-optimized Operating Reserves in the Day-Ahead Energy Market reflecting all system needs, such as the proposed ESI products; (ii) incorporate a comprehensive set of local Operating Reserve requirements into the Day-Ahead and Real-Time markets; (iii) improve capacity accreditation by accrediting all resources consistent with their marginal reliability value and modifying the planning model to accurately estimate marginal reliability values; and (iv) modify the Payment Performance Rate (PPR) to rise with the reserve shortage level rather than implementing the remaining planned step increases in the payment rate.

COMMITTEE REPORTS

Markets Committee (MC). Mr. William Fowler, the MC Vice-Chair, reported that a two-day meeting would be held July 7-8. Discussion would focus on the region's response to Order 2222 and MOPR reform issues. The committee was working through stakeholder ideas and alternatives. He encouraged those seeking time on the agenda for the next meeting to contact the Chair and Secretary of the Markets Committee. A special meeting was scheduled for July 26 for a presentation by the EMM concerning MOPR reform issues discussed earlier in the meeting.

Transmission Committee (TC). Mr. José Rotger, the TC Vice-Chair, reported that the scheduled July 14 TC meeting would include (i) continued discussions on a stakeholder proposal to eliminate from Schedule 11 of the Tariff operating and maintenance (O&M) charges for network upgrades associated with generation interconnections, (ii) Order 2222 compliance including ISO and stakeholder feedback, (iii) information on ISO-proposed changes to Attachment K, which would include changes to the regional system planning process and changes relative to lessons learned from the Order 1000 transmission request for proposals (RFP) discussed at the Planning Advisory Committee, and (iv) an annual review by the Transmission Owners of the components of the regional network service transmission rate.

Reliability Committee (RC). Ms. Emily Laine, the RC Chair, reported that the RC continued to review changes to Planning Procedures and Operating Procedures.

Budget & Finance Subcommittee. Mr. Thomas Kaslow, the Subcommittee Chair, announced that the next meeting of the Subcommittee was scheduled for August 9.

Membership Subcommittee. Ms. Sarah Bresolin, the Subcommittee Chair, announced that the next meeting of the Subcommittee, which was scheduled for July 12, would include a discussion on potential changes to Fuels Industry Participant category and encouraged all those interested to attend.

Joint Nominating Committee (JNC). Mr. Cavanaugh noted the JNC had concluded its process by unanimously recommending a proposed slate of directors. He said that members would have time to consider that slate before being asked to vote. He noted that a confidential communication would be distributed to members the following week that would identify the proposed the slate, review the process for developing the slate, and discuss the challenges to the ISO Board during times of high turnover of directors. Additionally, he explained that the confidential distribution would describe actions that the members and alternates would be asked to consider at the July 21 meeting, to be held in executive session. He reported that the executive session would take place in the morning, and the Pathways working session would take place in the afternoon. He encouraged members to direct any questions, comments or concerns to their respective JNC members.

ADMINISTRATIVE MATTERS

Mr. Lombardi indicated that the July COO and litigation reports would be circulated the week of July 4. He noted two separate compliance filings related to the FCM parameters for FCA16 -- one addressing the Cost of New Entry (CONE), Net CONE and PPR values, and a second to comply with the recent Offer Review Trigger Price (ORTP) order. He noted that any requests for rehearing of the CONE and ORTP orders would need to be filed by June 28 and July 7, respectively. He further reported that post-conference replies to comments relating to the FERC's technical conference on principles and best practices for managing credit risk in organized markets were due by July 7.

Mr. Lombardi said that the next ~~N~~Participants Committee meeting following the July 21 meetings would take place on August 5. He reported that there was a tentative hold for a Pathways Study meeting on August 19, which would be confirmed in July. Sector meetings with the Board were planned over the following two Business Days, and the remaining Sector meetings with state officials were scheduled for June 28 and the second week in July.

There being no other business, the meeting adjourned at 3:22 p.m.

Respectfully submitted,

David Doot, Secretary
Sebastian Lombardi, Acting Secretary

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

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Advanced Energy Economy	Fuels Industry Participant	Caitlin Marquis		
Ampersand Energy Partners LLC	Supplier			Julia Frayer
AR Large Renewable Generation (RG) Group Member	AR-RG	Alex Worsley		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
Associated Industries of Massachusetts (AIM)	End User			Mary Smith
AVANGRID: CMP/UI	Transmission		Alan Trotta	
AVANGRID: Avangrid Renewables	Transmission	Kevin Kilgallen		
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
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	
Dominion Energy Generation Marketing	Generation	Mike Purdie		
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	
Excelerate Energy LP	Fuels Industry Participant	Gary Ritter		
Exelon Generation Company	Supplier		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		Bob Stein	
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Holyoke Gas & Electric Department	Publicly Owned Entity		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Industrial Energy Consumer Group	End User	Alan Topalian		

ATTACHMENT 1

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

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
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		
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
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 Brennan	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	
Princeton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PSEG Energy Resources & Trade LLC (PSEG)	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	
Small RG Group Member	AR-RG	Erik Abend		
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	
Union of Concerned Scientists	End User		Francis Pullaro	
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny		
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw

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

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Versant Power	Transmission	Lisa Martin	David Norman	
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	

CONSENT AGENDA

Reliability Committee (RC)

From the previously-circulated notice of actions of the RC's July 13, 2021 meeting, dated July 13, 2021.[1]

1. **Changes to OP-8 (Correction to Definition of Reportable Event; Updated Language to Align with Directory 5)**

   Support revisions to ISO New England Operating Procedure (OP) No. 8 (Operating Reserve and Regulation), which correct the definition of Reportable Event and update the language to align with Directory 5, as recommended by the RC at its July 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 unanimously approved.

2. **Changes to OP-23 (Biennial Updates; Clarifications to Reactive Capability Auditing)**

   Support revisions to OP No. 23 (Resource Auditing) which update terminology, make grammatical changes and clarify Section 4 regarding Dual-Fuel Auditing, as recommended by the RC at its July 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 unanimously approved.

3. **Changes to Appendix D to OP-24 (Refinement to Instructions for Timely Review of Outage Applications; Table 1 Updates)**

   Support revisions to Appendix D (Required Protection Outage Request Form and Examples) to OP No. 24 (Protection Outages, Settings and Coordination), which refine instructions for timely review of outage applications and update Table 1, as recommended by the RC at its July 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 with one abstention.

4. **Changes to Appendix C to OP-17 (Revised Use and Purpose Description; Global Change to TLC and TLC Contact; Table 1 Updates)**

   Support revisions to Appendix C (Instructions for the ISO Load Power Factor Survey) to OP No. 17 (Load Power Factor Correction), which describe the current use and purpose of Appendix C, replace "Transmission Load Customer" (TLC) and "Transmission Load Customer Contact" for "Company" and "Reporting Agent", respectively, updates to the Table 1 list of TLCs and TLC Contacts, all as recommended by the RC at its July 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 unanimously approved

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

Summary of ISO New England Board and Committee Meetings

August 5, 2021 Participants Committee Meeting

Since the last update, the System Planning and Reliability Committee and the Information Technology and Cyber Security Committee met on June 22. The Compensation and Human Resources Committee, the Nominating and Governance Committee, and the Board of Directors met on June 23. In addition, the Board of Directors met on July 16. All of the meetings were held virtually.

The System Planning and Reliability Committee discussed the themes for the Regional System Plan report and executive summary, and plans for the upcoming 2021 Regional System Plan virtual public meeting. The Committee received updates on regional planning activities, economic and special study requests, integration of distributed energy resources, and a preview of planned activities for the summer and early fall of 2021. The Committee also received updates on the system operations outlook for summer 2021 and key observations from the economic study results. In light of recent extreme weather events, and consistent with the Committee's responsibilities, the Committee and management also reviewed roles and responsibilities related to emergency preparedness. During executive session, the Committee reviewed the results of its self-evaluation.

The Information Technology and Cyber Security Committee was provided with an update on cyber security projects and current activities. The Committee also received an overview of the Next Generation Electricity Market project and its timeline through 2028 to replace the software system that is the foundation for the day-ahead and real-time markets. The Committee then considered topics for discussion at the annual cyber security "deep dive" at its September meeting and agreed to focus on the topic of ransomware.

The Compensation and Human Resources Committee conducted its annual assessment of the risks within the Committee's purview, and agreed that the primary risks relate to succession planning, recruitment and retention of employees, increased stress on the workforce, and loss of focus on diversity and inclusion efforts. The Committee then met in executive session to review the Company's organizational structure and succession plans for management. The Committee also reviewed the Company's return-to-office plan and discussed the results of its self-evaluation.

The Nominating and Governance Committee considered topics for its upcoming annual corporate governance review. The Committee discussed post-pandemic meeting practices, director education and director onboarding, and the ongoing use of virtual Board and committee meeting participation. The

Committee also reviewed the governance topics raised at the Federal Energy Regulatory Commission's May 25 Technical Conference on Resource Adequacy.

The Board of Directors, on the day prior to its June meeting, met with Commissioner Mark Christie of the Federal Energy Regulatory Commission and discussed the Company's priorities, including energy security, addressing the conflicts between the markets and state policy, and public policy planning. At its meeting on June 23, the Board considered the topics raised in advance by participants for discussion at the upcoming sector meetings, and received an update on the Company's corporate goals. The Board then approved changes related to the Audit and Finance Committee's oversight of employee benefit plans, and related changes to the Committee's charter. The Board also approved the transfer of certain charter responsibilities from Audit and Finance to the new Information and Technology and Cyber Security Committee, and approved that committee's initial charter. The Board also reviewed the Company's Form 990 for 2020 to be filed with the Internal Revenue Service and received reports from the standing committees. During executive session, the Board discussed the results of its self-evaluation.

At its meeting in July, the Board of Directors approved the issuance of a message to employees for the flexibility and dedication displayed over the last 16 months, and thanking them for the continuing work efforts to transition the New England states to a clean and reliable energy system. The Board also discussed the issues in the states' report to the governors regarding the states' energy vision related to markets, transmission, and governance. The Board determined that the Nominating and Governance Committee should undertake a thorough review of the report.

NEPOOL Participants Committee Report

August 2021

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

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  - Regional System Plan (RSP) Page 88
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  - Operable Capacity Analysis – Appendix Page 128

Regular Operations Report - Highlights

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - Update: June 2021 Energy Market value totaled $478M
  - July 2021 Energy market value was $427M, down $51M from June 2021 and up $100M from July 2020
    - July 2021 natural gas prices over the period were 14% higher than June average values
    - Average RT Hub Locational Marginal Prices ($36.04/MWh) over the period were 0.6% higher than June averages
      - DA Hub LMP: $37.59/MWh
    - Average July 2021 natural gas prices and RT Hub LMPs over the period were up 99% and 60%, respectively, from July 2020 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 100.6% during July, up from 99.1% during June*
    - The minimum value for the month was 96.2% on Sunday, July 4th

All data through July 28th

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

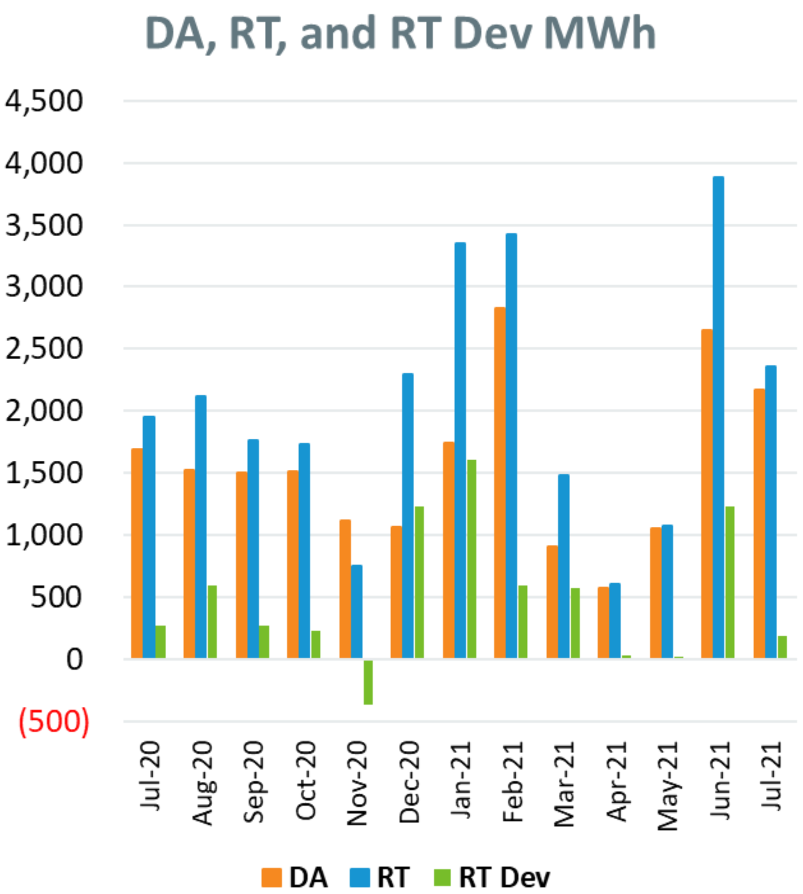
*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

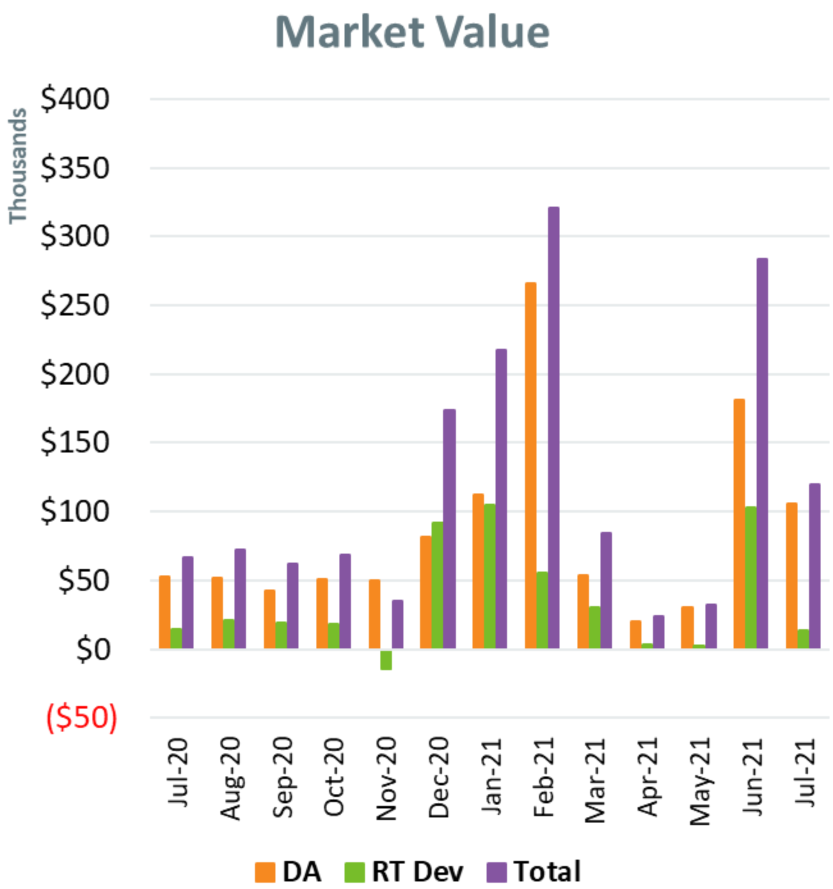
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - July 2021 NCPC payments totaled $2.7M over the period, down $1.2M from June 2021 and up $0.9M from July 2020
    - First Contingency payments totaled $2.1M, down $0.6M from June
      - $2.1M paid to internal resources, down $0.3M from June
        - » $368K charged to DALO, $1M to RT Deviations, $661K to RTLO*
      - $20K paid to resources at external locations, down $352K from June
        - » $9K charged to DALO at external locations, $11K to RT Deviations
    - Second Contingency payments totaled $331K, down $850K from June
    - Distribution payments totaled $276K, up $245K from June
    - Voltage payments were zero
  - NCPC payments over the period as percent of Energy Market value were 0.6%

* NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $194K; Rapid Response Pricing (RRP) Opportunity Cost - $256K; Posturing - $210K; 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

- Production cost preliminary results for the 2021 Economic Study (Future Grid Reliability Study) continued to be presented at the July Planning Advisory Committee meeting, with the remaining results expected in September
- FCA 16 Installed Capacity Requirement (ICR) assumptions and results are being discussed at the Power Supply Planning Committee
  - RC to vote on ICR and Related Values at their September 21 meeting
- Regional System Plan development continues and stakeholder comments are due on August 3
  - Public Meeting will be held virtually on October 6
- Four Attachment K revisions are in various stages of development

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) was held on June 1-3, and results were posted June 30
- CCP 15 (2024-2025)
  - Auction results were filed with FERC on February 26 and FERC approved on June 24

CCP – Capacity Commitment Period

FCM Highlights, cont.

- CCP 16 (2025-2026)
  - FCA 16 will model the same zones as FCA 15
    - Export-constrained zones: Northern New England and Maine nested inside Northern New England
    - Import-constrained zones: Southeast New England
  - New Capacity Qualification Package (NCQP) submission window closed on June 18, and review of the NCQPs is ongoing
  - ICR and Related Values development continues and discussions regarding assumptions and results are being held at the PSPC; on track for an RC vote in September

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

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
- On 5/3/21, the ISO issued a memo to the PAC summarizing next steps in the process
- The ISO held its first discussion on the associated Tariff changes at the 7/14/21 TC meeting. The next discussion is scheduled for the 8/24/21 TC meeting.

Highlights

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

- The lowest 50/50 and 90/10 Preliminary Fall Operable Capacity Margins are projected for week beginning September 25, 2021.

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal (1.7°F) Max: 95°F, Min: 57°F Precipitation: 10.07" – Above Normal Normal: 3.27"	Hartford	Temperature: Below Normal (1.3°F) Max: 93°F, Min: 52°F Precipitation: 10.15" - Above Normal Normal: 4.17"

Peak Load:	22,354 MW	7/16/2021	18:00 (ending)

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

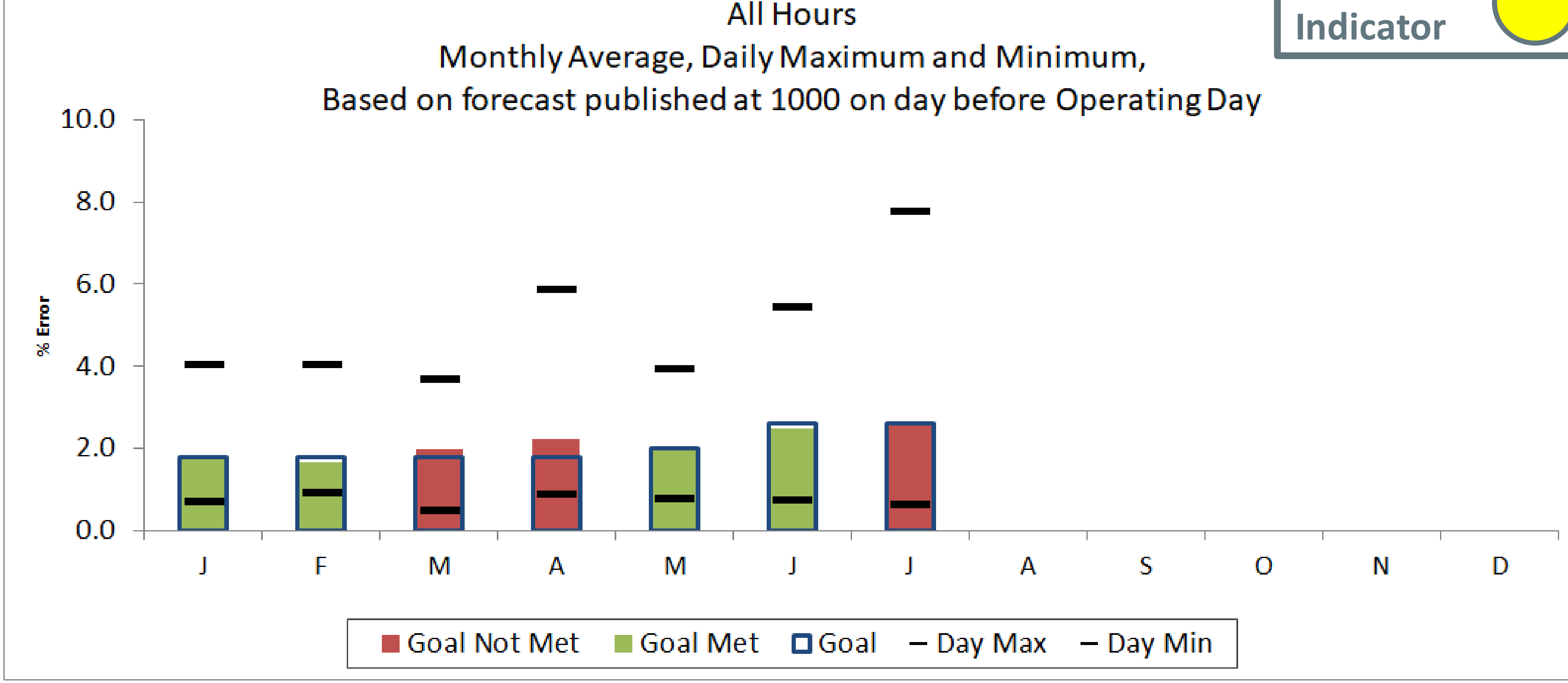
Procedure	Declared	Cancelled	Note
M/LCC 2	7/8/2021 17:00	7/9/2021 11:00	Severe Weather

System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
7/8/2021	NYISO	530
7/16/2021	ISO-NE	650

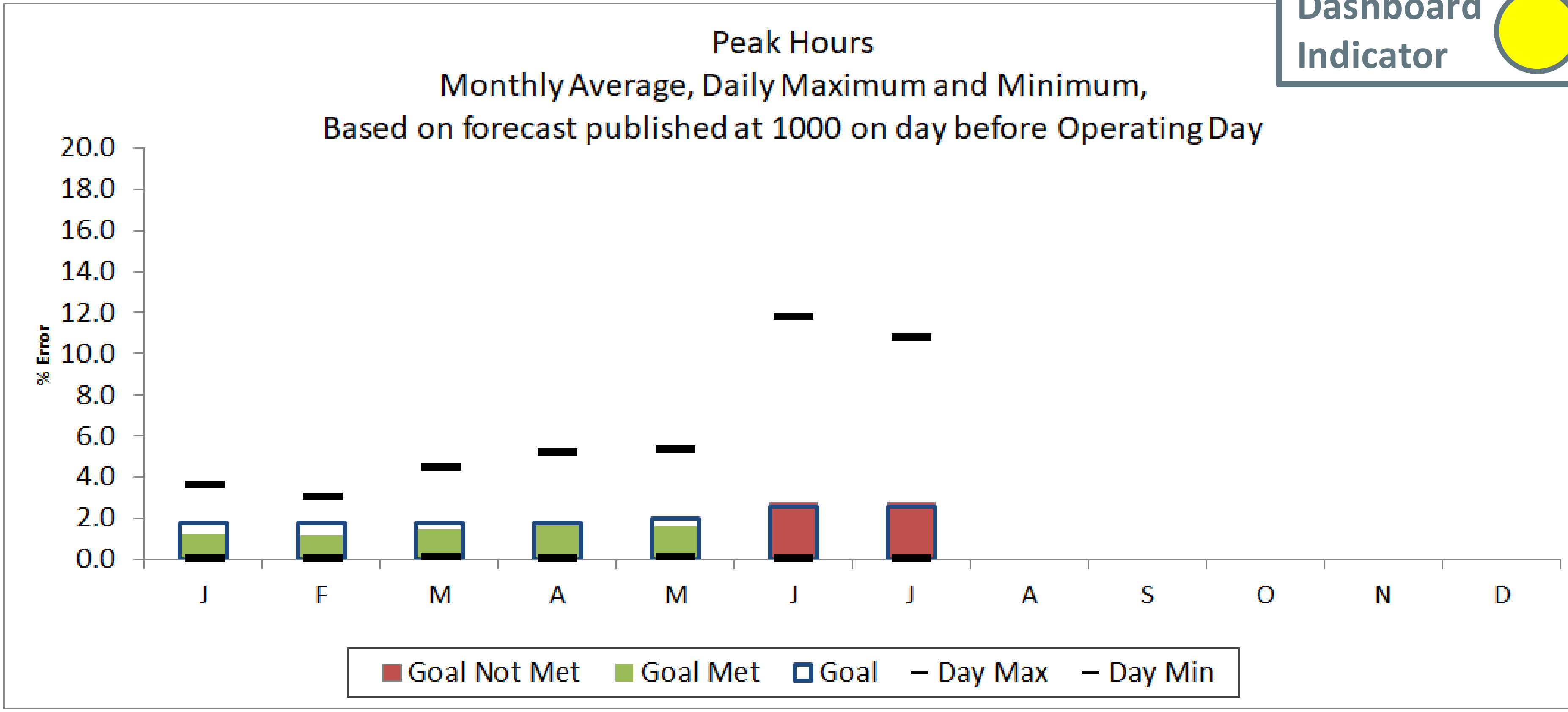
2021 System Operations - Load Forecast Accuracy



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.04	4.03	3.67	5.85	3.92	5.41	7.75						7.75
Day Min	0.70	0.92	0.49	0.88	0.77	0.73	0.63						0.49
MAPE	1.72	1.66	1.97	2.24	1.95	2.50	2.61						2.10
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60						

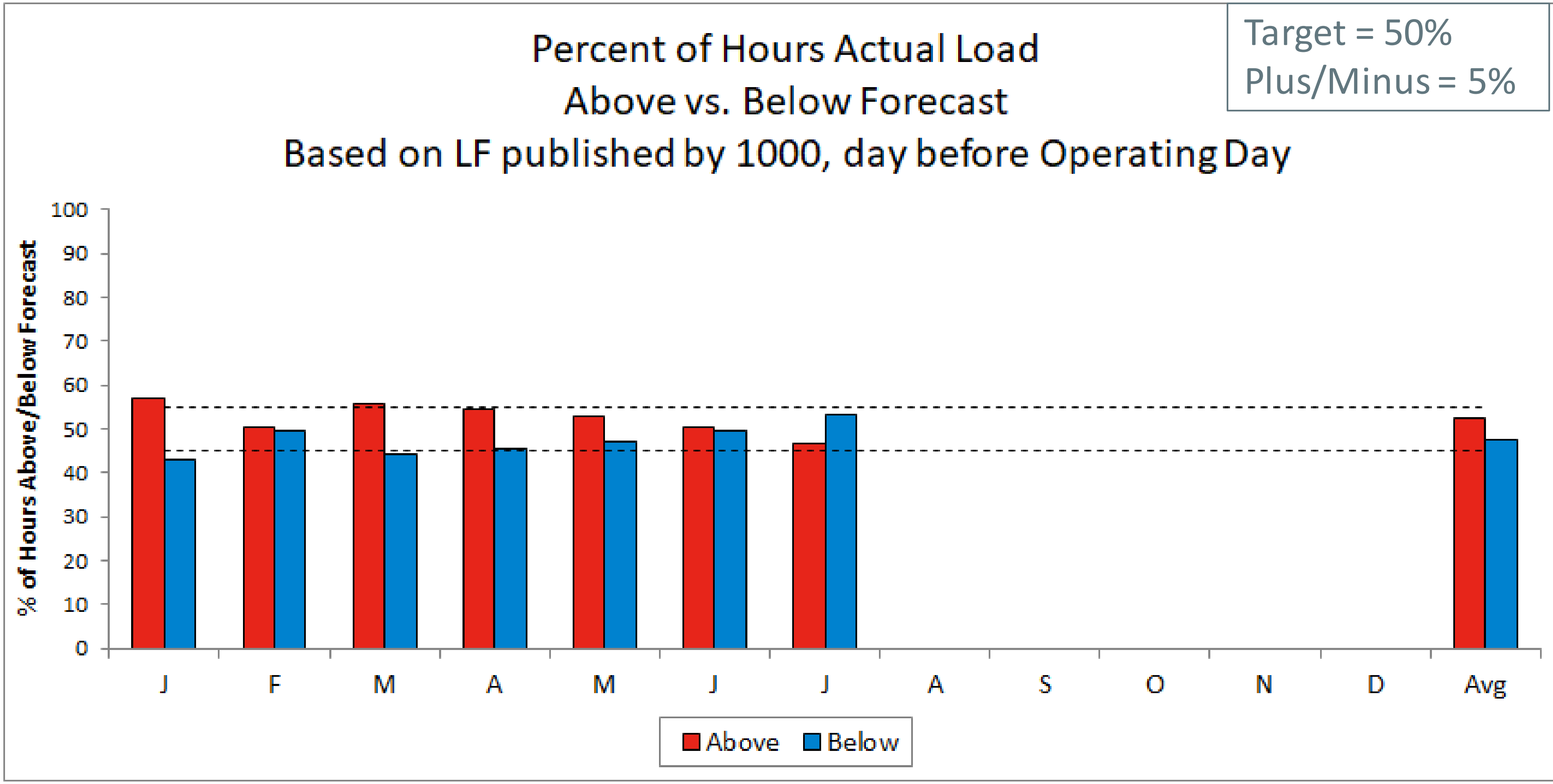
2021 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator



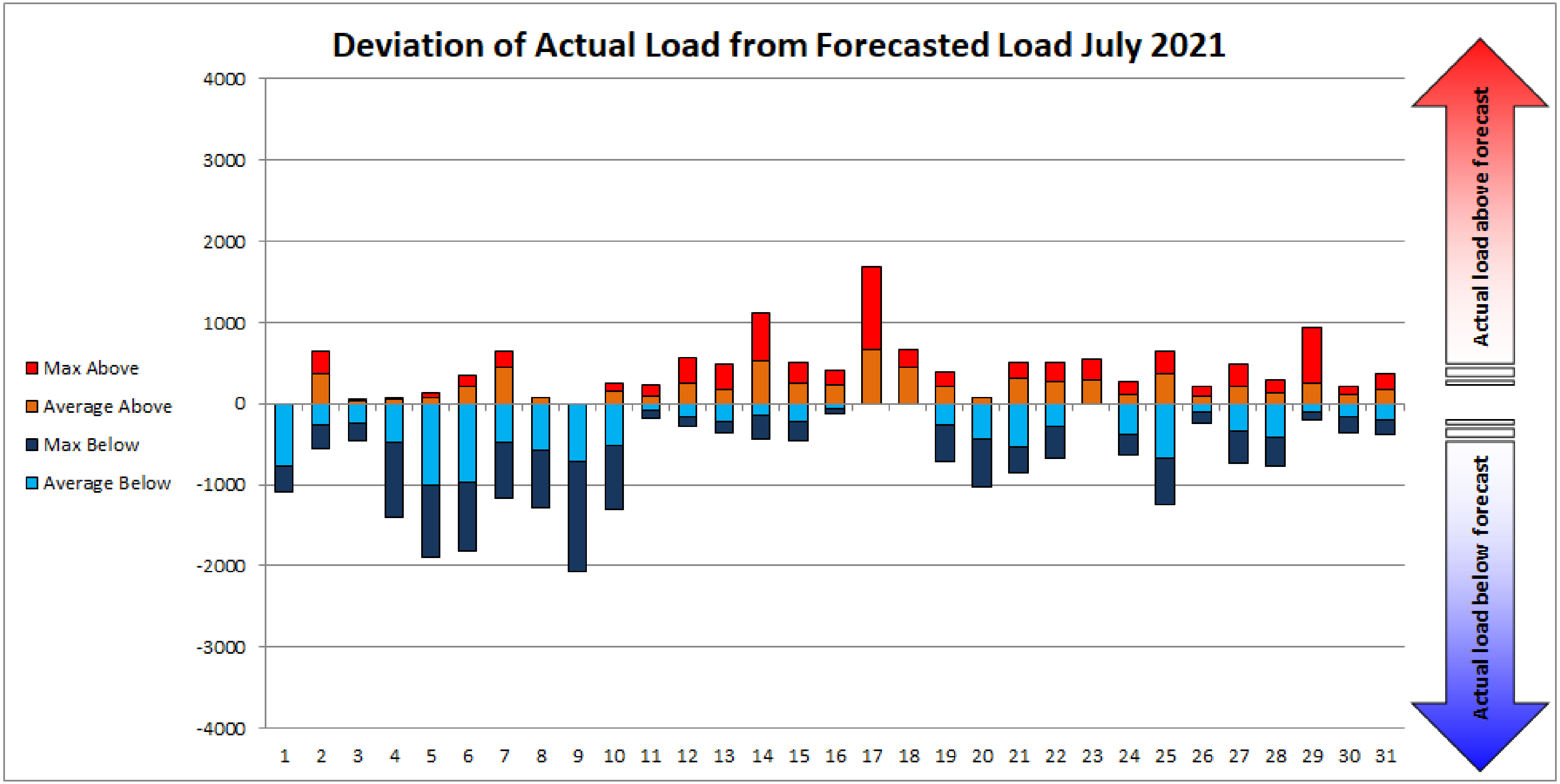
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	3.61	3.03	4.47	5.19	5.31	11.76	10.75						11.76
Day Min	0.02	0.06	0.08	0.03	0.11	0.04	0.05						0.02
MAPE	1.26	1.18	1.48	1.66	1.60	2.79	2.78						1.83
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60						

2021 System Operations - Load Forecast Accuracy cont.

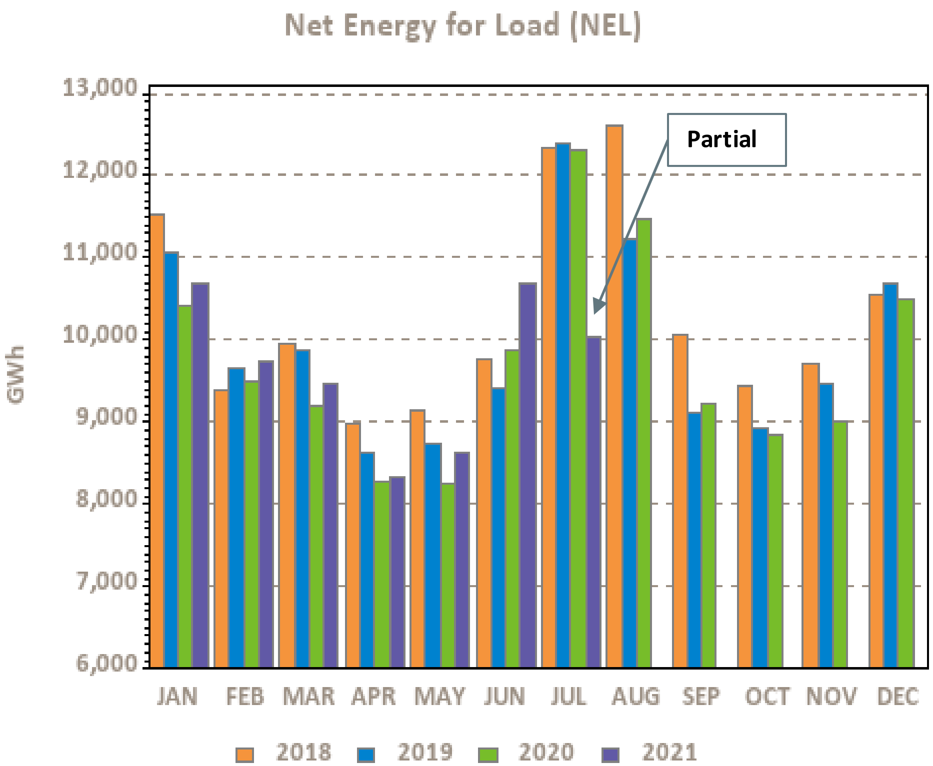


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	57.1	50.4	55.6	54.4	52.8	50.3	46.9						53
Below %	42.9	49.6	44.4	45.6	47.2	49.7	53.1						47
Avg Above	209.5	166.7	185.4	206.1	227.4	233.1	214.6						233
Avg Below	-147.6	-216.4	-188.0	-167.9	-146.8	-309.1	-348.1						-348
Avg All	60	-25	30	40	61	-48	-122						0

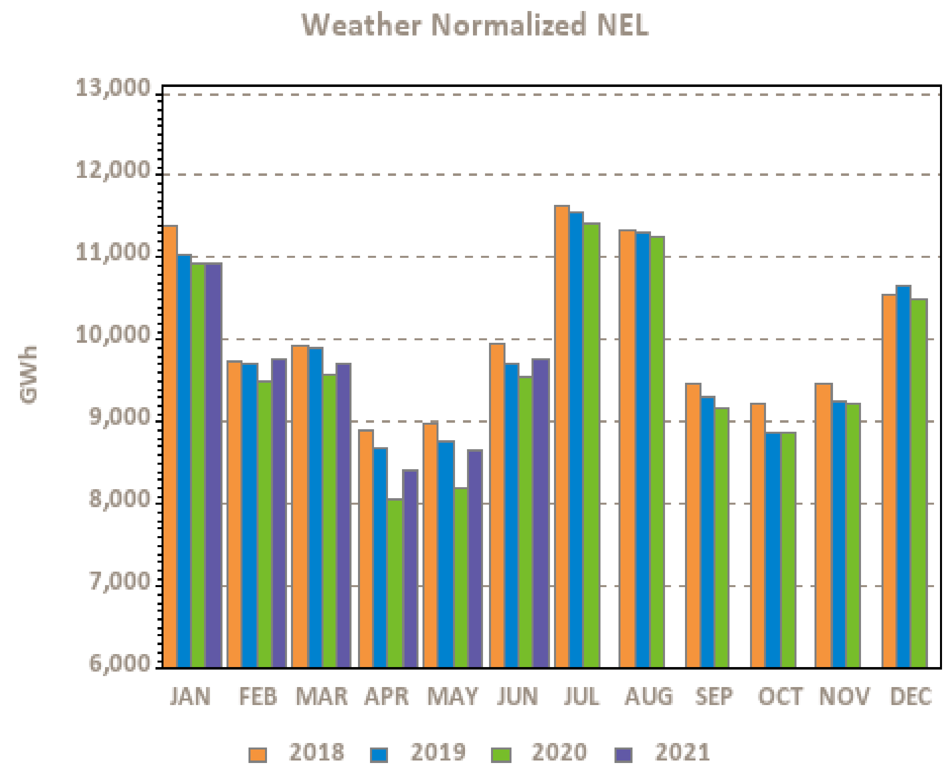
2021 System Operations - Load Forecast Accuracy cont.



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



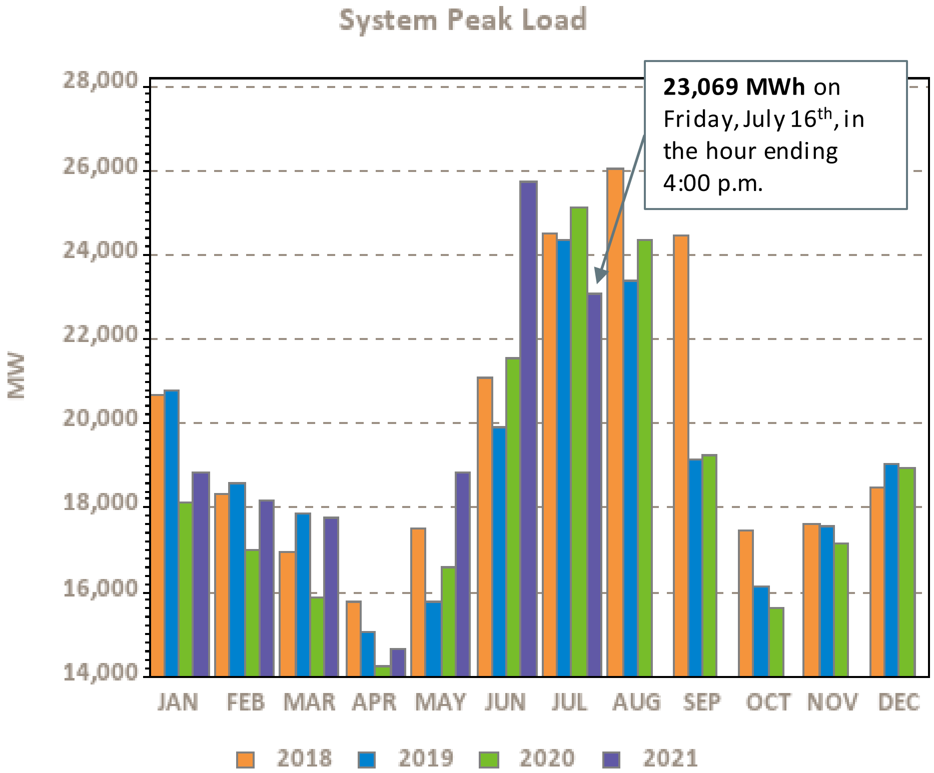
Ann Tot (TWh): 123.5 119.2 116.9 67.6



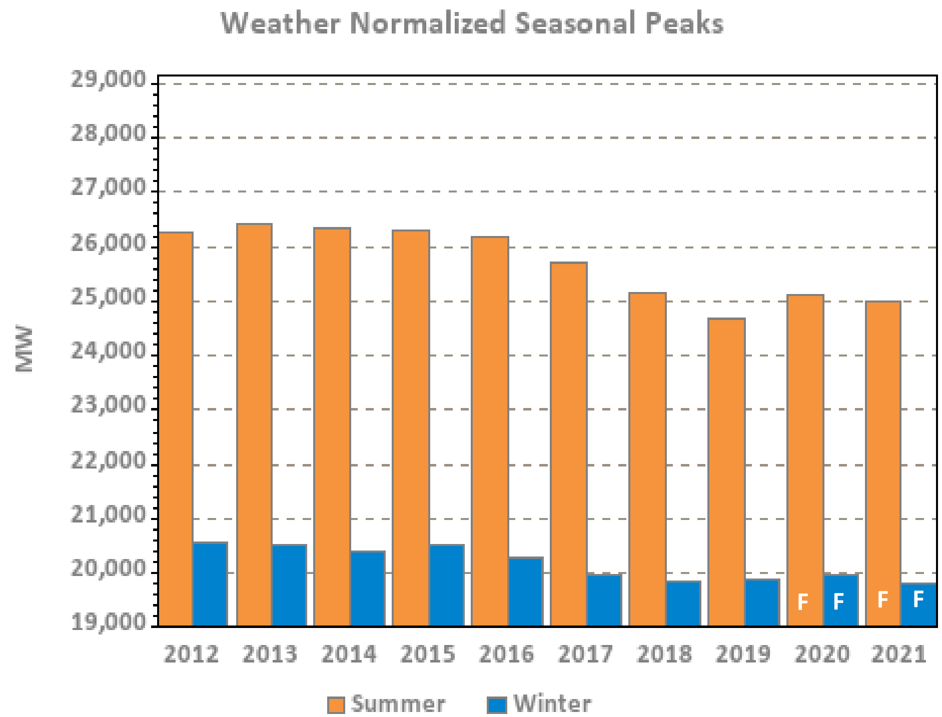
Ann Tot (TWh): 120.6 118.8 116.3 57.2

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

Monthly Peak Loads and Weather Normalized Seasonal Peak History



Revenue quality metered value

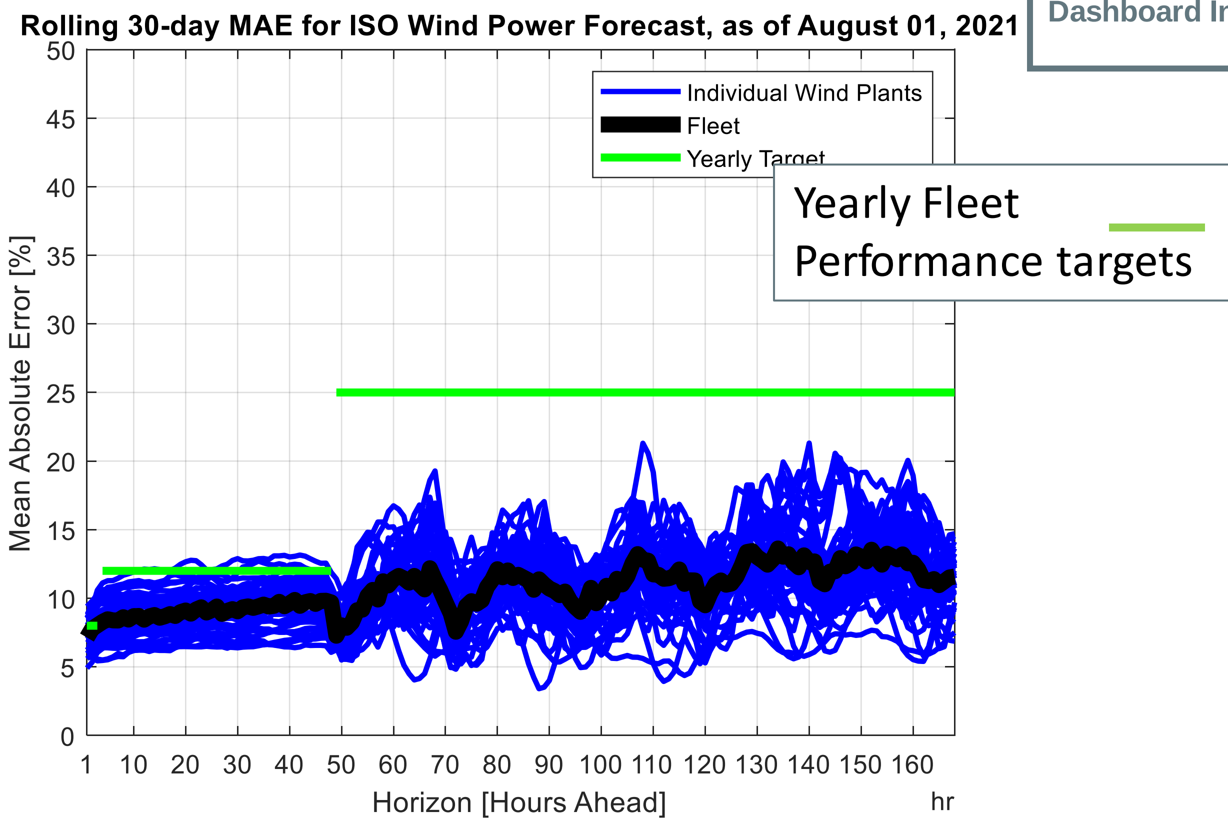


Winter beginning in year displayed

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

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

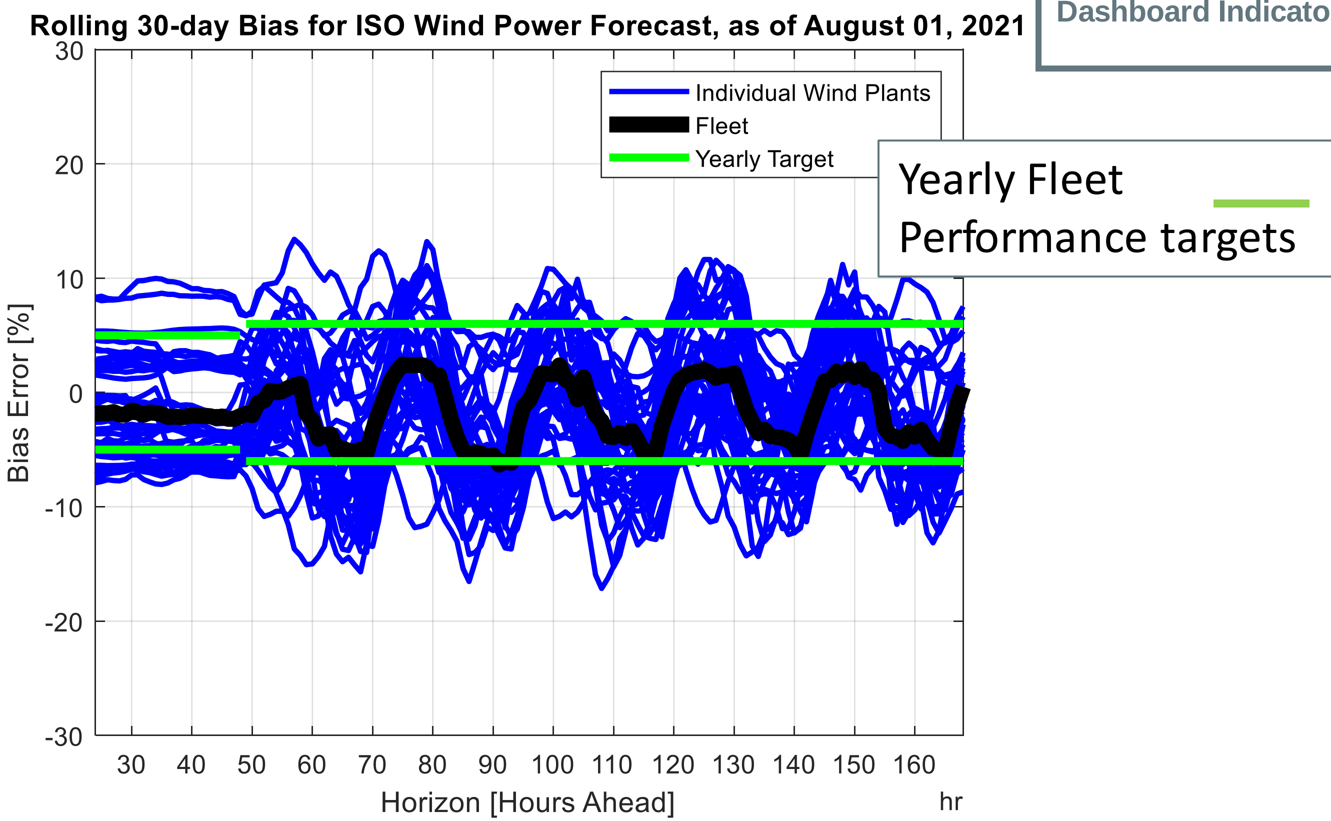
Dashboard Indicator



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

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

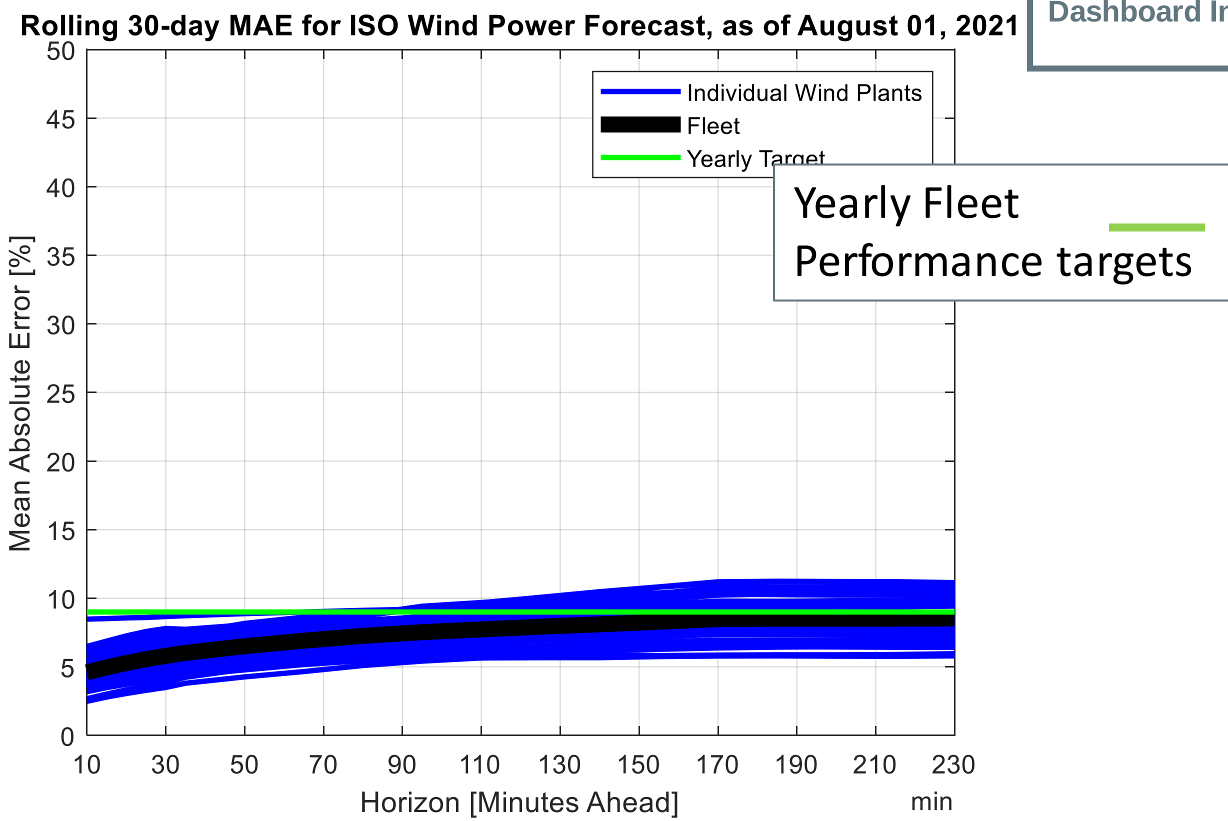
Dashboard Indicator



Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV forecast compares well with industry standards, and except for the 91 hour lookahead horizon, monthly Bias is within yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast MAE

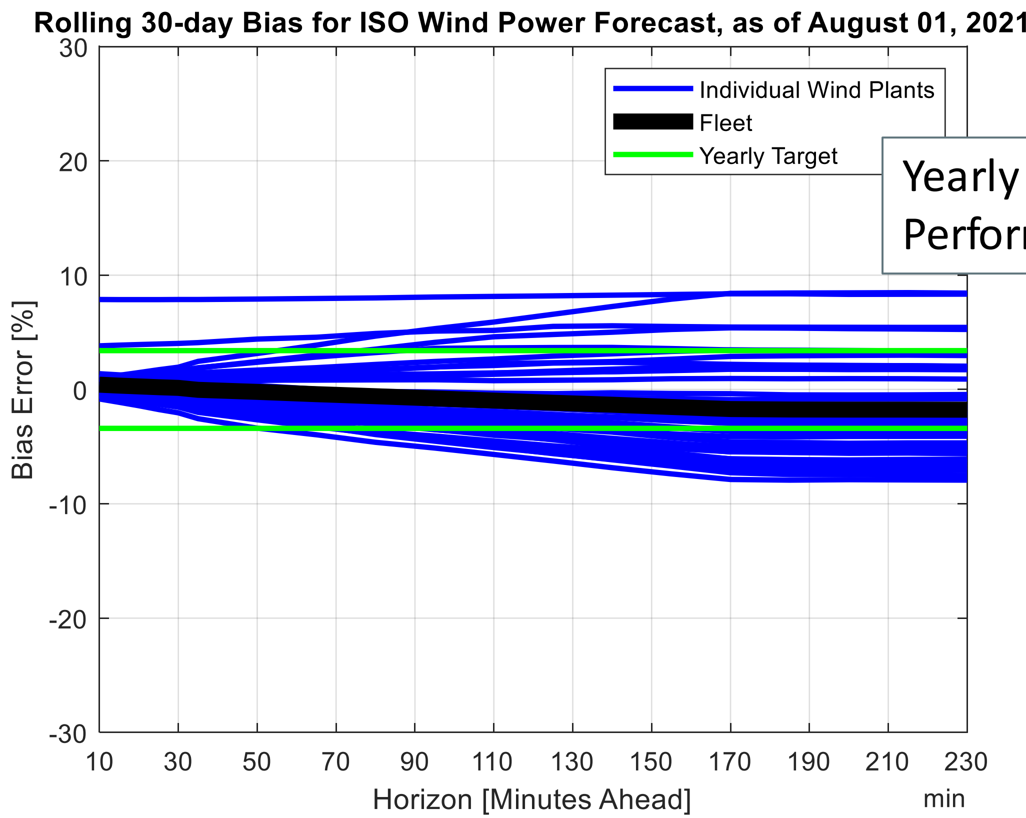
Dashboard Indicator



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

Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator

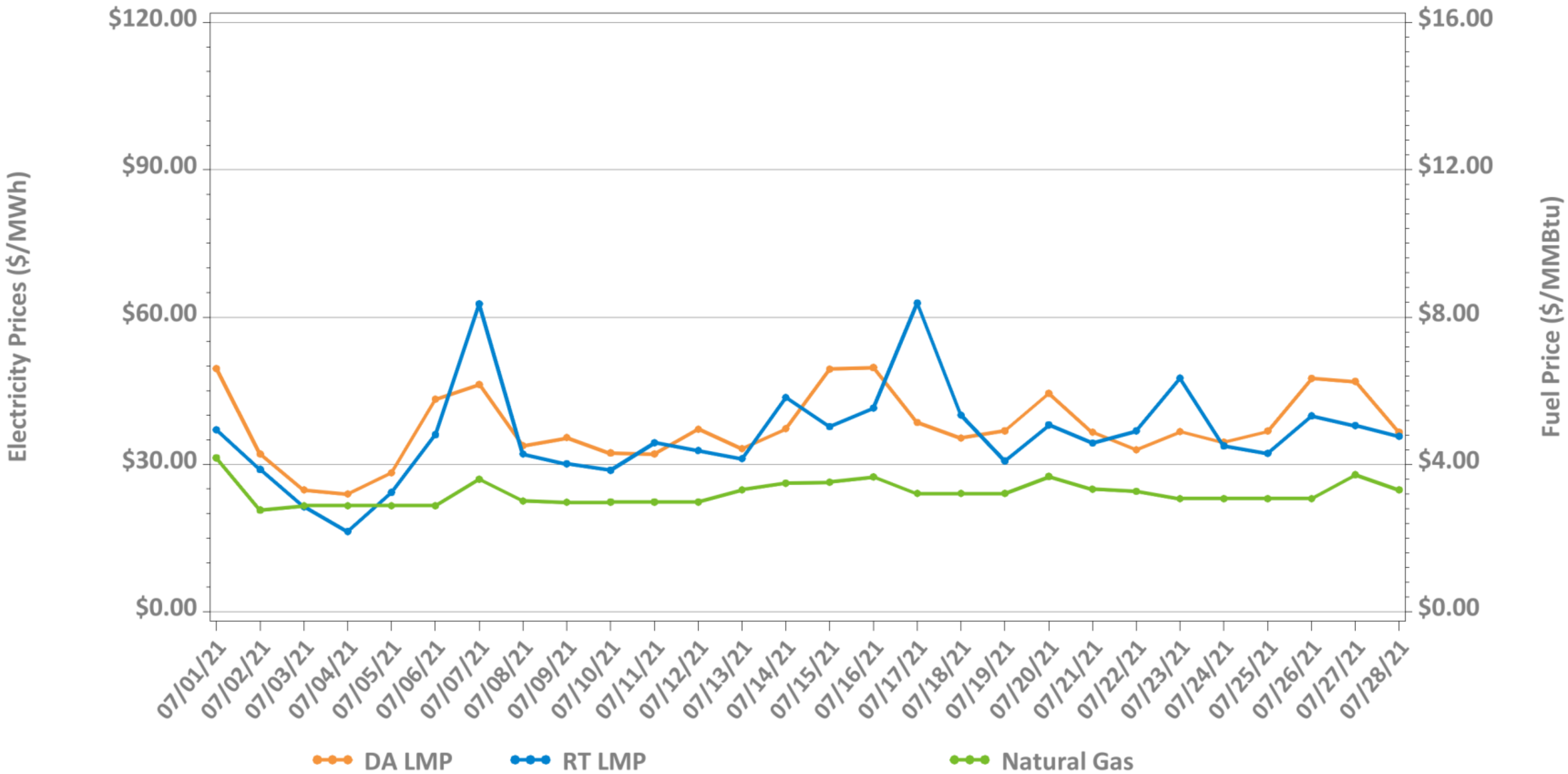


Yearly Fleet Performance targets

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

MARKET OPERATIONS

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

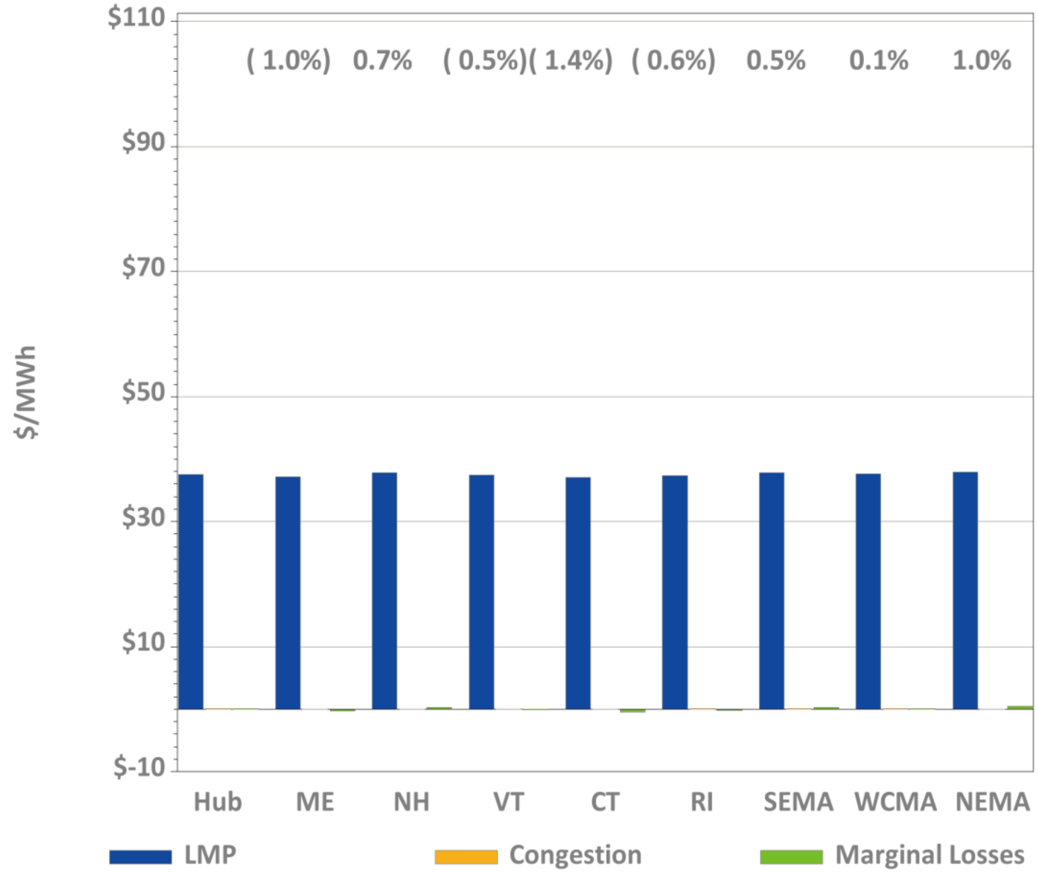


Underlying natural gas data furnished by:

ICE Global markets in clear view

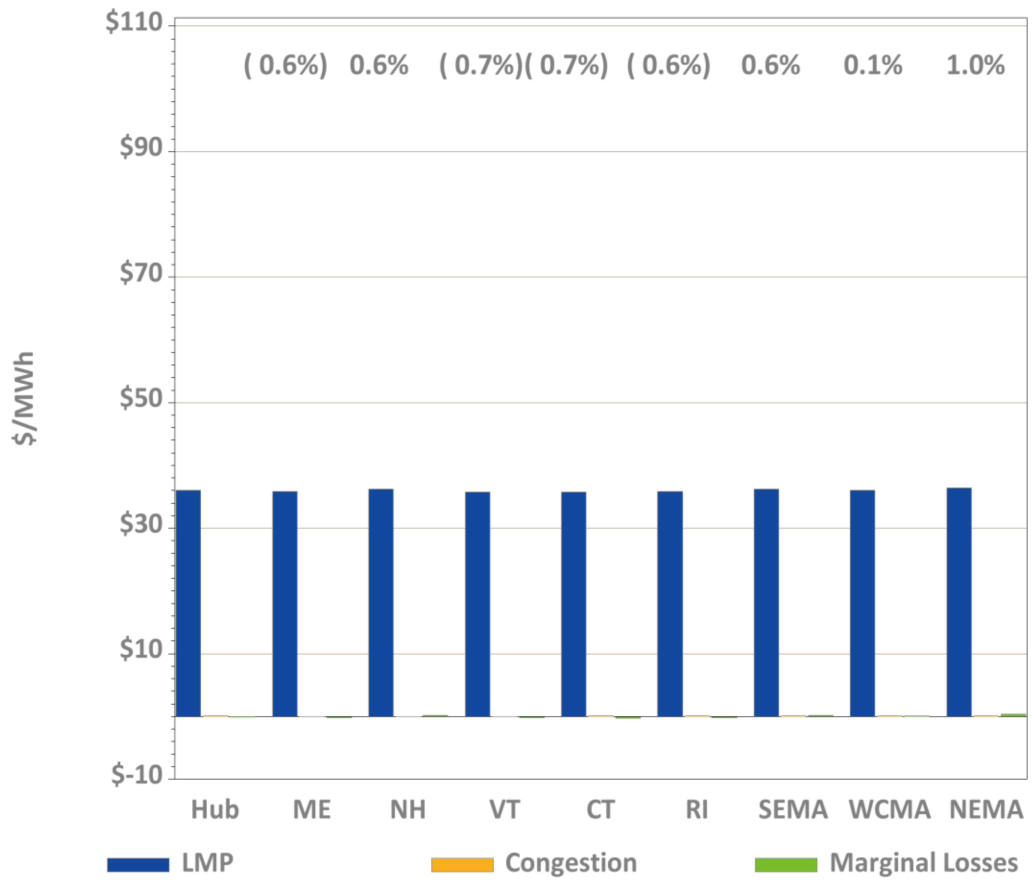
Average price difference over this period (DA-RT): $1.55
Average price difference over this period ABS(DA-RT): $6.47
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 18%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, July 2021



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

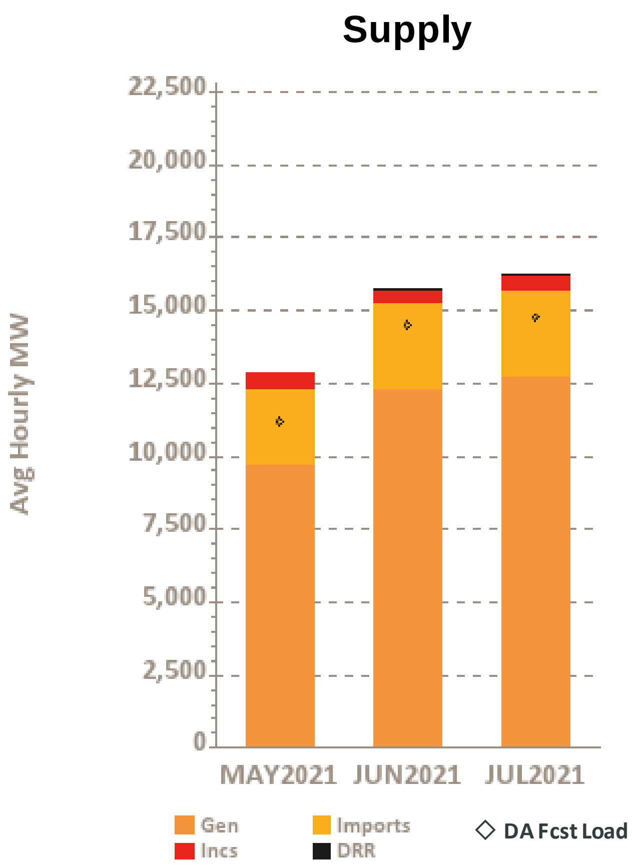
RT LMPs Average by Zone & Hub, July 2021

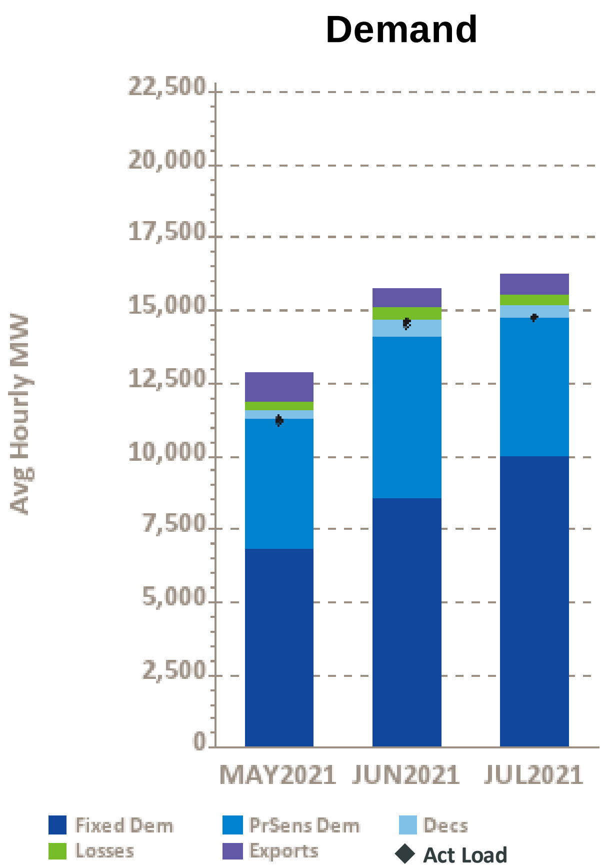


Definitions

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

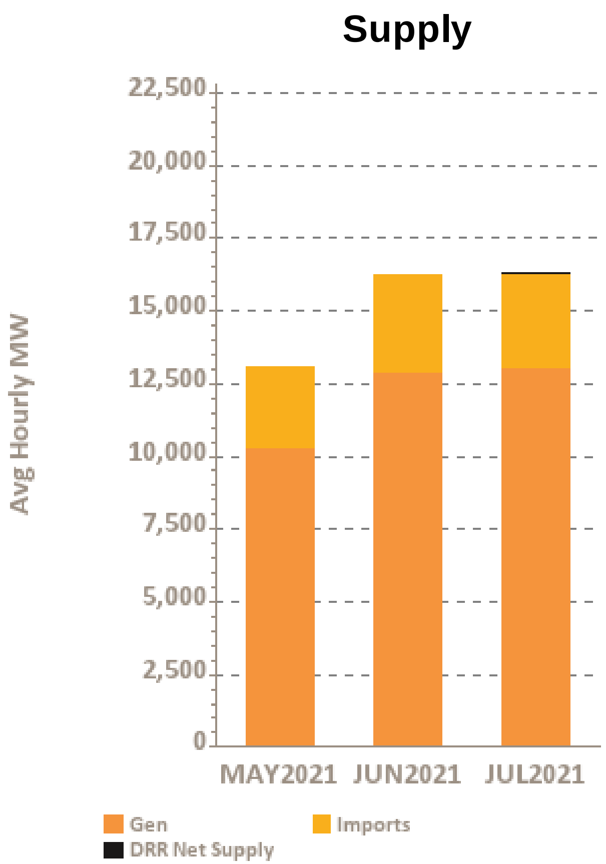


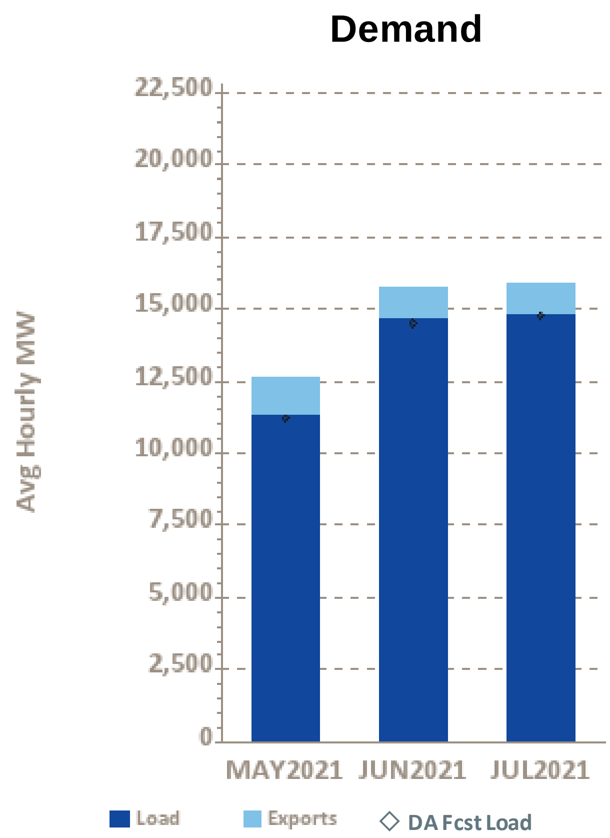


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load
DRR – Demand Response Resource

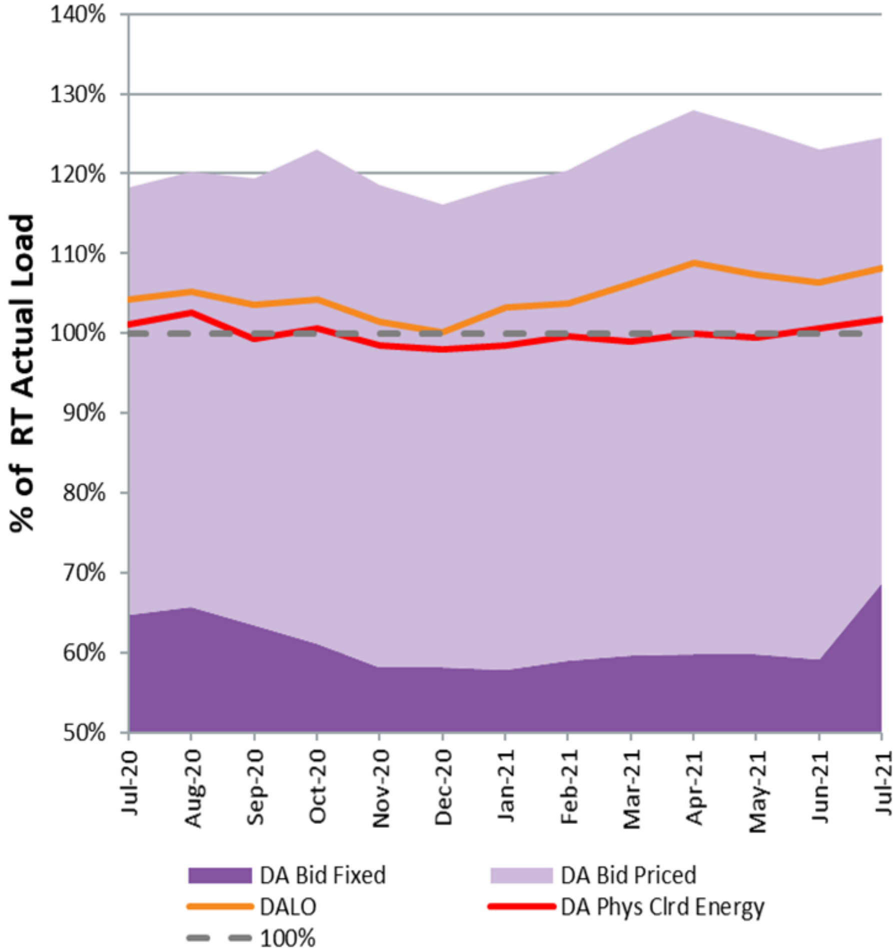
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

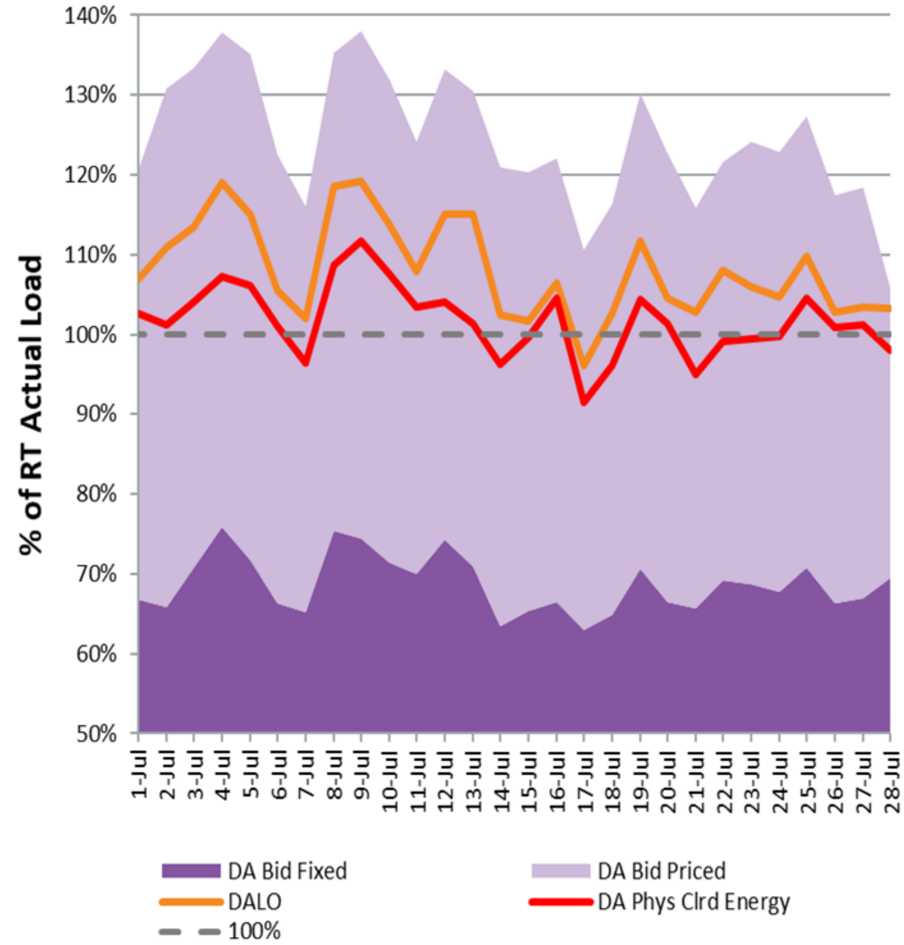
Components of RT Supply and Demand – Last Three Months





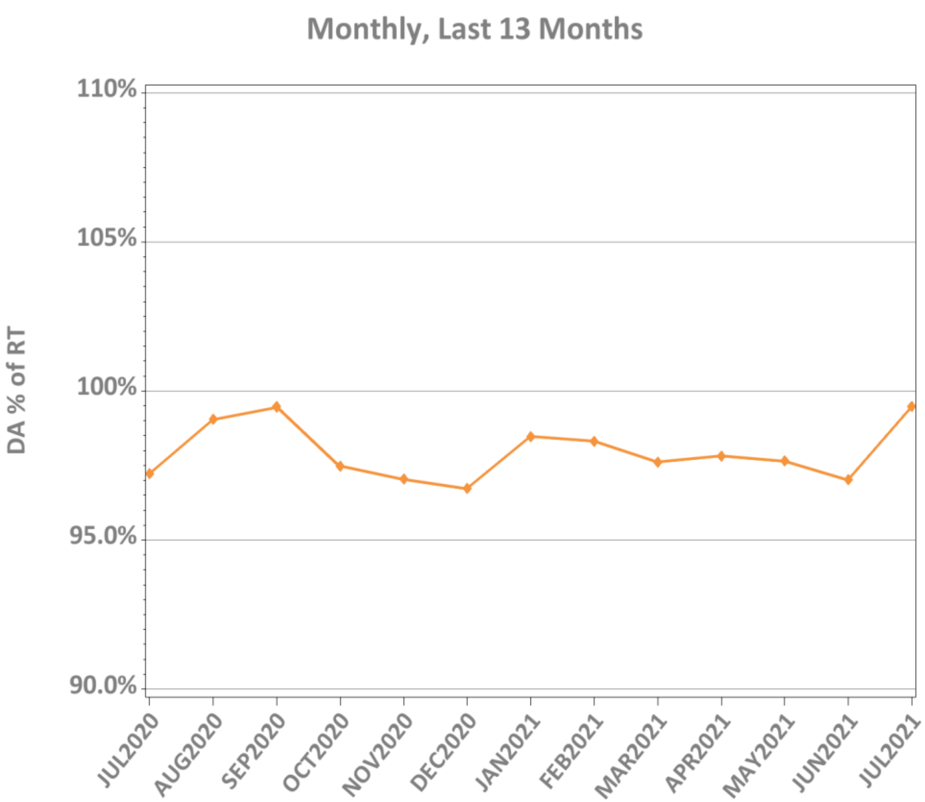
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

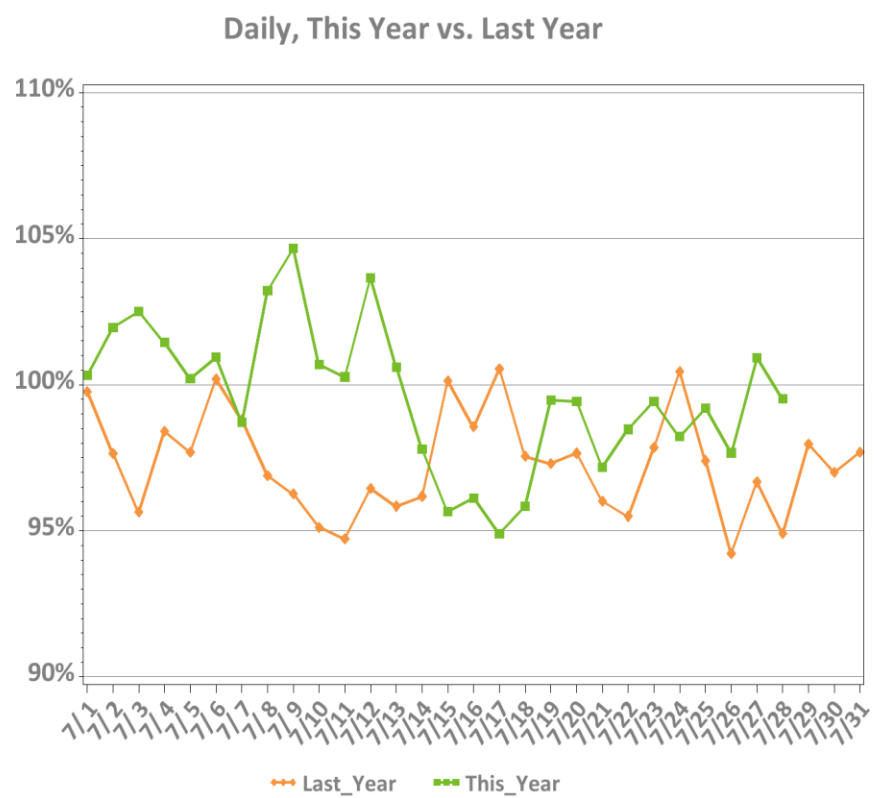




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

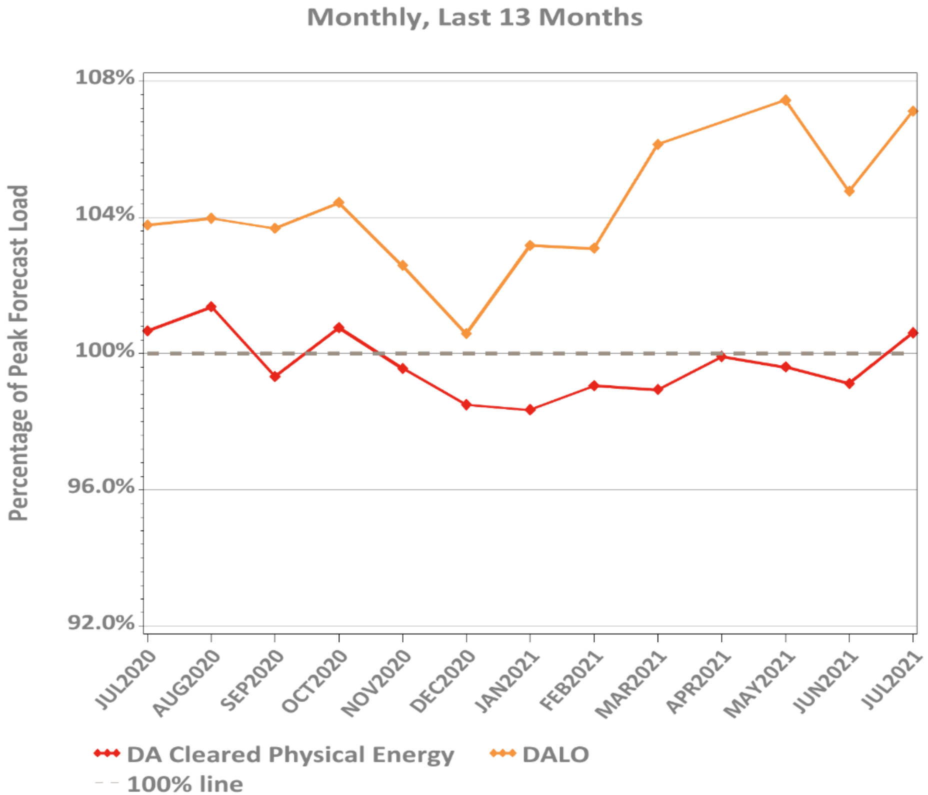
DA vs. RT Load Obligation: July, This Year vs. Last Year

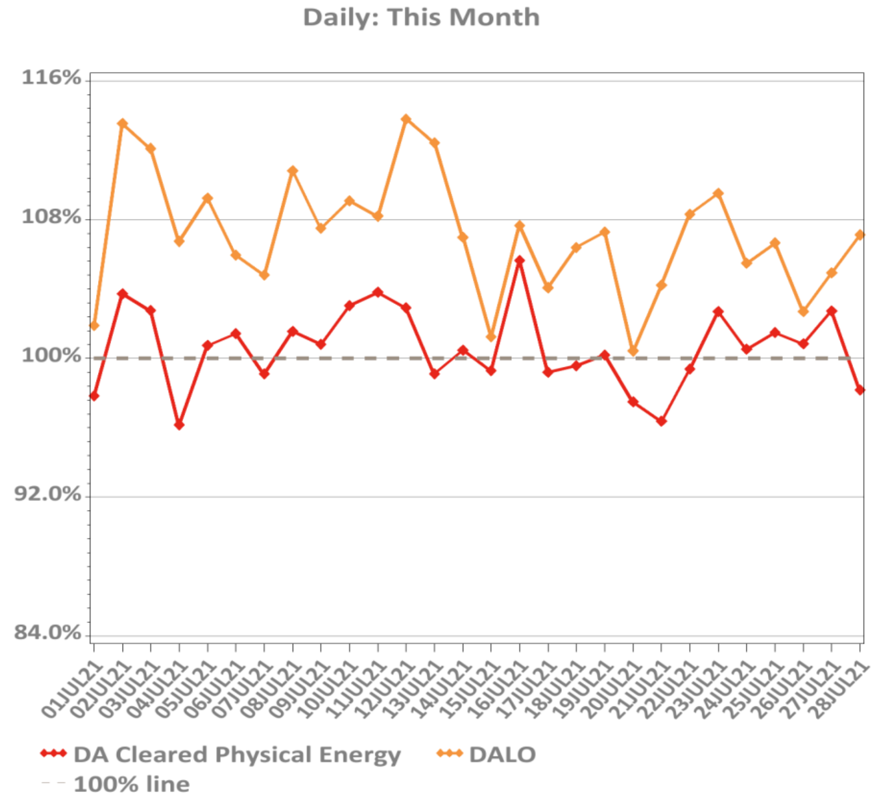




*Hourly average values

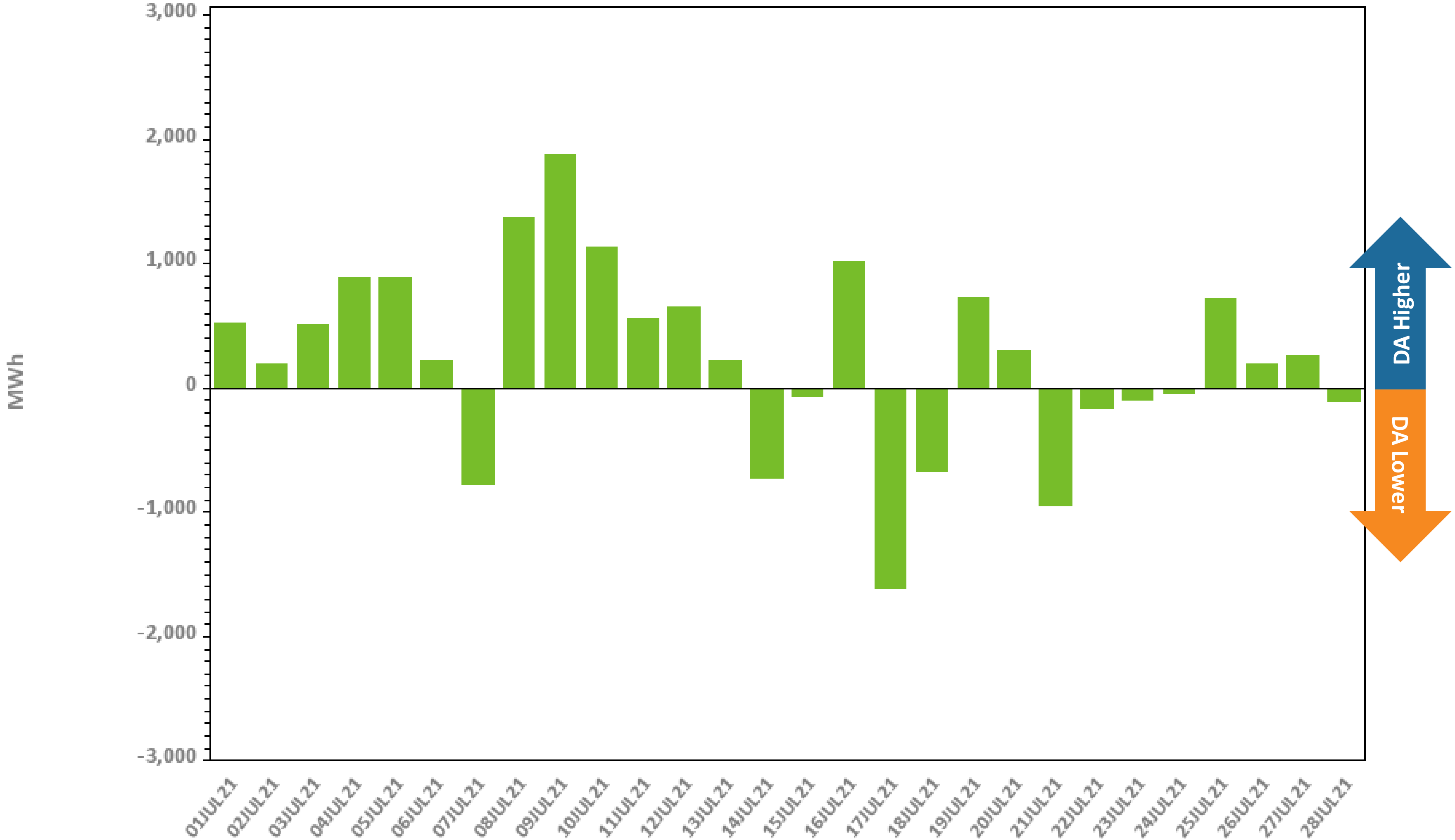
DA Volumes as % of Forecast in Peak Hour





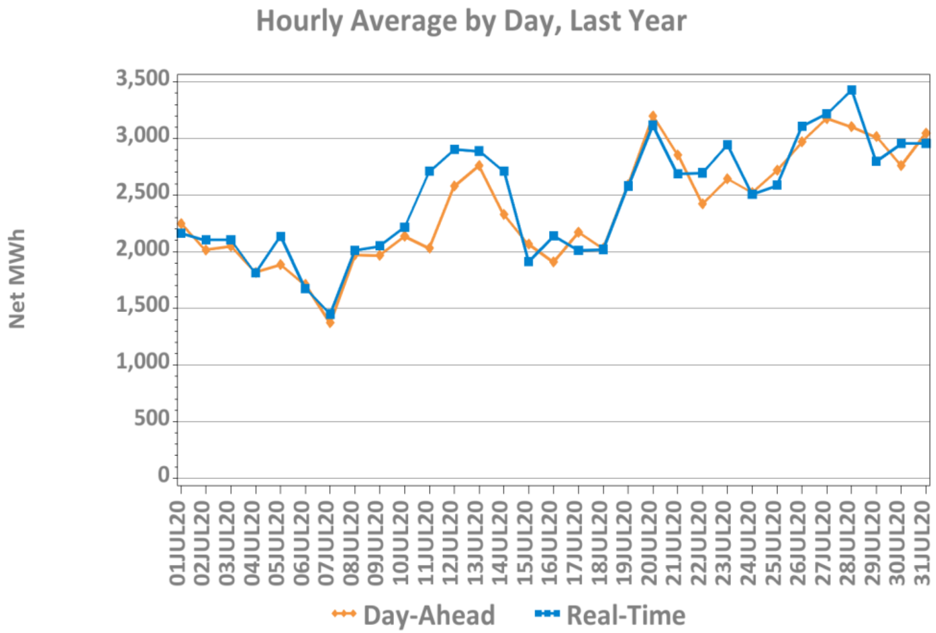
Note: There were no instances of system-level manual supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during July.

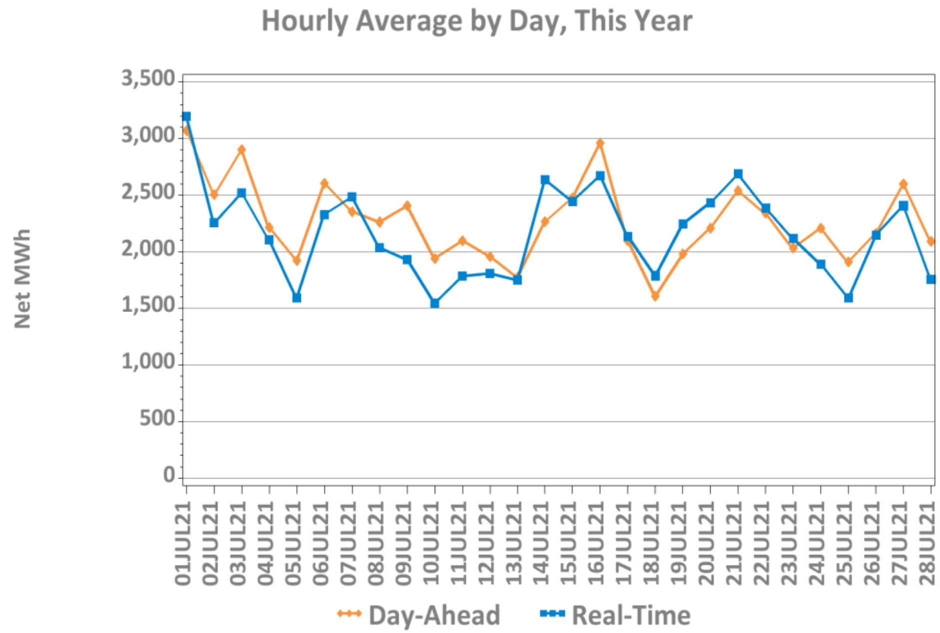
DA Cleared Physical Energy Difference from RT System Load at Forecasted Peak Hour*



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

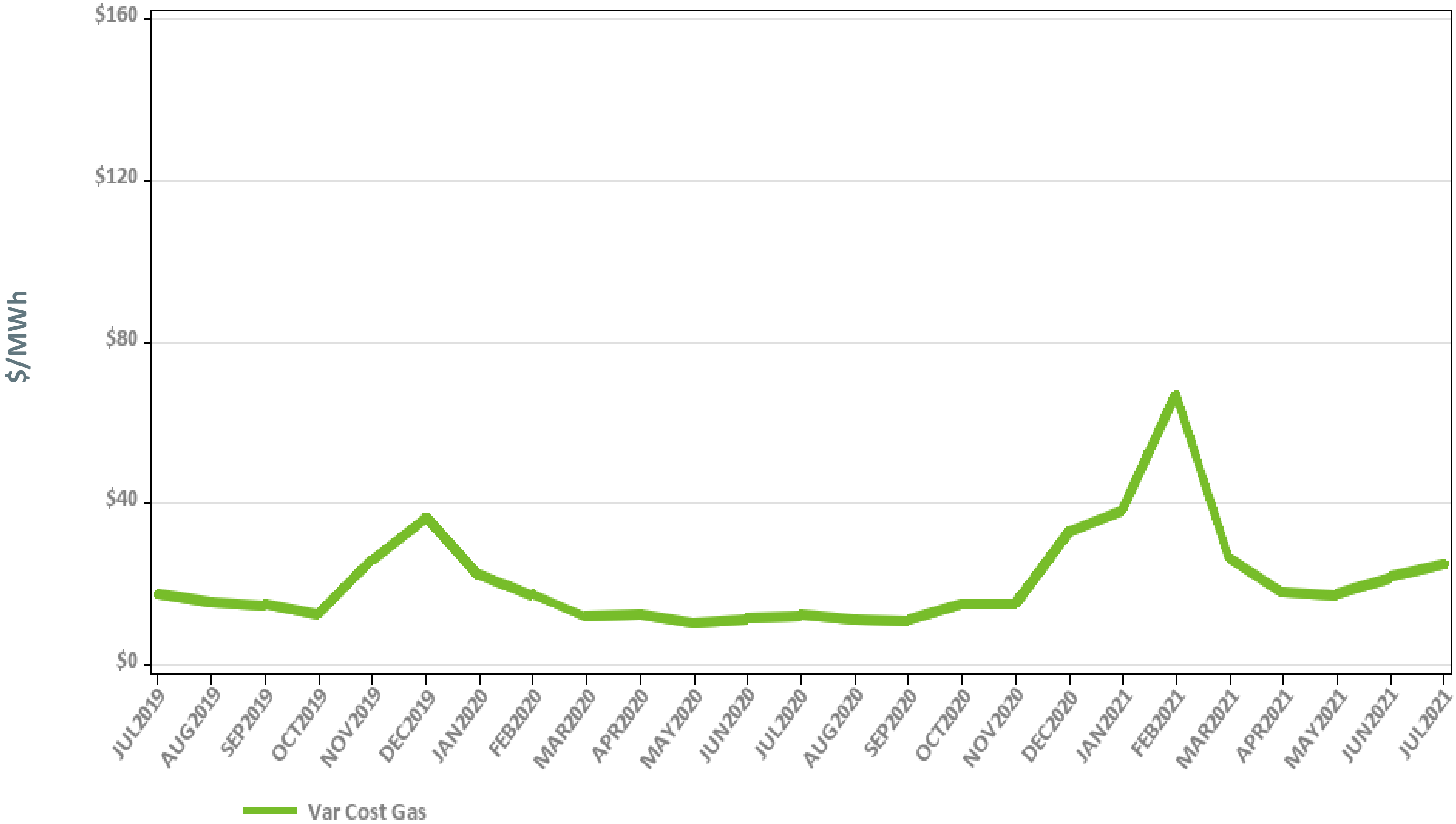
DA vs. RT Net Interchange July 2020 vs. July 2021





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

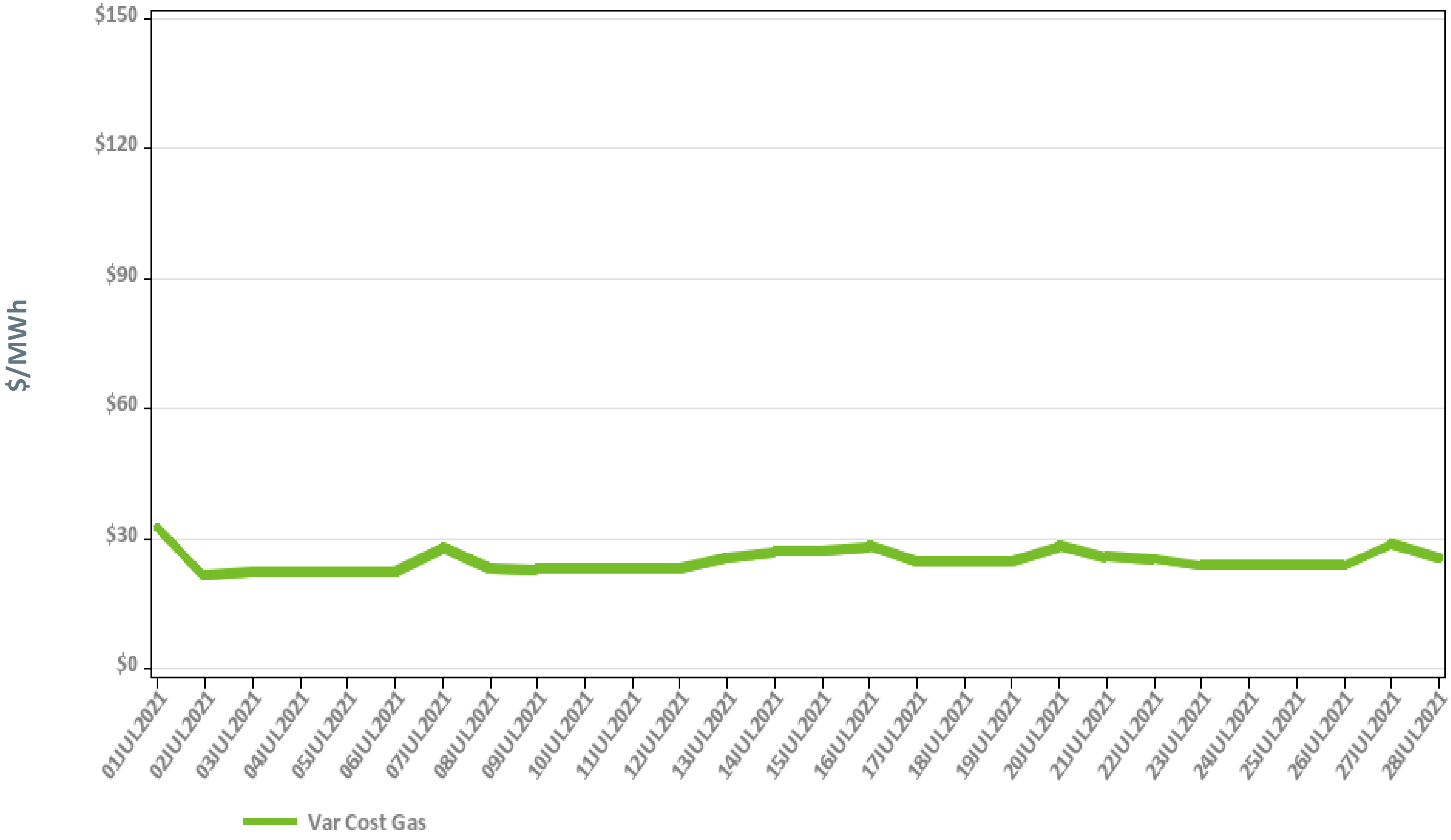


Underlying natural gas data furnished by:

ICE Global markets in clear view

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

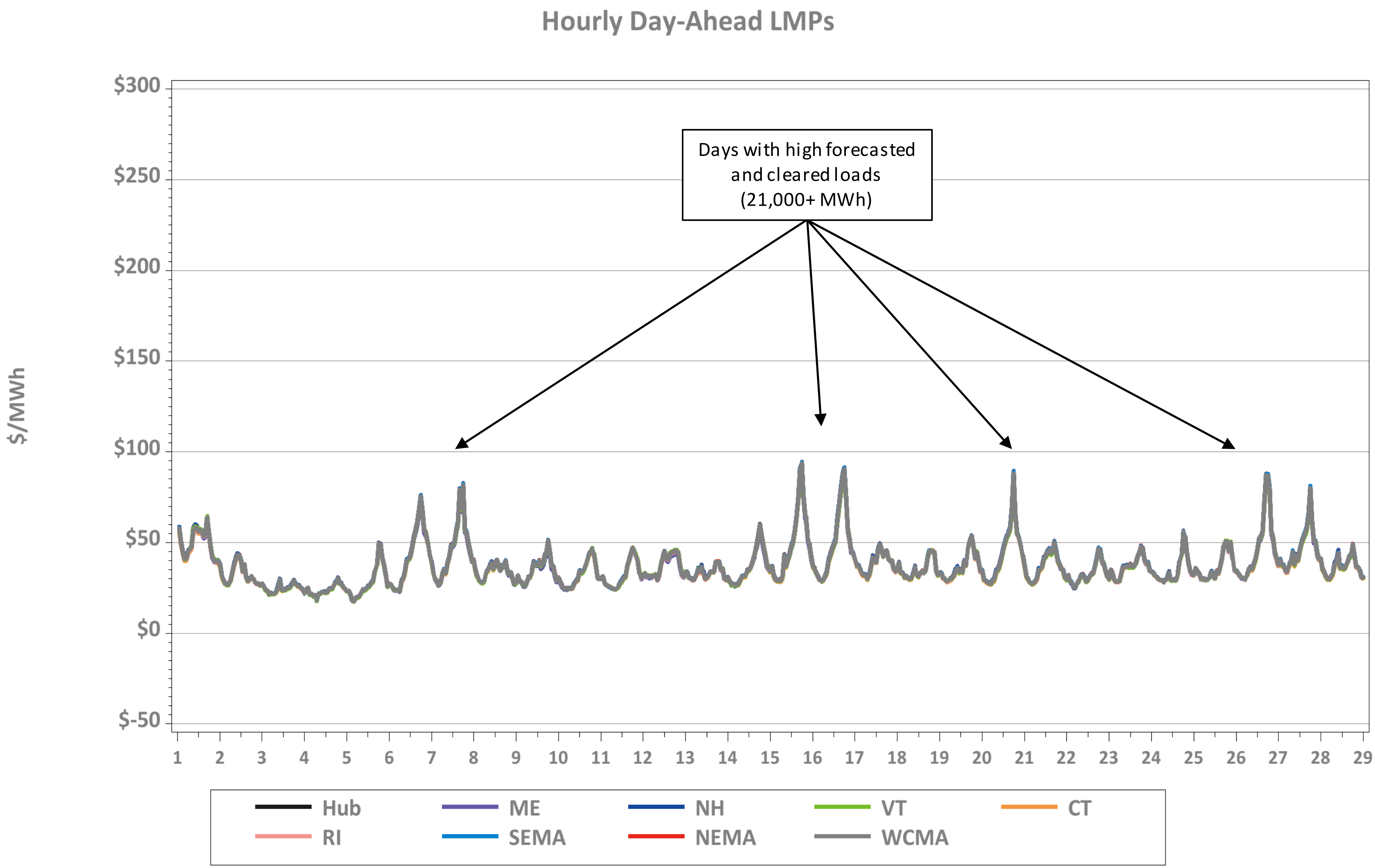
Variable Production Cost of Natural Gas: Daily



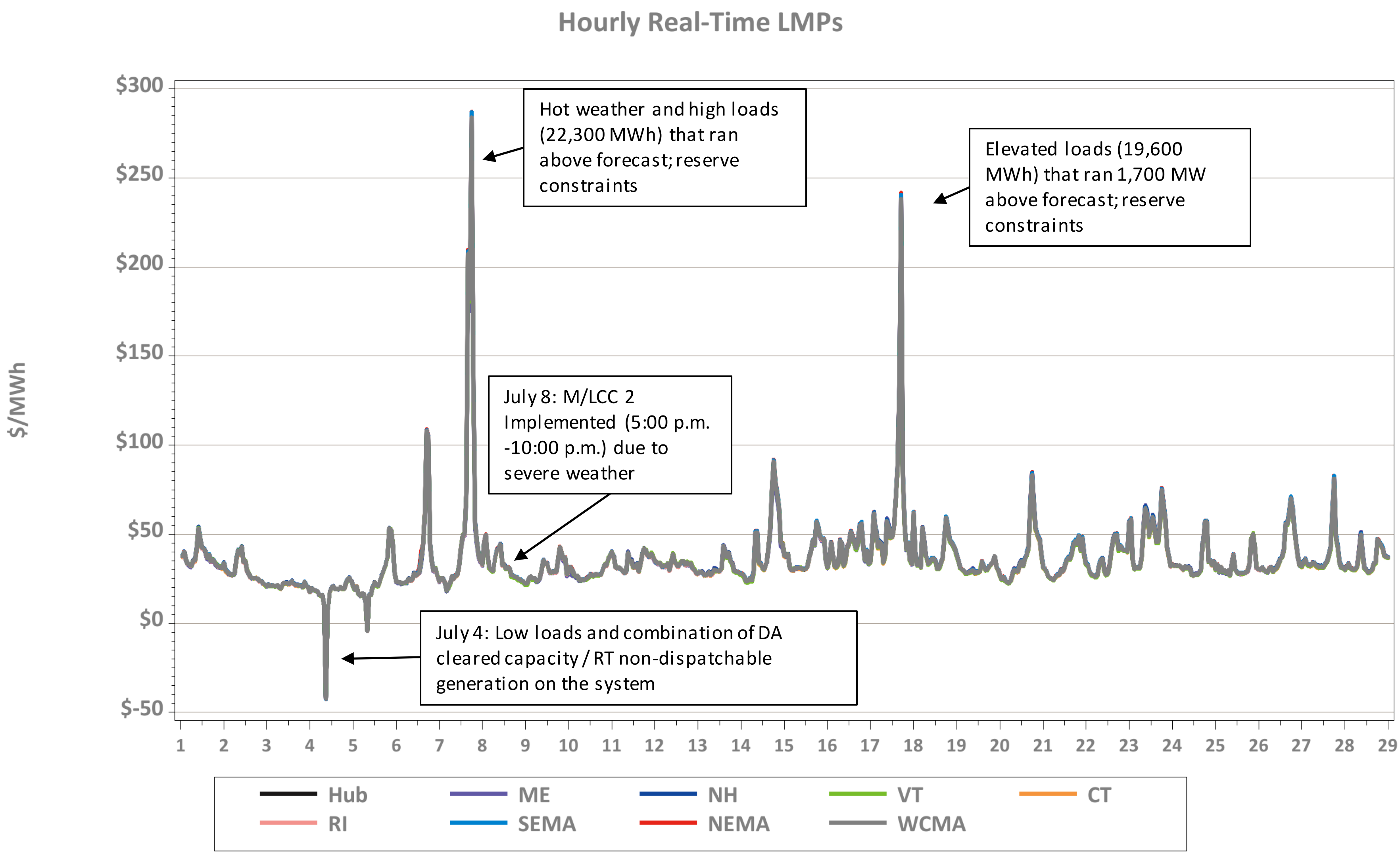
Underlying natural gas data furnished by: ICE Global markets in clear view

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

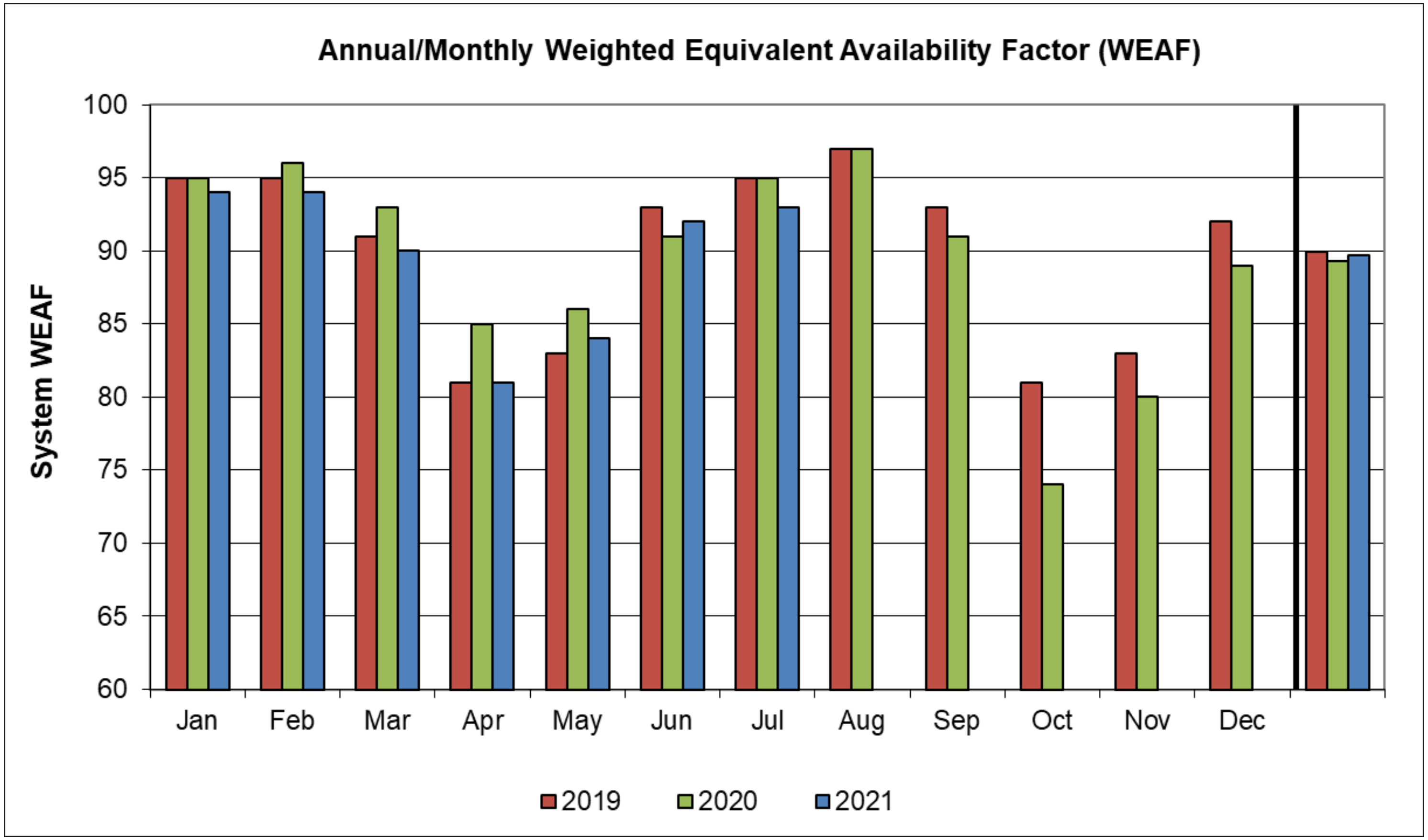
Hourly DA LMPs, July 1-28, 2021



Hourly RT LMPs, July 1-28, 2021



System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2021	94	94	90	81	84	92	93						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 7/26/2021

BACK-UP DETAIL

DEMAND RESPONSE

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

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	85.4	202.5	0.0	287.9
NH	42.1	147.6	0.0	189.7
VT	43.8	125.6	0.0	169.3
CT	134.8	132.6	614.8	882.2
RI	39.2	323.4	0.0	362.6
SEMA	44.6	505.9	0.0	550.5
WCMA	91.0	539.8	39.6	670.3
NEMA	61.7	861.1	0.0	922.8
Total	**542.5**	**2,838.3**	**654.4**	**4,035.3**

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

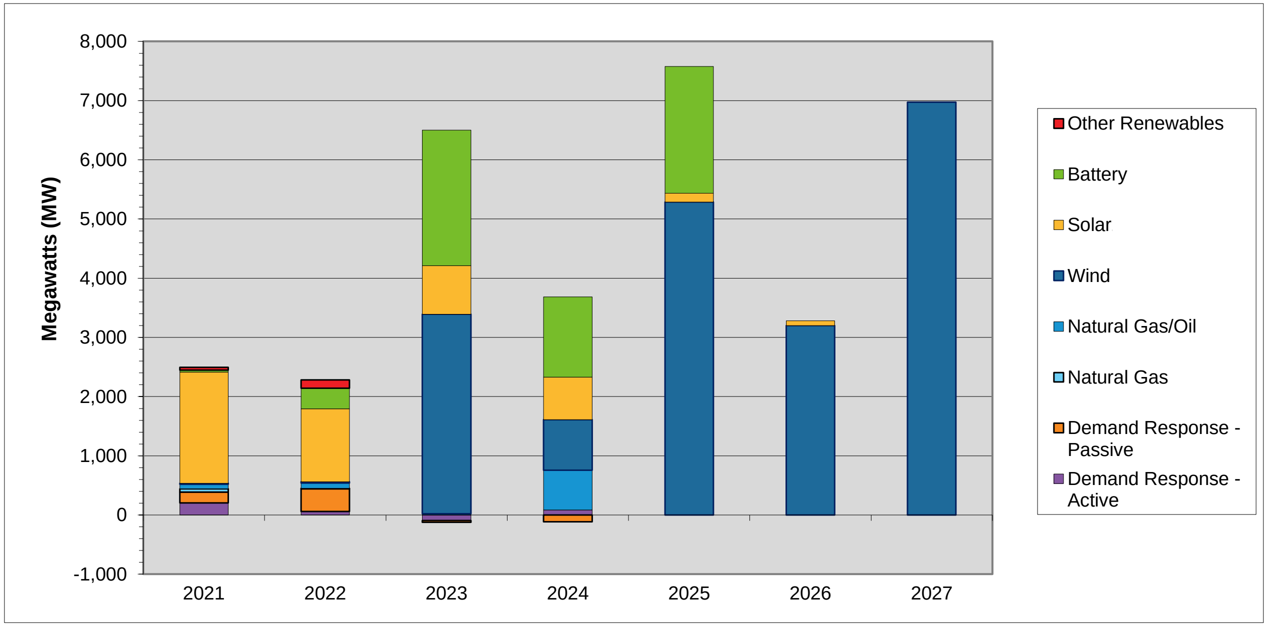
NEW GENERATION

New Generation Update
Based on Queue as of 7/30/21

- Five new projects totaling 410 MW applied for interconnection study since the last update
  - They consist of two battery, one wind and two solar projects with in-service dates ranging from 2022 to 2024
- One project went commercial and two projects were withdrawn
- In total, 292 generation projects are currently being tracked by the ISO, totaling approximately 31,884 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type

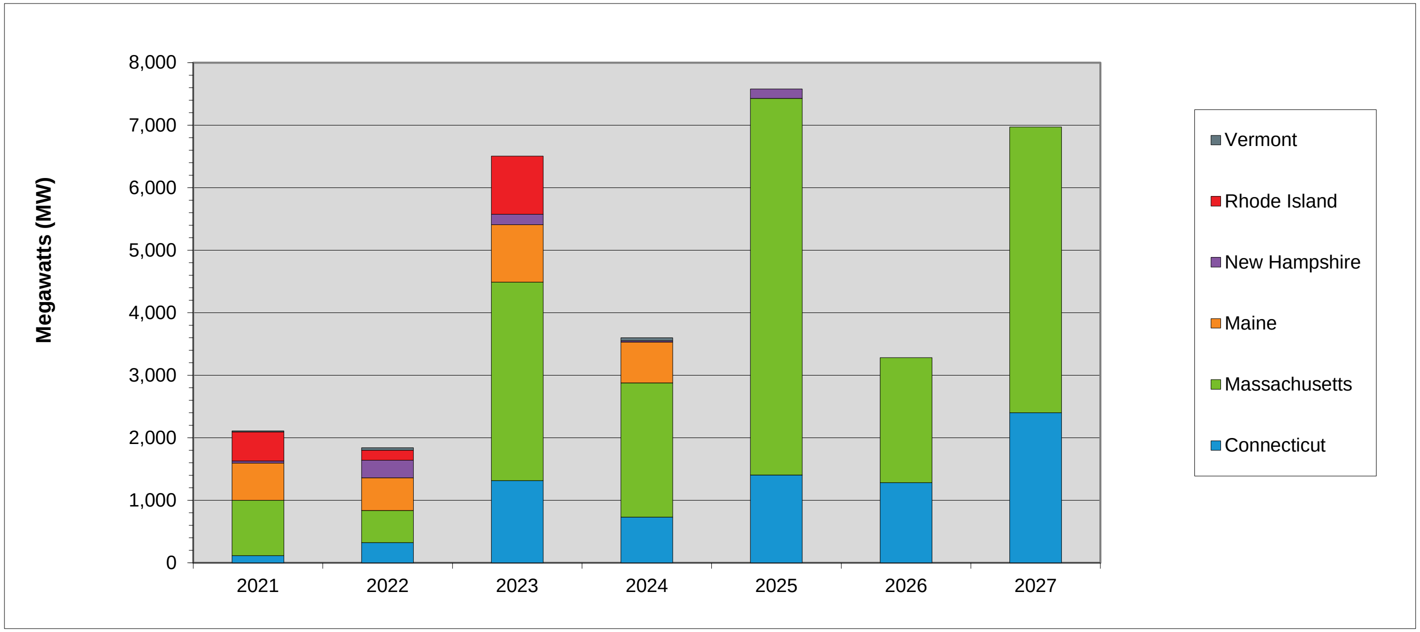


	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Other Renewables	48	142	0	0	0	0	0	190	0.6
Battery	34	347	2,294	1,354	2,140	0	0	6,169	18.9
Solar[2]	1,878	1,232	820	721	150	83	0	4,884	15.0
Wind	19	20	3,367	852	5,287	3,200	6,972	19,717	60.5
Natural Gas/Oil[3]	76	89	23	672	0	0	0	860	2.6
Natural Gas	53	11	0	0	0	0	0	64	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	**2,496**	**2,283**	**6,382**	**3,571**	**7,577**	**3,283**	**6,972**	**32,564**	**100.0**

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

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

Actual and Projected Annual Generator Capacity Additions
By State



	2021	2022	2023	2024	2025	2026	2027	Total MW	% of Total[1]
Vermont	15	40	0	50	0	0	0	105	0.3
Rhode Island	466	160	931	0	0	0	0	1,557	4.9
New Hampshire	30	281	164	20	150	0	0	645	2.0
Maine	596	523	919	652	0	0	0	2,690	8.4
Massachusetts	888	513	3,178	2,145	6,022	2,000	4,572	19,318	60.6
Connecticut	113	324	1,312	732	1,405	1,283	2,400	7,569	23.7
Totals	**2,108**	**1,841**	**6,504**	**3,599**	**7,577**	**3,283**	**6,972**	**31,884**	**100.0**

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

New Generation Projection

By Fuel Type

Unit Type	Total		Green		Yellow	
	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0
Battery Storage	35	6,169	0	0	35	6,169
Fuel Cell	4	54	1	10	3	44
Hydro	3	99	2	71	1	28
Natural Gas	7	64	0	0	7	64
Natural Gas/Oil	7	860	1	14	6	846
Nuclear	1	37	0	0	1	37
Solar	207	4,884	20	336	187	4,548
Wind	28	19,717	1	15	27	19,702
Total	292	31,884	25	446	267	31,438

- 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	7	124	2	15	5	109
Intermediate	9	822	1	14	8	808
Peaker	248	11,221	21	402	227	10,819
Wind Turbine	28	19,717	1	15	27	19,702
Total	292	31,884	25	446	267	31,438

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

New Generation Projection

By Operating Type and Fuel Type

	Total		Baseload		Intermediate		Peaker		Wind Turbine	
Unit Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Biomass/Wood Waste	0	0	0	0	0	0	0	0	0	0
Battery Storage	35	6,169	0	0	0	0	35	6,169	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	7	64	0	0	4	47	3	17	0	0
Natural Gas/Oil	7	860	0	0	5	775	2	85	0	0
Nuclear	1	37	1	37	0	0	0	0	0	0
Solar	207	4,884	0	0	0	0	207	4,884	0	0
Wind	28	19,717	0	0	0	0	0	0	28	19,717
Total	292	31,884	7	124	9	822	248	11,221	28	19,717

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

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

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

Capacity Supply Obligation FCA 15

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

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

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

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/Passive	Existing	New	Grand Total
2019-20	Active	357.221	20.304	377.525
	Passive	2,018.20	350.43	2,368.63
	Grand Total	**2375.422**	**370.734**	**2746.156**
2020-21	Active	334.634	85.294	419.928
	Passive	2,236.73	554.292	2,791.02
	Grand Total	**2571.361**	**639.586**	**3210.947**
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	**3085.734**	**514.072**	**3599.806**
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	**3386.703**	**653.541**	**4040.244**
2023-24	Active	560.55	31.493	592.043
	Passive	3,035.51	291.565	3,327.07
	Grand Total	**3596.056**	**323.058**	**3919.114**
2024-25	Active	674.153	3.520	677.673
	Passive	3,046.064	166.801	3,212.865
	Grand Total	**3,720.217**	**170.321**	**3,890.538**

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

What are Daily NCPC Payments?

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

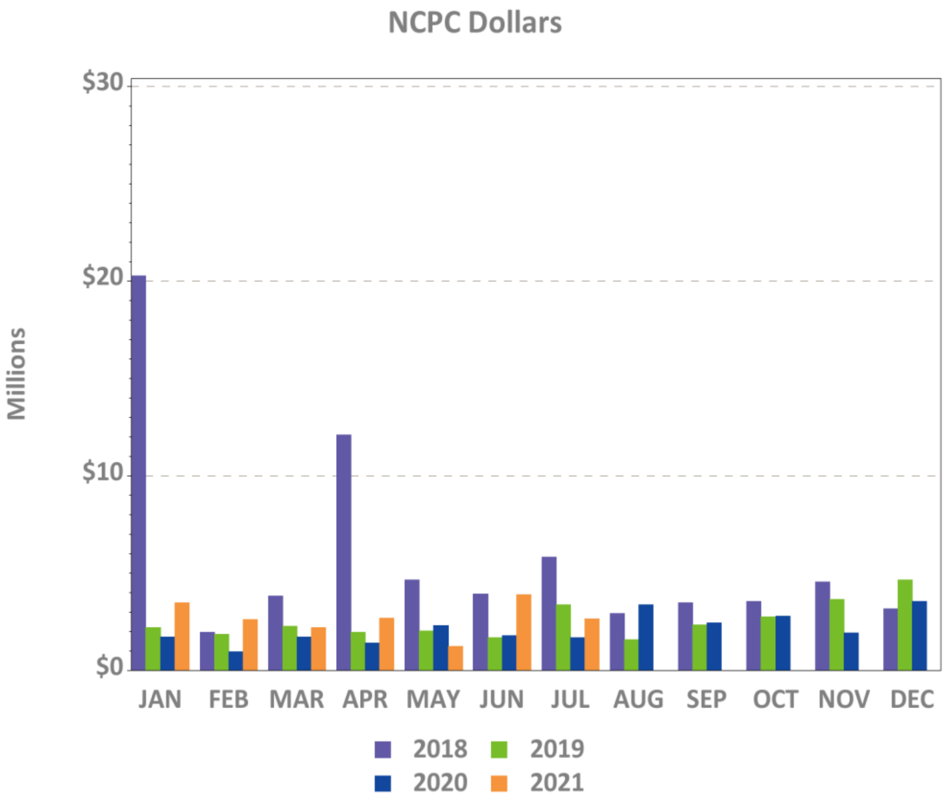
Definitions

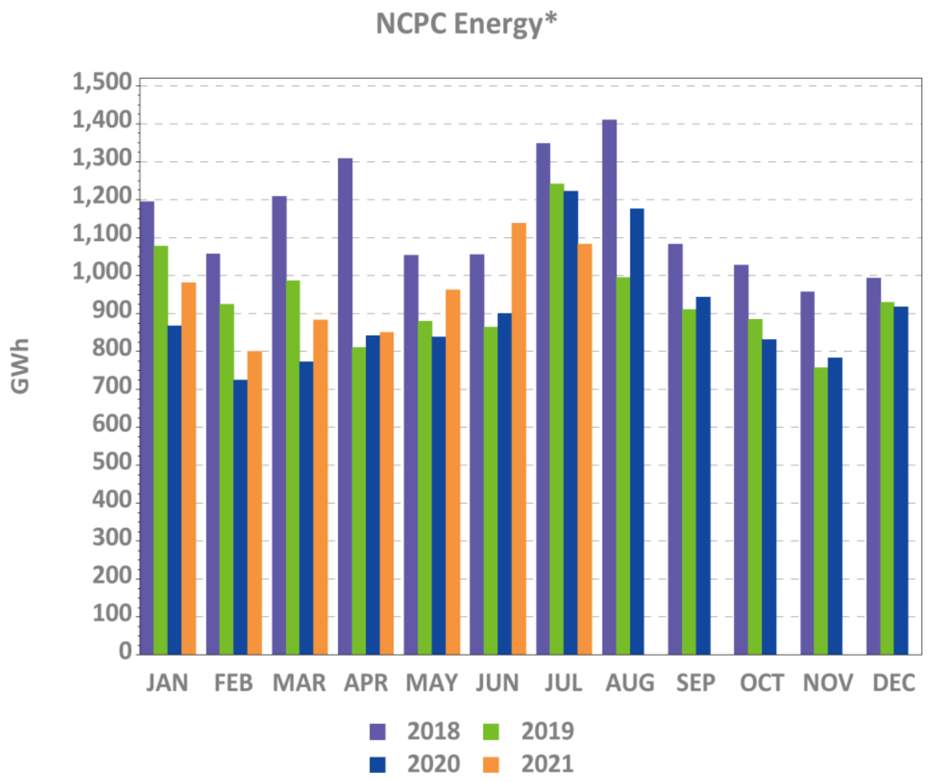
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

Charge Allocation Key

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

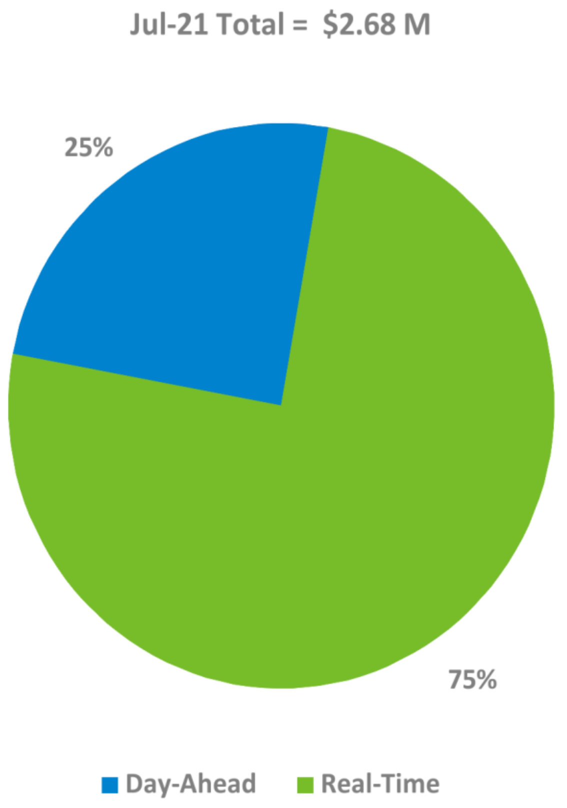
Year-Over-Year Total NCPC Dollars and Energy

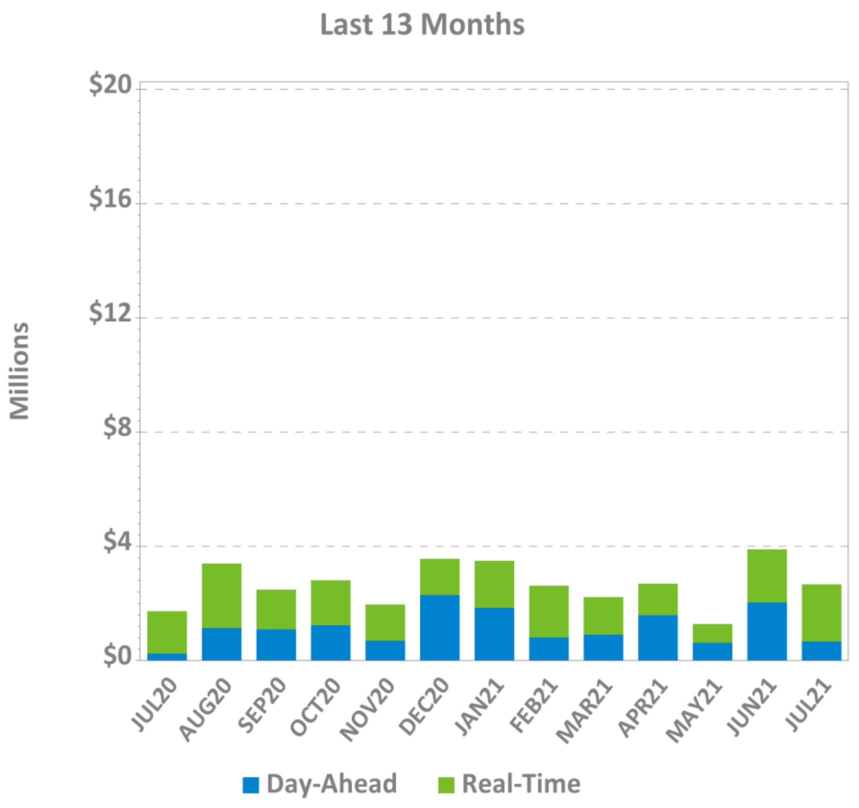




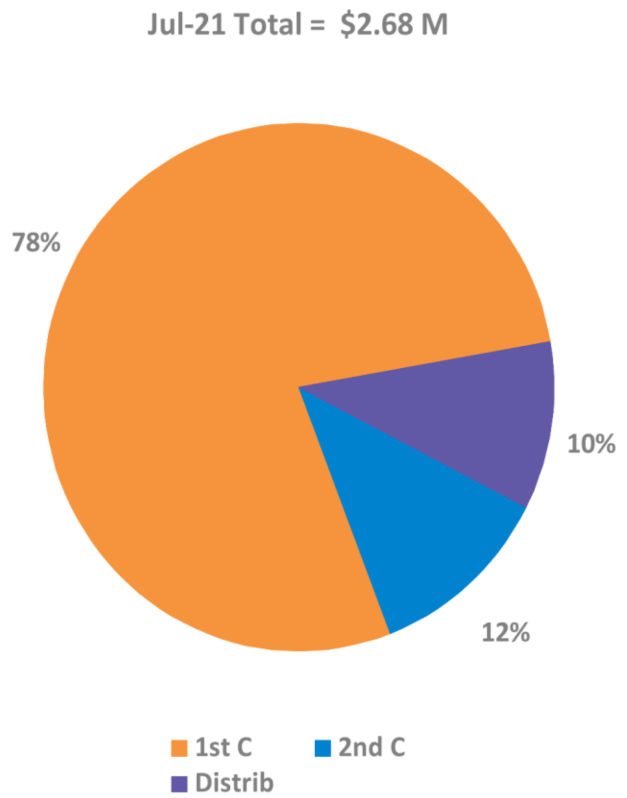
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

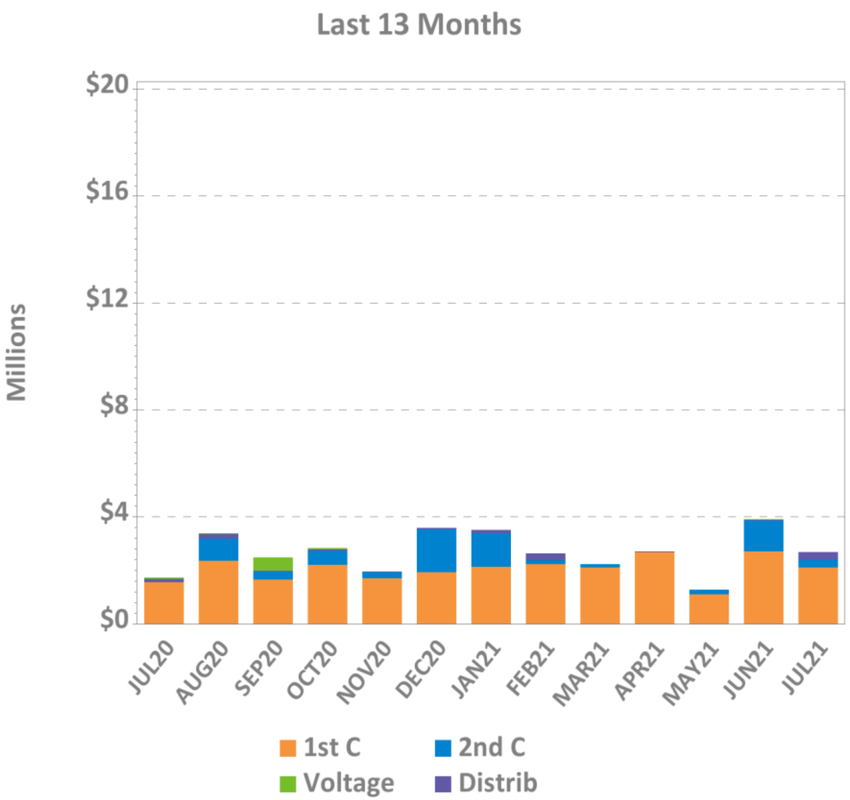
DA and RT NCPC Charges





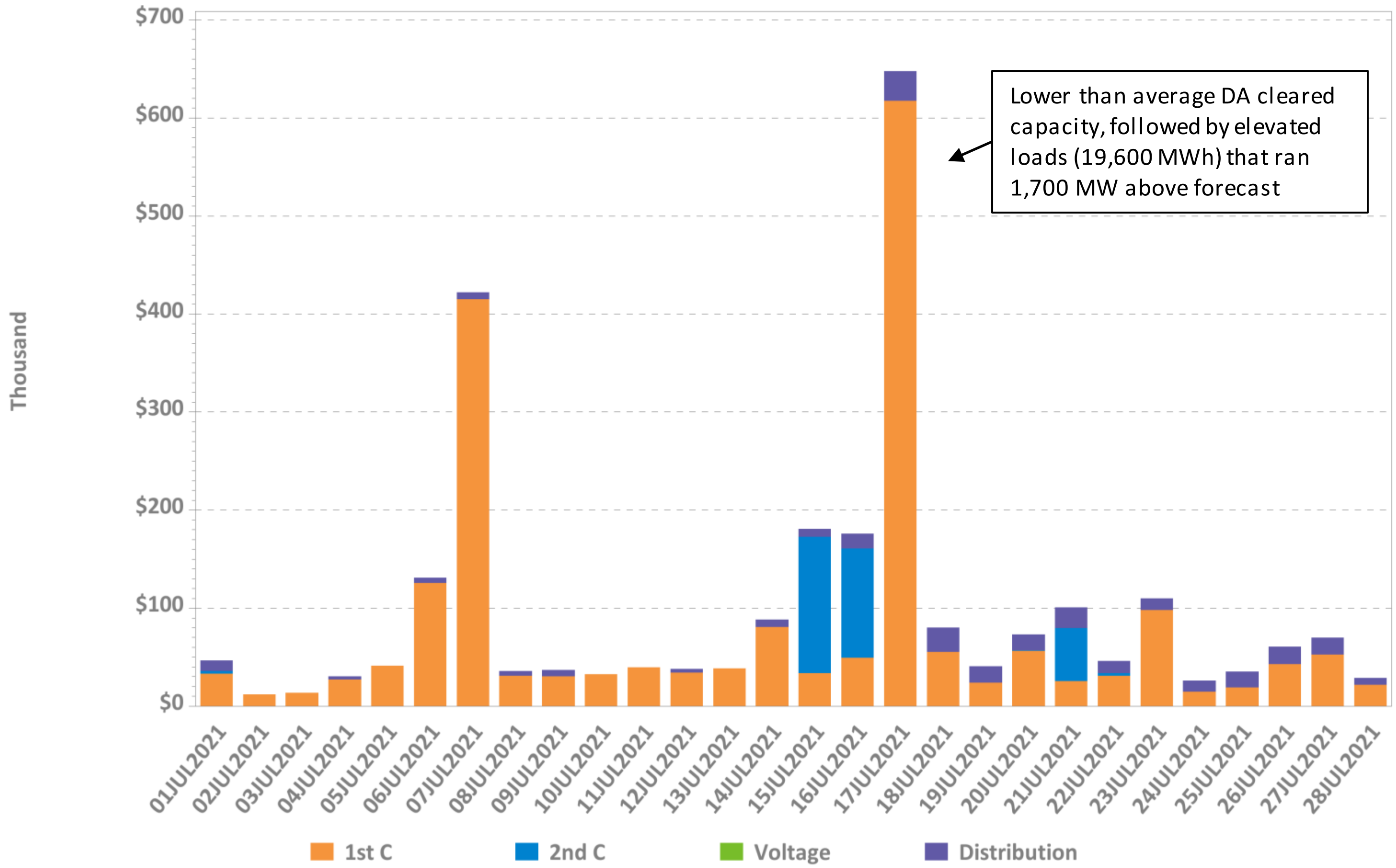
NCPC Charges by Type



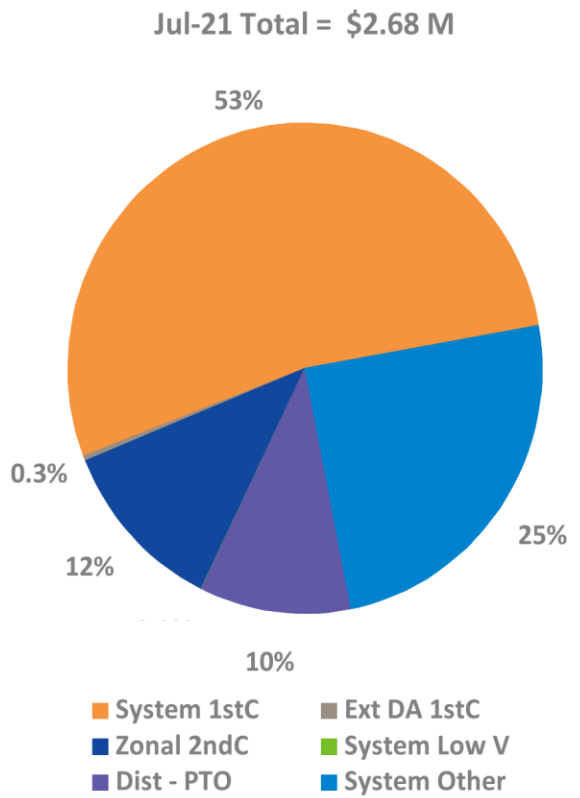


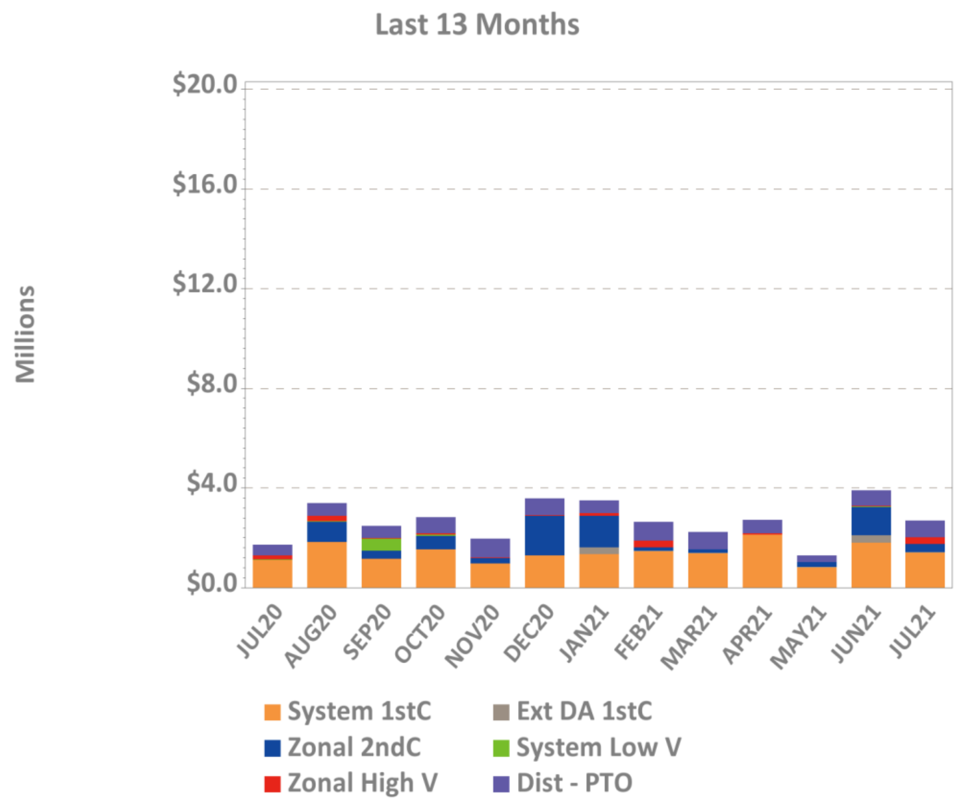
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



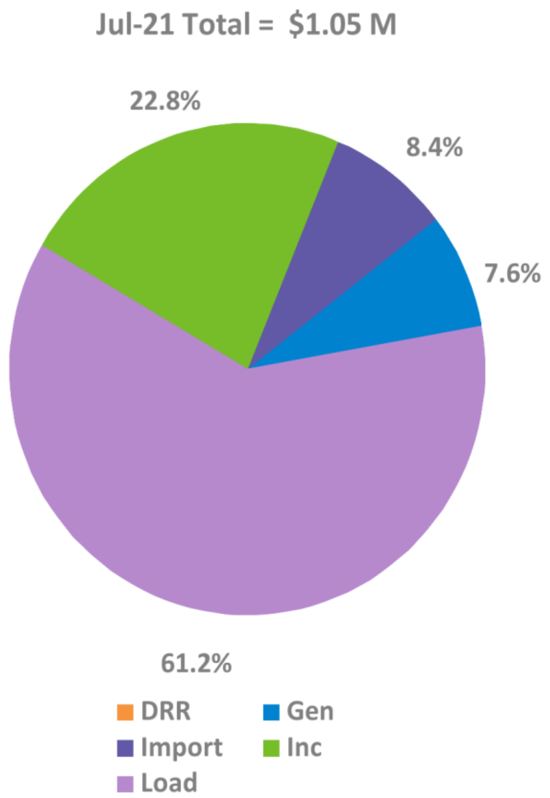
NCPC Charges by Allocation

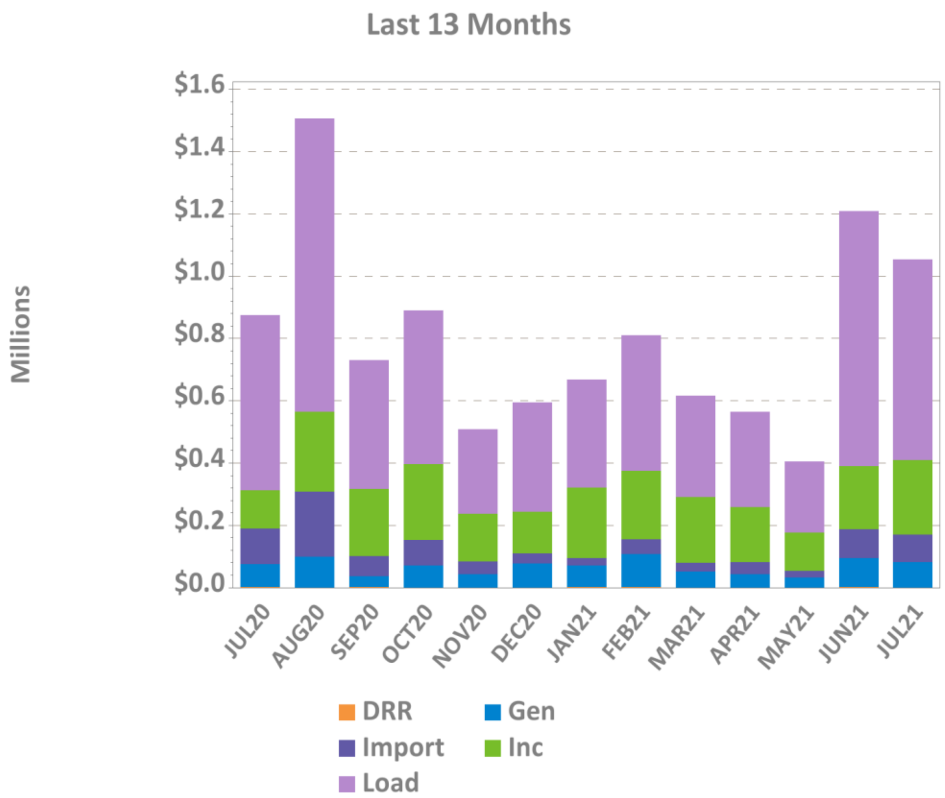




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

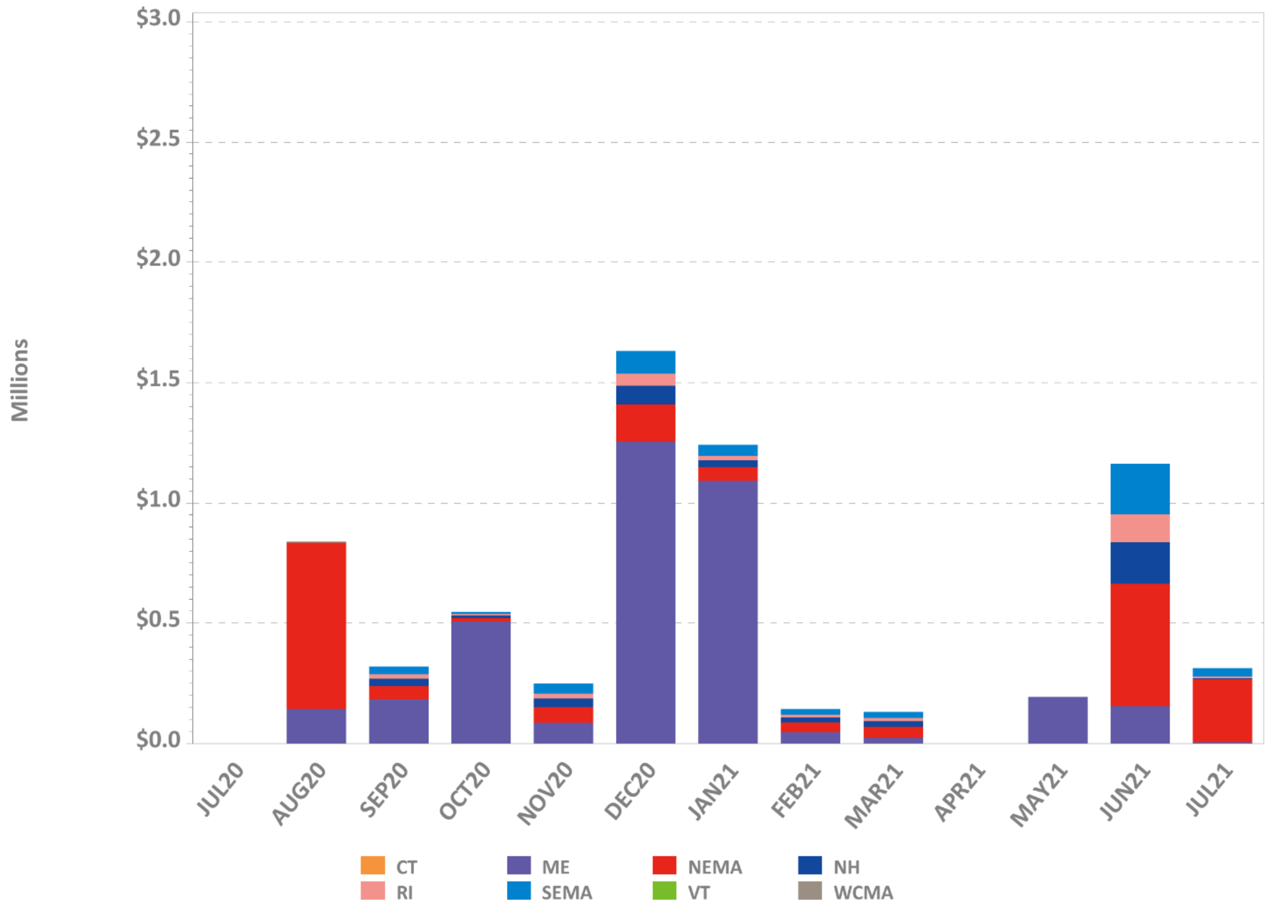
RT First Contingency Charges by Deviation Type





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

LSCPR Charges by Reliability Region



CT – Connecticut Region

ME – Maine Region

NH – New Hampshire Region

RI – Rhode Island Region

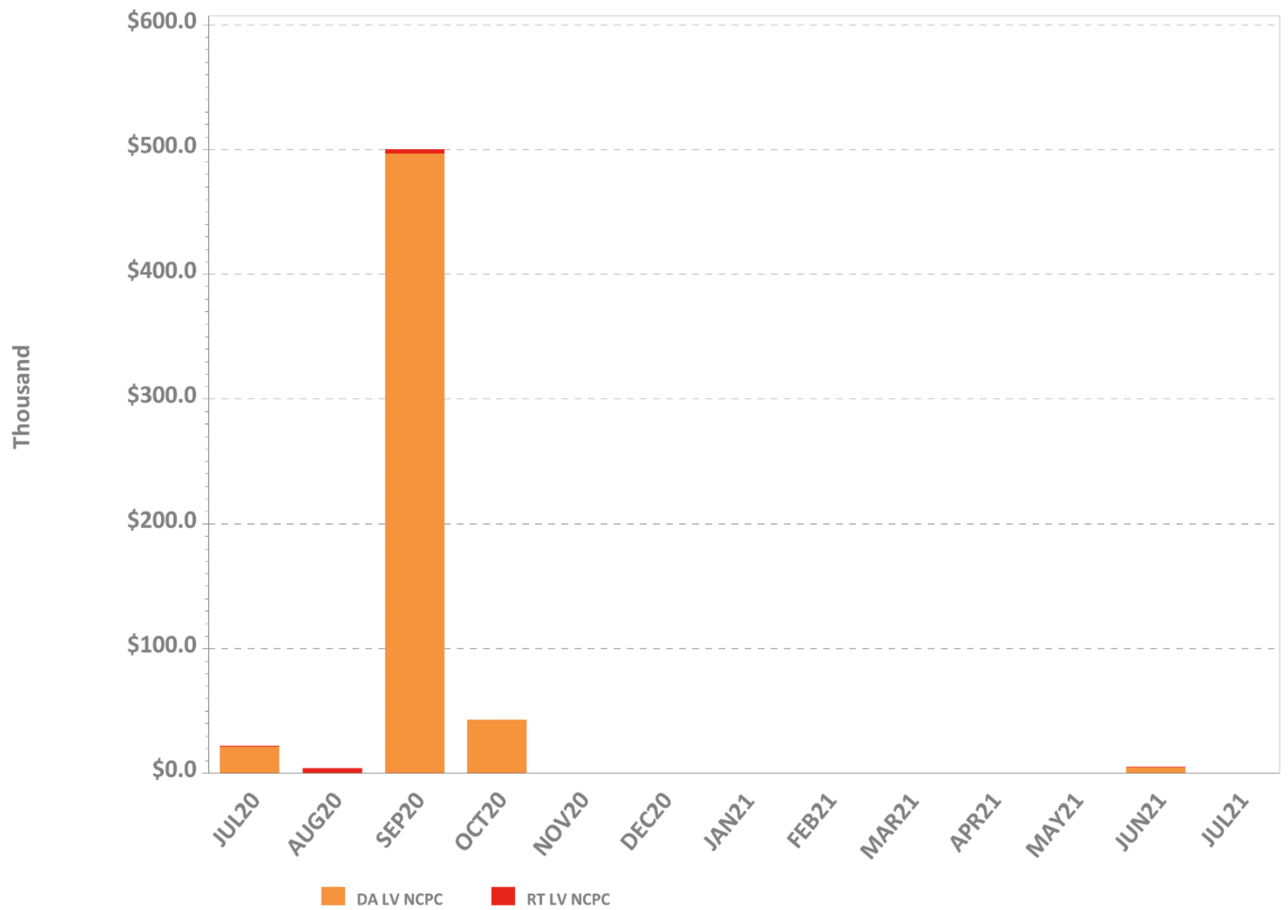
VT – Vermont Region

SEMA – Southeast Massachusetts Region

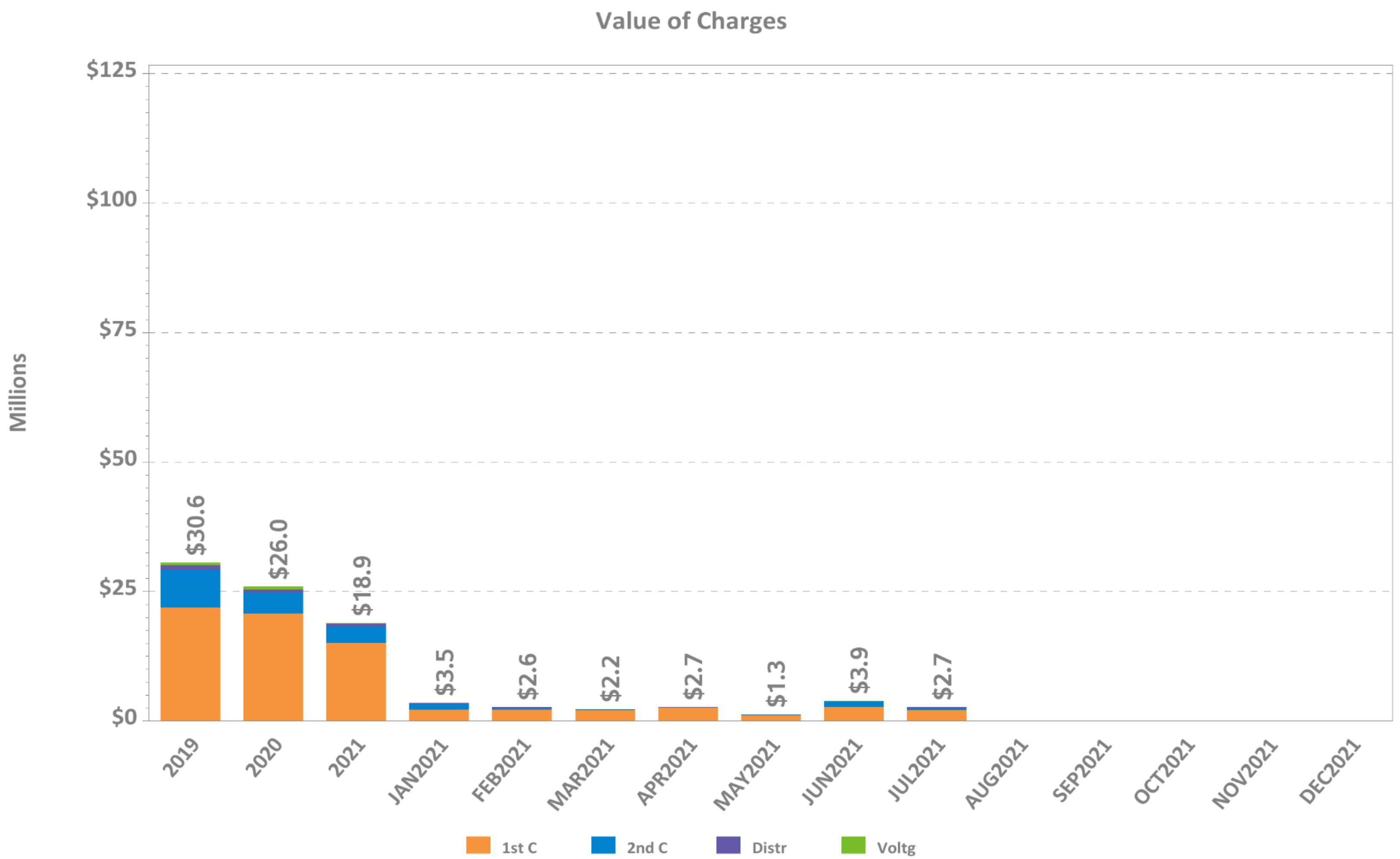
WCMA – Western/Central Massachusetts Region

NEMA – Northeast Massachusetts Region

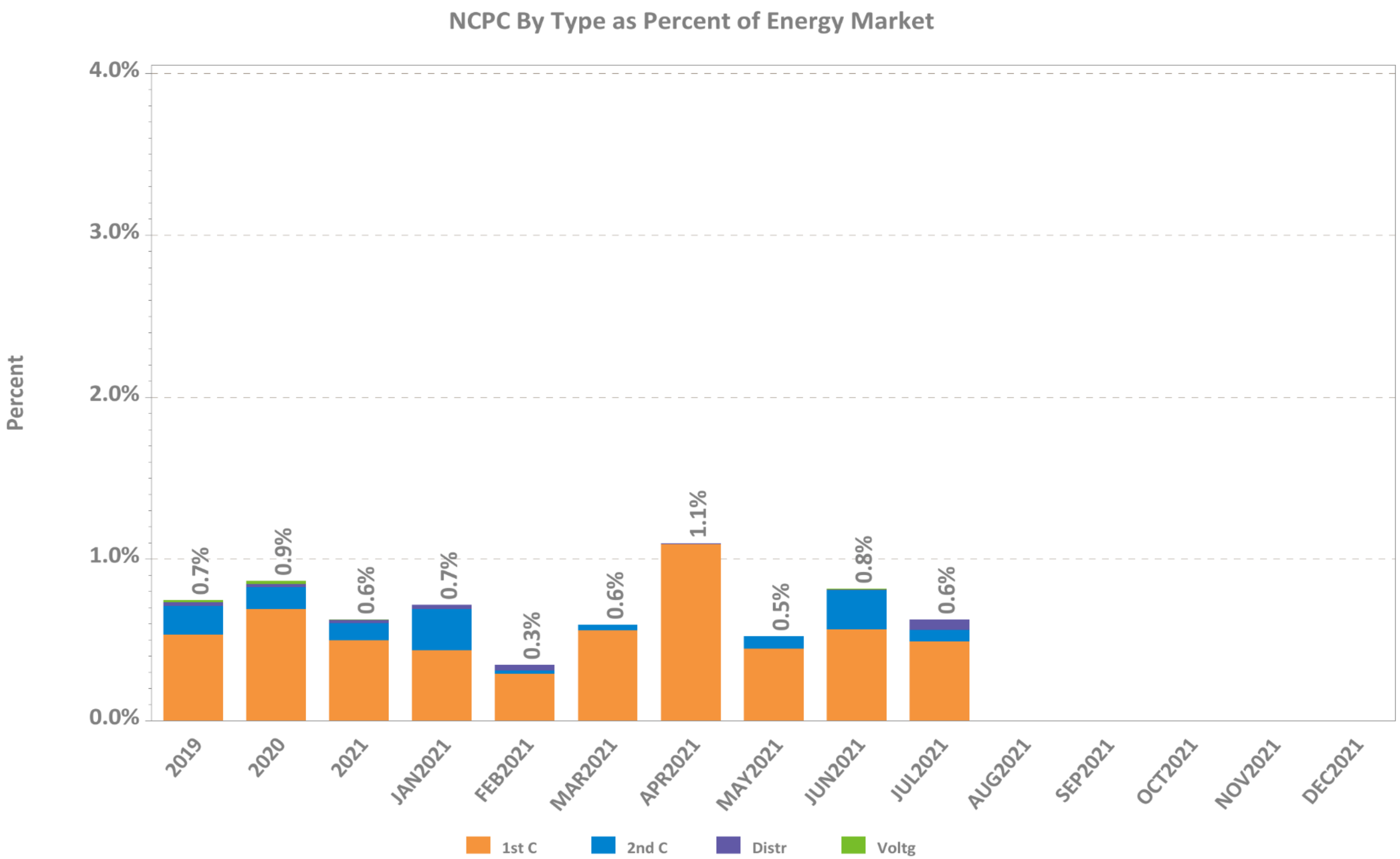
NCPC Charges for Voltage Support and High Voltage Control



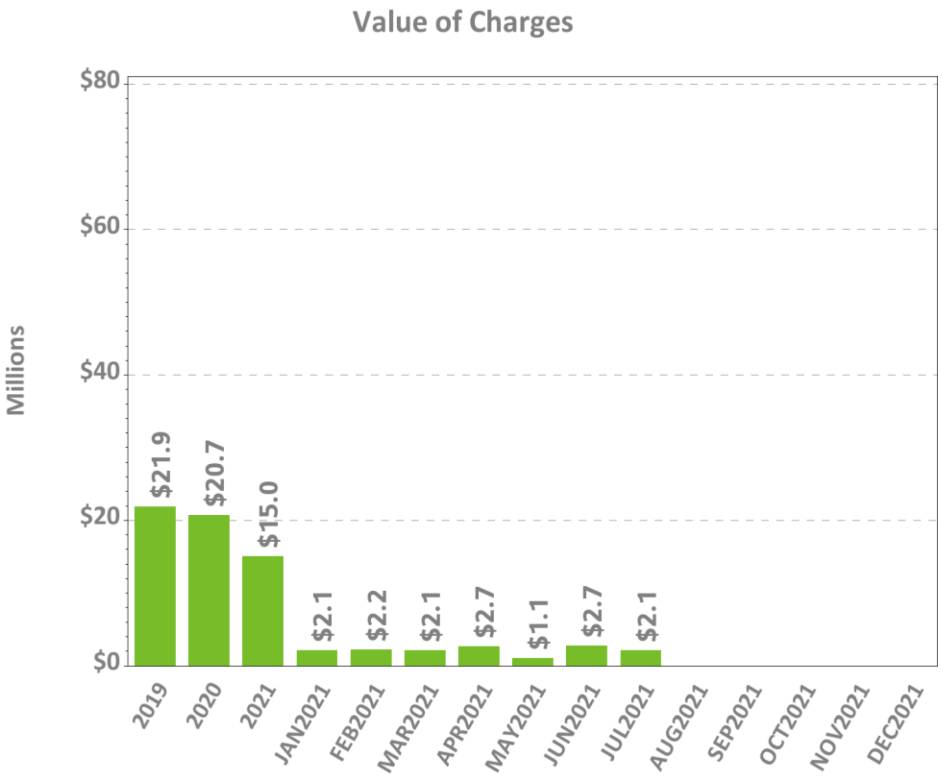
NCPC Charges by Type

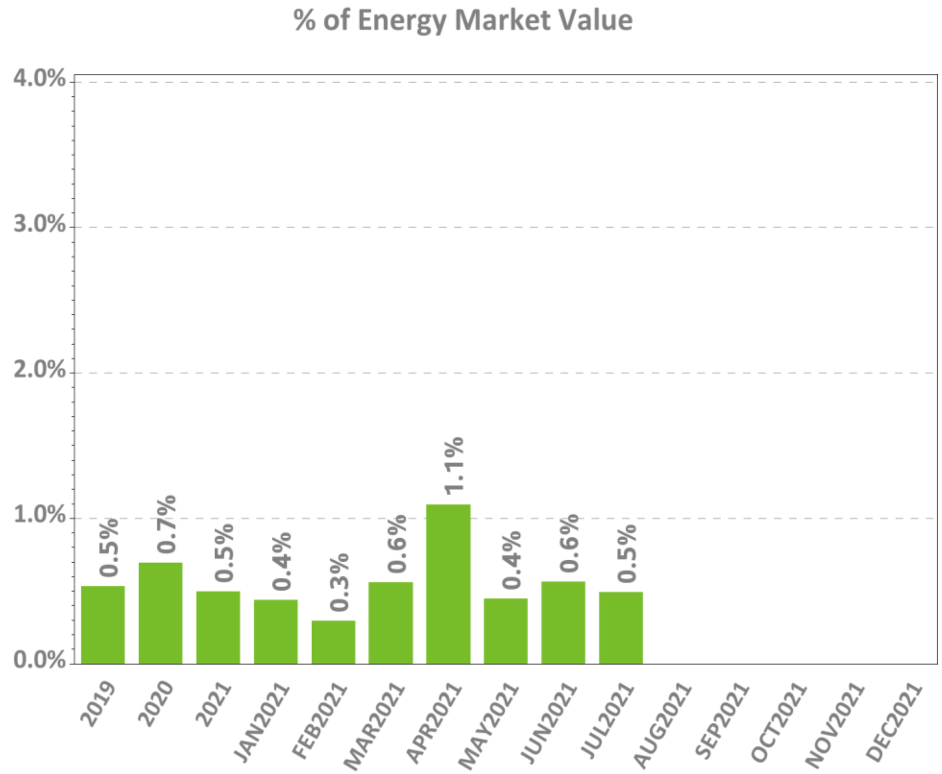


NCPC Charges as Percent of Energy Market



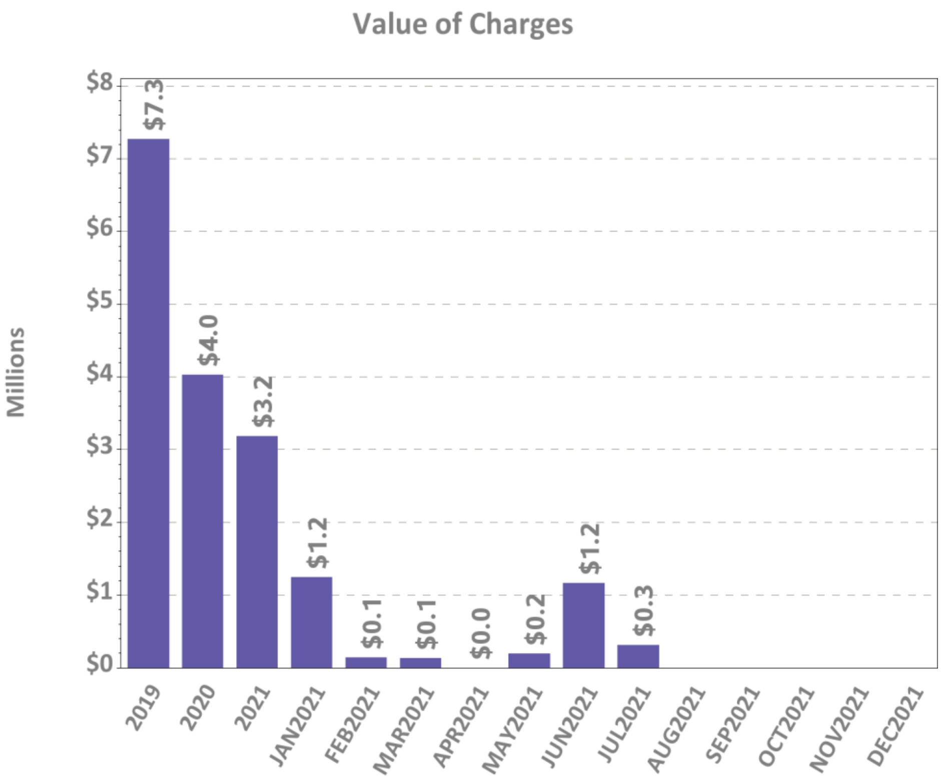
First Contingency NCPC Charges

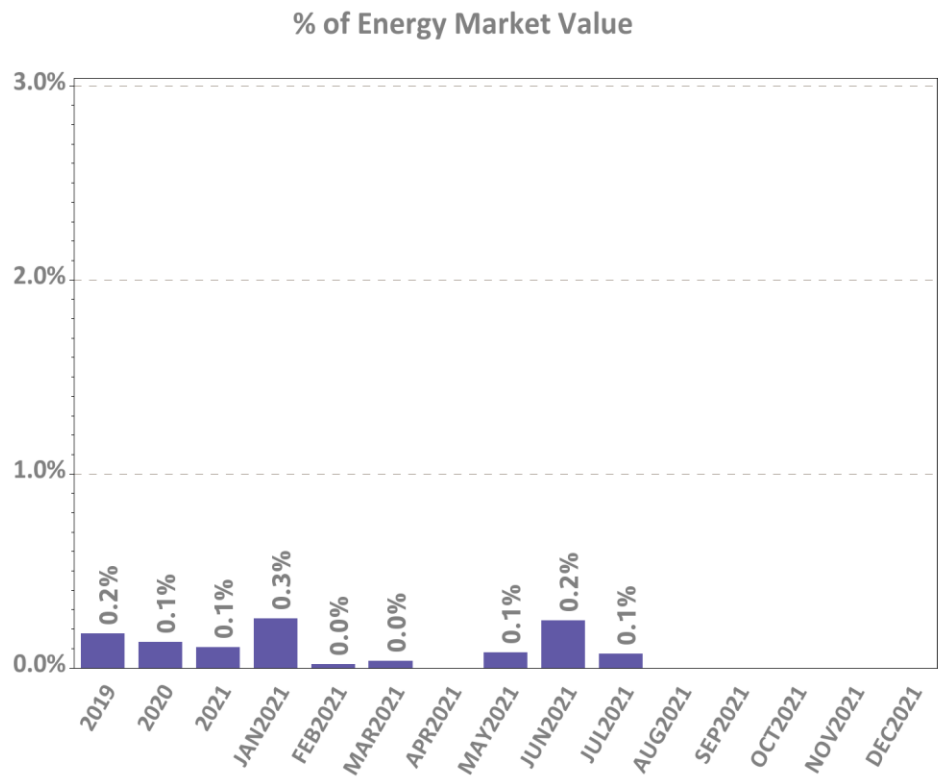




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

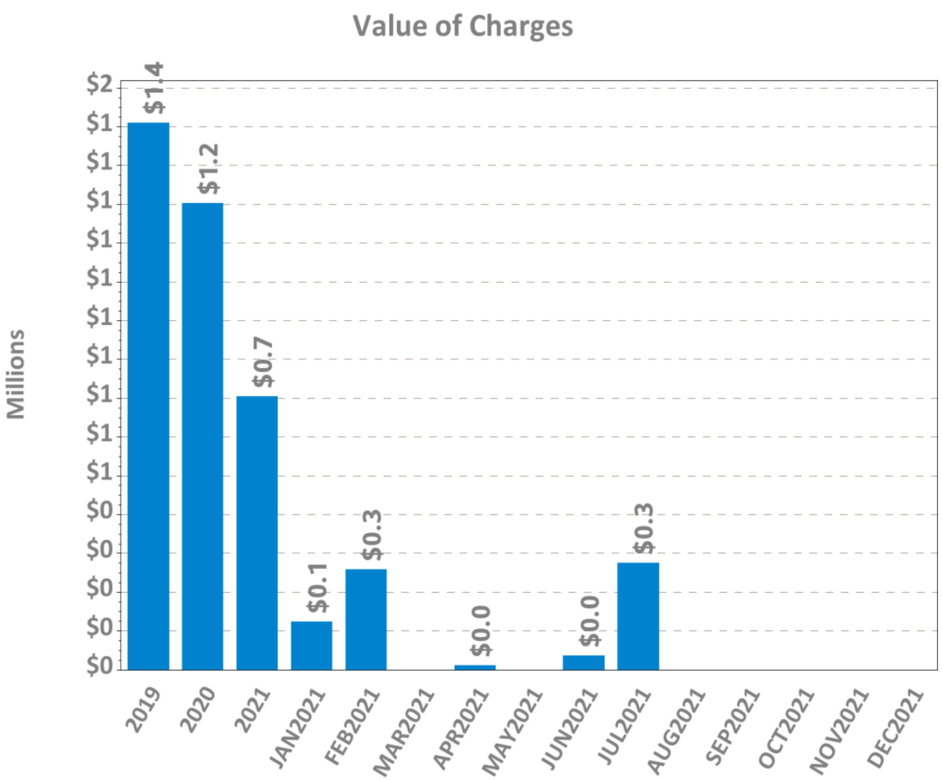
Second Contingency NCPC Charges

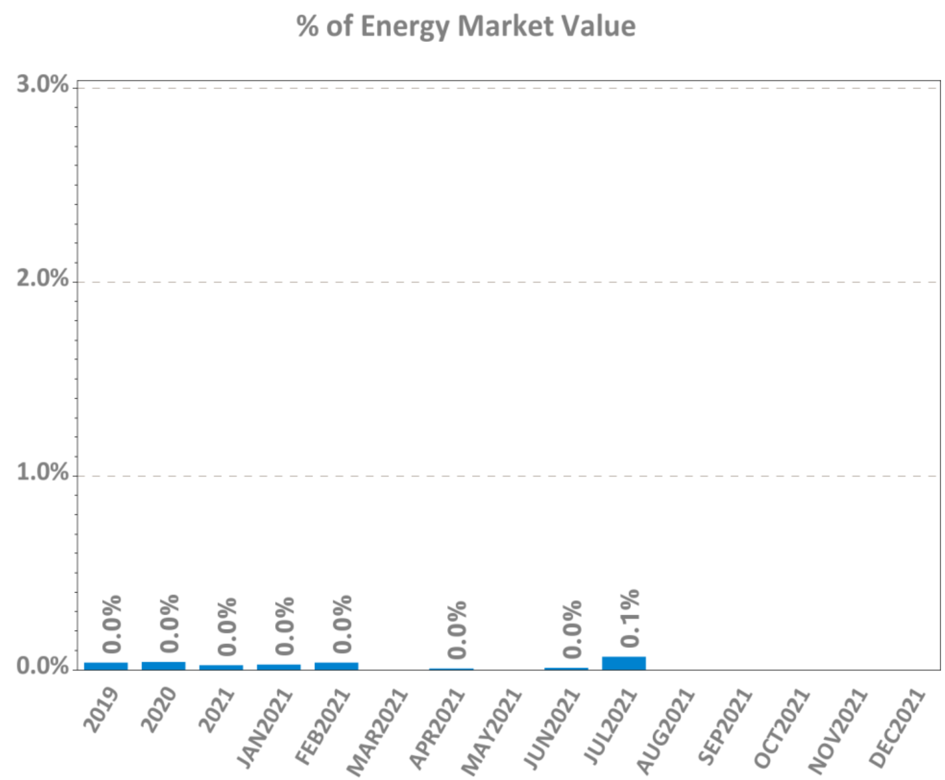




Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Voltage and Distribution NCPC Charges





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

DA vs. RT Pricing

The following slides outline:

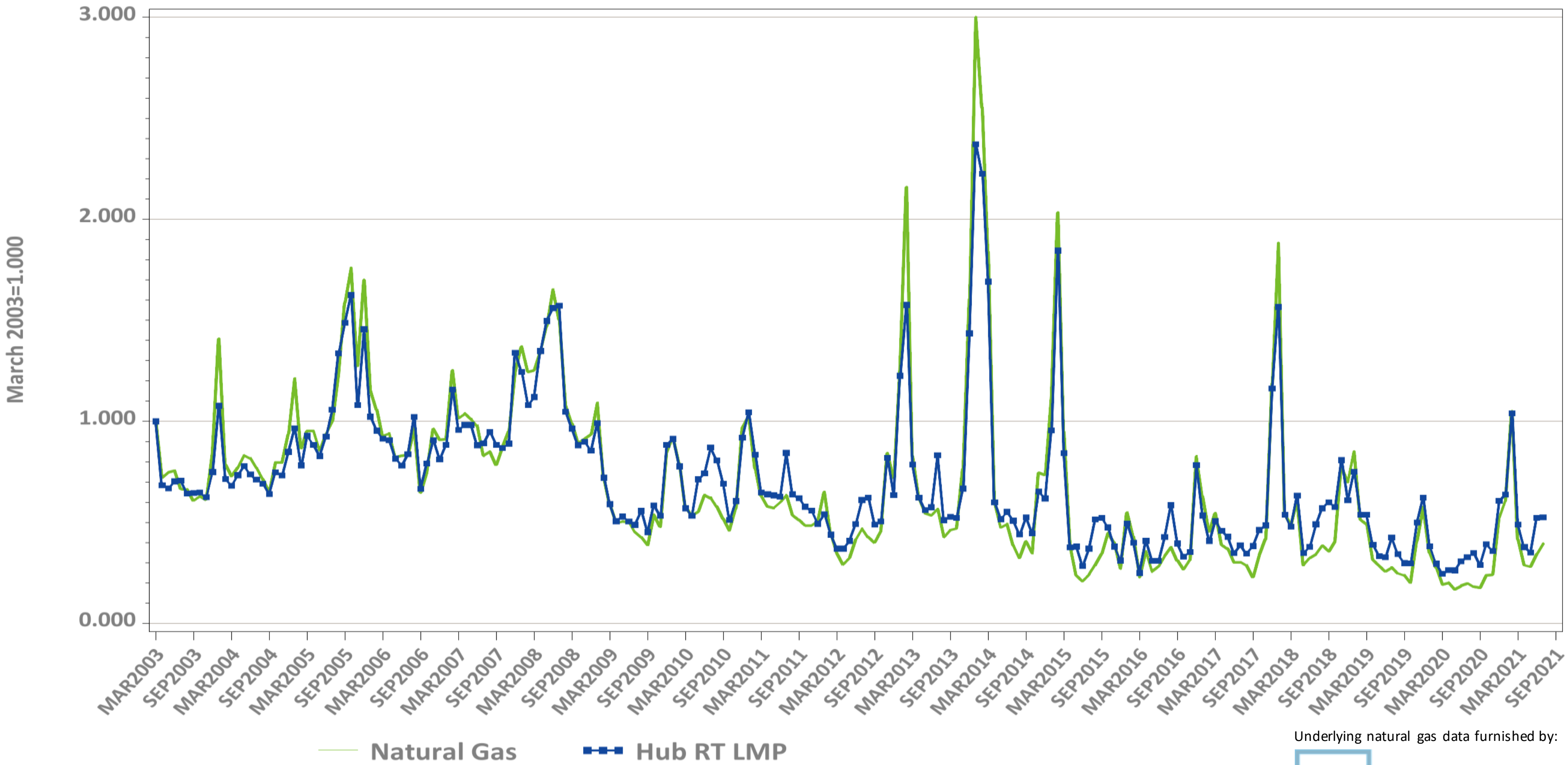
- This month vs. prior year's average LMPs and fuel costs
- Reserve Market results
- DA cleared load vs. RT load
- Zonal and total incs and decs
- Self-schedules
- DA vs. RT net interchange

DA vs. RT LMPs ($/MWh)

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%

July-20	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$23.93	$23.30	$23.72	$24.00	$23.65	$23.62	$23.88	$23.82	$23.78
Real-Time	$22.64	$22.23	$22.50	$22.70	$22.42	$22.35	$22.58	$22.52	$22.47
RT Delta %	-5.4%	-4.6%	-5.1%	-5.4%	-5.2%	-5.4%	-5.4%	-5.5%	-5.5%
July-21	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$37.95	$37.08	$37.21	$37.84	$37.41	$37.35	$37.79	$37.64	$37.59
Real-Time	$36.41	$35.78	$35.81	$36.27	$35.80	$35.84	$36.26	$36.08	$36.04
RT Delta %	-4.1%	-3.5%	-3.8%	-4.1%	-4.3%	-4.0%	-4.0%	-4.1%	-4.1%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	58.6%	59.2%	56.9%	57.7%	58.1%	58.1%	58.3%	58.0%	58.1%
Yr over Yr RT	60.8%	61.0%	59.1%	59.8%	59.7%	60.3%	60.6%	60.2%	60.4%

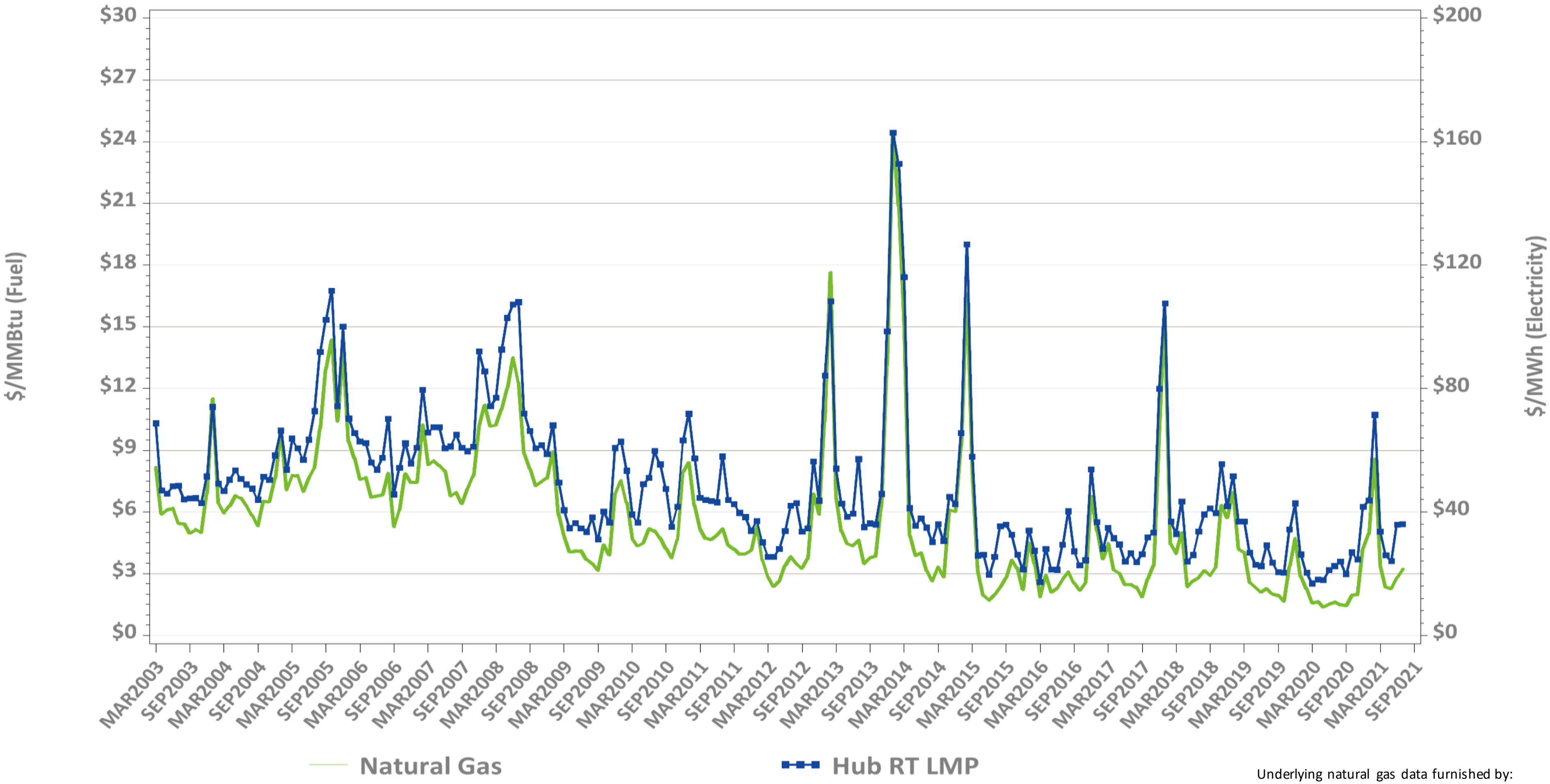
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ICE Global markets in clear view

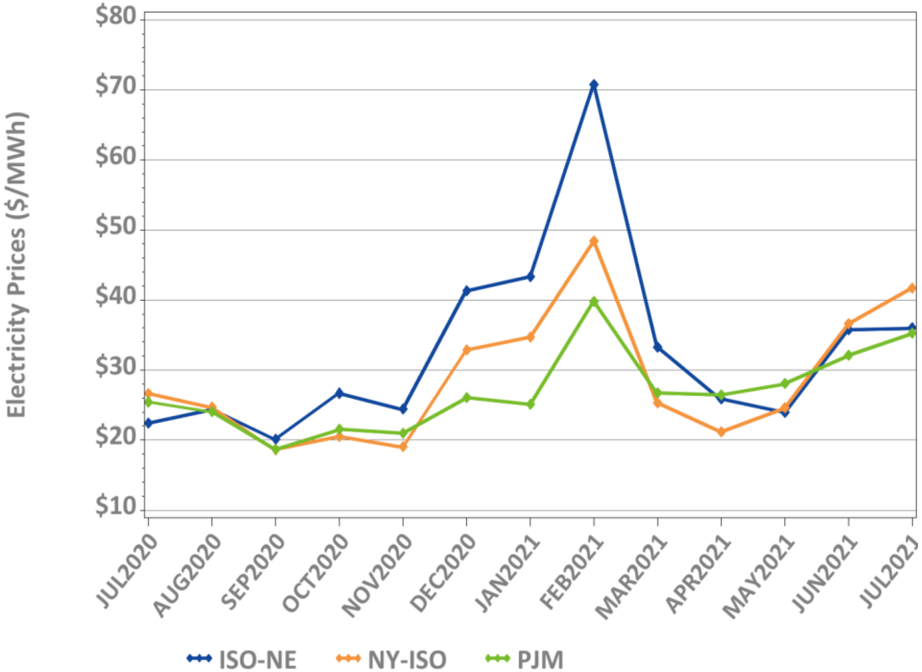
Monthly Average Fuel Price and RT Hub LMP



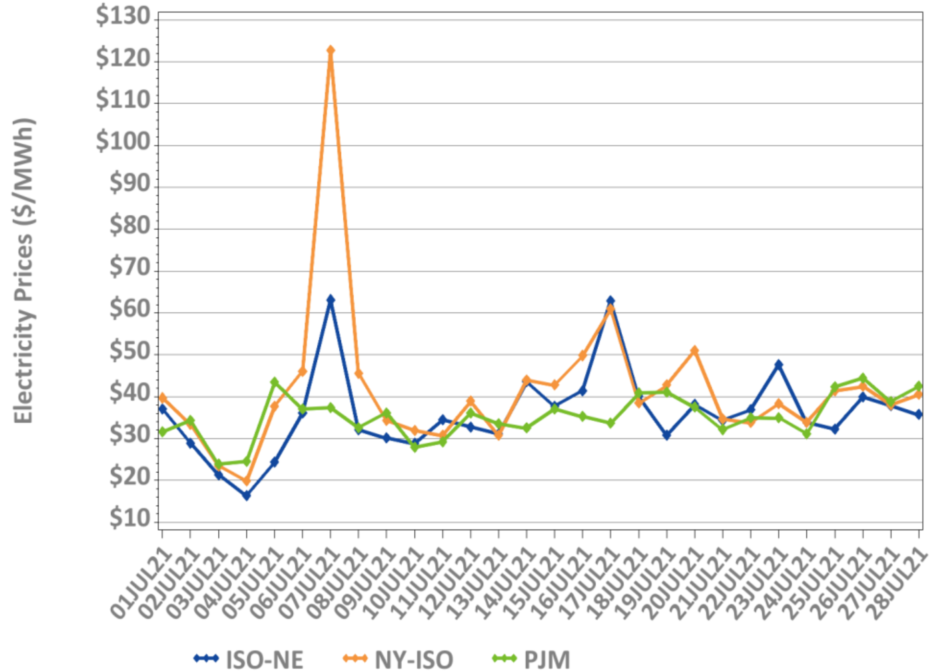
Underlying natural gas data furnished by:

ice Global markets in clear view

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

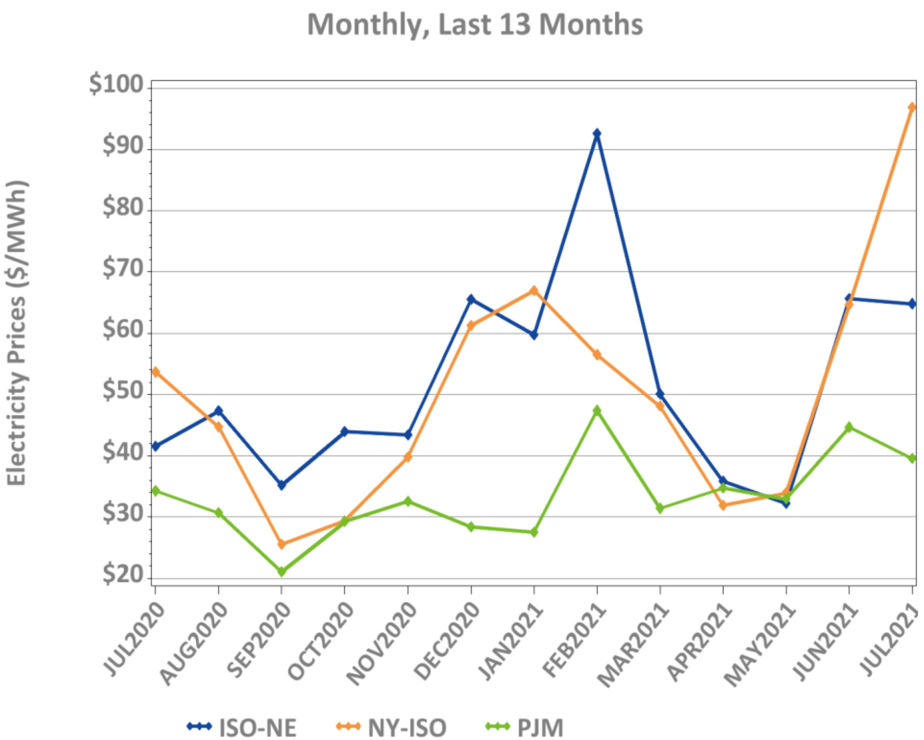


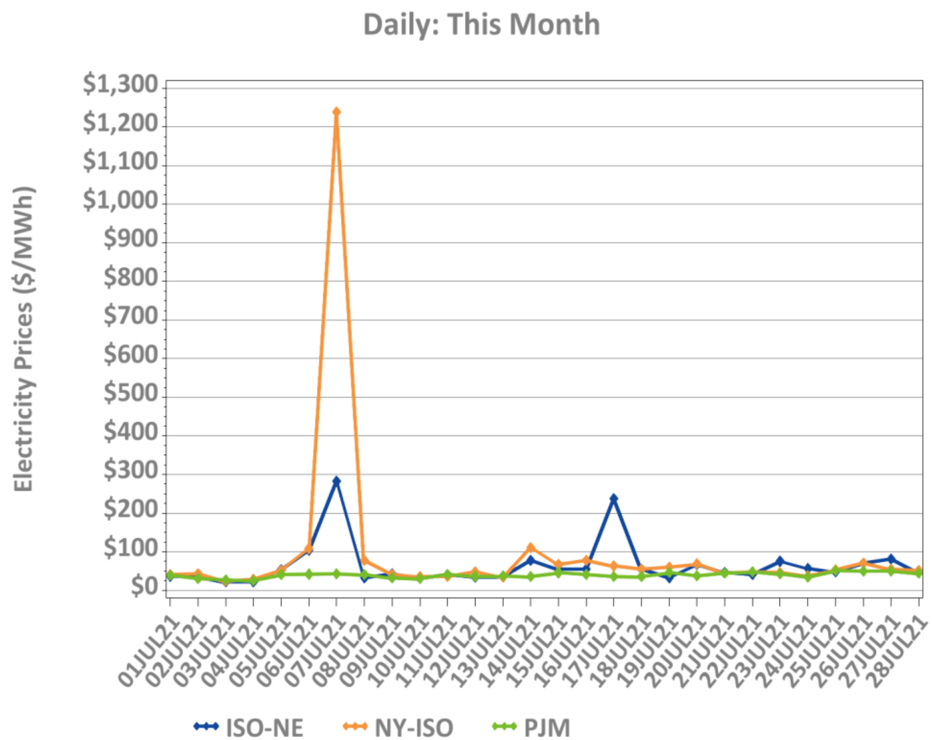
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





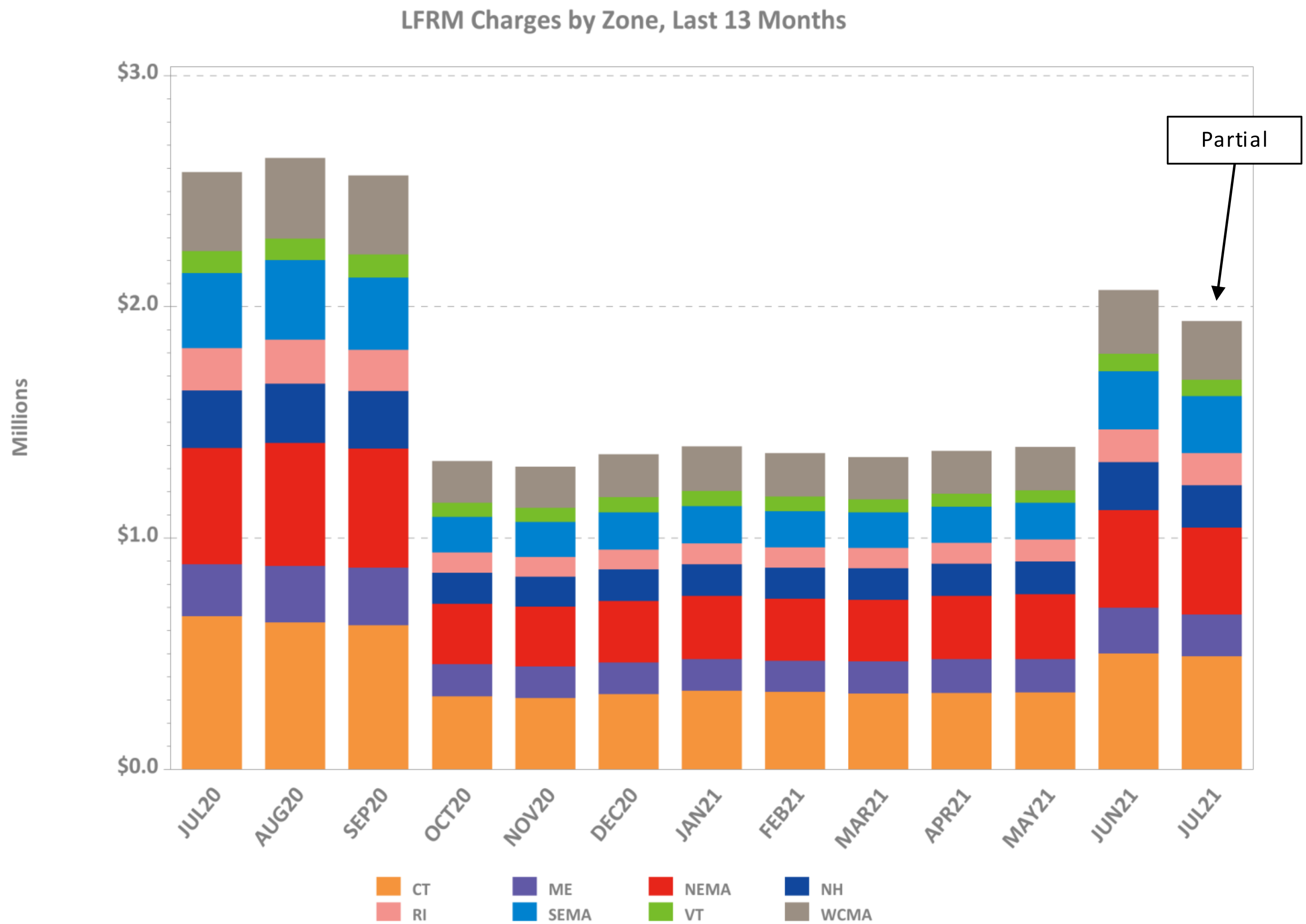
***Forecasted New England daily peak hours reflected**

Reserve Market Results – July 2021

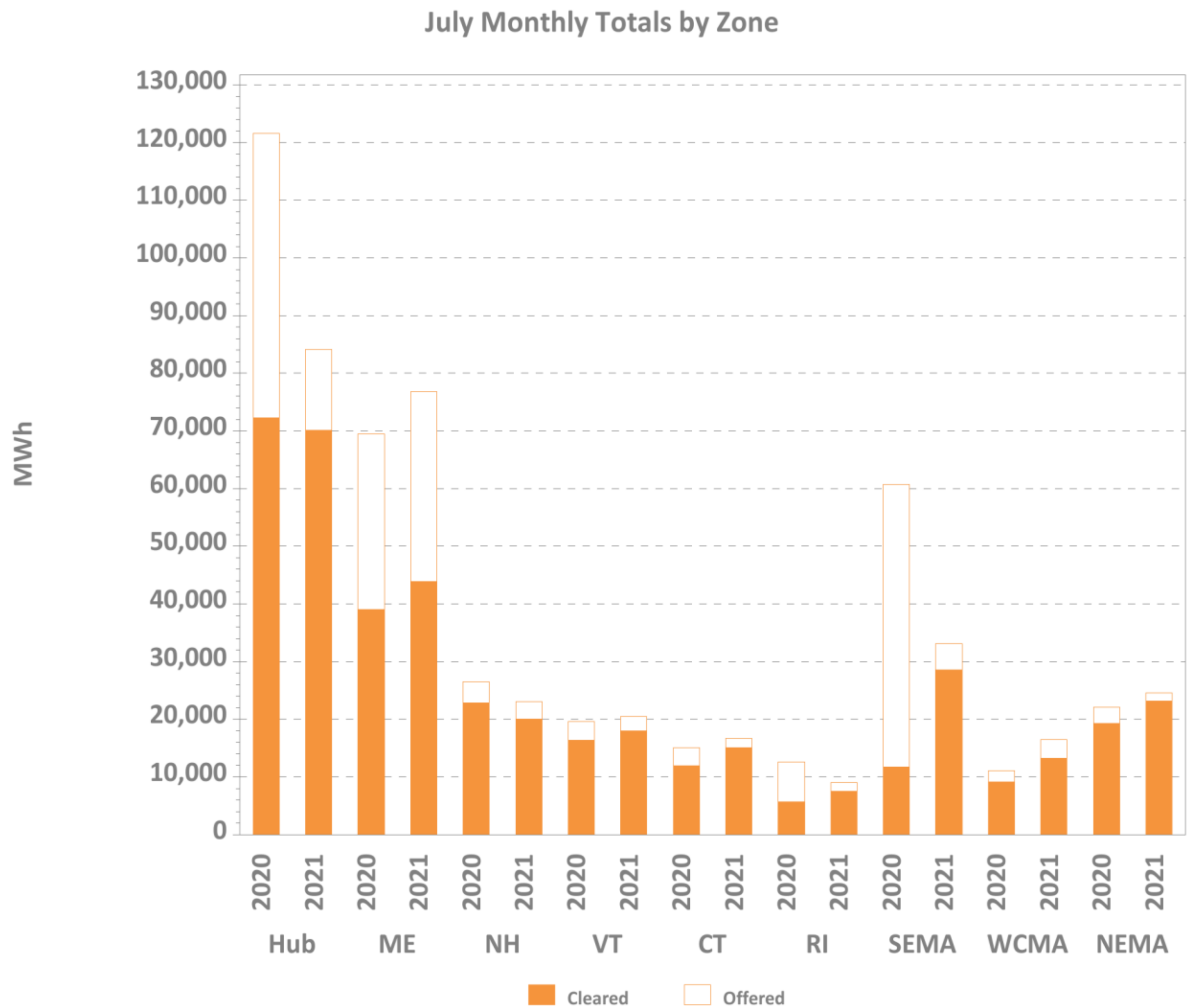
- Maximum potential Forward Reserve Market payments of \$2.1M were reduced by credit reductions of \$29K, failure-to-reserve penalties of \$73K and failure-to-activate penalties of \$14K, resulting in a net payout of \$1.9M or 94% of maximum
  - Rest of System: \$1.55M/1.6M (97%)
  - Southwest Connecticut: \$0.04M/0.05M (81%)
  - Connecticut: \$0.33M/0.39M (87%)
- \$2.4M total Real-Time credits were reduced by \$788K in Forward Reserve Energy Obligation Charges for a net of \$1.6M in Real-Time Reserve payments
  - Rest of System: 215 hours, \$947K
  - Southwest Connecticut: 215 hours, \$314K
  - Connecticut: 215 hours, \$244K
  - NEMA: 215 hours, \$122K

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

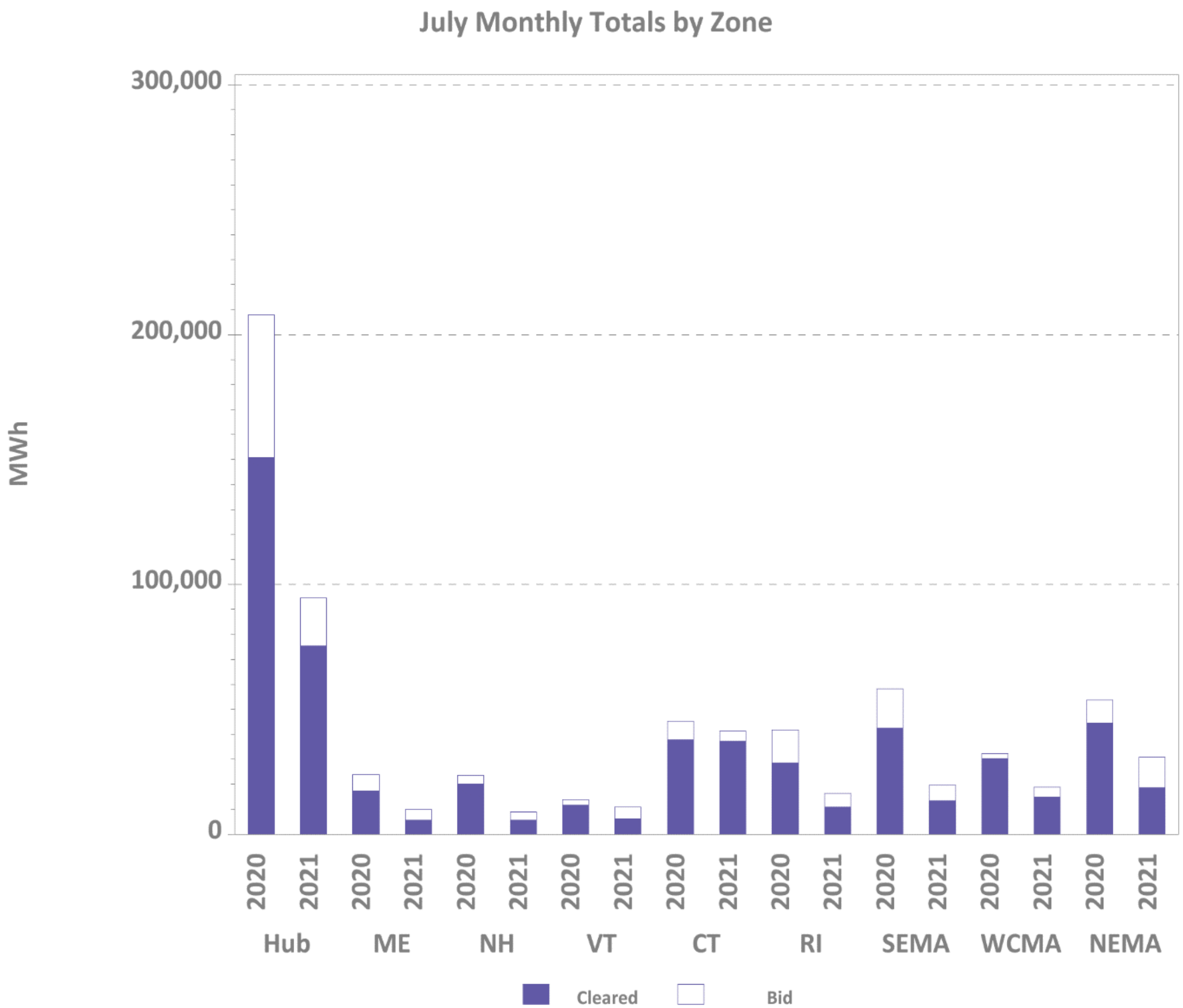
LFRM Charges to Load by Load Zone ($)



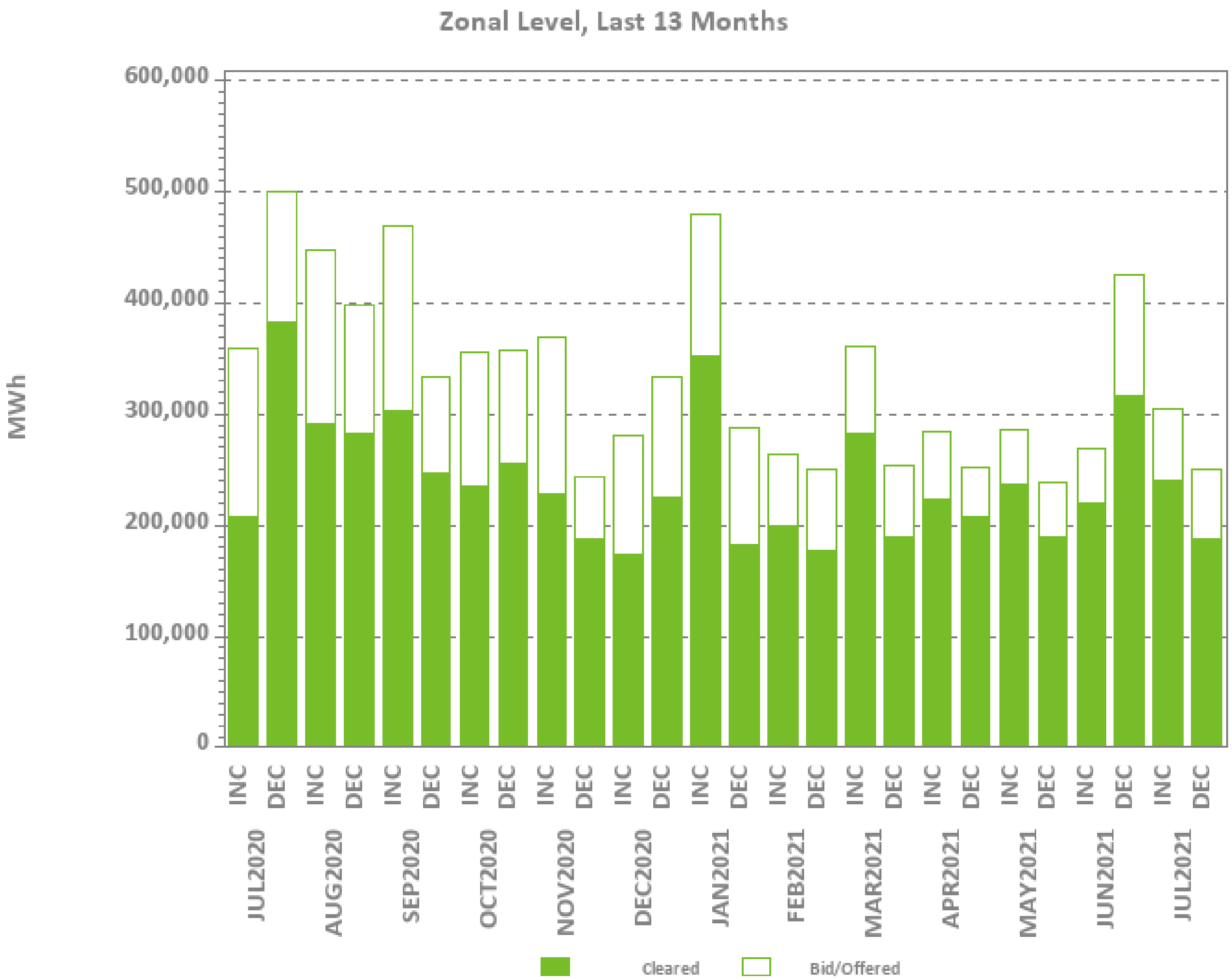
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

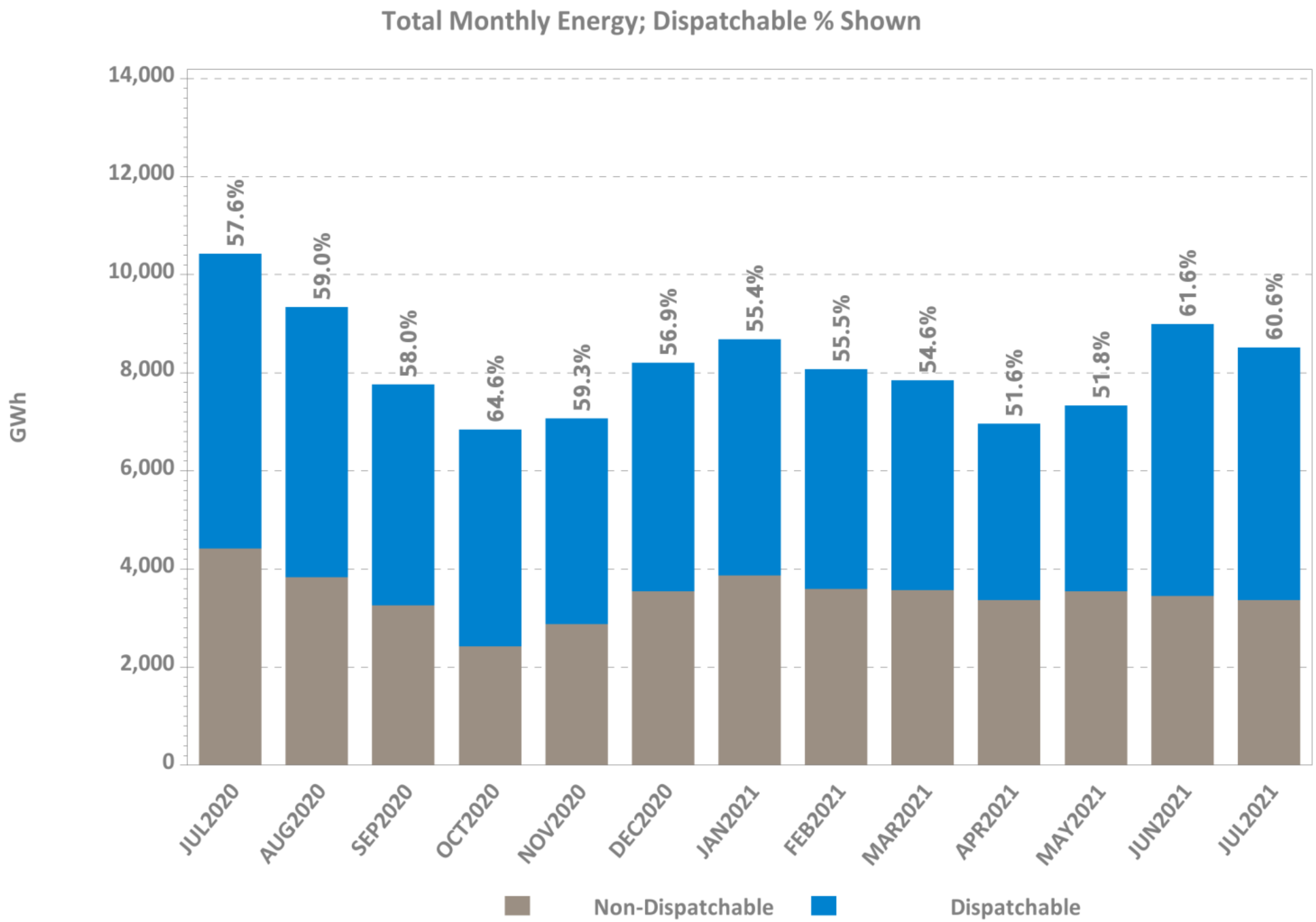


Total Increment Offers and Decrement Bids



Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



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

REGIONAL SYSTEM PLAN (RSP)

Regional System Plan (RSP)

- RSP21 development continues
  - PAC and various regulatory bodies were sent a draft of the report on July 20 and comments are due by August 3
  - Stakeholder comments to be discussed at the August 18 PAC meeting
- RSP21 Public Meeting will be held virtually on October 6
  - Keynote speaker/panelists are being pursued
  - Panel Discussion: Grid of the Future: Preparing and Responding to Extreme Events

Planning Advisory Committee (PAC)

- August 18 PAC Meeting Agenda Topics*
  - Transmission Planning for the Clean-Energy Transition: Pilot Study Results and Proposed Changes to Assumptions
  - RSP21 Process Update
  - Singer 345 kV Substation - Flood Mitigation Project Update

* 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
- Results were discussed at the 6/16/21 and 7/22/21 PAC meetings, with further discussion of results continuing throughout Q3

Economic Studies

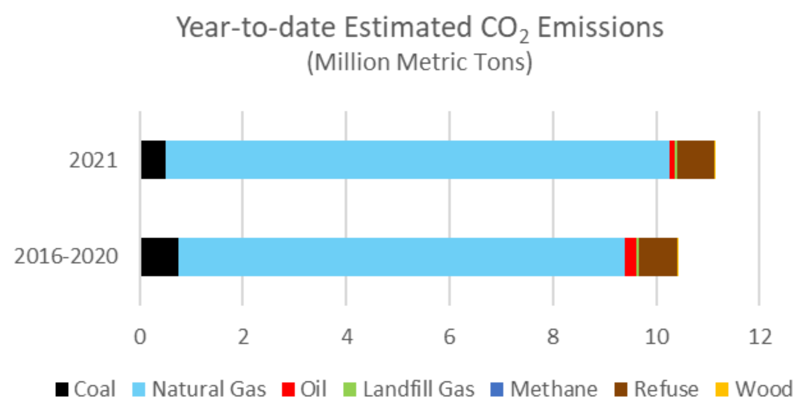
- 2020 Economic Study Request
  - Study proponent is National Grid
  - Study simulations are complete, and results have been presented to PAC
    - Draft report to be completed by Q3 2021
- 2021 Economic Study Request
  - Also known as Future Grid Reliability Study – Phase 1 (FGRS)
  - Study proponent is NEPOOL
    - Preliminary production cost simulation results presented at the June and July PAC meetings; remaining preliminary production cost results expected at the September PAC meeting
    - Preliminary ancillary services analyses results to be presented at the September PAC meeting

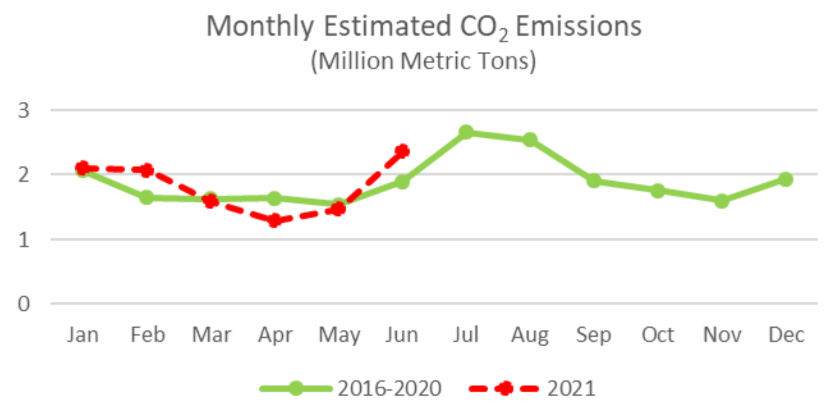
Future Grid Reliability Study (FGRS)

- Phase 1
  - Studies include: Production Cost Simulations; Ancillary Services Simulations; Resource Adequacy Screen; and Probabilistic Resource Availability Analysis
  - Framework Document and supporting assumptions table, which describe study scenarios and objectives, have been developed by stakeholders
  - Phase 1 work was submitted as the only 2021 economic study
  - Production Cost Simulations preliminary results presented at the June and July PAC with remaining results to be presented in September
  - Ancillary Services Simulation initial results expected at the September PAC meeting
- 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 – Shift in Power System Emission Trends

- In the first half of 2021, power system carbon dioxide (CO_2) emissions increased, diverging from other system emission trends
  - Total system nitrogen oxide (-6%) and sulfur dioxide (-14%) emissions declined compared to the 2016-2020 average for the same period (January - June)
- Total CO_2 emissions increased by 7%, driven by greater natural-gas-fired generation, compared to the 2016-2020 average for the same period (January – June)
  - Total CO_2 emissions from all other emitting fuel categories declined in the first half of 2021



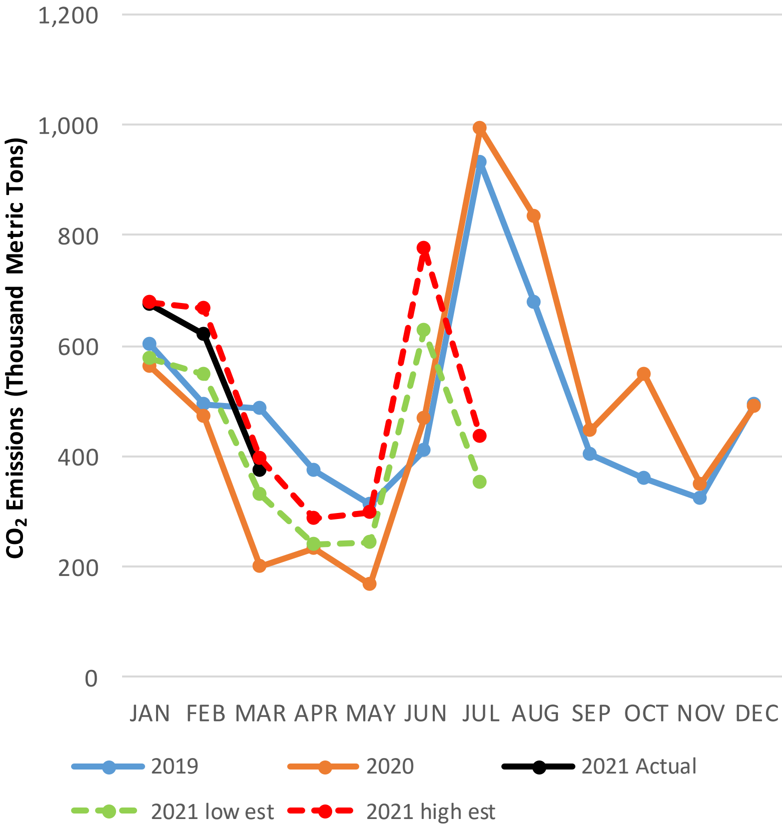


Environmental Matters – Massachusetts CO_2 Generator Emissions Cap

2021 CO_2 GWSA Emissions Trending Lower in July

- July 2021: YTD estimated CO_2 emissions range between 2.9 and 3.5 million metric tons (MMT)
  - 35% to 43% of the 8.23 MMT 2021 cap
- 6/9/21: GWSA auction clearing price was $7.75 per metric ton
- Affected generators have access to banked allowances, in excess of expected 2021 emissions

2019-2021 Estimated Monthly Emissions (Thousand Metric Tons)



GWSA - Global Warming Solutions Act

RSP Project Stage Descriptions

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

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

Greater Boston Projects

Status as of 7/23/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1213, 1220, 1365	Install new 345 kV line from Scobie to Tewksbury	Dec-17	4
1527, 1528	Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Apr-17	4
1212, 1549	Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
1549	Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
1260	Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
1550	Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-19	4
1551, 1552	Install new 345 kV cable from Woburn to Wakefield Junction, install two new 160 MVAR variable shunt reactors and associated work at Wakefield Junction and Woburn*	May-22	3*
1329	Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	4
1327	Reconductor W-23W 69 kV line from Woodside to Northboro Road	Jun-19	4

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

Greater Boston Projects, cont.

Status as of 7/23/2021

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

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

Greater Boston Projects, cont.

Status as of 7/23/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1336	Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-19	4
1553	Install a 345 kV breaker in series with breaker 104 at Woburn	Jun-17	4
1337	Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	4
1339	Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
1521	Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	4
1522	Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	4
1352	Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	May-19	4
1353	Install a 115 kV breaker on the East bus at K Street	Jun-16	4
1354, 1738	Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	Jul-21	3*
1355	Split 110-522 and 240-510 DCT from Baker Street to Needham for a portion of the way and install a 115 kV cable for the rest of the way	Mar-21	4

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

Greater Boston Projects, cont.

Status as of 7/23/2021

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

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

Greater Boston Projects, cont.

Status as of 7/23/2021

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

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

SEMA/RI Reliability Projects

Status as of 7/23/2021

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

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

SEMA/RI Reliability Projects, cont.

Status as of 7/23/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1718	Add 115 kV circuit breaker at Robinson Ave substation and re-terminate the Q10 line	Dec-21	3
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Cancelled*	N/A
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	May-25	2
1721	Reconfigure Bell Rock to breaker-and-a-half station, split the M13 line at Bell Rock substation, and terminate 114 line at Bell Rock; install a new breaker in series with N12/D21 tie breaker, upgrade D21 line switch, and install a 37.5 MVAR capacitor	Dec-23	2
1722	Extend the Line 114 from the Dartmouth town line (Eversource- NGRID border) to Bell Rock substation	Dec-23	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Cancelled*	N/A

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

SEMA/RI Reliability Projects, cont.

Status as of 7/23/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1725	Build a new 115 kV line from Bourne to West Barnstable substations which includes associated terminal work	Dec-23	1
1726	Separate the 135/122 DCT from West Barnstable to Barnstable substations	Dec-21	3
1727	Retire the Barnstable SPS	Dec-21	3
1728	Build a new 115 kV line from Carver to Kingston substations and add a new Carver terminal	Dec-22	1
1729	Install a new bay position at Kingston substation to accommodate new 115 kV line	Dec-22	1
1730	Extend the 114 line from the Eversource/National Grid border to the Industrial Park Tap	Dec-23	1

SEMA/RI Reliability Projects, cont.

Status as of 7/23/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1731	Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	3
1732	Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Jan-23	3
1733	Separate the 325/344 DCT lines from West Medway to West Walpole substations	Cancelled**	N/A
1734	Reconductor and upgrade the 112 Line from the Tremont substation to the Industrial Tap	Jun-18	4
1736	Reconductor the 108 line from Bourne substation to Horse Pond Tap*	Oct-18	4
1737	Replace disconnect switches on 323 line at West Medway substation and replace 8 line structures	Aug-20	4

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

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

SEMA/RI Reliability Projects, cont.

Status as of 7/23/2021

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

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1741	Rebuild the Middleborough Gas and Electric portion of the E1 line from Bridgewater to Middleborough	Apr-19	4
1782	Reconductor the J16S line	Jun-22	2
1724	Replace the Kent County 345/115 kV transformer	Mar-22	2
1789	West Medway 345 kV circuit breaker upgrades	Apr-21	4
1790	Medway 115 kV circuit breaker replacements	Nov-20	4

Eastern CT Reliability Projects

Status as of 7/23/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1815	Reconductor the L190-4 and L190-5 line sections	Dec-26	1
1850	Install a second 345/115 kV autotransformer (4X) and one 345 kV breaker at Card substation	Mar-23	2
1851	Upgrade Card 115 kV to BPS standards	Mar-23	2
1852	Install one 115 kV circuit breaker in series with Card substation 4T	Mar-23	2
1853	Convert Gales Ferry substation from 69 kV to 115 kV	Dec-23	1
1854	Rebuild the 100 Line from Montville to Gales Ferry to allow operation at 115 kV	Dec-22	1

Eastern CT Reliability Projects, cont.

Status as of 7/23/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

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

Eastern CT Reliability Projects, cont.

Status as of 7/23/2021

Project Benefit: Addresses system needs in the Eastern Connecticut area

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

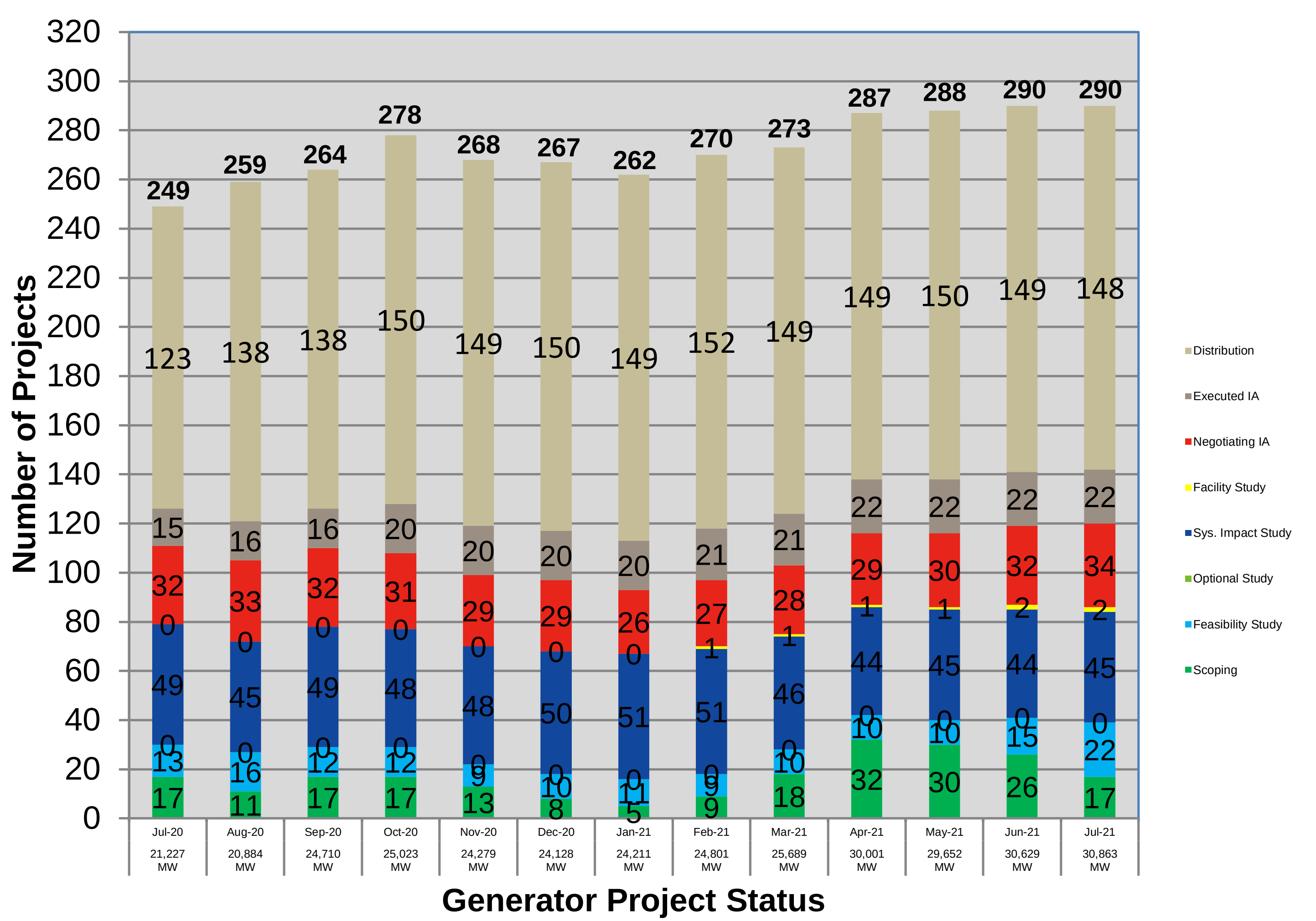
Boston Area Optimized Solution Projects

Status as of 7/23/2021

Project Benefit: Addresses system needs in the Boston area

RSP Project List ID	Upgrade	Expected/ Actual In-Service	Present Stage
1874	Install two 11.9 ohm series reactors at North Cambridge Station on Lines 346 and 365	Jun-23	3
1875	Install a direct transfer trip (DTT) scheme between Ward Hill and West Amesbury Substations for Line 394	Jan-23	1
1876	Install one +/- 167 MVAR STATCOM at Tewksbury 345 kV Substation	Oct-23	1

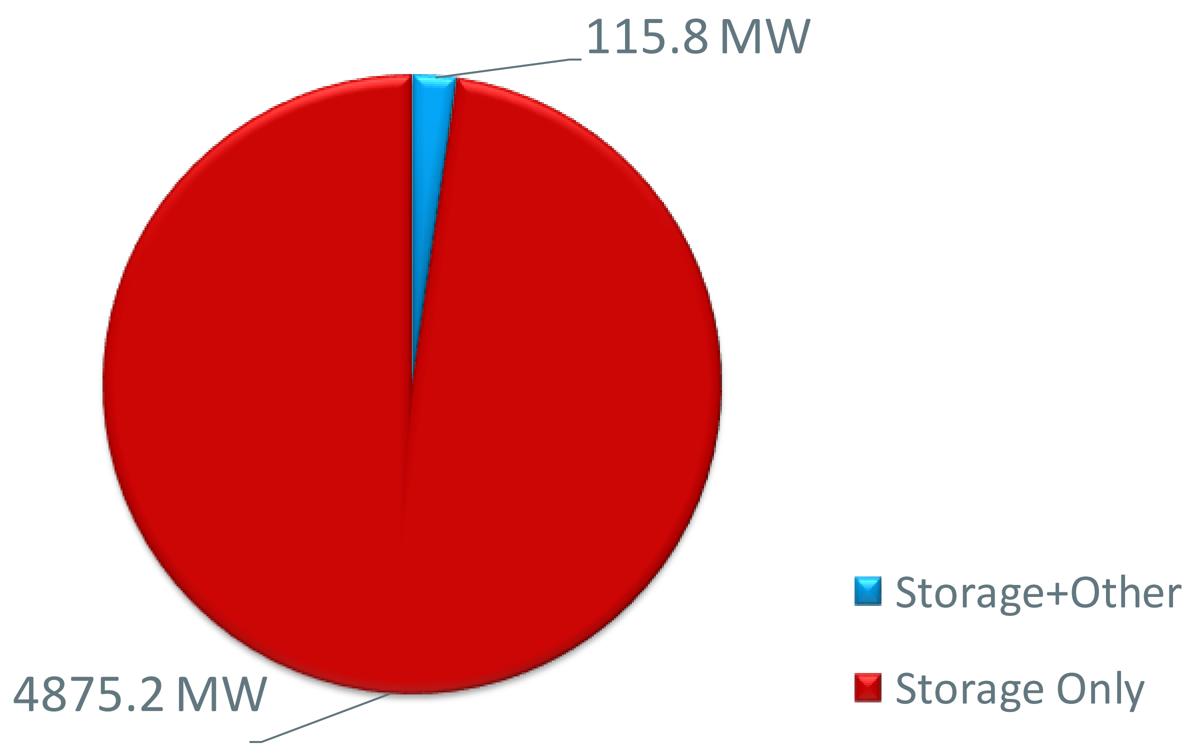
Status of Tariff Studies



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

What is in the Queue (as of July 27, 2021)

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



OPERABLE CAPACITY ANALYSIS

Summer 2021 and Preliminary Fall 2021

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]	29,368	29,927
Active Demand Capacity Resource (+) [5]	540	459
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,208	1,208
Non Commercial Capacity (+)	45	45
Non Gas-fired Planned Outage MW (-)	2,063	2,670
Gas Generator Outages MW (-)	368	406
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)	26,630	26,463
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	-484	-652

[1] Operable Capacity is based on data as of **July 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 **July 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	September - 2021[2] CSO (MW)	September - 2021[2] SCC (MW)
Operable Capacity MW [1]	29,368	29,927
Active Demand Capacity Resource (+) [5]	540	459
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,208	1,208
Non Commercial Capacity (+)	45	45
Non Gas-fired Planned Outage MW (-)	2,063	2,670
Gas Generator Outages MW (-)	368	406
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)	26,630	26,463
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	-2,385	-2,553

[1] Operable Capacity is based on data as of **July 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 **July 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

July 27, 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: 7/27/2021

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
8/14/2021	29150	502	1160	44	75	176	2100	0	28507	24810	2305	27115	1392	N	Summer 2021
8/21/2021	29150	502	1103	44	38	0	2100	0	28662	24810	2305	27115	1547	N	Summer 2021
8/28/2021	29150	502	1160	44	32	0	2100	0	28725	24810	2305	27115	1610	N	Summer 2021
9/4/2021	29368	540	1208	45	1334	0	2100	0	27728	24810	2305	27115	613	N	Summer 2021
9/11/2021	29368	540	1208	45	2063	368	2100	0	26630	24810	2305	27115	-484	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

ISO-NE OPERABLE CAPACITY ANALYSIS

July 27, 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: 7/27/2021

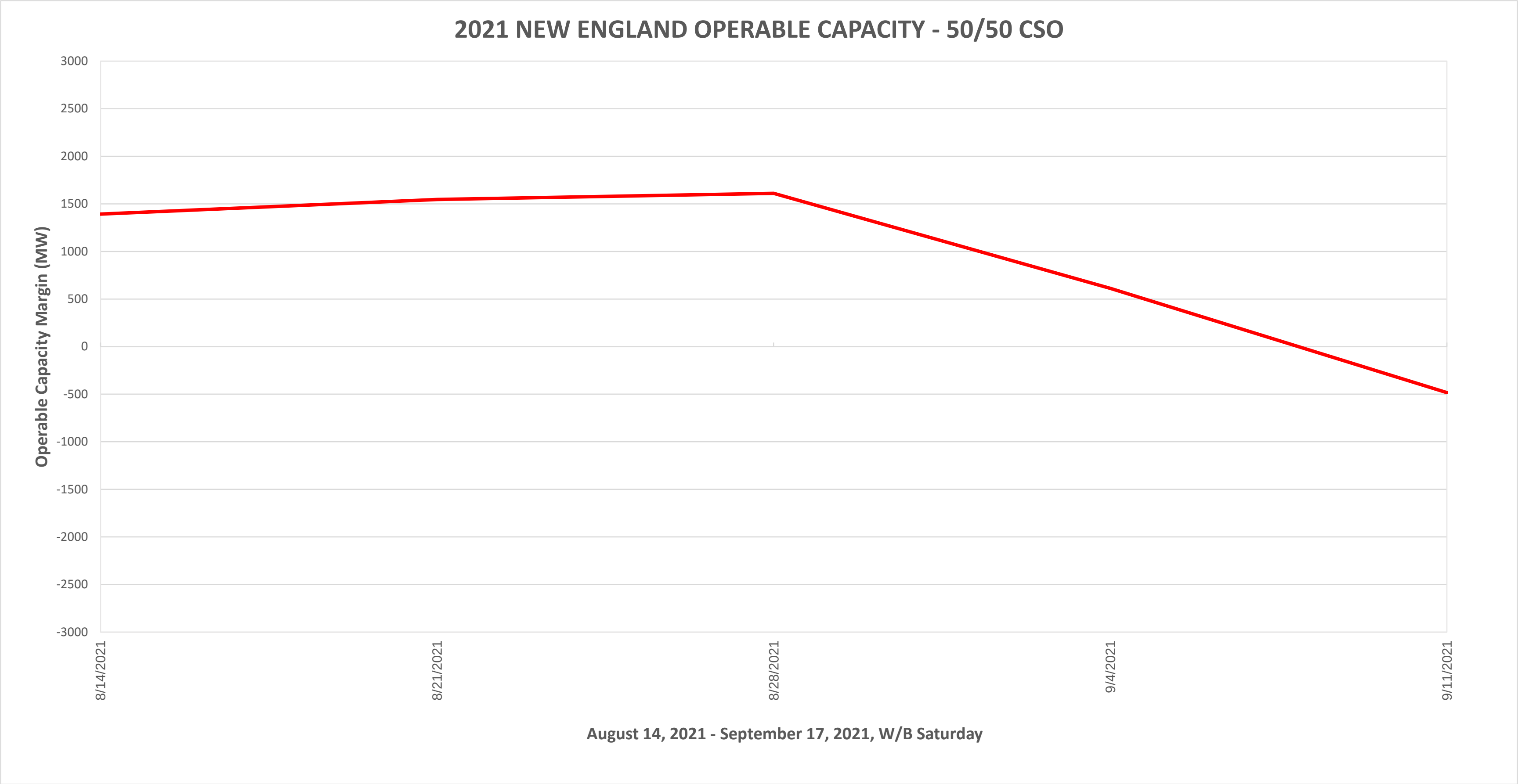
Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
8/14/2021	29150	502	1160	44	75	176	2100	0	28507	26711	2305	29016	-509	N	Summer 2021
8/21/2021	29150	502	1103	44	38	0	2100	0	28662	26711	2305	29016	-354	N	Summer 2021
8/28/2021	29150	502	1160	44	32	0	2100	0	28725	26711	2305	29016	-291	N	Summer 2021
9/4/2021	29368	540	1208	45	1334	0	2100	0	27728	26711	2305	29016	-1288	N	Summer 2021
9/11/2021	29368	540	1208	45	2063	368	2100	0	26630	26711	2305	29016	-2385	Y	Summer 2021

Column Definitions

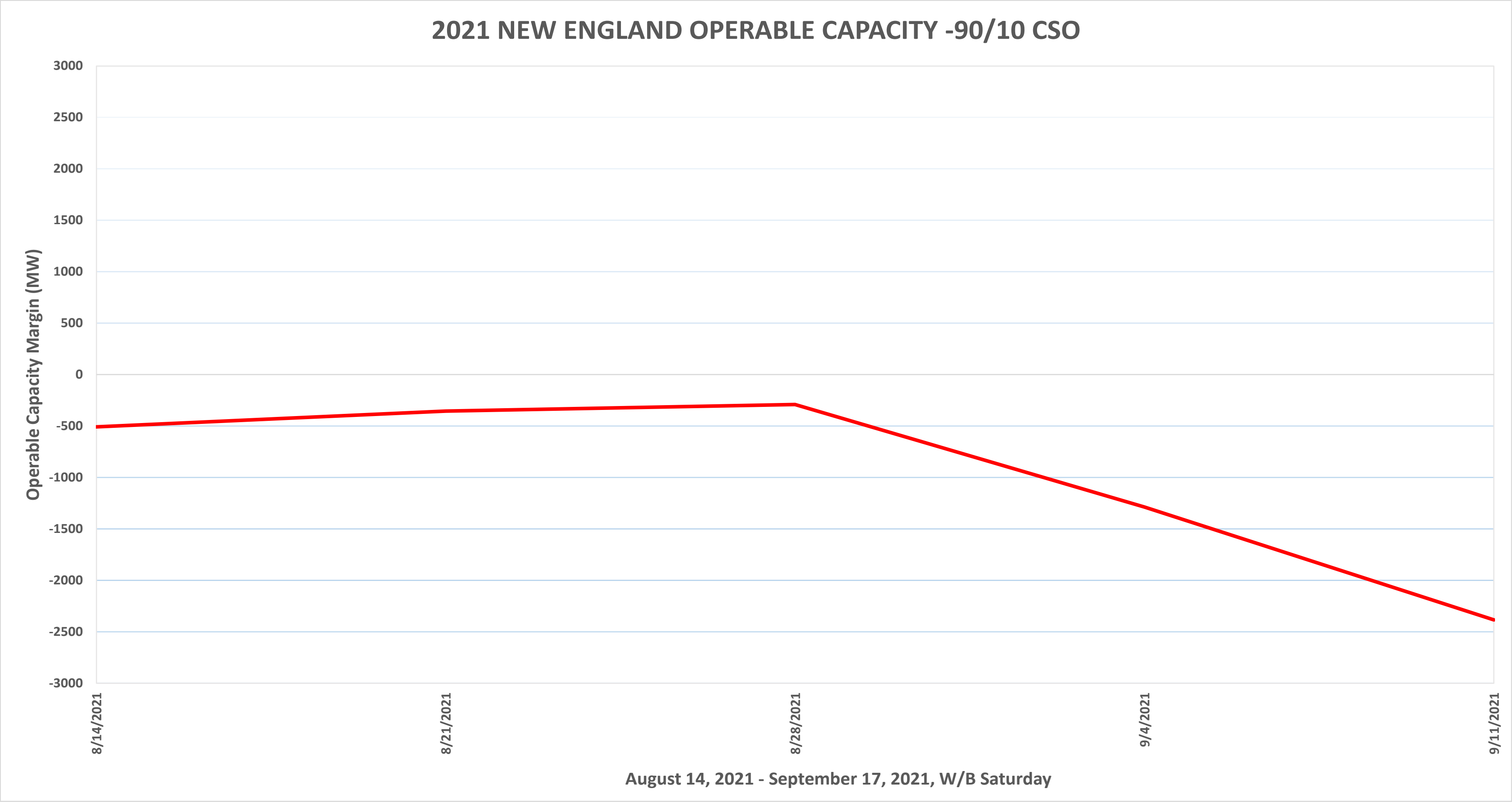
1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can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



OPERABLE CAPACITY ANALYSIS

Preliminary Fall 2021 Analysis

Preliminary Fall 2021 Operable Capacity Analysis

50/50 Load Forecast (Reference)	September - 2021[2] CSO (MW)	September - 2021[2] SCC (MW)
Operable Capacity MW [1]	29,368	29,927
Active Demand Capacity Resource (+) [5]	540	459
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	766	766
Non Commercial Capacity (+)	45	45
Non Gas-fired Planned Outage MW (-)	3,550	4,173
Gas Generator Outages MW (-)	1,992	2,045
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)	23,077	22,879
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,658	20,658
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,963	22,963
Operable Capacity Margin	115	-83

[1] Operable Capacity is based on data as of **July 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 **July 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 25, 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.

Preliminary Fall 2021 Operable Capacity Analysis

90/10 Load Forecast	September - 2021[2] CSO (MW)	September - 2021[2] SCC (MW)
Operable Capacity MW [1]	29,368	29,927
Active Demand Capacity Resource (+) [5]	540	459
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	766	766
Non Commercial Capacity (+)	45	45
Non Gas-fired Planned Outage MW (-)	3,550	4,173
Gas Generator Outages MW (-)	1,992	2,045
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)	23,077	22,879
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	22,280	22,280
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,585	24,585
Operable Capacity Margin	-1,507	-1,705

[1] Operable Capacity is based on data as of **July 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 **July 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 25, 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.

Preliminary Fall 2021 Operable Capacity Analysis 50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

July 27, 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: 7/27/2021

Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 50-50PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 50-50PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
9/18/2021	29368	540	766	45	3118	1012	2100	0	24489	20751	2305	23056	1434	N	Fall 2021
9/25/2021	29368	540	766	45	3550	1992	2100	0	23077	20658	2305	22963	115	Y	Fall 2021
10/2/2021	29751	540	1135	50	4855	3312	2800	0	20509	14789	2305	17094	3416	N	Fall 2021
10/9/2021	29751	540	1135	50	4419	3141	2800	0	21116	14825	2305	17130	3987	N	Fall 2021
10/16/2021	29751	540	1135	50	5110	3416	2800	0	20149	15749	2305	18054	2096	N	Fall 2021
10/23/2021	29751	540	1078	50	5345	2422	2800	0	20852	16113	2305	18418	2434	N	Fall 2021
10/30/2021	29751	540	1135	50	4226	1101	3600	0	22548	16320	2305	18625	3924	N	Fall 2021
11/6/2021	29751	540	1135	50	2179	1187	3600	0	24509	16435	2305	18740	5770	N	Fall 2021
11/13/2021	29751	540	1135	50	1185	767	3600	49	25875	16780	2305	19085	6790	N	Fall 2021
11/20/2021	29751	540	1135	50	1057	610	3600	816	25393	17517	2305	19822	5571	N	Fall 2021

Column Definitions

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

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

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

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

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

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

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

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

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

10. Peak Load Forecast MW: Provided in the annual 2021 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV).

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

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

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

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

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

Preliminary Fall 2021 Operable Capacity Analysis 90/10 Forecast

ISO-NE OPERABLE CAPACITY ANALYSIS

July 27, 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: 7/27/2021

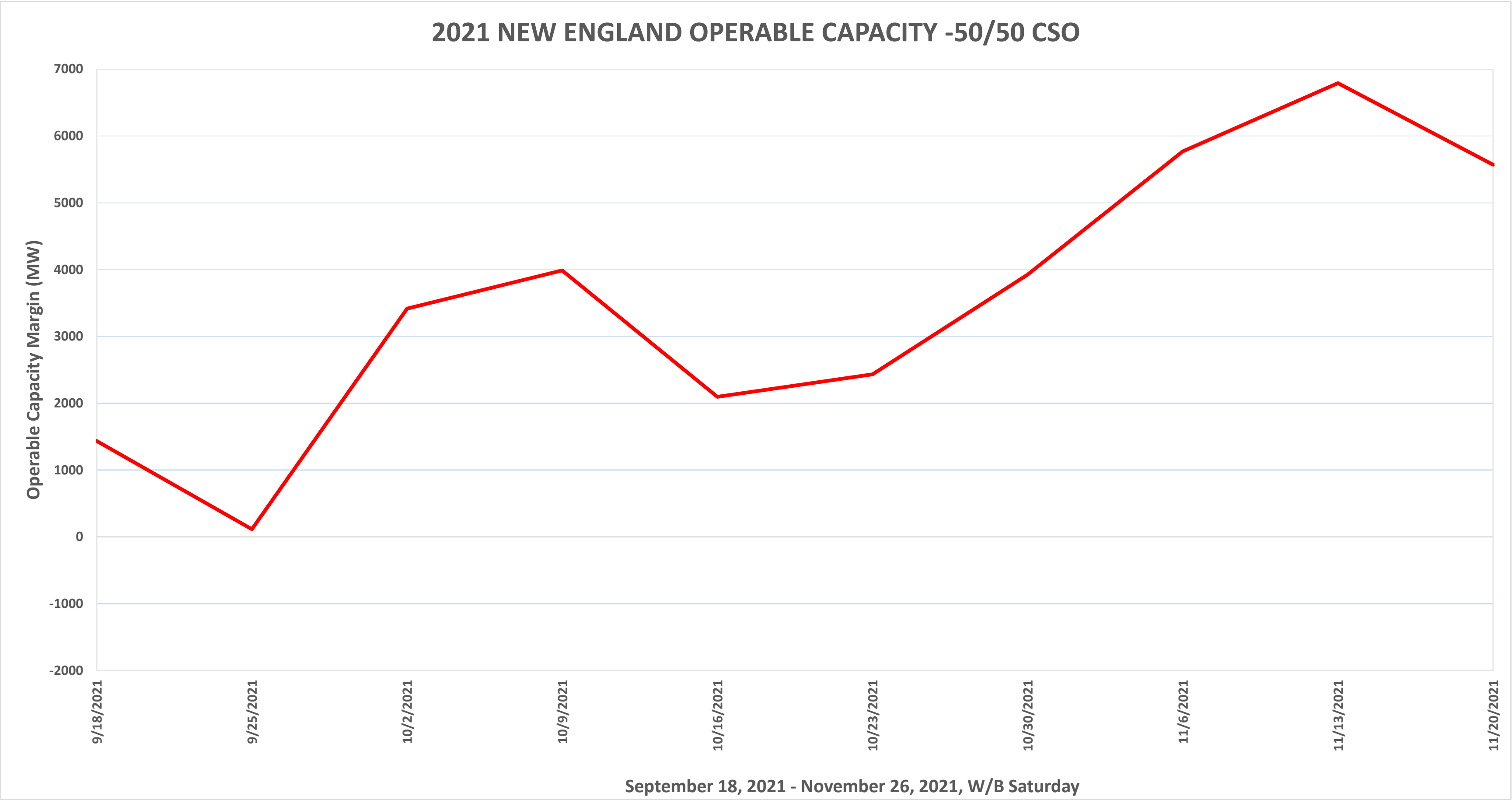
Study Week (Week Beginning , Saturday)	CSO Supply Resource Capacity MW	CSO Demand Resource Capacity MW	External Node Capacity MW	Non-Commercial Capacity MW	CSO Non Gas-Only Generator Planned Outages MW	CSO Gas-Only Generator Planned Outages MW	Unplanned Outages Allowance MW	CSO Generation at Risk Due to Gas Supply 90-10PLE MW	CSO Net Available Capacity MW	Peak Load Forecast 90-10PLE MW	Operating Reserve Requirement MW	CSO Net Required Capacity MW	CSO Operable Capacity Margin MW	Season Min Opcap Margin Flag	Season_Label
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
9/18/2021	29368	540	766	45	3118	1012	2100	0	24489	22380	2305	24685	-195	N	Fall 2021
9/25/2021	29368	540	766	45	3550	1992	2100	0	23077	22280	2305	24585	-1507	Y	Fall 2021
10/2/2021	29751	540	1135	50	4855	3312	2800	0	20509	15292	2305	17597	2913	N	Fall 2021
10/9/2021	29751	540	1135	50	4419	3141	2800	0	21116	15328	2305	17633	3484	N	Fall 2021
10/16/2021	29751	540	1135	50	5110	3416	2800	0	20149	16279	2305	18584	1566	N	Fall 2021
10/23/2021	29751	540	1078	50	5345	2422	2800	0	20852	16654	2305	18959	1893	N	Fall 2021
10/30/2021	29751	540	1135	50	4226	1101	3600	0	22548	16866	2305	19171	3378	N	Fall 2021
11/6/2021	29751	540	1135	50	2179	1187	3600	0	24509	16985	2305	19290	5220	N	Fall 2021
11/13/2021	29751	540	1135	50	1185	767	3600	415	25509	17339	2305	19644	5865	N	Fall 2021
11/20/2021	29751	540	1135	50	1057	610	3600	987	25222	18098	2305	20403	4819	N	Fall 2021

Column Definitions

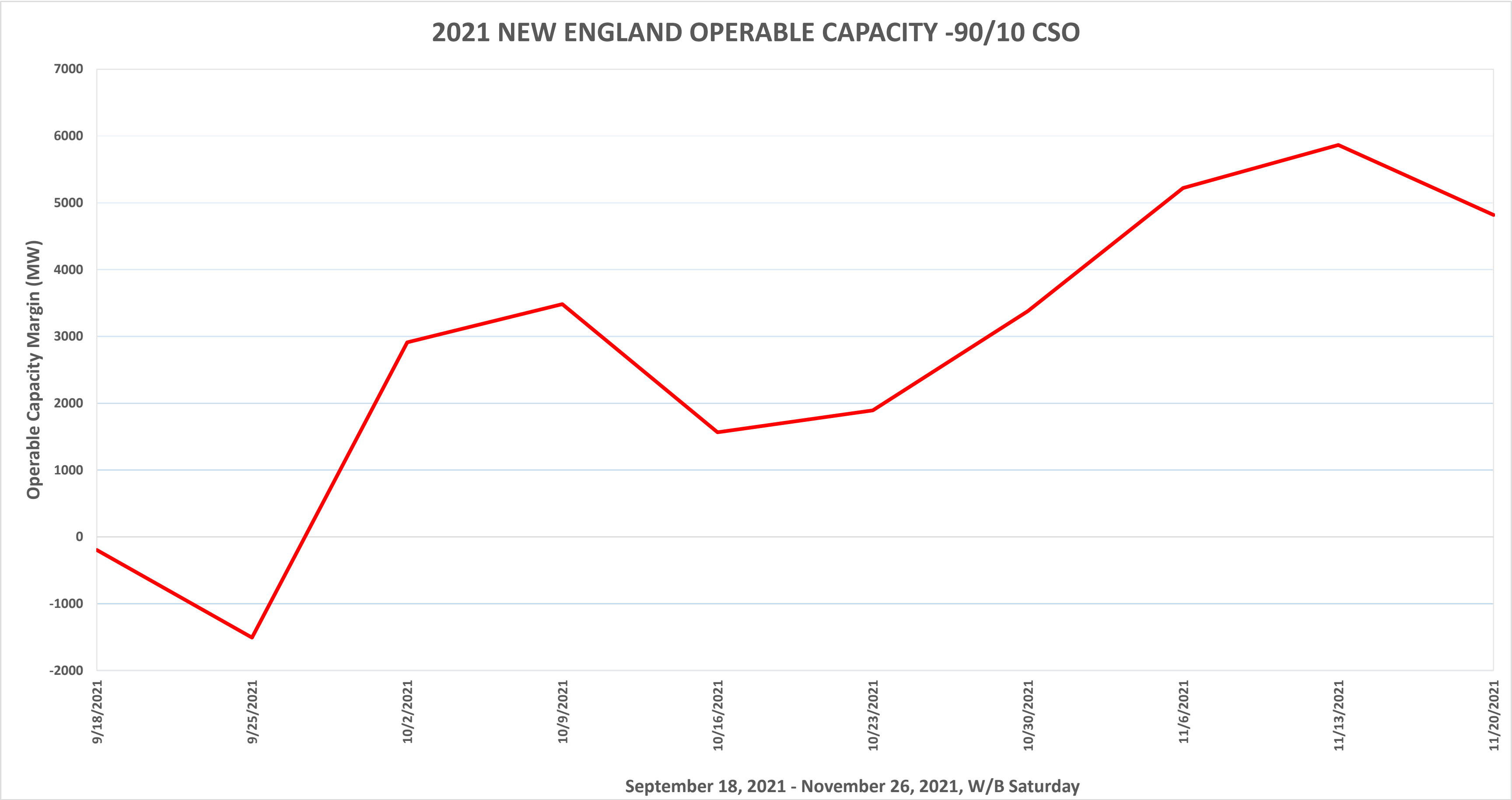
1. CSO Supply Resource Capacity MW: Summation of all resource Capacity supply Obligations (CSO). Does not include Settlement Only Generators (SOG).
2. CSO Demand Resource Capacity MW: Demand resources known as Real-Time Demand Response (RTDR) will become Active Demand Capacity Resources (ADCRs) and can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

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

Preliminary Fall 2021 Operable Capacity Analysis
50/50 Forecast (Reference)



Preliminary Fall 2021 Operable Capacity Analysis
90/10 Forecast



OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4: Appendix A

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

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

Possible Relief Under OP4: Appendix A

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

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

New England Energy Vision Statement

REPORT TO THE GOVERNORS

Advancing the Vision

NESCOE
New England States Committee on Electricity

NEW ENGLAND STATES' VISION FOR A CLEAN, AFFORDABLE, AND RELIABLE

21ST CENTURY REGIONAL ELECTRIC GRID

Submitted by:
Managers of the New England States Committee on Electricity
June 2021

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Equity & Environmental Justice Forum p. 21

Appendix A:
2020 Governors' Electricity System Reform Statement

Appendix B:
Summary - Technical Forum Written Comments

REPORT: ADVANCING THE VISION

The New England States' Vision for a clean, affordable, reliable 21st century power grid has brought about important dialogue among state and federal officials, consumers, environmental justice educators, ISO New England (ISO-NE)[1] management and Board of Directors, and electricity market participants.

> Changes to wholesale market design, transmission and ISO-NE governance are intricately tied together as we move toward a modern grid that meets needs cost-effectively.

The dialogue around each Vision Statement element - market design, transmission and ISO-NE governance - occurred at technical forums and through written comments. The discussion affirmed that all three elements are intricately tied as we move to a modern grid that meets needs cost-effectively. Since the Vision Statement's October 2020 release, significant progress has been made toward the frameworks and elements the New England states advanced jointly. That progress is described in this report.

For each of the three elements - wholesale market design, transmission and ISO-NE governance - this Report provides: a summary of the relevant Vision Statement section, a status on current activity, and recommendations. Following those sections is a summary of the relevant technical forum. That includes its objectives, speakers, and the written public comments summarized in Appendix B, all of which inform current activities and recommendations.

We are deeply grateful for the time technical forum participants contributed. They helped explain current constructs and their challenges to the public - those whom regional electricity markets exist to serve. Technical forum participants also informed and accelerated our thinking about potential solutions. We are similarly appreciative of those who provided written comments, which merit review beyond the brief summaries in Appendix B.

A Transmission technical forum speaker spotlighted concerns that transcend transmission development: the need to eliminate or mitigate equity and environmental injustices disproportionately borne by certain communities. We are especially grateful to those who participated with state officials in the subsequent *Engage with Energy* session on Equity and Environmental Justice. Certain governance recommendations in this report are important to further state officials' efforts to integrate these issues into energy infrastructure decisions.

This report is another step toward the significant work we need to execute collaboratively as states, and in partnership with the Federal Energy Regulatory Commission (FERC), ISO-NE, and the New England Power Pool (NEPOOL),[2] for the public we all serve. We look forward to taking the next steps together.

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[1] ISO-NE describes itself as "the independent, not-for-profit corporation responsible for keeping electricity flowing across the six New England states and ensuring that the region has reliable, competitively priced wholesale electricity today and into the future." See https://www.iso-ne.com/about.
[2] NEPOOL describes itself "as New England's independent, FERC-approved stakeholder advisory group on all matters relating to the competitive wholesale market rules and transmission tariff design." See https://nepool.com/about-nepool/.

Wholesale Electricity Market Design


NESCOE
New England States Committee on Electricity

NEW ENGLAND STATES' VISION FOR A CLEAN, AFFORDABLE, AND RELIABLE 21ST CENTURY REGIONAL ELECTRIC GRID

VISION STATEMENT HIGHLIGHTS

New England's existing wholesale electricity markets must modernize if they are to support achievement of clean energy laws, while maintaining system reliability and fostering more affordable electricity for regional consumers.

The New England States are committed to pursuing a new, regionally-based market framework that delivers reliable electricity service to local homes and business, but that framework must also account for and support States' clean energy laws in an efficient and affordable manner. The States believe that such a framework must, at a minimum, reflect the following principles:

- Meet States' decarbonization mandates and maintain resource adequacy at the lowest cost by using market-based mechanisms;
- Establish effective mechanisms that accommodate existing and future long-term contracts for clean energy resources executed pursuant to state law;
- Integrate distribution-level resources effectively and efficiently;
- Allow interested buyers and sellers to participate; and
- Provide for an appropriate level of state involvement in market design and implementation.

. . .

NESCOE[3] supports continued exploration of an FCEM-like framework and other wholesale market structures and reforms that address the aforementioned challenges associated with the existing capacity market design and our energy and ancillary services markets.

[3] NESCOE, the New England States Committee on Electricity, is New England's Regional State Committee. Governed by a Board of Managers appointed by each of the six New England Governors, it represents the collective views of the six New England states on regional electricity matters.

MARKET DESIGN: CURRENT ACTIVITY

ISO-NE, in collaboration with NEPOOL and NESCOE, has underway several high priority analyses in 2021 to assess a reliable future clean energy grid.

One is the ***Future Grid Reliability Study, Phase I***. NEPOOL initiated this study in 2020. This was in response to NESCOE's 2019 request to ISO-NE to dedicate market development and planning resources in 2020 to support states and stakeholders in analyzing and discussing potential future market frameworks that contemplate and are compatible with the implementation of state energy and environmental laws.

The *Future Grid Reliability Study, Phase I* is a series of engineering and economic analyses that use NESCOE and stakeholder-defined scenarios to identify grid reliability challenges that could occur in the year 2040 in light of state energy mandates and policies. ISO-NE, NEPOOL and NESCOE worked collaboratively through the NEPOOL Participants Committee to develop a consensus study approach and the scenarios. NEPOOL has submitted the request to ISO-NE as a 2021 Economic Study. ISO-NE will issue a Phase I report in the first quarter of 2022, which NESCOE will assess for its implications.

A contemplated Phase II that would assess revenue sufficiency and system security in a gap analysis is paused. ISO-NE, NEPOOL and NESCOE will consider Phase II after reviewing the results of and issues resolved through the Phase I study and other future grid-related studies. These ongoing analyses will be critical inputs into Phase II; assessing their results will enable efficiencies in how the region approaches and shapes Phase II.

"Prioritize analysis of cumulative impacts, while reducing burdens and increasing benefits to environmental justice populations ~ *Equity and Environmental Justice Forum comment*

Another study effort is ***Pathways to the Future Grid***, which ISO-NE is undertaking at the request of its Board of Directors. In this analysis, ISO-NE will evaluate the effectiveness and efficiency of two potential market frameworks in facilitating the evolution of New England's power grid that reflects state energy mandates and policies. ISO-NE will evaluate a Forward Clean Energy Market at the request of NEPOOL and NESCOE. A Forward Clean Energy Market is a centralized auction that procures clean energy attributes on a forward basis. A forward procurement would settle on a spot basis in the commitment year. ISO-NE will also evaluate a net carbon pricing framework, its preferred market mechanism. Net carbon pricing is a mechanism that charges carbon emitting generators a price per unit of carbon emitted. This cost would be reflected in generator offers into the wholesale energy market, which has the effect of increasing energy revenues for both emitting and non-emitting resources. The carbon costs collected from emitting generators is netted back to load serving entities. NEPOOL has prioritized advancing this work in a collaborative way with ISO-NE and states through dedicated meetings of its Participants Committee. ISO-NE will issue a report on this analysis in the first quarter of 2022, which NESCOE will assess for its implications.

In furtherance of a potential **Forward Clean Energy Market**, New England state officials, and separately, a diverse group of New England stakeholders, are each exploring a range of questions. These include product definition, interplay with Renewable Portfolio Standards, and authority around demand bids. These parallel efforts and information sharing between them is not to judge a Forward Clean Energy Market ahead of forthcoming analysis, but rather to help shape that analysis, to identify and narrow issues that may require more in-depth analysis and discussion, and to preliminarily assess options and inherent trade-offs.

As noted in the Vision Statement, NESCOE supported continued exploration of a Forward Clean Energy Market and **other wholesale market structures and reforms** that address the challenges associated with the existing capacity market design and our energy and ancillary services markets. NESCOE is in the early stages of considering concepts for new wholesale energy and ancillary service market mechanisms - or for improvements to the current market mechanisms - that would support the continued availability of existing highly efficient generation resources, as well as existing clean energy resources, which are needed for system reliability.

To the extent that ancillary services and energy market mechanisms are enhanced, this has the potential to de-emphasize the capacity market as a primary source of revenue for supporting resources needed for resource adequacy. In the technical forums, many panelists observed that resource adequacy needs are changing with a resource adequacy model based on summer peak load as the central focus for resource retention and incentivizing new resources becoming less important as the integration of variable energy resources increases on the grid. Reforms addressing this changing landscape must be addressed contemporaneously with other major market design reforms.

Since the Vision Statement was issued, there has been broad recognition that action is needed to prevent the **Minimum Offer Price Rule** (a federal rule requiring a minimum price for new resources entering the capacity market) from impeding the ability of resources sponsored by states from clearing in the Forward Capacity Market. Reforming this rule has become a regional priority, given the preference expressed by FERC's chairman and comments from some fellow Commissioners. ISO-NE distinguishes New England from other regional markets as requiring the rule's reform to be filed concurrent with other changes to influence capacity prices that ISO-NE believes are needed to maintain reliability, though ISO-NE has yet to provide supporting data or analysis.

Finally, there appears to be broad recognition that ISO-NE's **Competitive Auctions with Sponsored Policy Resources** market mechanism that was intended to integrate certain state-supported resources into the Forward Capacity Market is not an effective means to do so.

MARKET DESIGN: RECOMMENDATIONS

Support what will work best for consumers in considering potential new market mechanisms or adjustments to existing mechanisms. To that end,

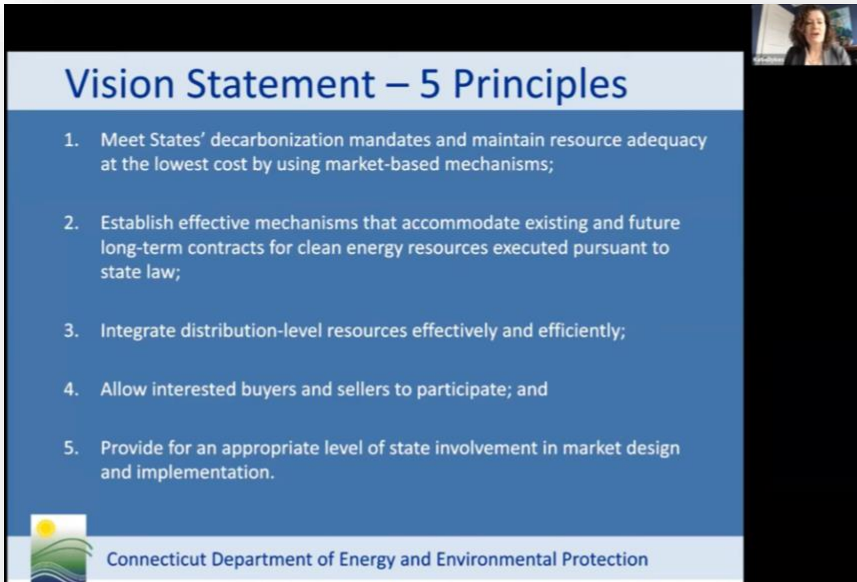
- Progress to the next level of market design detail on a regional forward market through which states may elect, at each state's option, to procure clean energy attributes. Discussion to date on such a market shows some promise compared to other designs. Such a forward, opt-in style regional market has the potential to deliver scalable clean energy that provides predictability to all market participants and appropriate flexibility for each state to make determinations about whether, when, and to what extent participation makes sense based on then-current needs. With ISO-NE and market participants, work to develop market design details and associated analyses to further inform state judgments about pursuing the implementation of such a market. This assessment will include consideration of any interim or transitional design features that may be necessary before ultimately achieving the most economically efficient form of regional forward market, including, as one example, a single regional clean energy product definition. The development of any mechanism that the states pursue to achieve state jurisdictional policy goals and mandates must carefully consider the states' role in the governance of that program.

- Continue to assess other potential market mechanisms, such as but not limited to, a market approach that supports the needs of new and existing clean energy resources. Assessment of a mechanism that supports the differing needs of new resources, as well as existing resources that help meet reliability needs, will turn in part on the design details of the forward market described above.

- Continue to explore potential new energy and ancillary service market mechanisms - or improvements to such current market mechanisms - that could support the region in reliably and cost-effectively integrating large amounts of intermittent renewable energy resources in a way that is compatible with states' decarbonization mandates.

- Engage in ISO-NE's recommended approach to eliminating the Minimum Price Offer Rule (MOPR), and any related FERC proceeding, while ensuring that any other changes that ISO-NE seeks to pair with MOPR reforms in the name of promoting system reliability are fully evaluated and justified based on verifiable data.

WHOLESALE MARKET DESIGN TECHNICAL FORUM



Markets Technical Forum Video Day 1 and Day 2

The Connecticut Department of Energy and Environmental Protection, Maine Governor's Energy Office, Massachusetts Executive Office of Energy and Environmental Affairs, New Hampshire Public Utilities Commission, Rhode Island Office of Energy Resources, and Vermont Department of Public Service held a technical forum in February 2021. The purpose was to discuss with the public wholesale electricity market design changes needed in the New England region to advance the principles identified in the Vision Statement. A complete record of the technical forums, including recordings of Wholesale Market Design forums One and Two, is available at this link.

Technical Forum Objectives

reach common understanding
- states' energy laws, policies and perspectives
- basics of the regional electricity market, NEPOOL, ISO-NE and NESCOE
- Vision Statement market design principles

discuss
- resource adequacy and approach in various regions, including jurisdictional issues
- current problems with the wholesale market design as it relates to consumer costs and state clean energy laws and mandates

explore
- proposed alternative market designs - energy only, forward clean energy market, residual capacity market, modified fixed resource requirement - and criteria for evaluation
- pros and cons of each, along with jurisdictional questions

The New England states appreciated the contribution of experts on various aspects of wholesale market design. Their presentations and biographies are available at this link.

Wholesale Market Design Speakers Session 1

New England State Officials

Identified laws, policies, perspectives that drive energy policy; highlighted state modeling related to carbon reduction goals and mandates

Dave Cavanaugh, NEPOOL Chair

Explained NEPOOL, its history and stakeholder process; reviewed relevant initiatives underway - Future Grid Reliability Study and Future Market Pathways

Eric Johnson, ISO-NE

Described ISO-NE and its role, resource adequacy, why it administers the wholesale markets and its various components - capacity, energy and ancillary services.

NESCOE Managers

Provided an overview of NESCOE and its role

New England State Officials

Discussed the wholesale market principles in the Vision Statement and why they are key to state support for market reforms

Wholesale Market Design Speakers Session 2

The Honorabale Tony Clark, Wilkinson Barker Knauer, LLP

Provided an overview of resource adequacy, how other regions approach it, and the importance of clarity around planning responsibilities; discussed forward capacity markets; summarized state/federal jurisdictional issues.

Market Participant Panel (Abby Krich, Pete Fuller, Doug Hurley, James Daly, Phil Martin)

Identified and discussed current problems with the wholesale market design as it relates to consumer costs and state clean energy laws and mandates.

Consultant/Observer Panel (Steve Corneli, Kathleen Spees/Brattle, Casey Roberts/Sierra Club, Jennie Chen)

Identified and discussed alternative market designs and concepts, such as an energy-only market, a forward clean energy market, a residual capacity market, and a modified fixed resource requirement approach.

Rob Gramlich, Grid Strategies, LLC

Discussed pros and cons of centralized procurement approaches, including jurisdictional considerations.

Transmission Planning


NESCOE
New England States Committee on Electricity

NEW ENGLAND STATES' VISION FOR A CLEAN, AFFORDABLE, AND RELIABLE 21ST CENTURY REGIONAL ELECTRIC GRID

VISION STATEMENT HIGHLIGHTS

> NESCOE supports the efficient use of existing transmission facilities and the construction of new facilities, where necessary and appropriate, to ensure the transmission grid's reliability, efficiency, and ability to integrate clean energy resources, consistent with certain States' legal requirements and other mandates.

However, ISO-NE currently does not conduct a routine transmission planning process that helps to inform all stakeholders of the amount and type of transmission infrastructure needed to cost-effectively integrate clean energy resources and DERs across the region. The need for such planning has become paramount.

NESCOE recommends that ISO-NE conduct a comprehensive long-term regional transmission planning process that involves interested stakeholders who wish to provide input into the development and implementation of a framework. As a starting point, such a framework would include the following:

1. Initiate a regional transmission planning effort that provides a high-level transmission system plan to meet the needs of States' energy transition, with participation and input by State officials,
2. Use the scenarios that have been developed and used in various States' analyses of pathways to decarbonization as a starting point for developing multiple future resource scenarios (e.g., 3-4) as the basis for assessing future regional transmission needs, and conduct a conceptual regional transmission system plan for the select future scenarios for identified timeframes (e.g., 2030, 2040 and 2050),
3. Provide needed transmission system planning information to the region, including high-level cost estimates,
4. From the conceptual system plan, conduct detailed analyses for specific scenarios, with the objective being to understand future conditions and needs, including:
    1. Onshore system upgrades, including specific areas that need strengthening,
    2. Offshore systems that may be needed to support offshore wind resources,
    3. Potential options that should be explored, including non-transmission alternatives, and
    4. The impact of DERs (both distributed generation and flexible load sources) on transmission needs,
5. With the insights gained from the scenarios used in the long-term system planning, conduct stakeholder meetings to discuss the potential use of transmission to integrate all of the necessary energy resources in the region at the lowest cost possible, and
6. Informed by States' direction, conduct detailed planning processes to maximize the use of existing transmission, build new transmission only where absolutely necessary, and use competitive processes to minimize costs to consumers.
7. After completing the steps above with States and stakeholders, ISO-NE should identify process changes that may be required, the frequency at which the process would be repeated (or the analysis updated), and the adoption of such a process into ISO-NE's routine transmission planning efforts to ensure the integration of clean energy resources at the lowest possible cost.

TRANSMISSION PLANNING: ISO-NE RESPONSE AND CURRENT ACTIVITY

The ISO-NE Board of Directors responded to the Vision Statement's transmission component by committing that ISO-NE would conduct a high-level, long-term transmission study, the *2050 Transmission Study*.

The *2050 Transmission Study* will inform the region of the amount, type and high-level cost estimates of transmission infrastructure that would be necessary to cost-effectively incorporate clean-energy and distributed energy resources and to meet New England states' energy policy requirements and goals, including economy wide decarbonization. The analysis and cost estimates are expected to include material upgrades to the distribution system necessary to integrate such a level of clean energy resources.

The analysis may affirm the need for substantial new infrastructure investment to advance state mandates and policies, including emerging reliability challenges associated with anticipated electrification of the transportation and heating sectors.

The study will look out to 2050, well beyond ISO-NE's current ten-year requirement for transmission planning to meet the region's reliability needs. This will enable the New England states to prepare for that time horizon, as well as interim points in time such as 2035 and 2040.

"Transmission planning must: 1) include a wide-array of environmental justice community stakeholders' voices during the entire planning process; 2) seek input from environmental justice populations; and 3) translate environmental justice populations' viewpoints into coherent and concrete policies." ***~ Equity and Environmental Justice Forum comment***

The *2050 Transmission Study* is not a recommendation, plan or foreshadowing of a specific transmission project to satisfy one or more New England state policy objectives or mandates. No transmission project will move forward unless one or more New England states elect to move ahead with incremental transmission infrastructure to satisfy policy requirements or mandates.

Examining the interim year 2040 will align transmission system analysis and cost estimates with the *Future Grid Reliability Study*. As discussed earlier, the *Future Grid Reliability Study*, requested by NEPOOL, is a series of engineering and economic analyses that uses NESCOE and stakeholder-defined scenarios to identify grid reliability challenges that could occur in the year 2040 in light of state energy mandates and policies. ISO-NE expects to issue a report explaining that analysis in early 2022.

The New England states and ISO-NE's transmission planning staff are actively working to identify inputs and assumptions for the *2050 Transmission Study*, as well as discussing other potential applications of the long-term planning studies. ISO-NE has agreed that proactive system planning is necessary and useful to support the states' policy directions.

Following those early conversations, and before ISO-NE commences work, the *2050 Transmission Study* will be discussed with ISO-NE's Planning Advisory Committee. This will include conversation and feedback about its scope, assumptions and inputs. The Planning Advisory Committee is a public forum in which interested persons may ask questions and provide feedback at the meeting or later in writing. These meetings are accessible to persons across the region through remote participation. The request in this report for ISO-NE to issue information about major infrastructure planning items to the Planning Advisory Committee in non-technical terms will enable community engagement and help state officials' efforts to integrate equity and environmental justice considerations into infrastructure decision-making.

> This month, FERC took two noteworthy steps toward enhanced federal-state coordination that are directionally supportive of the Vision Statement's focus on transmission system reliability, efficiency, and ability to integrate clean energy resources:
>
> - Established a Joint Federal-State Task Force on Electric Transmission that may consider issues and potential solutions related to transmission planning, resource interconnection, and cost allocation.
> - Issued a policy statement clarifying how states and other entities can enter into voluntary agreements relative to the development and funding of electric transmission facilities.
>
> The New England states welcome the opportunity to engage in these emerging developments.

This type of long-term, state-led transmission planning tool must be routine. To that end, ISO-NE has committed to developing and submitting to FERC modifications to its transmission planning tariff, the rules that govern its planning processes and activities. Revising the tariff will ensure that this flexible, scenario-based mechanism is integrated into the planning process, providing critical insight into transmission system needs and costs that result from state mandates and policies. ISO-NE has indicated that work on tariff language will begin by the third quarter of 2021.

TRANSMISSION PLANNING: RECOMMENDATIONS

- Continue to inform and define the *2050 Transmission Study*, with input from stakeholders. Assess the results of the *2050 Transmission Study* and, leveraging insight gained from the scenario analysis, determine collective or individual state interest in exploring the use of "competitive processes to minimize costs to consumers" consistent with the Vision Statement and in furtherance of state policies or mandates.

- Work with ISO-NE and stakeholders to ensure that ISO-NE's transmission planning tariff is reformed on a timely basis to implement a state-led, proactive scenario-based planning process for long-term analysis of state mandates and policies as a routine planning practice.

- Proactively engage in and shape other anticipated transmission system planning reform efforts, such as updating ISO-NE's rules to provide states with a more meaningful role in the evaluation and selection of public-policy driven transmission projects and continue to explore ways to improve the process to interconnect clean energy. This recommendation is also important to enabling state officials' efforts to integrate equity and environmental justice considerations in each state into infrastructure decision-making.

TRANSMISSION PLANNING TECHNICAL FORUM

Transmission Planning Technical Forum Video

The Connecticut Department of Energy and Environmental Protection, Maine Governor's Energy Office, Massachusetts Executive Office of Energy and Environmental Affairs, New Hampshire Public Utilities Commission, Rhode Island Office of Energy Resources, and Vermont Department of Public Service held a technical forum in February 2021. The purpose was to discuss with the public transmission planning changes needed in the New England region to advance the priorities identified in the Vision Statement. A complete record of the technical forum, including a recording, is available at this link.

Technical Forum Objectives

reach common understanding
- states' position on regional market and system needs
- current transmission planning process

discuss
- magnitude of system needs
- need to maximize use of existing system
- importance of environmental justice in planning and developing transmission projects

share
- knowledge of how other system planners are developing plans to meet the needs of the future

The New England states appreciated the contribution of experts on various aspects of transmission planning. Their presentations and biographies are available at this link.

Transmission Speakers

Bob Ethier, ISO-NE, VP of System Planning
Provided a simplified summary of ISO-NE's current transmission planning process

Bill Quinlan, Eversource, President of Transmission
Provided a synthesis of states' simulated future electricity load and resource mix, including distributed energy resources, in the context of transmission needs

Dr. Biljana Stojkovska, National Grid Electricity System Operator
Gave an overview of the United Kingdom's analysis in planning for offshore wind grid to meet clean energy goals

Marc Montalvo, Daymark Energy
Discussed the traditional drivers of transmission needs and the new paradigm for transmission needs, and how the traditional planning process needs improvement

Rebecca Tepper, Office of the Massachusetts Attorney General
Described the importance of maximizing the use of the existing system by using advanced technologies to reduce environmental and ratepayers' cost impact

Sharon Lewis, Executive Director of Connecticut Coalition for Environmental Justice
Explained the importance of environmental justice when planning and developing transmission

Craig Price, Australia System Operator (AEMO)
Shared Australia's experience with scenario-based long-term transmission planning

ISO-NE GOVERNANCE


NESCOE
New England States Committee on Electricity

NEW ENGLAND STATES' VISION FOR A CLEAN, AFFORDABLE, AND RELIABLE
21ST CENTURY REGIONAL ELECTRIC GRID

VISION STATEMENT HIGHLIGHTS

> ISO-NE's mission and governing structure were established when the electric industry was restructured about twenty-five years ago. At that time, regional planning and markets had relatively marginal interaction with the requirements of state laws: markets were to be fuel-neutral, transmission needs were largely reliability-based, and states were to achieve their clean energy goals through the new Renewable Portfolio Standards. Today, we need all that, and more.

Accordingly, as noted above, in July 2019, NESCOE called for an assessment of ISO-NE's wholesale market objectives, market designs, and mission statement given these changed circumstances and legal requirements.

Just as the time is right for a holistic relook at markets and transmission planning, so too is it time to ensure ISO-NE's mission and governance keep pace with changes in law and a transitioning energy system.

ISO-NE's governance does not give a sufficiently meaningful voice to State and consumer interests and its mission statement does not reflect the relationship between ISO-NE's functions and the New England States' legal requirements, policy imperatives, and associated consumer interests.

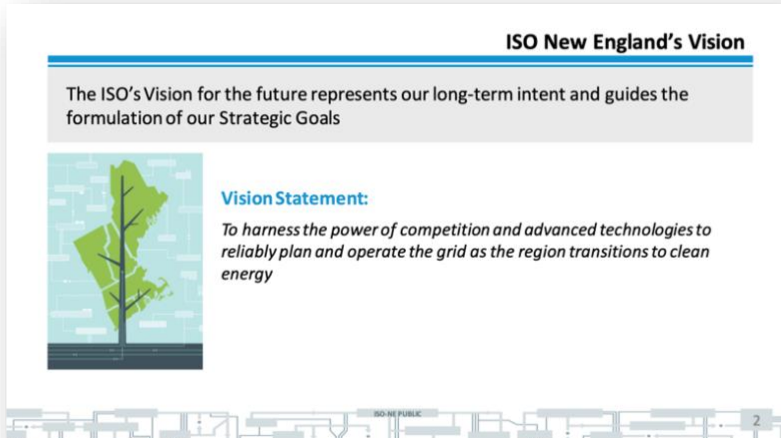
Beginning in 2021, ISO-NE and its Board should convene a collaborative process with States and stakeholders to identify potential changes to its mission statement and governance structure that improve transparency and foster improved alignment with a rapidly-evolving 21st century clean energy grid. As part of this process, NESCOE seeks to explore reform of ISO-NE governance to achieve greater transparency around decision-making, a needed focus on consumer cost concerns, and support for States' energy and environmental laws.

Commencing that discussion next year affords time now for the States and stakeholders to consider best governance practices that other grid operators have adopted and to review other relevant information. Doing so will permit the gathering of constructive ideas on how to ensure that ISO-NE's management and Board become more transparent and accountable to the public in their decision-making, including meaningful consideration of consumer interests and States' energy and environmental requirements.

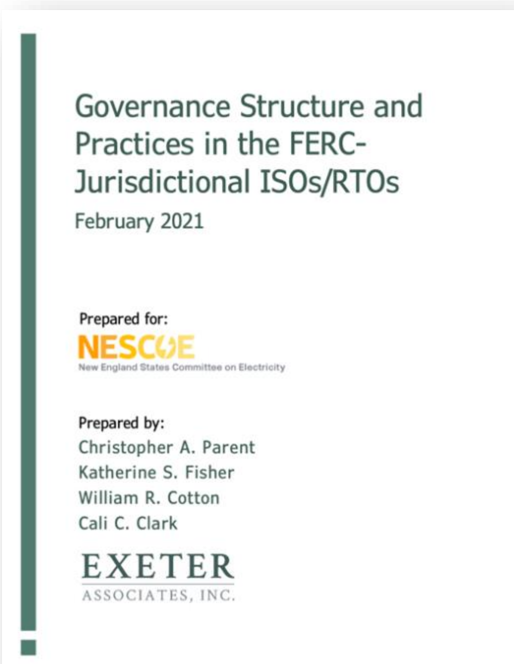
The States expect that any governance changes pursued through this collaborative process should be informed by consideration of the issues raised in this Vision Statement, including, but not limited to: (1) whether the process for identifying and recommending ISO-NE Board members provides State officials with an appropriately meaningful role that is commensurate with the public interest, (2) the interplay described in this Vision Statement between the requirements of State laws and regional planning and markets, and (3) the lack of transparency in ISO-NE management and Board of Director decision-making.

ISO-NE GOVERNANCE: ACTIVITY

ISO-NE adopted a Vision Statement to guide its Strategic Goals in November 2020. The Vision has important echoes of the states' 2020 Vision Statement in recognizing the transition to clean energy.



NESCOE commissioned Exeter Associates, Inc. to produce a report, *Governance Structure and Practices in the FERC-Jurisdictional ISOs/RTOs*. The full report, issued in February 2021, is available at this link.


Governance Structure and Practices in the FERC-Jurisdictional ISOs/RTOs
February 2021

Prepared for:
NESCOE
New England States Committee on Electricity

Prepared by:
Christopher A. Parent
Katherine S. Fisher
William R. Cotton
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EXETER
ASSOCIATES, INC.

The report provides a summary of the governance structure and practices of the six FERC-jurisdictional independent system operators and regional transmission organizations (ISOs/RTOs): California ISO, New York ISO, ISO New England, Midcontinent ISO, PJM Interconnection, and Southwest Power Pool.

The report does not capture every nuance of governance, but rather provides a macro view across the different ISOs/RTOs for comparison and discussion purposes. Matrices produce a summary comparison of the key aspects of the governance structure and practices across the six regions. The report helps to identify both simple practices that ISO-NE could adopt on its own initiative without the need for tariff reforms and those that would require a stakeholder process and FERC consideration and approval.

Shortly after the Vision Statement issuance, the **ISO-NE Board of Directors** indicated an intent to discuss governance issues.

The **ISO-NE Board of Directors' Nominating and Governance Committee** agenda indicates it discussed the technical forum on Governance in March 2021. A subsequent Board Report confirms "[t]he Committee discussed comments regarding the need for improved Board transparency," although it offered no additional information. The May 2021 agenda indicates it is formulating a proposal regarding Board transparency. The June 2021 Board Report explains that "[T]he Committee also discussed the governance component of the states' vision document" without further elaboration.

ISO-NE GOVERNANCE: RECOMMENDATIONS

- The assessment of governance practices used by other regional transmission operators and discussion of governance reforms described below reveal a number of best practices that would enhance ISO-NE's transparency and accountability. Some are within ISO-NE's discretion and could be implemented quickly. The Vision Statement called on ISO-NE and its Board to "convene a collaborative process with States and stakeholders to identify potential changes to its mission statement and governance structure that improve transparency and foster improved alignment with a rapidly-evolving 21st century clean energy grid." To date, agendas of an ISO-NE Board Committee indicate governance and transparency discussion; however, no process has been convened or proposal advanced.

  The New England States call on ISO-NE to adopt the following practices and governance reforms, at a minimum:

  - ISO-NE Board of Directors establish a standing Board of Director Committee on State and Consumer Responsiveness, with a charter that includes explicit assessment of consumer costs and interests in fulfilling its responsibilities, and consideration of how state requirements and mandates interact with and should be accounted for as part of ISO-NE's work and mission. State officials should be invited to attend and participate in discussions of this Committee as non-voting participants. Such Committee will also assist state officials' efforts to integrate equity and environmental justice considerations.

- ISO-NE Board of Directors schedule at least annual public meetings of its Board of Directors to allow states and the public to hear from Board members on current issues and priorities. Holding some public Board meetings in the evenings, after traditional work hours, will increase public accessibility for all communities.

- ISO-NE Board of Directors provide increased substantive detail in Board reports and minutes to inform the public and stakeholders about the Board's decision-making, including how it balanced different interests in making decisions and issuing guidance to ISO-NE management.

> Supplementing reports and summaries with material explained in non-technical terms will enhance transparency and accessibility for all communities, as well as state officials' efforts to integrate equity and environmental justice considerations into decision-making

- ISO-NE management issue public summaries of reports to the Board in those circumstances when there are alternative proposals in order to provide some visibility into the information upon which the Board and management bases decisions that affect New England electricity consumers.

- ISO-NE updates its mission statement to appropriately balance and account for consumer and state interests in exercising its authority to affect electric power rates and system reliability, designing and implementing markets and market rules, and planning for the interconnection of resources providing service to the regional grid.

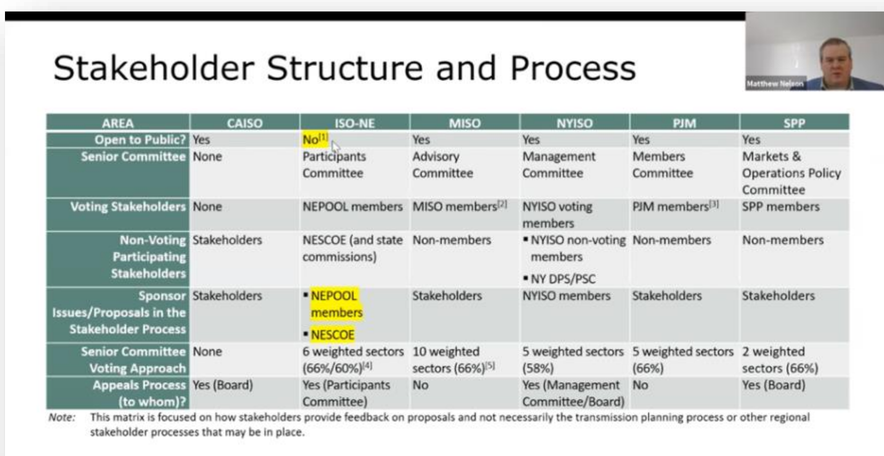
- In circumstances where ISO-NE rejects a proposal or amendments supported by at least a majority of the six New England states, ISO-NE details in writing prior to the NEPOOL Participants Committee vote on such matter how it balanced consumer costs and other state interests against other factors.

- In connection with the development of future ISO-NE market rule changes, where such changes seek to execute or integrate state energy and environmental policies and requirements, ISO-NE should collaborate with the states to propose a form of shared section 205 rights with states.

> "States should have a stronger role in ISO-NE and NEPOOL processes, so that they can further the intent of their environmental justice laws and policies." ~ *Equity and Environmental Justice Forum comment*

- The New England states would also support FERC revisiting the ISO/RTO governance and process requirements set out in Order No. 719, issued over a decade ago, to ensure, among other things, that states and consumers in New England are meaningfully represented in: (i) the composition of ISO-NE's Board of Directors, (ii) the Joint Nominating Committee process that governs Board nominations, and (iii) ISO-NE's mission statement. Additionally, governance procedures must provide appropriate public access to, and transparency into, ISO-NE management and Board decision-making. This includes but is not limited to material that is presented in non-technical terms to enable accessibility by all communities.

ISO-NE GOVERNANCE TECHNICAL FORUM



ISO-NE Governance Technical Forum Video

The Connecticut Department of Energy and Environmental Protection, Maine Governor's Energy Office, Massachusetts Executive Office of Energy and Environmental Affairs, New Hampshire Public Utilities Commission, Rhode Island Office of Energy Resources, and Vermont Department of Public Service held a technical forum in February 2021. The purpose was to discuss with the public regional transmission system operators' governance practices and reforms needed in the New England region to advance the priorities identified in the Vision Statement. A complete record of the technical forum, including a recording, is available at this link.

Technical Forum Objectives

reach common understanding
- current ISO-NE governance practices and processes
- states' concerns about transparency, accountability, and mission statement alignment

gather
- information about consumer- and state-responsive governance frameworks

discuss
- elements of existing governance pratices and procesess that should be preserved
- alternative governanance practices and processes that should be considered

The New England states appreciated the contribution of experts in various aspects of regional system operator governance. Their presentations and biographies are available at this link.

Governance Speakers

Anne George, ISO-NE, Vice President External Affairs and Corporate Communications
Provided an introduction and overview of current governance practices, including state engagement, decision-making, board selection

Panel: Anne George/ISO-NE, Doug Hurley/Synapse, Christina Belew/MA AG, Matt Nelson/NESCOE Managers
Identified and discussed current problems and areas of improvement with governance in the State/NEPOOL/ISO-NE structure

Panel: Prof. Stephanie Lenhart, Christina Simeone, Prof. Seth Blumsack, Steve Gaw
Gave an overview of Lessons Learned: Governance in other Regions

Prof. Michael Dworkin
Reflected on Governance Over the Past 15 Years

Panel: Prof. Kate Konschnik (moderator), Travis Kavulla/NRG, Prof. Shelley Welton, Michael Panfil
Discussed alternative governance frameworks and options to improve the existing governance process

Equity and Environmental Justice Forum

Equity and Environmental Justice Forum Video

The Connecticut Department of Energy and Environmental Protection, Maine Governor's Energy Office, Massachusetts Executive Office of Energy and Environmental Affairs, New Hampshire Public Utilities Commission, Rhode Island Office of Energy Resources, and Vermont Department of Public Service held a public forum on the evening of March 18, 2021 to talk about equity and environmental justice concerns related to the Vision Statement. This state official hosted forum was incremental to and not a substitute for the regular public input and comment opportunities administered by state officials in state agency proceedings and other forums.

A recording of the Equity and Environmental Justice Forum, which had several hundred attendees, is at this link. The purpose was to introduce the broad range of issues in the Vision Statement and to afford an opportunity for participants to question and discuss it with state officials. In addition to engaging about the Vision Statement, the forum welcomed comment on other questions, as follows:

- What energy challenges exist in your community?
- When you think about energy, what matters most to you?
- What changes to the energy system would you most like to see?
- What are the biggest barriers to changing our energy system?
- What ways can state governments better engage people on energy issues?
- What is your vision for our energy future?

After the forum, fourteen individuals and organizations submitted written comments including: Aaron Goode, Acadia Center, Brian Campbell, Clifford Krolick, Community Action Works, Darla Bruno, Environmental Defense Fund, Hannah Metzger, Innu Nation of Labrador, Letecia Colon de Mejias, Massachusetts Climate Justice Working Group, Northeast Clean Energy Council – Advanced Energy Economy – Sunrun – Enel, Regina Cornwell, and William Lynch. The comments are at this link.

EQUITY AND ENVIRONMENTAL JUSTICE: NEXT STEPS

Pursue creation of an *Ad Hoc State Work Group on Equity and Environmental Justice in Energy Infrastructure*, comprised of New England state officials with policy, permitting, siting, and regulatory authorities. Such group would work with the participation of regional partners, including for example, ISO-NE leadership, NEPOOL sector representatives, environmental justice representatives, academic experts, FERC, and others. Initial goals would include identifying barriers to integrating individual states' environmental justice considerations into the regional planning processes and to develop best practices that seek to address these barriers over time.

Preliminarily, and in advance of such best practices work group, some near-term action items will facilitate transparency and accessibility in regional electricity matters for all communities. NESCOE will:

- Share the Engage with New England Energy forum comments and requests with ISO-NE leadership and state officials in each New England state with energy infrastructure planning, permitting and siting authority.

- Suggest that the ISO-NE's Planning Advisory Committee, an open public forum, consider issuing supplemental meeting material that describes the major infrastructure agenda items briefly in non-technical language.

- Suggest that the ISO-NE's Regional System Plan include a supplement that explains the primary findings and project list in non-technical language.

APPENDIX A
October 2020 Governors' Statement

NEW ENGLAND'S REGIONAL WHOLESALE ELECTRICITY MARKETS AND ORGANIZATIONAL STRUCTURES MUST EVOLVE FOR 21ST CENTURY CLEAN ENERGY FUTURE

A clean, affordable, and reliable regional electric grid – together with transparent decision-making processes and competitive market outcomes that fully support clean energy laws – is foundational to achieving our shared clean energy future. Connecticut, Maine, Massachusetts, Rhode Island and Vermont are deeply committed to addressing climate change and cost-effectively reducing economy-wide greenhouse gas emissions by at least 80 percent below 1990 levels by 2050, recognizing some states have higher goals. To achieve these goals, we need a decarbonized grid capable of supporting the accelerated adoption of more sustainable electric, heating, and transportation solutions for families and businesses. Moreover, the region's electric markets must account for the full value of on-going state investments in clean energy resources made pursuant to our laws.

Going forward, we require a regional electricity system operator and planner that is a committed partner in our decarbonization efforts, and will:

1. ***Proactively develop market-based mechanisms, in concert with state policymakers, that facilitate growth in clean energy resources and enabling services, while fully accounting for on-going renewable energy investments made pursuant to enacted state laws;***

2. ***Conduct best-in-class system planning activities that proactively address our clean energy needs;***

3. ***Ensure grid resiliency and reliability at least cost in a manner that is responsive to state and consumer needs; and***

4. ***Adopt an organizational mission and structure to reflect our energy transition and establish a higher degree of accountability and transparency to the participating States and other stakeholders.***

Our States have long supported open, competitive market-based mechanisms as a primary means to meet the resource adequacy and reliability needs of our shared electricity grid. Our States restructured the markets for electric generation and retail supply in the 1990s (with the exception of Vermont), and rely on FERC jurisdictional markets and an Independent System Operator (ISO-New England) to operate the regional power system, implement competitive wholesale markets, and ensure open access to the transmission system. As our States accelerate efforts to expand clean energy resources and combat the global challenge of climate change, we now seek to better align our regional competitive markets with the achievement of our decarbonization goals.

Long-range modeling efforts conducted in our States are providing an increasingly clear picture of the electricity system that will be needed to support deep economy-wide decarbonization. The gap between our current system and the system we need to achieve deep decarbonization is marked. Today's wholesale electricity market and organizational structures: (1) are based on a market design that is misaligned with our States' clean energy mandates and thereby fails to recognize the full value of our States' ratepayer-funded investments in clean energy resources; (2) lack a proactive transmission planning approach and tools that facilitate the development of a future system with more clean, dynamic and distributed resources; and (3) are based on a governance structure that is not transparent to the states and customers it serves, with a mission that is not responsive to States' legal mandates and policy priorities. Recognizing these shortfalls, it is time to make the necessary changes to meet the challenges of our 21st century energy transition.

Working together, in consultation with the New England States Committee on Electricity (NESCOE), we have developed a Vision document outlining areas where reform is vital if New England is to achieve its carbon-reduction goals. In the coming months, our States will convene open and accessible forums to ensure that all interested stakeholders have an opportunity to participate in further refinement of our shared Vision for market reform, system planning, reliability, and governance. Through ongoing collaboration with all interested parties, our States are committed to realizing long-lasting, functional, and transparent market-based solutions that will truly facilitate New England's clean energy future.

Charlie Baker
Governor of Massachusetts

Ned Lamont
Governor of Connecticut

Janet Mills
Governor of Maine

Gina Raimondo
Governor of Rhode Island

Phil Scott
Governor of Vermont

APPENDIX B
SUMMARY OF WRITTEN PUBLIC COMMENTS

Wholesale Market Design: Written Public Comments

The New England states appreciate the interest and input from a wide variety of stakeholders on wholesale electricity market design. Below is a summary of comments submitted to the New England states after the Wholesale Market Design technical forums.[1] They will continue to inform ongoing state and stakeholder deliberations. The comments are available in their entirety at this link.

Acadia Center, Conservation Law Foundation, Natural Resources Defense Council, and Sierra Club (collectively, "Public Interest Organizations")

Public Interest Organizations observes that current market structures increasingly conflict with state policy priorities and expresses concerns over the pace and trajectory of change, high consumer prices, and surplus resources. Public Interest Organizations comment on certain alternative market designs over the long term and other market reforms in the near term. Public Interest Organizations recommend changes to the capacity market and the prices at which clean energy resources are permitted to offer supply into this market. Public Interest Organizations also recommend reforms to energy and ancillary services markets that provide proper price signals to and enable greater participation of renewable generation, advanced technologies, and customer-side resources. Public Interest Organizations urge continued effort to implement and strengthen climate and clean energy laws and continued use of state-led competitive procurements while, in parallel, supporting longer-term market reforms. Public Interest Organizations provide specific recommendations for near-term changes to current market design and express skepticism regarding an incremental price on carbon emissions. Public Interest Organizations encourages addressing current market design issues before adding additional wholesale market designs and objectives.

Advanced Energy Economy, Enel X North America, Northeast Clean Energy Council, and Sunrun ("Advanced Energy Stakeholders")

Advanced Energy Stakeholders offer a set of guiding principles for economically and environmentally sustainable outcomes. Advanced Energy Stakeholders view reform of the Forward Capacity Market as centrally important to the goal of achieving the states' energy and environmental goals and contend that the proposed Integrated Clean Capacity Market (ICCM)[2] could align with their guiding principles, if designed and implemented

[1] The comment summaries in this Report are intended to provide a brief sense of commenters' perspectives. The summaries are not intended to be comprehensive or to reflect states' positions. All comments warrant direct review.
[2] This design integrates the Forward Clean Energy Market into the Forward Capacity Market.

appropriately. Advanced Energy Stakeholders offer views on some wholesale market design issues and alternate proposals.

Guiding Principles for recommended next steps:

- Ensure states' priorities are respected in competitive wholesale markets
- Maintain reliability at a reasonable cost to customers
- Leverage regional, competitive solutions and promote durable, predictable markets
- Make full use of flexible demand and empower customers to contribute to the energy transition through investments in distributed energy resources
- Define and procure needed grid services through technology-neutral markets
- Remove existing barriers to market entry for new technologies and facilitate market exit of resources no longer needed to meet regional needs

Alternative market design observations: Advanced Energy Stakeholders contend that regional market-based approaches are preferable to alternative resource adequacy constructs and state-by-state resource adequacy plans in attracting diverse, cost-competitive new advanced energy resources and maintain existing advanced energy resources. Advanced Energy Stakeholders also contend that alternative resource adequacy constructs and state-by-state resource adequacy plans increase reliability and cost risks for individual states that may arise from portfolios they construct. Advanced Energy Stakeholders state that regional competitive markets help to mitigate and share risks, whereas residual capacity market and energy-only market designs increase risks. Advanced Energy Stakeholders view an ICCM and carbon pricing as consistent with its guiding principles and as potentially promising solutions.

Next steps: Advanced Energy Stakeholders recommend the New England states continue proactive and vocal engagement on wholesale market reforms, especially in the NEPOOL process and through active discussion with ISO-NE and the ISO-NE Board. Advanced Energy Stakeholders also request the New England states provide periodic updates on progress related to this work and to concurrently strive to identify any state law changes that may be indicated through the future market framework and pathway process.

American Clean Power Association

American Clean Power Association promotes market designs that foster competition and enable development of clean, affordable and reliable power. To that end, American Clean Power Association describes an alternative market design framework. American Clean Power Association contends that the "Capacity as a Commodity" market design that values reliability and consumer choice is superior to the current capacity market design. American Clean Power Association supports an online exchange reflecting bilateral market transactions to meet consumer choice objectives that is also supplemented by a centralized auction to meet remaining reliability requirements.

Environmental Defense Fund

Environmental Defense Fund recommends the states reaffirm the principles that will be applied when evaluating potential market designs for decarbonizing the region's electricity sector in a responsible and equitable manner. Environmental Defense Fund seeks guidance from states on the types, amounts, and timing of necessary balancing services relative to the growing share variable energy resources. Environmental Defense Fund contends that analysis of and eligibility to provide ancillary services should be technology neutral.

FirstLight Power

FirstLight strongly supports decarbonizing the electric grid at a pace and scale commensurate with emissions reduction targets. FirstLight contends that to create a system that is simultaneously clean, affordable and reliable, contributions will be needed from new and existing renewable resources, and new and existing storage resources, as well as energy efficiency and other demand-side resources. FirstLight recommends a focus on equitable compensation of existing zero-carbon resources and electric storage. FirstLight contends that the best outcomes for the states' consumers will be achieved by transporting clean energy delivered during periods of low demand (e.g., midday peak solar contributions, or possibly the highest clean generation periods of offshore wind) to periods of greater reliability or emission reduction needs using electric storage. Accordingly, FirstLight recommends market designs that differentiate the value of clean energy by the timing of clean energy delivery.

Hull Street Energy

Hull Street Energy identifies the importance of building a stable framework for attracting and retaining private capital investment over time, insulated from shifts in state priorities and changes to energy policy. Hull Street Energy recommends a technology-neutral approach to market design that automatically adapts to technology changes over time. Hull Street Energy recommends treating new and existing resources comparably. Hull Street Energy seeks to better understand how environmental externalities can be incorporated into the power market without pricing carbon dioxide emissions to a greater extent.

Mark Montalvo of Daymark Energy Advisors

Mr. Montalvo recommends that market design objectives be updated to align pricing incentives with current state policy objectives. Mr. Montalvo recommends an approach that clearly defines the attributes desired by state policy objectives and structures a procurement mechanism that acquires a portfolio that, in the aggregate, meets the demand for such attributes. Mr. Montalvo espouses simplicity in market design and observes that any potential market reforms must evaluated against the efficacy of state-led competitive solicitations.

New England for Offshore Wind

New England for Offshore Wind supports regional collaboration in designing a market that appropriately values clean energy resources and aligns with states' climate mandates. New England for Offshore wind supports the states' recommendation to establish market mechanisms that accommodate existing and future long-term contracts for clean energy resources executed pursuant to state law. New England for Offshore Wind prefers that any future clean energy market design appropriately values social, economic, and environmental benefits such as environmental and wildlife protection, equity, and economic development. New England for Offshore Wind urges a continued push for offshore wind procurements and regional collaboration to the extent possible to capture economies of scale as well as regional social and economic benefits.

New England Power Generators Association (NEPGA)

NEPGA supports identification of economically efficient, market-based solutions that can help states meet legal obligations while maintaining long-term system reliability and competitive market outcomes. NEPGA observes consumer benefits associated with electricity restructuring and associated transfer of investment risk from ratepayers to competitive market participants and related economic and environmental benefits from a cleaner and more efficient generation portfolio. NEPGA supports measures to address climate change and invest in enabling electricity infrastructure through a price on carbon dioxide emissions and through reliability products and services. NEPGA emphasizes a need for a sustainable and durable market design to support competitive revenue opportunities for all resources, including resources that provide firm, flexible, and/or dispatchable energy as well as low- and zero-carbon emissions. NEPGA perceives long-term contracting outside of regional wholesale markets as presenting financial risks to existing competitive resources needed for reliability and clean energy generation. NEPGA seeks to work collaboratively to develop a durable, long-term market solution that facilitates orderly entry and exit of resources and balances inclusion of renewable and zero-carbon generation and competitive market outcomes.

RENEW Northeast

RENEW supports competitive approaches for wholesale market compatibility with achieving state clean energy and climate policies. RENEW perceives a need for resource-neutral reforms to wholesale markets, clearly defined reliability criteria for balancing services[3] in a future with high penetrations of variable energy resources, and proper compensation for existing non-emitting resources, including a price on carbon dioxide emissions. RENEW favors a two-pronged approach to reforms that includes continued clean energy procurements in parallel with future changes to competitive wholesale markets.

Vistra Corporation

Vistra supports comprehensive and durable market reform that enables states to achieve clean energy goals while preserving the benefits of regional markets. Vistra observes two prominent approaches for achieving state carbon emissions reduction goals within the wholesale markets: carbon pricing and a clean energy standard, with a preference for carbon pricing. Vistra highlights unresolved details related to proposed market designs and recommends retaining resource neutrality to the extent possible. Vistra urges continued effort toward developing sustainable market designs.

[3] Balancing services are generally meant as resources that can "balance" the system needs when variable energy resources are unable to operate (e.g. when the wind isn't blowing).

Written Public Comments – Transmission Planning

The New England states appreciate the interest and input from a wide variety of stakeholders on forward-looking transmission analysis. Below is a summary of comments submitted to the New England states after the Transmission technical forum. They will continue to inform ongoing state and stakeholder deliberations. The comments are available in their entirety at this link.

Acadia Center, Conservation Law Foundation, Natural Resources Defense Council, and the Nature Conservancy

Acadia Center, Conservation Law Foundation, Natural Resources Defense Council, and the Nature Conservancy (collectively, "Public Interest Organizations") comment extensively on a host of transmission planning issues and related reforms. Public Interest Organizations recommend the following changes:

- Broaden the scope of transmission planning to integrate reliability, public policy and economic potential into the evaluation of transmission investments;
- Expand or redefine the approach to enumerating benefits and costs of transmission solutions and non-transmission alternatives to allow for states and stakeholders to base decisions on a full accounting of alternatives' impacts, including as it relates to environmental and economic justice;
- Require planning processes that significantly improve accountability to state regulators, greater transparency and accessibility for a broader range of market participants, and broaden stakeholder engagement;
- Consider reforming siting and cost allocation processes;
- Ensure full consideration of non-transmission alternatives, which can often help achieve environmental benefits, save consumers money, and enhance reliability and energy adequacy while avoiding unnecessary infrastructure buildout, in planning, analyses, need identification, competitive solicitation, and selection of approaches to meeting the region's transmission needs; and
- Closely examine and actively work to address underlying state and federal regulatory barriers, biases, adverse incentives and lack of information that currently limit the consideration of non-transmission alternatives and participation of third-party providers and stakeholders in future planning efforts.

To that end, Public Interest Organizations specifically contend that:

- The scope of transmission planning must be broadened to integrate reliability, public policy and economic potential to maximize the value of transmission investments.
- Load forecasting must make the best use of state and ISO New England data to help identify when, where and how transmission needs to be built to ensure it serves multiple values.

- Transmission planning must be open, accessible and transparent: transmission project siting will only be successful where the entire region understands the broad benefits of these projects.
- Environmental justice and equity: those who have had the least say historically and borne the greatest burden of transmission development must be included in transmission planning and siting.
- The states should consider revisiting the order 1000 public policy process for future planning.
- Transmission planning reform will not be productive unless the region addresses cost allocation and ways to reform the current system.
- Transmission planning should maximize the equitable use of existing transmission rights-of-way and build new transmission only where necessary.

Advanced Energy Economy & Northeast Clean Energy Council

Advanced Energy Economy (AEE) and the Northeast Clean Energy Council (NECEC) observes that offshore wind development, growth in distributed energy resources, and electrification of heating and transportation will require changes to planning and operating the transmission system. AEE and NECEC state that longer-term transmission planning performed iteratively (refreshed on a regular cycle) will better prepare the region for change. AEE and NECEC provide a list of principles for transmission planning:

- Make efficient use of existing transmission infrastructure
- Prioritize proactive, long-term planning
- Rely on competition when possible
- Take demand-side resources into account
- Remove barriers to use of non-infrastructure solutions and advance energy technologies
- Prioritize distribution system planning

AEE and NECEC also provide recommendations for a 2050 Transmission Plan to be developed by ISO New England at the request of the states. AEE and NECEC support public meetings, for example through the Planning Advisory Committee, to enable and open and transparent processes that improve on the analysis and build confidence in results. AEE and NECEC contend that such public meetings are essential for diverse stakeholder participation and should be sustained throughout the process, especially for planning issues with community and environmental impacts.

Anbaric Development Partners

Anbaric Development Partners ("Anbaric") states that New England will need tens of gigawatts of new renewable energy sources and that transmission is a cost-effective means for increasing the scale of renewable energy. Anbaric observes that recent analysis identifies consumer cost savings associated with a planned approach to transmission development. Anbaric suggests that transmission expansion can also help facilitate renewable power purchases by third-party buyers (corporations and municipalities, example) to supplement state-led procurements. Anbaric recommends the states pursue near term analysis that results in competitive procurements in late 2021 or early 2022 in parallel to longer-term transmission planning. Anbaric states that asset condition projects should also be studied with a focus on public policy goals and subject to competitive procurement. Anbaric observes that developing a portfolio of projects has facilitated cost allocation arrangements in other regions of the country. Anbaric provides a sample framework for transmission planning and procurement under existing ISO New England Tariff provisions.

FirstLight Power

FirstLight Power supports maintaining a competitive and reliable grid that advances clean energy goals. FirstLight states that grid-scale energy storage can serve as a less expensive and easier to site alternative to some transmission development. FirstLight advocates for market reforms that would encourage retirement of certain existing resources. FirstLight contends that strategic re-use of certain locations on the transmission system, currently occupied by potential candidates for retirement, could also serve to better utilize the existing and future transmission system.

Joel N. Gordes, electricity consumer

Mr. Gordes states that over dependence on any source of energy has risk. Mr. Gordes expresses concern about offshore wind and associated transmission development.

Nature Conservancy

The Nature Conservancy states that NESCOE should have more influence on grid planning matters. Nature Conservancy envisions increased stakeholder participation in long-term grid planning through NESCOE. Nature Conservancy supports change to technical committee invitation practices to be open to all stakeholders. Nature Conservancy supports immediate transmission planning for offshore wind as a means to limit impacts on the environment and aquatic species, mitigate winter time fuel security risks, and counter long lead times associated with siting, permitting, and construction.

New England for Offshore Wind

New England for Offshore Wind ("OSW") supports regional collaboration on long range transmission planning efforts. New England for OSW expresses concern about infrastructure siting and environmental justice. New England for OSW describes planning process characteristics that would improve access to and confidence in energy siting outcomes. New England for OSW recommends states set regional targets for OSW development in future milestone years to facilitate transmission planning. New England for OSW observes potential benefits of a planned approach that integrates policy goals, siting, and non-transmission alternatives.

RENEW Northeast

RENEW Northeast supports transmission planning and development efforts to enable renewable and clean energy delivery. RENEW observes the potential scale of renewable resource development associated with carbon emissions reduction targets. RENEW contends that upgrades to the transmission system will be necessary to meet such targets. RENEW provides specific suggested changes to planning practices intended to increase use of existing transmission infrastructure. Such changes include:

- Study raising the 1200 megawatt single contingency limit on new interconnections
- Consider system performance improvements and future policy impacts in addition to cost when making reliability or asset condition upgrades
- Consider transmission investments at a higher voltage than 345 kV
- Address jurisdictional seam issues between the transmission and distribution interface that inhibit technical solutions and increase interconnection costs for generators

RENEW advocates for reforms to the public policy transmission planning provisions in the ISO New England tariff.

Tufts Power Systems and Markets Research Group

Tufts Power Systems and Markets Research Group (Tufts) states that the transmission grid will be the ultimate enabler of renewable energy deployment and that doubling, if not tripling, the capacity of the existing grid is necessary for achieving 2050 emissions reductions targets. To that end, Tufts contends that the onshore grid infrastructure must be deliberately prepared to incorporate the supply from offshore wind. Tufts states that an affordable and lasting offshore grid infrastructure requires a coordinated, networked approach, rather than the current, project-by-project radial approach. Tufts observes that long-term transmission expansion planning is essential to preparing for and delivering the energy transition.

ISO-NE Governance: Written Public Comments

The New England states appreciate the interest and input from a wide variety of stakeholders on ISO-NE governance as well as those practices and processes used in other regions. Below is a summary of comments submitted to the New England states after the Governance technical forum. They will continue to inform ongoing state and stakeholder deliberations. The comments are available in their entirety at this link.

Acadia Center, CLF, EDF, NRDC, Sierra Club, & Sustainable FERC Project
Acadia Center, Conservation Law Foundation, Environmental Defense Fund, Natural Resources Defense Council, Sierra Club, and the Sustainable FERC Project (collectively, "Public Interest Organizations").
The Public Interest Organizations suggest several potential reforms for consideration, including:

- Aligning ISO-NE's mission statement with State decarbonization goals and policies
- Removing barriers to participation in the ISO New England and New England Power Pool stakeholder processes
- Change ISO New England's decision-making processes to establish stakeholder committees and working groups when appropriate, create and fund a regional consumer advocate, require state review of ISO New England decisions to consistency with state policy, and incorporate environmental issues and environmental justice criteria
- Requiring all proposals for major Tariff changes filed by ISO-NE for approval by FERC incorporate an enhanced impact assessment by a neutral third party and include sufficient information to allow for an understanding of how proposed Tariff changes are forecasted to impact consumers' energy burden, environmental externalities and co-benefits, and environmental justice
- Change ISO New England's board and leadership policies and structures by changing or expanding composition of the board, making board meeting public, and to establish a board committee on climate change

Public Interest Organizations recommend potential avenues for pursuing such reforms, including current and future stakeholder processes and regulatory proceedings.

AEE, NECEC and Sunrun
Advanced Energy Economy ("AEE"), the Northeast Clean Energy Council ("NECEC"), and Sunrun (collectively, "Advanced Energy Stakeholders") support continued evolution of the effective governance structures. Advanced Energy Stakeholders recommend that the states collectively identify ultimate objectives with respect to governance reforms. Advanced Energy Stakeholders suggest the states determine whether ISO New England's mission needs to change, what decision making role and issues the states envision in regional electricity matters, and whether decarbonization and consumer costs should be incorporated into ISO New England decision making. Advanced Energy Stakeholders recommend specific near term, incremental reforms:

- Reform the ISO New England board member joint-nominating committee process to increase transparency and consider stakeholder input on the slate of potential candidates
- Create new permanent committees on the ISO New England board related to the transition to a decarbonized grid; harmonizing ISO New England markets, planning, and operations with state policies; and consumer issues
- Hold open sessions of the ISO New England board meetings and make meeting minutes publicly available
- Consider establishing a role and funding source for a regional consumer advocate, similar to the Consumer Advocates of the PJM States
- Require ISO New England to publicly post an explanation of major or strategic decisions (for example, the annual work plan)
- Diversify ISO New England board membership to include more diverse gender representation, experience with consumer advocacy issues, and advanced energy technology sector experience
- Increase ISO New England board member participation in regional stakeholder activities

Advance Energy Stakeholders also recommend specific longer-term, substantial reforms to electricity sector governance:

- Update the ISO New England mission statement to also include achievement of state policies, advance grid decarbonization, and support energy innovation
- Strengthen ISO New England's obligation to analyze costs and benefits of major market rule change proposals by bringing clarity to current analytical requirements and by imposing new requirements for prospective and retrospective analysis of the holistic costs and benefits of major market rule change proposals
- Increase the state role in regional electricity matter decision-making

Mr. Brian Campbell

Mr. Brian Campbell, electricity consumer, expresses concern about electricity costs and power sector air emissions in New England. Mr. Campbell expresses concern about offshore wind resources' cost, environmental impacts, and reliability.

Ms. Jennie Chen

Ms. Jennie Chen submits a policy brief written in March of 2019 for the Nicholas Institute at Duke University titled, *State Participation in Resource Adequacy Decisions in Multistate Regional Transmission Organizations* for consideration.

Community Action Works

Community Action Works supports a transition to a clean, local, and renewable energy system. Community Action Works recommends changes that would result in less fossil fuel use, increased renewable and distributed energy use, and more transparent and democratic and affordable electricity grid.

Consumer Advocates of New England

The Connecticut Office of Consumer Counsel, Maine Office of the Public Advocate, Massachusetts Attorney General's Office, New Hampshire Office of the Consumer Advocate, and the Rhode Island Division of Public Utilities and Carriers (collectively, the Consumer Advocates of New England or "CANE") support ISO New England governance reform. CANE identifies shortcomings of the current system of regional electricity governance including a lack of transparency, barriers to stakeholder participation, lack of consumer advocacy experience on the ISO New England board, and a lack of concern for consumer costs. On the latter, CANE recommends ISO-NE's mission statement be amended to provide cost estimates for a wider range of initiatives reinforced with Tariff provision changes requiring certain cost/benefit analysis. CANE recommends creation of a funding source in the ISO New England tariff for ratepayer advocacy participation in regional electricity matters.

Energy Analysis

Mr. Paul Peterson of Energy Analysis supports decarbonization of the electricity grid by 2030 as a means to achieve emissions reductions targets. Mr. Peterson recommends aligning ISO New England's mission with state goals and policies. Mr. Peterson states that joint leadership between states and ISO New England will be essential to decarbonizing the electricity system.

The Nature Conservancy

The Nature Conservancy states that the current ISO New England governance structure lacks transparency in board makeup and decision making, accountability to consumers and rate payers, and inclusion of state policies and goals in planning and decisions. The Nature Conservancy suggests that ISO New England hold open board meetings like other regional transmission organizations or justify the current practice. The Nature Conservancy suggests that NESCOE and represented states hold a veto over ISO New England board decisions. The Nature Conservancy recommends that consumer perspectives be considered in ISO New England board decisions. The Nature Conservancy supports alignment of state policy and ISO New England planning. The Nature Conservancy states that ISO New England's mission statement should be changed to include transparency measures, cost considerations, and integration of state policies.

The NESCOE Managers express special thanks to the staff at the Connecticut Department of Energy and Environmental Protection for assistance in organizing technical forum logistics, and for easing public accessibility to information by creating and maintaining a dedicated web presence at www.newenglandenergyvision.com

AUGUST 5, 2021 | BRIEFING WITH NEPOOL

IMM Annual Markets Reports on 2020

Report Highlights

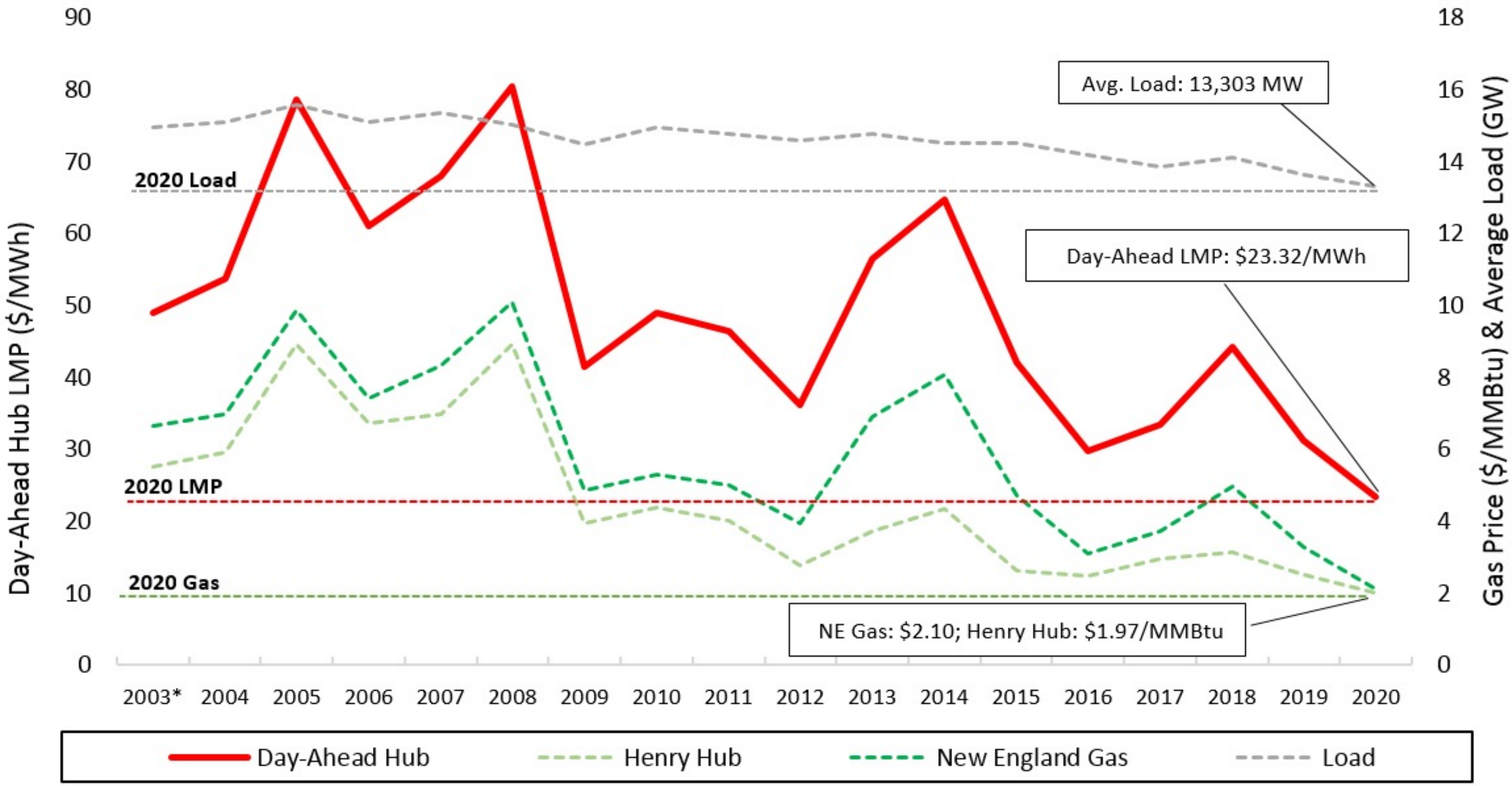
Jeff McDonald

VICE PRESIDENT, INTERNAL MARKET MONITOR

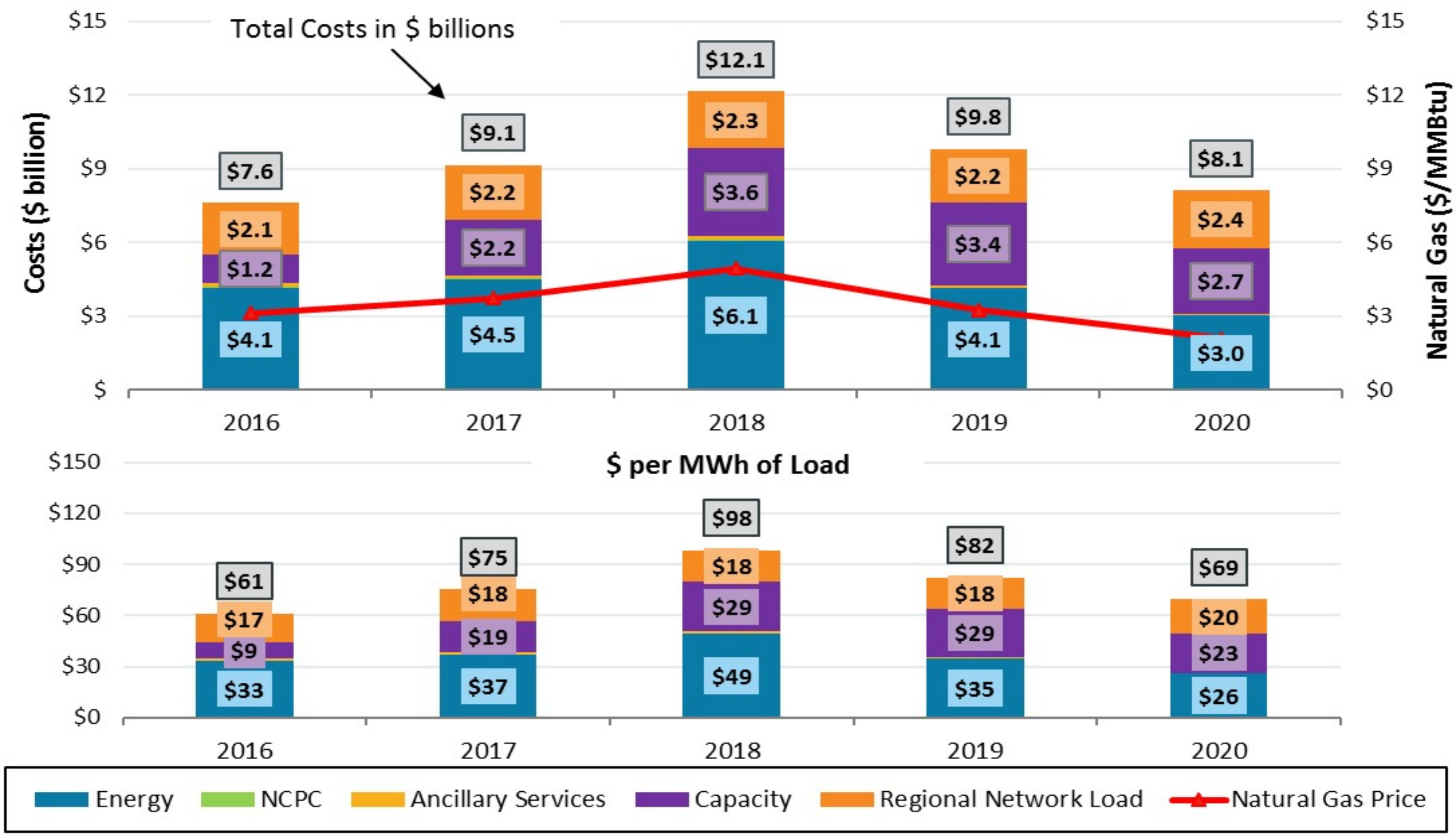
Summary

- Capacity, energy and ancillary services markets performed well and exhibited competitive outcomes.
- Record low wholesale energy prices and demand in New England; the avg. LMP ($23.3/MWh) was the lowest since the energy market construct was implemented (2003).
- A milder winter (Q1) brought low gas prices, wholesale demand and energy costs; Q1 accounted for almost 70% of the annual $1.1 billion drop in energy costs.
- Henry Hub gas prices at their lowest level in 25 years; New England gas prices lowest in 21 years.
- COVID-19 related restrictions reduced electricity demand, but mild winter conditions, and growth in energy efficiency and retail photovoltaic generation had a larger impact.
- ISO and industry successfully met operational challenges due to COVID-19 restrictions [e.g. load uncertainty, deferred equipment maintenance].
- Few significant system events and no shortage events due to high overall capacity and reserve surplus, lack of sustained cold weather and few significant supply/demand shocks.
- Low levels of structural market power and offer mitigations in the energy market.
- Three new market recommendations added since last year's report; two relating to the treatment of BTM generation for transmission cost allocation, and the third to the calculation of offer review trigger prices for co-located solar/battery projects.

Lowest prices and demand since SMD was implemented; very low national gas prices



Energy and capacity costs drove the overall decrease in wholesale costs, with a relatively small offsetting increase in transmission (RNL) costs



Highlights

Statistic	2016	2017	2018	2019	2020	% Change 2020 to 2019
Demand (MW)						
Real-time Load (average hourly)	14,164	13,838	14,095	13,614	13,303	-2%
Weather-normalized real-time load (average hourly)[a]	14,111	13,737	13,725	13,558	13,275	-2%
Peak real-time load (MW)	25,596	23,968	26,024	24,361	25,121	3%
Generation Fuel Costs ($/MWh) [b]						
Natural Gas	24.29	29.02	38.61	25.41	16.34	-36%
Coal	41.97	51.57	54.54	40.54	37.83	-7%
No.6 Oil	73.34	94.76	127.80	130.90	89.43	-32%
Diesel	120.78	148.36	187.60	173.54	112.06	-35%
Hub Electricity Prices - LMPs ($/MWh)						
Day-ahead (simple average)	29.78	33.35	44.13	31.22	23.32	-25%
Real-time (simple average)	28.94	33.93	43.54	30.67	23.38	-24%
Day-ahead (load-weighted average)	31.74	35.23	46.88	32.82	24.57	-25%
Real-time (load-weighted average)	31.56	36.15	46.85	32.32	24.79	-23%
Estimated Wholesale Costs ($ billions)						
Energy	4.1	4.5	6.1	4.1	3.0	-27%
Capacity	1.2	2.2	3.6	3.4	2.7	-22%
Net Commitment Period Compensation	0.07	0.05	0.07	0.03	0.03	-15%
Ancillary Services	0.1	0.1	0.1	0.1	0.1	-26%
Regional Network Load Costs	2.1	2.2	2.3	2.2	2.4	9%
Total Wholesale Costs	**7.6**	**9.1**	**12.1**	**9.8**	**8.1**	**-17%**
Supply Mix [c]						
Natural Gas	41%	40%	40%	39%	42%	3%
Nuclear	26%	26%	25%	25%	22%	-3%
Imports	16%	17%	17%	19%	20%	1%
Hydro	6%	7%	7%	7%	7%	-1%
Other[d]	6%	5%	5%	5%	5%	0%
Wind	2%	3%	3%	3%	3%	0%
Solar	1%	1%	1%	1%	2%	0.4%
Coal	2%	1%	1%	0%	0%	0%
Oil	0%	1%	1%	0%	0%	0%

Demand continued to decline, but trend expected to reverse slightly over the next 10 years, with a projected total growth of 4% by 2029, largely due to the electrification of the heating and transportation sectors.

Prices of all major fuels decreased largely due to reduced demand related to COVID-19 restrictions.

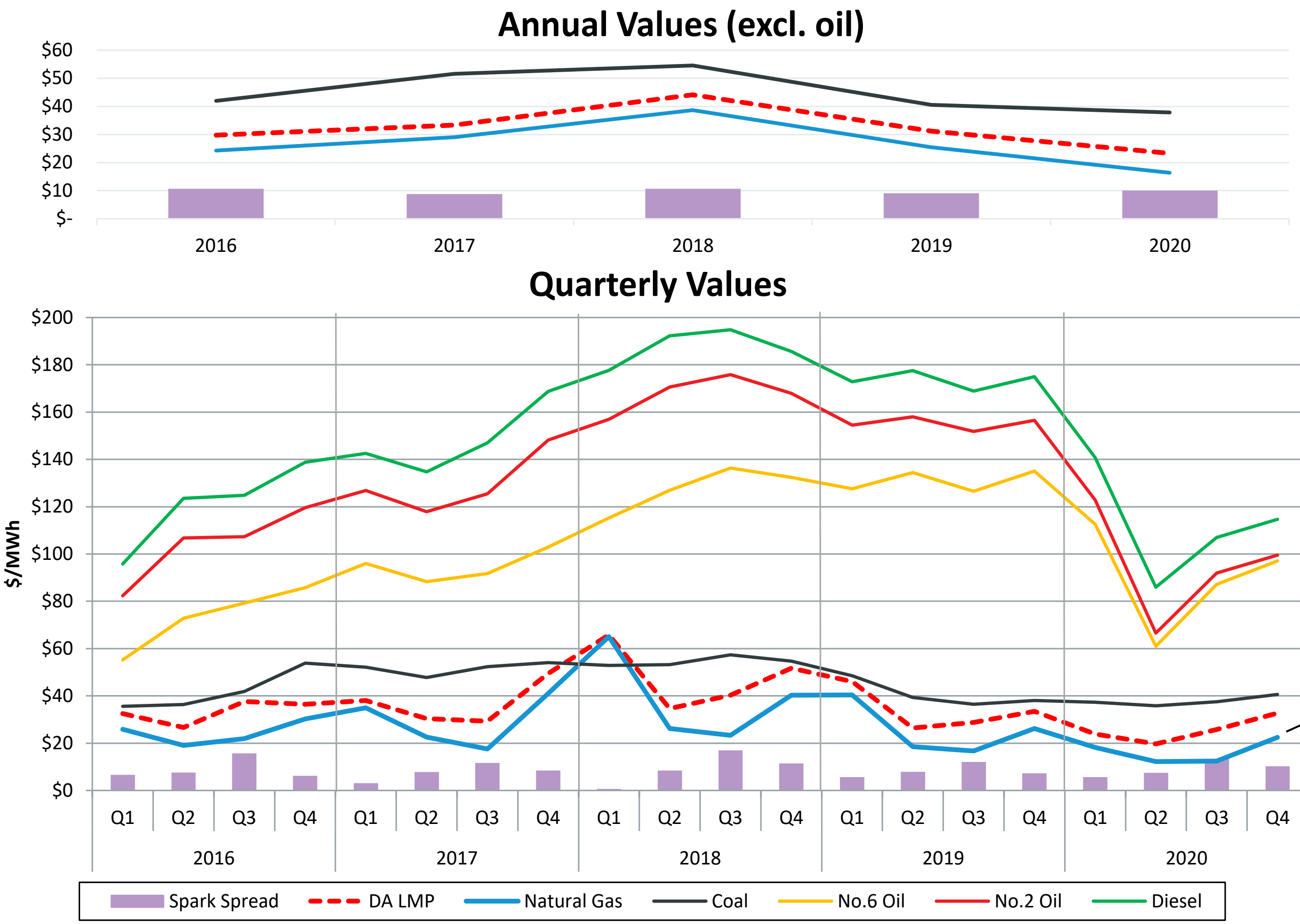
Simple- and load-weighted avg. LMPs down significantly, but not as much as the decline in gas prices. Offsetting factors included lower nuclear generation (down 500 MW/hr), which was replaced by relatively more expensive gas generation, and an increase in RGGI CO_2 prices (up 15%).

Energy comprised just 37% of wholesale costs, compared to avg. of 50% over prior 4 yrs. Reductions in all wholesale market cost categories, with the exception of increased transmission infrastructure costs.

Reductions in share of nuclear generation due to Pilgrim retirement and refueling outages. Gap filled by gas generation. Coal and oil generation share was negligible in 2020 (0.3%). No significant changes in share of renewable generation.

[a] Weather-normalized results are those that would have been observed if the weather were the same as the long-term average.
[b] Generation costs are calculated by multiplying the daily fuel price ($/MMBtu) by the average standard efficiency of generators for each fuel (MMBtu/MWh)
[c] Provides a breakdown of total supply, which includes net imports. Note that section 2 provides a breakdown of native supply only.
[d] The "Other" fuel category includes landfill gas, methane, refuse and steam
⇨ denotes change is within a band of +/- 1%

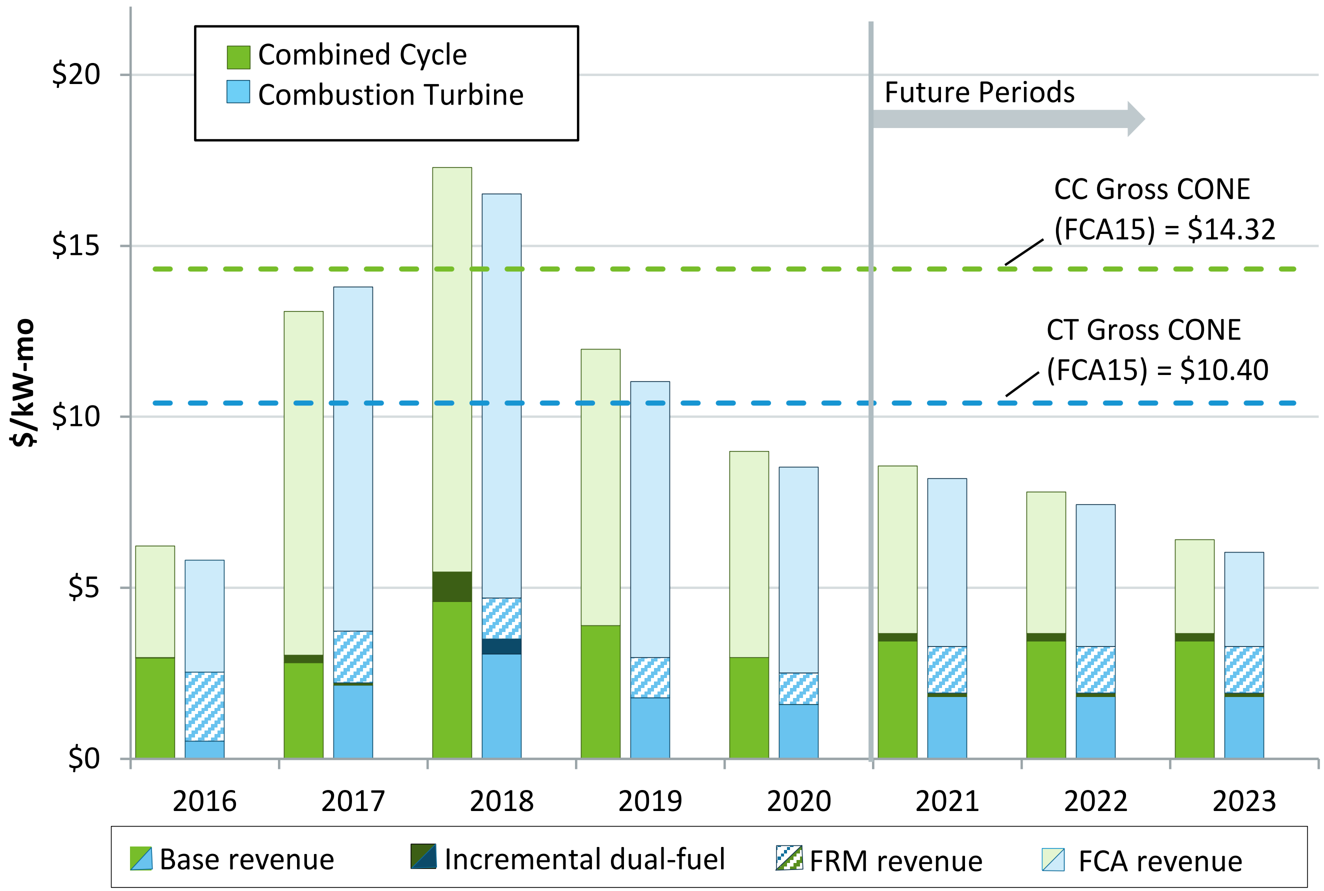
Lower gas prices/costs drove decrease in LMP; sparks spreads comparable to prior years



Relatively narrow range in qtr'ly gas costs compared to prior years due to milder winter weather (range of $10/MWh in 2020 compared to $24 in 2019 and $42 in 2019).

Variable generation costs are calculated by multiplying the average daily fuel price ($/MMBtu) by the average standard efficiency of generators of a given technology and fuel type. Our standard heat rates are measured in MMBtu/MWh as follows: Natural Gas 7.8, Coal – 10.0, No. 6 Oil – 10.7, No. 2 Oil – 11.7. The spark spread is the difference between the LMP and the fuel cost of a gas-fired generator with a heat rate of 7.8.

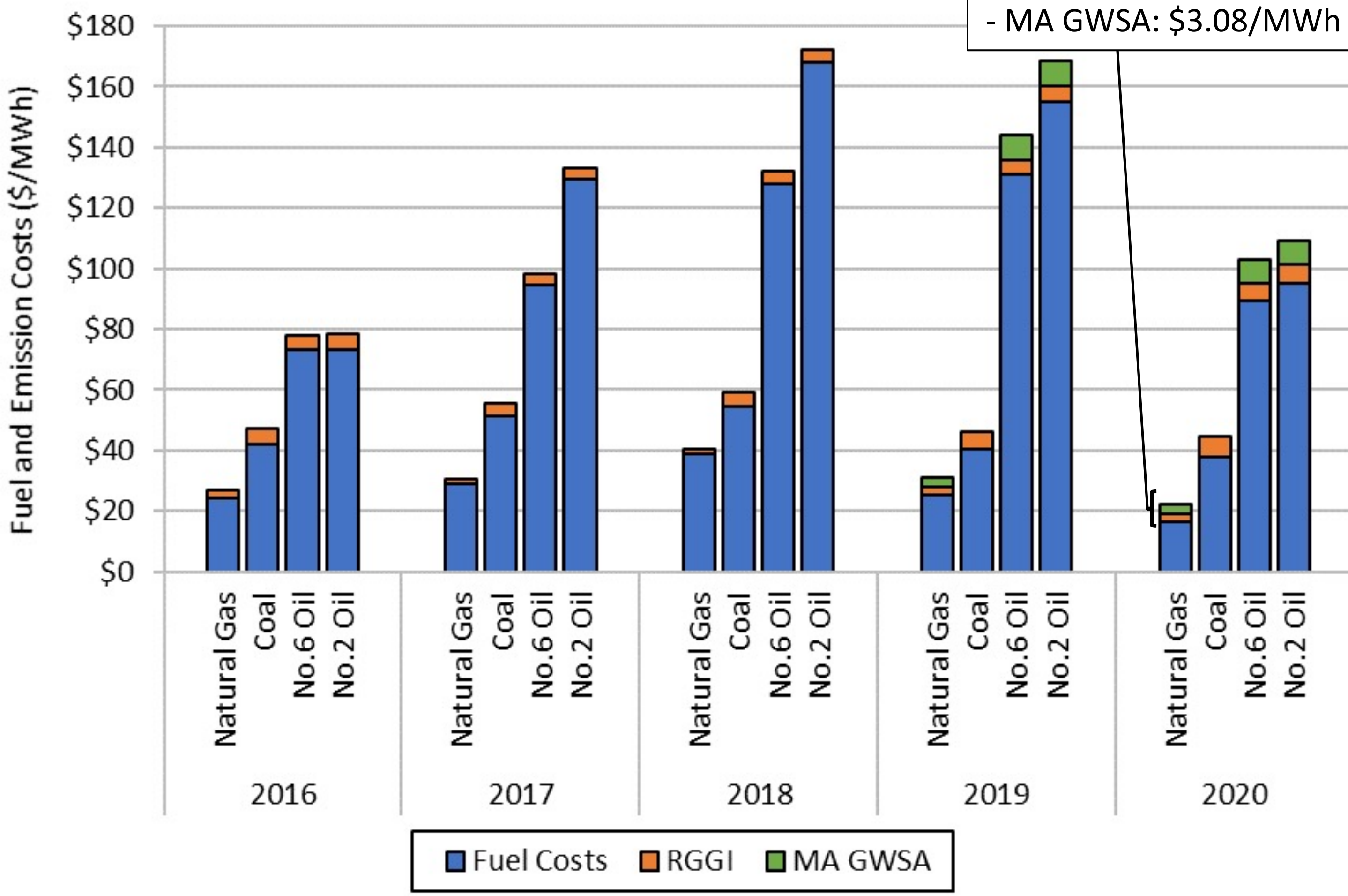
Lower 2020 profitability due to lower energy and capacity prices, and increase in RGGI prices



Note that the methodology was updated this year to include the cost of RGGI CO_2 allowances. Historical values were updated to incorporate this change. RGGI decreases net revenue by approx. $1.6/kW-mo for a CC and $1.2/kW-mo for a CT in 2020.

… but CO_2 costs still comprise a relatively small proportion of variable production costs with little impact on the economic merit order

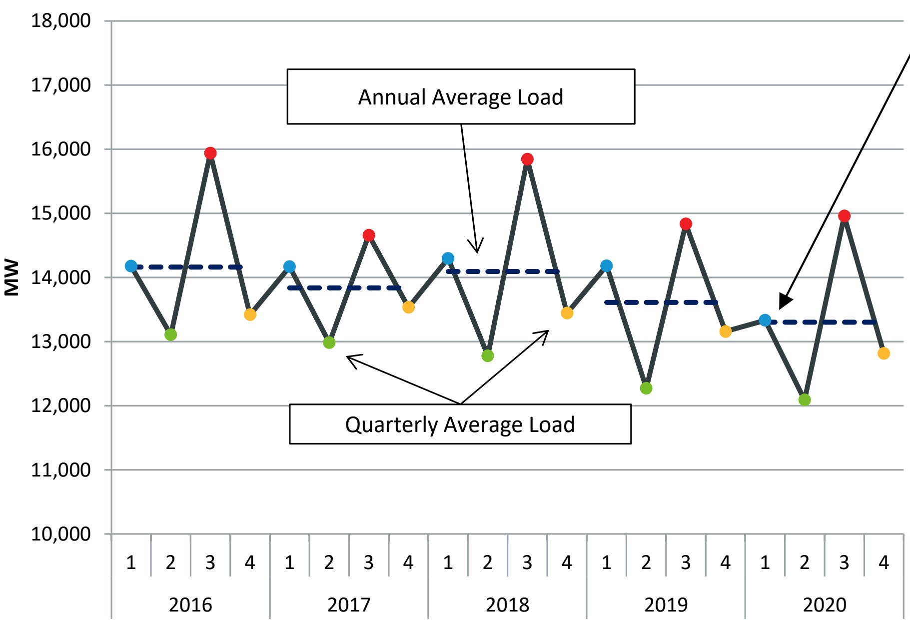
CO_2 costs for typical gas generator:
- RGGI: $2.88/MWh
- MA GWSA: $3.08/MWh



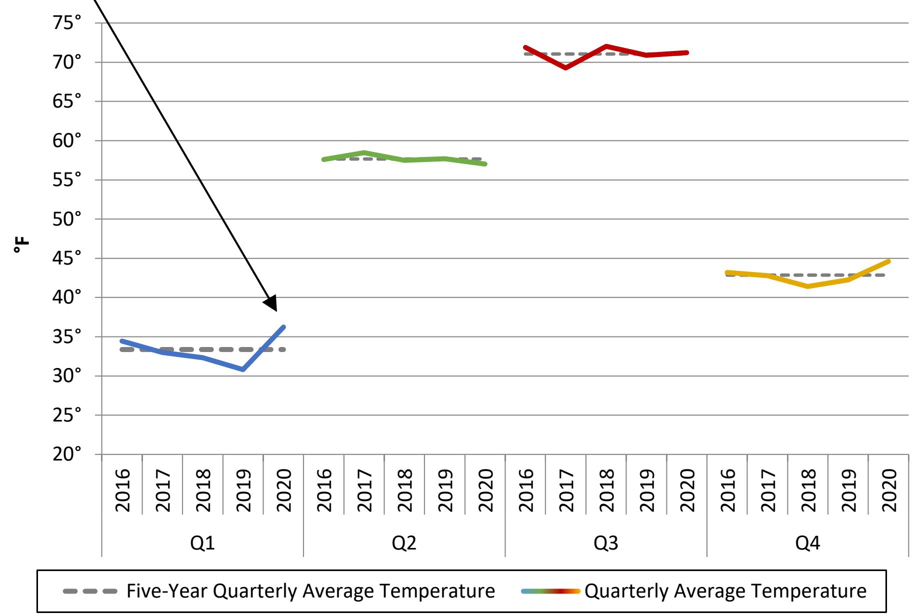
Demand in Q1 down significantly due to mild winter and early stages of COVID-19 restrictions; demand rebounded in Q3 with higher residential AC load

An 850 MW per hour (6%) decline in average Q1 demand largely due to higher temps than 2019, up 5°F. With milder weather, gas prices averaged just \$2.33/MMBtu (or \$18.20/MWh) in Q1 2020, compared to \$5.18/MMBtu (or \$40.38/MWh) in Q1 2019, and drove a significant portion of the overall annual reduction in energy costs and prices.
[Q4 demand also down (by 345 MW per hour) due to milder weather]

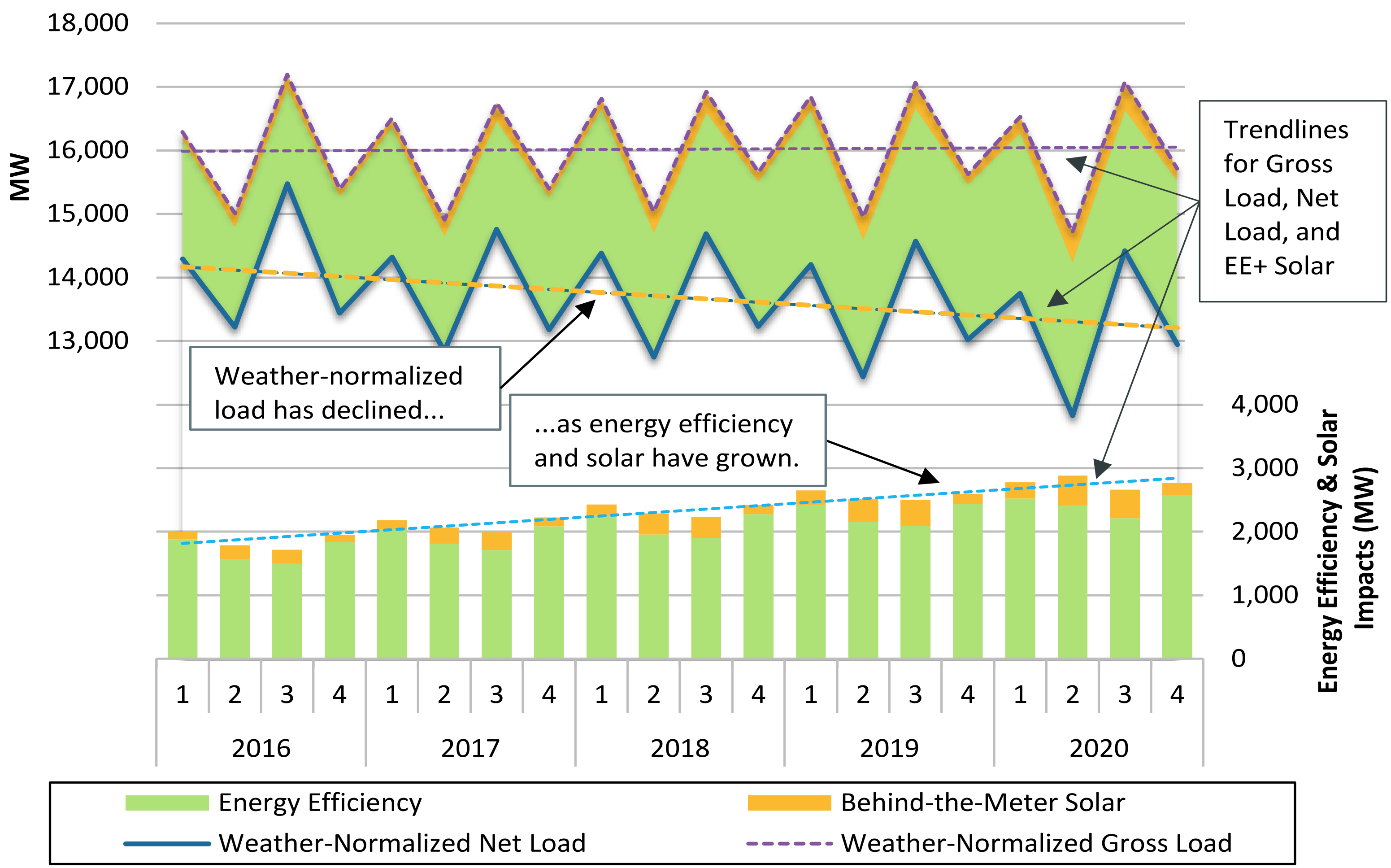
Average Hourly Load by Quarter and Year



Average Hourly Load by Quarter and Year



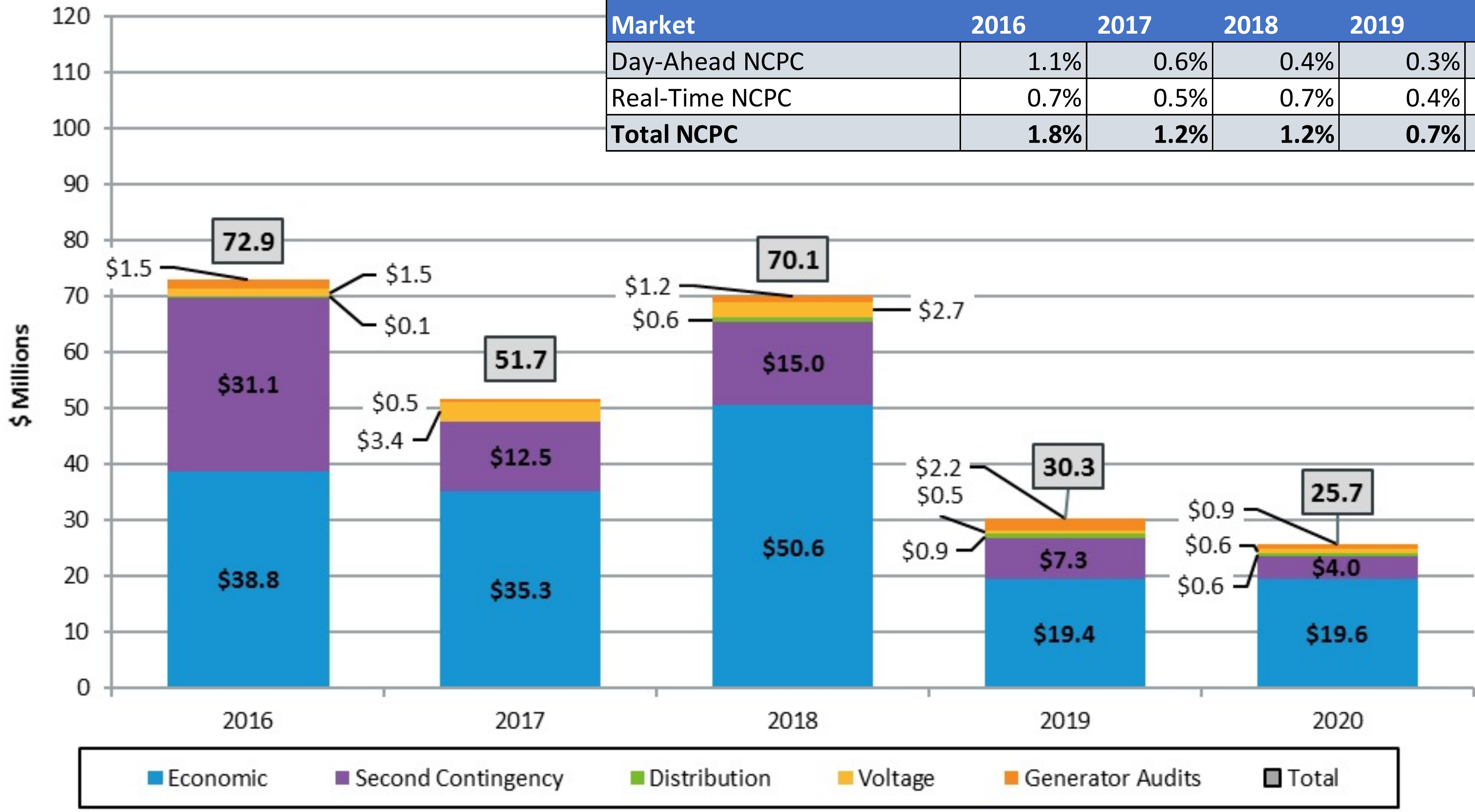
Trend of declining demand driven by growth in Energy Efficiency and BTM photovoltaic



Relatively low uplift due to few local reliability commitments and few significant operator out-of-market actions (e.g. posturing of oil generators)

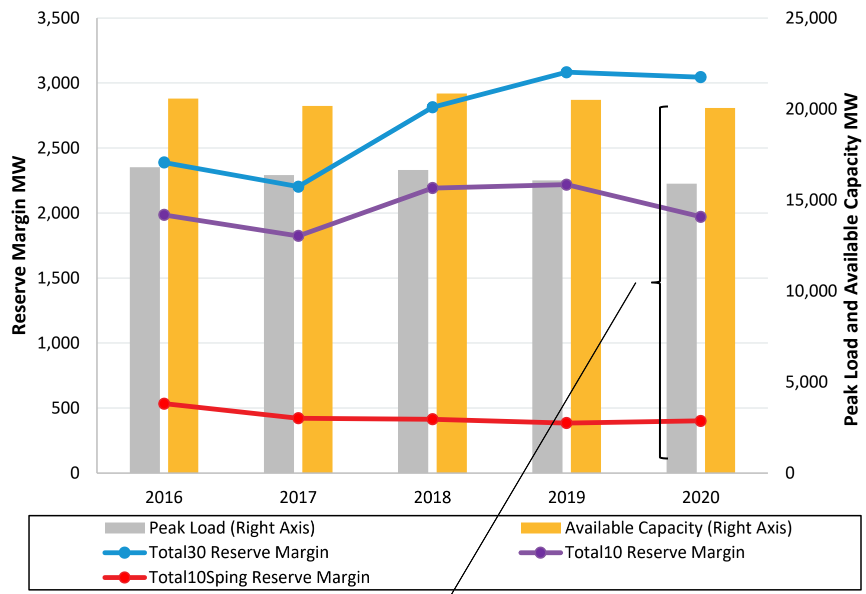
Uplift Payments as a Percent of Energy Costs

Market	2016	2017	2018	2019	2020
Day-Ahead NCPC	1.1%	0.6%	0.4%	0.3%	0.3%
Real-Time NCPC	0.7%	0.5%	0.7%	0.4%	0.5%
Total NCPC	**1.8%**	**1.2%**	**1.2%**	**0.7%**	**0.9%**



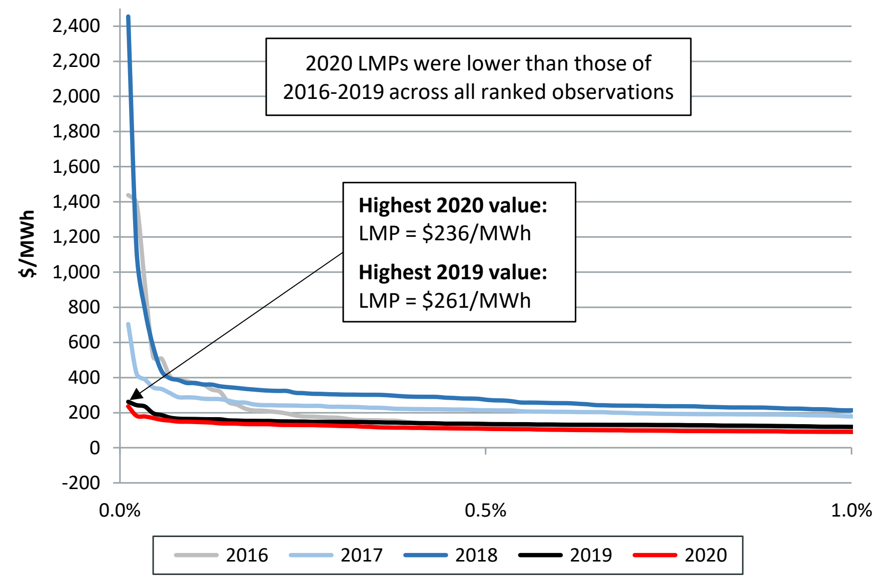
Large average energy market surplus with few periods of relatively high pricing

Reserve Margin, Peak Load, and Available Capacity

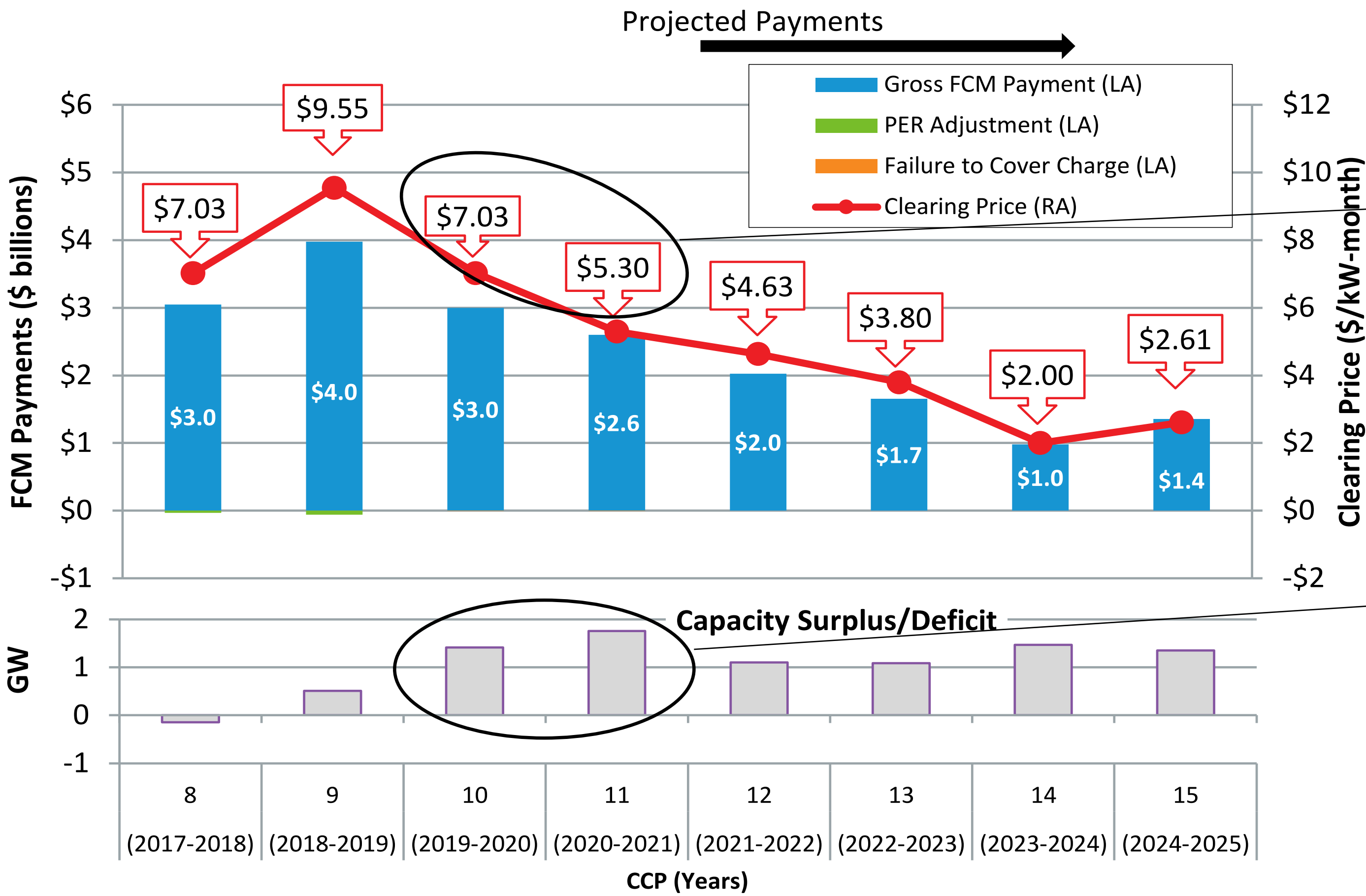


Bars show the avg. available capacity (that can be delivered within 30 mins) and demand during the daily peak hour. Difference is about 4,200 MW [Reserve margin lines are the average of *all* hours].

LMP Duration Curves for Top 1% of Real-Time Hours



FCM payments continue on a downward trajectory with a fairly large capacity surplus



Avg. 2020 capacity price of $6.16/kW-mo (FCA 10 and 11), down 26% from $8.29/kW-mo in 2019 (FCA 9 and 10).

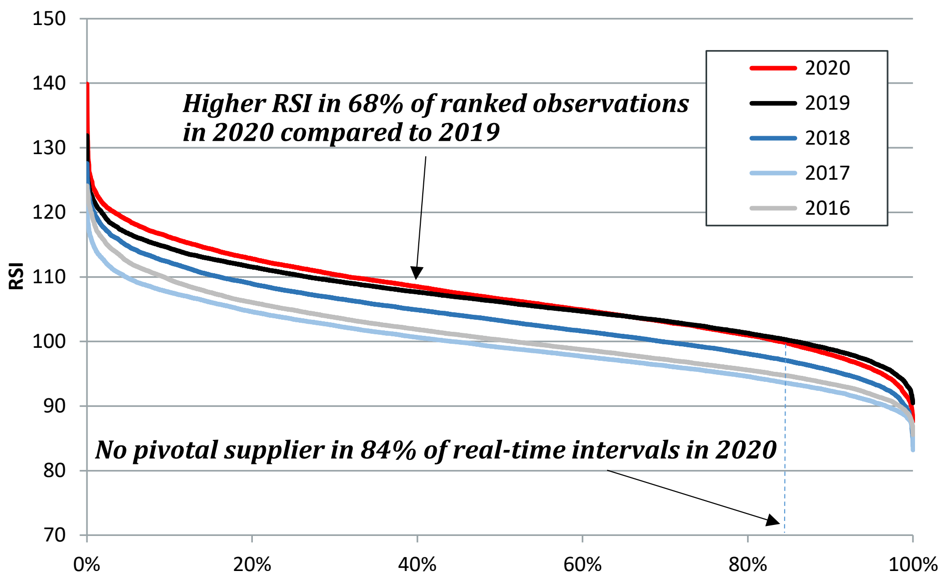
Avg. 2020 surplus of ~1,600 MW (5%) above NICR.

Energy market competitiveness metrics

Price-cost markup in the day-ahead market within a reasonable range

Year	Price-Cost Markup
2016	8.2
2017	4.9
2018	4.9
2019	6.6
2020	7.6

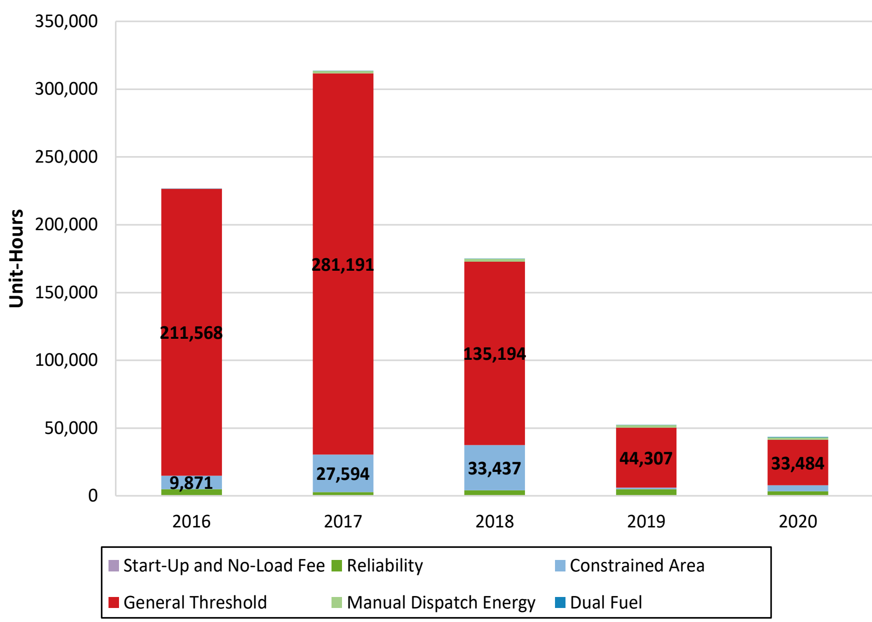
Low levels of structural market power in the real-time market; largest supplier required in ~17% of hrs



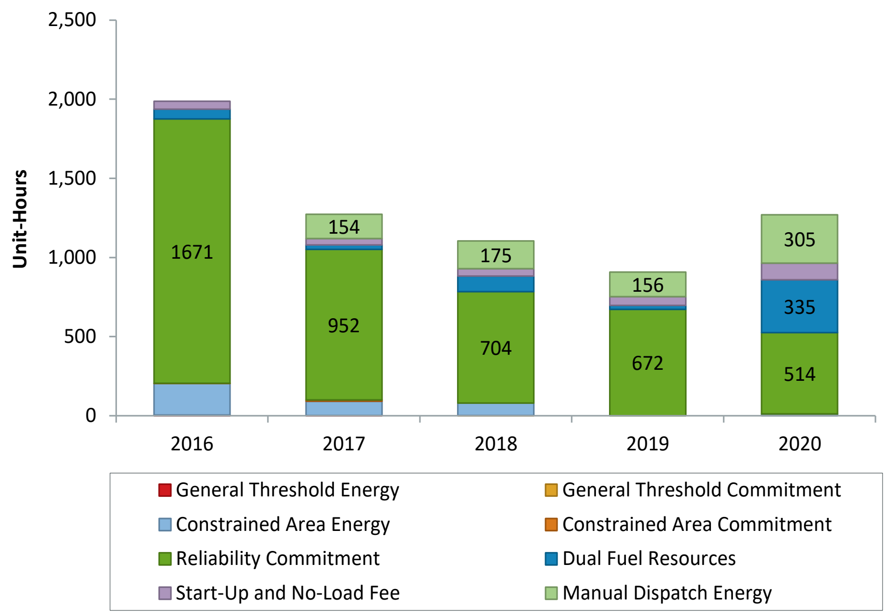
Year	% of Intervals With At Least 1 Pivotal Supplier	RSI
2016	48.4%	101.0
2017	55.7%	99.6
2018	30.7%	103.6
2019	14.7%	106.4
2020	16.6%	106.9

Energy market mitigation remained low, but increase in mitigation hours of dual fuel resources and manual dispatch

Unit-Hours with Potential Market Power Flagged



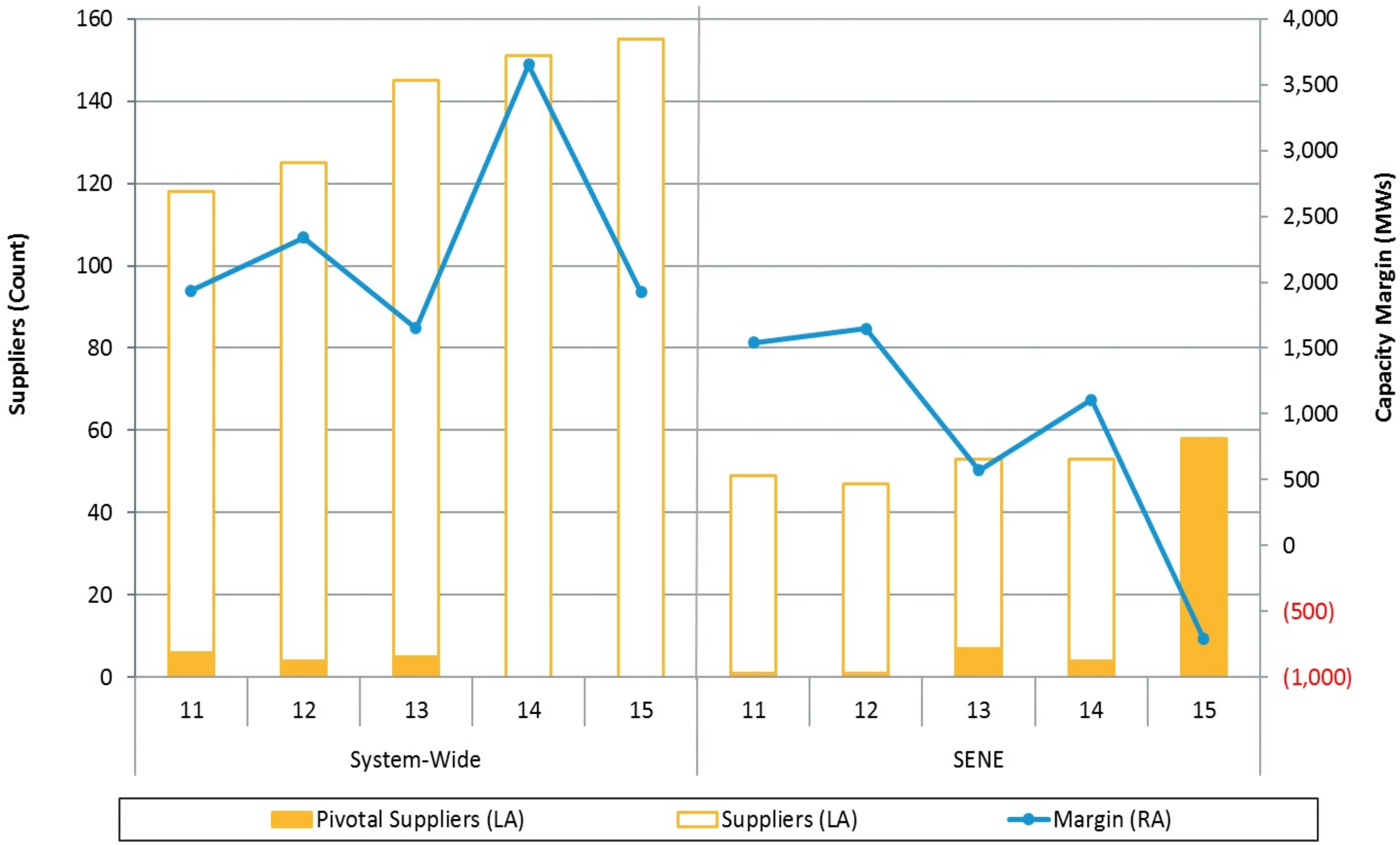
Mitigation Events, by Annual Period



The total unit-hours of on-line generation subject to mitigation rules is approximately 700,000 per year; given this, the portion of total unit-hours with potential market power has ranged from 42% in 2017 to 7% in 2020

Only 1,270 unit-hours of mitigation occurred in 2020, relative to the 43,500 unit-hours of potential market power (2.9%). Stated differently, about 0.2% of *all* supply offers were mitigated.

FCA 15 structurally competitive at the system level, but market power in SENE; no static de-list bids from pivotal suppliers



New Recommendations

Recommendation	When made	Status	Priority Ranking
Reconstitution of Regional Network Load for Behind-the-Meter (BTM) Generation (Part #1: Compliance) Participating Transmission Owners (PTOs) should change their current practices to comply with the express Tariff requirement to reconstitute peak demand by adding back BTM generation output for transmission charging purposes. We also recommended that the ISO consider incorporating a certification step in the data submittal and billing process whereby the PTOs would certify that their peak load data has been reconstituted in compliance with the Tariff. Lastly, we recommended that the Tariff and operating procedures be reviewed and changed, as appropriate, to provide helpful clarifications and specificity to aid compliance going forward.	Spring 2020 QMR (Jul 2020)	Several of the PTOs are jointly proposing changes to the rules to not require load reconstitution for BTM generation.	High
Reconstitution of Regional Network Load for Behind-the-Meter (BTM) Generation (Part #2: Wider Review of the Rate Structure) The PTOs should engage with ISO-NE and stakeholders to review the current rate structure, including the requirement to reconstitute BTM generation. This review would evaluate the rate structure for consistency with transmission planning processes and cost drivers. It would consider the value of BTM generation (e.g., avoiding transmission system constraints and potentially reducing future transmission investment needs). We recognized that the requirement to reconstitute BTM generation may undervalue its contribution. However, not requiring reconstitution could raise equity issues that result from shifting costs to customers with less BTM generation.	Spring 2020 QMR (Jul 2020)	Several of the PTOs are jointly proposing changes to the rules to not require load reconstitution for BTM generation. However, the PTOs are not undertaking this wider review to support their latest proposed rule changes.	Medium
Develop Offer Review Trigger Price for co-located solar/battery facilities Under the current rules, the ORTP for a co-located battery and solar project is based on the weighted average of the individual technologies. This results in a value that is below the true "missing money" for the combined resource, allowing such resources to offer in at prices below a competitive price without review and mitigation, and undermines the protections put in place by the MOPR. In our opinion, a bottom-up calculation is preferable because it accurately represents the constraints that co-located solar/battery facilities face and results in a more precise cost estimate.	Apr 2021	The IMM filed comments with FERC on the Recalculation of ORTPs stating that the Commission should consider directing the ISO and NEPOOL participants to develop an appropriate benchmark price for co-located solar/battery facilities for use in the future.	Medium

Questions

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of August 3, 2021

The following activity, as more fully described in the attached litigation report, has occurred since the report dated July 7, 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

1	Extension of Filing Deadlines (AD20-11)	Jul 26	FERC further extends through ***Jan 1, 2022*** FERC regulations that require filings be notarized or supported by sworn declarations
2	Blanket Waiver of ISO/RTO Tariff In-Person Meeting and Notarization Requirements (EL20-37)	Jul 26	FERC further extends through ***Jan 1, 2022*** blanket waivers of ISO/RTO Tariff in-person meeting and notarization requirements

I. Complaints/Section 206 Proceedings

2	Green Development DAF Charges Complaint Against National Grid (EL21-47)	Jul 27	Green Development submits motion to renew and reiterate its request for fast track processing of its Feb 10, 2021 complaint
2	NEPGA Net CONE Complaint (EL21-26)	Jul 29	FERC issues a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration" of the EPSA/NEPGA request for rehearing of the *NEPGA Net Cone Complaint Order*

II. Rate, ICR, FCA, Cost Recovery Filings

7	FCA16 De-List Bids Filing (ER21-2342)	Jul 9, 16	NEPOOL, National Grid intervene
7	CSC CIP IROL Cost Recovery: Pre-Jun 1, 2021 Regulatory Asset Cost Recovery (ER21-2334)	Jul 22	NESCOE protests CSC's proposal to establish and use a regulatory asset to recover CIP IROL Costs that it incurred from Jan 2016 to May 31, 2021
8	CSC CIP IROL Cost Recovery: Jun 1, 2021 Forward (ER21-2031)	Jul 8	FERC accepts CSC's post-Jun 1, 2021 CIP IROL rate schedule, eff. Jun 1, 2021
8	Mystic 8/9 Cost of Service Agreement (ER18-1639)	Jul 15 Jul 29	FERC issues order setting the base ROE at 9.33% FERC accepts fourth compliance filing, eff. Jun 1, 2022

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

9	Removal of Appendix B from Market Rule 1; Deletion of Assoc. Tariff Provisions (ER21-2220)	Jul 16-19	Eversource, National Grid intervene
9	CPower Waiver Request (ER21-2135)	Jul 28	FERC denies CPower's request for waiver of the ISO-NE Tariff provisions for the determination of CPower' Demand Capacity Resources' ARA3 Summer ARA Qualified Capacity
10	Solar Data Requirements & Relocation of Wind Data Requirements (ER21-1974)	Jul 16	FERC accepts revisions, eff. Jul 20, 2021
11	Updated CONE, Net Cone and PPR Values (eff. FCA16) (ER21-787)	Jul 29 Jul 30	FERC issues a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration" of the EPSA/NEPGA request for rehearing of the *Updated CONE, Net Cone and PPR Values Order* FERC accepts ISO-NE's compliance filing, eff. May 29, 2021

V. OATT Amendments / TOAs / Coordination Agreements

*	12	TOs *Order 676-I* Compliance Filing (ER21-2529)	Jul 27	PTO AC, ISO-NE, Schedule 20A Service Providers, GMP, and VTransco submit revisions to Schedule 21-Common and Schedule 20A-Common in accordance with *Order 676-I*; comment date ***Aug 19, 2021***
*	12	CSC *Order 676-I* Compliance Filing (ER21-2509)	Jul 26	CSC and ISO-NE submit *Order 676-I* revisions to Schedule 18, Attachment Z of the ISO-NE Tariff; comment date ***Aug 16, 2021***
	12	BTM Generation Proposal (ER21-2337)	Jul 22	Comments and protests filed by: ISO-NE IMM, AEE, IECG, NECOS/ENE, NEPGA, Public Systems, MPUC/CT PURA/MA DPU, VT PUC
			Jul 13	NEPOOL files comments
			Jul 8-16	Calpine, EMI, National Grid intervene

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

*	13	Schedule 21-VP 2021 Annual BHD Informational Filing (ER20-2119)	Jul 28	Versant files revised 12-CP values, changing calculation of retail transmission charges for Large Power – Transmission Voltage and other retail customers
*	13	Schedule 21-FG&E Annual Informational Filing (ER09-1498)	Jul 26	FG&E submits annual update to its Revenue Requirement recovered through the ISO-NE Tariff and Schedule 21-FG&E for the Jun 1, 2021 – May 31, 2022 period

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

*	15	LFTR Implementation: 51st Quarterly Status Report (ER07-476)	Jul 15	ISO-NE files its 51st quarterly report

IX. Membership Filings

	16	August 2021 Membership Filing (ER21-2552)	Jul 29	NEPOOL requests that the FERC accept (i) the memberships of In Commodities US and Jupiter Power; (ii) the termination of the Participant status of GenOn Energy Management and GenOn Canal; and (iii) the name change of Rivercrest Power-SOUTH, LLC (f/k/a BioUrja Power LLC); comment date ***Aug 19, 2021***

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

*	19	FERC/NERC Joint Report on Real Time Assessments (not docketed)	Jul 8	FERC/NERC Joint Report on Real Time Assessments (not docketed)

XI. Misc. - of Regional Interest

*	20	First Rev LGIA: National Grid / New England Wind (Hoosac) (ER21-2548)	Jul 29	National Grid and ISO-NE file a First Revised LGIA with New England Wind to include details regarding DAF charges and to update the CNRC of the Hoosac wind farm; comment date ***Aug 19, 2021***
*	21	Versant Power MPD OATT Order 676-I Compliance Filing (ER21-2498)	Jul 23	Versant Power files proposed revisions to MPD OATT Section 4 to incorporate by reference certain *Order 676-I* revisions and requests waiver of certain of those standards not applicable to MPD; comment date ***Aug 13, 2021***

*	21	Versant Waiver Request: Unreserved Transmission Use Penalty Policy (ER21-2447)	Jul 16	Versant Power requests waiver of the application of its current Unreserved Transmission Use Penalty Policy to Black Bear, instead proposing to use its prior version; comment date ***Aug 6, 2021***

XII. Misc. - Administrative & Rulemaking Proceedings

	23	Joint Federal-State Task Force on Electric Transmission (AD21-15)	Jul 19	NARUC nominates state commissioners to Transmission Task Force, including New England Commissioners Riley Allen (VT PUC) and Matt Nelson (Chair, MA DPU)
	24	Climate Change, Extreme Weather, and Elec. Sys. Reliability: Jun 1-2 Tech. Conf. (AD21-13)	Jul 22	Jun 1-2 transcripts posted to eLibrary
	24	Resource Adequacy - Modernizing Electricity Mkt Design (AD21-10)	Jul 19	Post-technical conference comments filed by: AEE, Calpine, CT Parties, Dominion, Eversource, MMWEC, NESCOE, NEPGA, NextEra, NRG, Public Interest Orgs, Vistra, AEMA, EPSA, RENEW
			Jul 19	FERC issues notice of 2 staff-led tech confs to discuss potential energy and ancillary services market reforms that may be needed as the resource fleet and load profiles change over time; tech conf dates: ***Sep 14, 2021 and Oct 12, 2021***
	26	Hybrid Resources (AD20-9)	Jul 19	ISO/RTOs, including ISO-NE, file reports on implementation of hybrid resources as directed in Jan 19 order; comment date ***Aug 18, 2021***
			Jul 28	ESA requests 30-day extension of time, to Sep 20, 2021, to file comments in response to the ISO/RTO reports
	26	NOI: Removing the DR Opt-Out in ISO/RTO Markets (RM21-14)	Jul 23	Nearly 30 parties file comments, including by: AEE, Voltus, AEMA, APPA/NRECA, EEI, and NARUC
	27	NOPR: Electric Transmission Incentives Policy (RM20-10)	Jul 26	28 sets of reply comments filed, including by the New England TOs, NECOS, NESCOE, CT PURA/CT DEEP/MA AG, CT AG, and Public Interest Groups
	22	*Orders 864/864-A* (Public Util. Trans. ADIT Rate Changes): New England Compliance Filings (various)	Jul 27	*ER20-2429-001 (CMP)*. MPUC protests CMP deficiency letter response

XIII. FERC Enforcement Proceedings

*	35	Terra-Gen, LLC (IN21-7)	Aug 2	FERC approves Stipulation and Consent Agreement that resolved OE's investigation into whether Terra-Gen submitted false/misleading information to CAISO about Cameron Ridge's physical capabilities and whether Terra Gen violated the CAISO Tariff by deviating Cameron Ridge's output from CAISO's dispatch instructions; Terra-Gen must ***disgorge $117,231 plus interest***, and pay a ***$510,962 civil penalty*** to the United States Treasury
	35	PacifiCorp (IN21-6)	Jul 16	PacifiCorp answers *PacifCorp Show Cause Order*, denying violating FAC-009-1; Enforcement Staff answer due ***Sep 14, 2021***
	36	GreenHat (IN18-9)	Jul 6	Respondents answer Order to Show Cause and Notice of Proposed Penalty
			Jul 27	Enforcement Litigation Staff answers Respondents' Jul 6 answers
	36	Rover Pipeline, LLC and Energy Transfer Partners, L.P. (IN19-4)	Jul 21	Enforcement Staff answers Rover and ETP answer to Show Cause Order

37	Total Gas & Power North America, Inc. et al. (IN12-17)	Jul 15	FERC issues order establishing hearing procedures
		Jul 16	TG&P requests Track III Schedule
		Jul 20	FERC Trial Staff responds to TG&P request for Track III Schedule
		Jul 21	TG&P answers FERC Trial Staffs' Jul 20 response
		Jul 27	Chief Judge designates Judge Suzanne Krolikowski as the presiding ALJ and establishes an extended Track III Schedule for the proceeding

XIV. Natural Gas Proceedings

38	Iroquois ExC Project (CP20-48)	Jul 8	Comment date on draft EIS revised to ***Aug 9, 2021***
		Jul 15-Aug 3	Over 200 et of individual comments submitted
38	Atlantic Bridge Project (CP16-9)	Jul 16	Algonquin, INGAA requests for rehearing of *May 19 Order* denied by operation of law
		Jul 16, 19	Algonquin, INGA petition DC Circuit for review of *Briefing Order, April 19 Notice of Denial of Rehearings by Operation of Law*, and *May 19 Order*; consolidated with DC Circuit Case No. 21-1115

XV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XVI. Federal Courts

42	ISO-NE Implementation of *Order 1000* Exemptions for Immediate Need Reliability Projects (20-1422)	Jul 8	MMWEC files notice that it would not submit a Reply Brief
		Jul 9	LSP Transmission files Petitioner Reply Brief
		Jul 16	LSP Transmission files Joint Appendix
		Jul 28	MMWEC files Intervenor for Petitioner Final Brief
		Jul 30	LSP Transmission and FERC Trial Staff file Final Briefs
42	CIP IROL Cost Recovery Rules (20-1389)	Jul 16	Cogentrix/Vistra file Deferred Appendix
		Jul 26	Cogentrix/Vistra and FERC file Final Briefs
43	Mystic 8/9 COS Agreement (20-1343 et al.) (consol.)	Jul 12	FERC files certified index to the record
45	Order 872 (9th Cir.) (20-72788 et al.) (consol.)	Jull 26	NewSun Energy submits Intervenor Brief
46	*Opinion 569/569-A*: FERC's Base ROE Methodology (16-1325 et al.) (consol.)	Jul 8	Petitioners' and Joint Petitioners' file Reply Briefs
		Jul 22	Intervenors in Support of Petitioners file Reply Brief
47	Algonquin Atlantic Bridge Project *Briefing Order* (21-1115; 21-1138, 21-1153, 21-1155) (consol.)	Jul 19, 22	Court consolidates Cases 21-1153 and 21-1155 with 21-1115; 21-1153 and 21-1155 held in abeyance pursuant to Jun 21 order in 21-1115; parties to file motions to govern future proceedings by ***Aug 6, 2021***

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: August 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 August 3, 2021. If you have questions, please contact us.

COVID-19

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

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

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

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

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

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

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

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

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

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

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

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

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

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

I. Complaints/Section 206 Proceedings

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

On July 27, 2021, Green Development, LLC ("Green Development") submitted a motion to renew and reiterate its request for fast track processing of it February 10, 2021 complaint ("Complaint"). As previously reported, the Complaint against New England Power Company and Narragansett Electric Company (together, "National Grid" or "Grid") requests 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)**

On May 28, 2021, the FERC denied NEPGA's December 11, 2020 Net CONE complaint against ISO-NE.[12] 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.[13] In denying the Complaint, the FERC found that ISO-NE did not violate its current Tariff or the filed rate doctrine by using the proposed methodology to recalculate Net CONE. The FERC said that ISO-NE was "entitled to file a revised Net CONE definition pursuant to FPA section 205 and, as such, it was appropriate for ISO-NE to have performed its Net CONE calculations for the next FCA

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

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

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

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

12 *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 175 FERC ¶ 61,177 (May 28, 2021) ("*NEPGA Net Cone Complaint Order*"), *reh'g denied*, 176 FERC ¶ 62,058 (July 29, 2021).

13 NEPGA also asked the FERC to find unjust and unreasonable the Net CONE value for FCAs 16-18 filed in ER21-787. Those values were conditionally accepted in a concurrently-issued order (*see* ER21-787 in Section III below). In the *NEPGA Net Cone Complaint Order*, the FERC said that NEPGA had not demonstrated that substituting the Net CONE values calculated using the old methodology (undoing the filing in ER21-787) was appropriate or necessary to address the alleged filed rate doctrine violation. *NEPGA Net Cone Complaint Order* at P. 55.

consistent with the definition it intended to file and have in effect in advance of that FCA".[14] Assertions regarding the impact of the proposed methodology to the market were left to be addressed in ER21-787 (*see* Section III below).[15]

Request for Rehearing Denied by Operation of Law. On June 28, 2021, EPSA and NEPGA jointly requested rehearing of both the *NEPGA Net Cone Complaint Order* and the *Updated CONE, Net Cone and PPR Values Order*. On July 29, 2021, the FERC issued a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration".[16] The Notice confirmed that the 60-day period during which a petition for review of the *NEPGA Net Cone Complaint Order* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of the *NEPGA Net Cone Complaint Order*. The Notice also indicated that the FERC would address, as is its right, the rehearing request in a future order, and may modify or set aside its order, in whole or in part, "in such manner as it shall deem proper."

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

Avangrid amended the Complaint on March 26, 2021 to reflect that aspects of the relief originally requested in the Complaint are no longer feasible within the timeline previously sought. Avangrid continues to seek expeditious FERC action, requesting in its March 26 filing a FERC order on or before May 7, 2021 (which did not occur). On April 15, 2021, NextEra answered the amended Complaint. On April 20, 2021, Avangrid answered NextEra's April 15 answer. On May 6, 2021, ISO-NE submitted a letter to express importance of prompt resolution of these matters. On May 17, Avangrid submitted a letter supporting ISO-NE's May 6, 2021 letter. There has been no activity in this proceeding since the last Report and 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

[14] *Id.* at P 53.

[15] *Id.* at P 54.

[16] *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 176 FERC ¶ 62,058 (July 29, 2021) ("*Order Denying NEPGA Net Cone Complaint Order*").

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

its dispute with NECEC". Specifically, Seabrook asked the FERC to declare that: (1) Seabrook is not required to incur a financial loss to upgrade, for NECEC's sole benefit, a 24.5 kV generator circuit breaker and ancillary equipment ("Generation Breaker") at Seabrook Station; (2) "Good Utility Practice" for replacement of the nuclear plant Generation Breaker is defined in terms of the practices of the nuclear power industry, such that Seabrook's proposed definition of that term is appropriate for use in a facilities agreement with NECEC; and (3) Seabrook will not be liable for consequential damages for the service it provides to NECEC under a facilities agreement (collectively, the "Requested Declarations"). Alternatively, Seabrook asked that the FERC declare that nothing in ISO-NE's Tariff requires Seabrook to enter into an agreement to replace the Generation Breaker, and therefore, Seabrook and the Joint Owners are entitled to bargain for appropriate terms and conditions to recover their costs, to define Good Utility Practice, and to limit liability associated with providing the service ("Alternative Declaration").

Comments on Seabrook's Petition were filed by Eversource, MMWEC and NEPGA. Avangrid and NECEC Transmission ("Avangrid") protested the Declaratory Order Petition. Doc-less interventions were filed by Avangrid, Dominion, Eversource, Calpine, Exelon, HQ US, National Grid, NESCOE, NRG, and Public Citizen. NextEra answered Avangrid's protest and Avangrid answered NextEra's answer. On May 6, 2021, ISO-NE submitted a letter in this proceeding, as well as in EL21-6, to express importance of prompt resolution of these matters. There has been no activity in this proceeding since the last Report and this matter also remains pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

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

- ***Base ROE Complaint I (EL11-66)***. In the first Base ROE Complaint proceeding, the FERC concluded that the TOs' ROE had become unjust and unreasonable,[18] 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*).[19] However, the FERC's orders were challenged, and in *Emera Maine,*[20] the DC Circuit vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the FERC remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.

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[18] 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*")).

[19] *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*").

[20] *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*"). *Emera Maine* vacated the FERC's prior orders in the Base ROE Complaint I proceeding, and remanded the case for further proceedings consistent with its order. The Court agreed with both the TOs (that the FERC did not meet the Section 206 obligation to first find the existing rate unlawful before setting the new rate) and "Customers" (that the 10.57% ROE was not based on reasoned decision-making, and was a departure from past precedent of setting the ROE at the midpoint of the zone of reasonableness).

- ***Base ROE Complaints II & III (EL13-33 and EL14-86) (consolidated)***. The second (EL13-33)[21] and third (EL14-86)[22] 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.[23] 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[24] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[25] The *Base ROE IV Initial Decision* concluded that the currently-filed base ROE of 10.57%, which may reach a maximum ROE of 11.74% with incentive adders, was ***not*** unjust and unreasonable for the Complaint IV period, and hence was not unlawful under section 206 of the FPA.[26] 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.[27] 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*[28] (EL14-12; EL15-45) in

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[21] 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%.

[22] 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.

[23] *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*").

[24] 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.

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

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

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

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

Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[29]

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

The FERC directed participants in the four proceedings to submit briefs regarding the proposed approaches to the FPA section 206 inquiry and how to apply them to the complaints (separate briefs for each proceeding). Additional financial data or evidence concerning economic conditions in any proceeding must relate to periods before the conclusion of the hearings in the relevant complaint proceeding. Following a FERC notice granting a request by the TOs and Customers[31] 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.

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

[29] *Id.* at P 19.

[30] *Id.* at P 59.

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

TOs Request to Re-Open Record and file Supplemental Paper Hearing Brief. On December 26, 2019, the TOs filed a Supplemental Brief that addresses the consequences of the November 21 *MISO ROE Order*[32] and requested that the FERC re-open the record to permit that additional testimony on the impacts of the *MISO ROE Order*'s changes. On January 21, 2020, EMCOS and CAPs opposed the TOs' request and brief.

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

II. Rate, ICR, FCA, Cost Recovery Filings

- **FCA16 De-List Bids Filing (ER21-2342)**

Pursuant to Market Rule 1 § 13.8.1(a), ISO-NE submitted on July 1, 2021 a filing describing the Permanent De-List Bids and Retirement De-List Bids, as well as the substitution auction test prices, that were submitted on or prior to the March 12, 2021 FCA16 Existing Capacity Retirement Deadline. ISO-NE reported that it received 1 Permanent De-List Bid, 13 Retirement De-List Bids, and 2 substitution auction test prices from 8 Lead Market Participants. The bids were for resources located in the CT, VT, ME, South Eastern Massachusetts, Northeastern Massachusetts Boston ("NEMA/Boston") and Western Central MA Load Zones, with 996.460 MWs of aggregate capacity. Six of the Bids, totaling 26.262 MW in aggregate, were for resources under 20 MW or that did not meet the affiliation requirements that would have required IMM review. Two of those six (representing 23.174 MWs) required substitution auction test price reviews because the Bids were for greater than 3 MWs. The IMM did review the remaining eight Bids (from three separate suppliers) for 232.240 MWs of capacity. The IMM also reviewed two substitution auction test prices that were not associated with a Retirement or Permanent De-List Bid. The two bids were from a single Market Participant and for a total of 737.958 MW. The IMM's determination regarding those bids is described in the version of the filing that was filed confidentially as required under §13.8.1(a) of Market Rule 1. Comments on this filing were due on or before July 22; none were filed. Doc-less interventions were filed by NEPOOL, Calpine, National Grid, and NRG. 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).

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

On July 1, 2021, Cross-Sound Cable Company LLC ("CSC") requested FERC authorization to establish a regulatory asset that would include all CIP-IROL Costs[33] that CSC prudently incurred between January 1, 2016 and May 31, 2021 ($1.324 million) and permit CSC to recover those costs under Schedule 17 (from all ISO-NE transmission customers) over a five-year period (beginning on the date the FERC makes this rate treatment and related cost recovery effective).[34] CSC stated that the first year annual revenue requirement would be $335,785, and that CSC would file with the FERC by July 1 of each year to establish the revenue requirement for each successive year of the five-year recovery period. CSC stated that it "engaged in an extensive pre-filing information exchange process" consistent with the Schedule 17 pre-filing process. CSC avers that its regulatory asset approach is consistent with the FERC's order on requests for rehearing in ER20-739[35] (*see* Sep 29, 2020 Report and Section XV below) and will "not run afoul of the filed rate doctrine or rule against

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

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

[34] CSC proposed three alternative bases upon which the FERC could grant its request to use a regulatory asset for CIP IROL cost recovery and rate treatment: (i) FPA section 219 and Order 679 (incentive rate framework); FPA section 205 (in furtherance of the FERC's expressed policy of ensuring reliability of the BES in response to cybersecurity threats); or (iii) FPA section 309 (FERC's remedial authority).

[35] *ISO New England Inc.*, 172 FERC ¶ 61,251 (Sep. 17, 2020).

retroactive ratemaking." CSC requested a September 1, 2021 effective date for the commencement of the five-year cost recovery period. Comments on this filing were due on or before July 22, 2021 and NESCOE protested the filing, asserting that Schedule 17 does not provide for the rate incentive treatment that CSC seeks, CSC should not be allowed to circumvent the parameters for cost recovery in Schedule 17, and CSC's arguments that its request for incentive rate treatment is consistent with the Filed Rate Doctrine and Rule Against Retroactive Ratemaking ignore the FERC's Schedule 17 Orders. 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).

- **CSC CIP IROL Cost Recovery: Jun 1, 2021 Forward (ER21-2031)**

On July 8, 2021, the FERC accepted CSC's proposed rate schedule to allow it to begin the recovery period for certain CIP-IROL Costs (incurred after June 1, 2021) under Schedule 17 of the ISO-NE Tariff.[36] CSC's rate schedule was accepted effective June 1, 2021, as requested. Unless the July 8 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).

- **MPD OATT 2021 Annual Informational Filing (ER20-1977)**

On May 3, 2021, as corrected June 14, 2021, Versant submitted its annual informational filing setting forth, for the June 1, 2021 to May 31, 2022 rate year, the charges for transmission service under the MPD OATT. Versant also separately submitted an updated transmission real power loss factor informational filing on May 7, 2021. Although these filings will not be noticed for public comment, they will be subject to the process established in the "Protocols for Implementing and Reviewing Charges Established by the MPD OATT Attachment J Rate Formulas" and may result in further proceedings. If there are questions on this latest MPD OATT Informational Filing, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

As previously reported, the FERC issued four orders in this proceeding in July 2020 (three on July 17 (together, the "*July 17 Orders*"); one on July 28, 2020). Each of the orders addressed in part or in whole the Cost-of-Service Agreement ("COS Agreement")[37] 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*[38] (and the earlier, underlying orders) have been appealed to the DC Circuit. Since the last Report, the FERC took action on two remaining aspects of this proceeding that had been pending before it:

ROE Paper Hearings (-000). On July 15, 2021, the FERC issued an order setting the base ROE for the Mystic COS Agreement at 9.33%.[39] As previously reported, the *Dec 2018 Order* established a paper hearing to

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[36] *Cross-Sound Cable Co., LLC*, Docket No. ER21-2031 (July 8, 2021) (*unpublished letter order*).

[37] 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.

[38] 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).

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

determine the just and reasonable ROE to be used in setting charges under Mystic's COS Agreement. There were two rounds of briefing, described in previous Reports, with the second and more recent round to allow parties an opportunity to present written evidence applying the FERC's *Opinion 569-A* ROE methodology to the facts of this proceeding. Challenges, if any, to the *Mystic ROE Order* are due on or before August 14, 2021.

Jun 2021 (Fourth) Compliance Filing (-009). On June 2, 2021, Mystic filed a revised COS Agreement in a fourth compliance filing, this time in response to the requirements of the *April 26 Order*,[40] that proposed the following two changes: (1) the adoption of accounting treatment that adds to accumulated depreciation the difference between the purchase price and net original cost (and not to the plant's gross book value), which results in an Annual Fixed Revenue Requirement ("AFRR") of $173,379,730 and $142,130,497 for the 2022/2023 and 2023/2024 Capacity Commitment Periods, respectively; and (2) a change to section 2.4 that simply removes the phrase "that were expensed". The FERC accepted that compliance filing on July 29, 2021.[41]

If you have questions on any aspect of this proceeding, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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

- **Removal of Appendix B from Market Rule 1; Deletion of Assoc. Tariff Provisions (ER21-2220)**

On June 28, 2021, ISO-NE and NEPOOL jointly filed Tariff changes to remove from Market Rule 1 Appendix B (Imposition of Sanctions by the ISO) and to make conforming changes to the Tariff reflecting the removal of that Appendix. Appendix B formerly established procedures and standards by which ISO-NE could impose sanctions, if subsequently approved by the FERC, for sanctionable conduct. However, ISO-NE concluded that the provisions of Appendix B were outdated, unclear, or internally inconsistent with other Tariff provisions. Accordingly, ISO-NE proposed, and the Participants Committee supported at its April 1, 2021 meeting (Agenda Item #6), its removal. Comments on this filing were due on or before July 19, 2021; none were filed. Doc-less interventions were filed by Calpine, Eversource, National Grid, NRG, and NESCOE. 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).

- **CPower Waiver Request (Determination of ARA3 Summer ARA Qualified Capacity for Demand Capacity Resources (ER21-2135)**

On July 28, 2021, the FERC denied CPower' June 14, 2021 request for waiver of Tariff Section III.13.4.2.1.2.2.4.1(a)(i)(2).[42] CPower requested the waiver so that the determination of the amount of capacity that CPower can offer into the monthly reconfiguration auctions for CPower's Summer-only On-Peak Demand Resources would not be based on October 2020 audit values (which were significantly lower Qualified Capacity values than its most recent audit (in April 2021) demonstrates is actually available). In denying the waiver, the FERC found that that "granting CPower's request could have broad implications on the effectiveness of the ISO-NE Tariff and auditing rules and result in preferential treatment by allowing CPower to incorrectly use the higher Qualified Capacity data to determine its Summer ARA Qualified Capacity, while applying actual values to other similarly situated Demand Capacity Resources who remain subject to the ISO-NE Tariff."[43] Unless the July 28 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).

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[40] *Constellation Mystic Power, LLC*, 75 FERC ¶ 61,069 (2021) ("Second Compliance Order").

[41] *Constellation Mystic, LLC*, Docket No. ER18-1639-009 (July 29, 2021).

[42] *Enerwise Global Technologies, Inc*., 176 FERC ¶ 61,051 (July 28, 2021).

[43] *Id.* at P16.

- **Solar Data Requirements & Relocation of Wind Data Requirements (ER21-1974)**

On July 16, the FERC accepted the Tariff changes filed jointly by IO-NE and NEPOOL to establish operational and meteorological data requirements for solar facilities and relocate and streamline already-existing data requirements for wind facilities.[44] Specifically, the changes: (i) add to Market Rule 1 section III.1.11.3 requirements for solar facilities to provide forced outage and meteorological data; (ii) move from the LGIA to section III.1.11.3 the requirements for wind facilities to provide forced outage and meteorological data (effectively extending the requirements to all wind facilities that interconnect through ISO-NE's generator interconnection process, as well as any wind facilities that may interconnect through state interconnection processes); (iii) add four new defined terms used in section III.1.11.3 (Solar High Limit, Solar Plant Future Availability, Wind High Limit, and Wind Plant Future Availability) to the Tariff's Definition section (I.2.2); and (iv) delete "photovoltaic" from section III.1.11.3 so that the Tariff consistently uses the generic term "solar." The revisions were accepted effective July 20, 2021, as requested. Unless the July 16 order is challenged, this proceeding will be concluded. If you have any questions concerning this proceeding, please contact please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

On June 7, 2021, the FERC accepted in part and rejected in part pieces of ISO-NE's and NEPOOL's proposals, effective June 8, 2021.[45] Specifically, the FERC accepted NEPOOL's proposed ORTP value for battery storage and NEPOOL's proposed federal tax credits adjustments to the ORTPs for PV solar resources for FCA17 and FCA18. Otherwise, the FERC accepted ISO-NE's proposed ORTP values (including ISO-NE's Offshore Wind ORTP value (on which the Commissioners split 3-2; *see* separate dissents by Commrs. Glick and Clements, who agreed with NEPOOL's Offshore Wind ORTP)) and ISO-NE's proposal to maintain the current Tariff language regarding economic life determination and the establishment of ORTPs for hybrid and co-located resources in the FCM (rejecting NEPOOL's proposed Tariff revisions in each case). The FERC also rejected NEPOOL's proposal to require ISO-NE to account for future federal tax credit changes through the Tariff's indexing process, finding instead that such changes are more appropriately made through a FERC filing when and if such changes are made. With respect to other issues, the FERC rejected (i) Generation Owners' argument that accepting either the ISO-NE-proposed or the NEPOOL-proposed ORTPs for FCA16 would violate the filed rate doctrine or the rule against retroactive ratemaking;[46] and (ii) arguments about the MOPR (as outside the scope of this proceeding). In light of this outcome, the FERC directed ISO-NE to submit a compliance filing on or before June 22, 2021 that combines the alternative proposals as accepted by the FERC.

Compliance filing (-001). On June 22, 2021, ISO-NE (i) submitted Tariff revisions to incorporate the ORTPs and related revisions accepted in the *ORTP Jump Ball Order* (including NEPOOL's proposed ORTP value for battery storage and NEPOOL's proposed federal tax credits adjustments to the ORTPs for PV solar resources for FCA17 and FCA18) and (ii) explained why it was not proposing further updates to the FCA16 ORTP values to account for adjustments to CONE and related values for FCA16 in the *Updated CONE, Net Cone and PPR Values Order*. Comments on the June 22 compliance filing were due on or before July 7, 2021; none were filed. The June 22 compliance filing is pending before the FERC.

[44] *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER21-1974 (July 16, 2021) (unpublished letter order).

[45] *ISO New England Inc.*, 175 FERC ¶ 61,195 (June 7, 2021) ("*ORTP Jump Ball Order*").

[46] *Id.* at P 127 et seq.

Requests for Rehearing of ORTP Jump Ball Order (-002). On July 7, 2021, Clean Energy Advocates[47] requested rehearing of the *ORTP Jump Ball Order*. Clean Energy Advocates' request for rehearing is pending, with FERC action required on or before August 6, 2021, or the request will be deemed denied by operation of law.

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).

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

As previously reported, the FERC conditionally accepted on May 28, 2021,[48] eff. May 29, 2021, the updates to the CONE, Net CONE and PPR values, as amended in ISO-NE's March 30, 2021 Deficiency Response,[49] as well as the modified definition of Net CONE, subject to a 15-day compliance filing that reflects the assumption that the reference unit has on-site compression.[50] As noted in Section II above (EL21-26), the FERC denied NEPGA's Net CONE Complaint in a concurrently-issued order.

Compliance Filing. On June 11, 2021, in response to the *Updated CONE, Net Cone and PPR Values Order*, ISO-NE filed updated CONE, Net CONE and PPR values, $12.400, $7.468 and $9,337, respectively, to reflect the cost of gas compression. The FERC accepted ISO-NE's compliance filing, effective May 29, 2021, on July 30, 2021.[51]

Request for Rehearing. On June 28, 2021, EPSA and NEPGA jointly requested rehearing of both the *Updated CONE, Net Cone and PPR Values Order* and the *NEPGA Net Cone Complaint Order*. On July 29, 2021, the FERC issued a "Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration".[52] The Notice confirmed that the 60-day period during which a petition for review of the *Updated CONE, Net Cone and PPR Values Order* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of the *Updated CONE, Net Cone and PPR Values Order*. The Notice also indicated that the FERC would address, as is its right, the rehearing request in a future order, and may modify or set aside its order, in whole or in part, "in such manner as it shall deem proper."

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[47] "Clean Energy Advocates" are Conservation Law Foundation ("CLF"), Natural Resources Defense Council ("NRDC"), Sierra Club, RENEW Northeast, Inc. ("RENEW"), and Sustainable FERC Project.

[48] *ISO New England Inc.,* 175 FERC ¶ 61,172 (May 28, 2021) ("*Updated CONE, Net Cone and PPR Values Order*"), *reh'g denied*, 176 FERC ¶ 62,059 (July 29, 2021).

[49] As previously reported, the FERC issued a deficiency letter, on March 1, 2021, directing ISO-NE to provide 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.

[50] In its answer to the Deficiency Letter protests, ISO-NE stated that, assuming the FERC determines (as it has) that the reference unit requires on-site compression, the FERC should direct ISO-NE to include $8.75 million for that cost, that ISO-NE would account for on-site compression by adding $100,000 in annual operating and maintenance costs, reducing the seasonal capacity in the dispatch model by 5.5 MW (to account for load to run the compression equipment), and reducing the plant capacity available for participation in the Forward Capacity Market by 5.5 MW. Accordingly, ISO-NE stated that the resulting CONE, Net CONE, and PPR values would be $12.400/kW-month, $7.468/kW-month, and $9,337/MWh, respectively. *May 28 Order* at P 59.

[51] *ISO New England Inc.,* Docket No. ER21-787-002 (July 30, 2021) (unpublished letter order).

[52] *New England Power Generators Assoc., Inc. v. ISO New England Inc.*, 176 FERC ¶ 62,059 (July 29, 2021) ("*Order Denying Reh'g of Updated CONE, Net Cone and PPR Values Order*").

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).

IV. OATT Amendments / TOAs / Coordination Agreements

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

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

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

On July 27, 2021, the PTO AC, ISO-NE, Schedule 20A Service Providers, GMP, and VTransco filed revisions to ISO-NE Tariff Schedule 21-Common and Schedule 20A-Common in accordance with *Order 676-I*. The revisions include certain updated business practice standards (Version 003.2) adopted by the Wholesale Electric Quadrant ("WEQ") of the North American Energy Standards Board ("NAESB") and incorporated by reference in the FERC's regulations through *Order 676-I*. Comments on this filing are due on or before August 19, 2021. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

On July 26, 2021, CSC and ISO-NE filed revisions to ISO-NE Tariff Schedule 18-Attachment Z in accordance with *Order 676-I*. The revisions include certain updated business practice standards (Version 003.2) adopted by NAESB's Wholesale Electric Quadrant and incorporated by reference in the FERC's regulations through *Order 676-I*. Comments on this filing are due on or before August 16, 2021. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

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

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

- **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,*[53] and certified by Settlement Judge Dring[54] to the Commission,[55] 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-VP 2021 Annual Informational Filing (ER20-2119)**

On June 15, 2021, as updated on June 30, 2021, Versant Power submitted its annual informational filing to update its local transmission service charges under Schedule 21-VP. Included in its June 30, 2021 update was a revised version of Attachment P that sets forth the rates that went into effect on June 1, 2021 and reflects a settlement in principle reached with the Maine Public Utilities Commission ("MPUC") regarding charges under Schedule 21-VP for the 2020-2021 rate. Since the last Report, on July 28, 2021, Versant filed a correction to certain of its 12-CP values, which will result in 29% reduction in the $/kW-month rate for Large Power – Transmission Voltage customers and a small increase (if any) in the rates for other retail customers (less than 25 basis points). With the correction and the timing of billing, the large customers will not have to pay incorrect rates; the other retail customers will continue to pay rates as filed in June, subject to a true-up "at the next available opportunity". The FERC will not notice these information filings 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).

- **Schedule 21-FG&E Annual Informational Filing (ER09-1498)**

On July 26, 2021, Fitchburg Gas & Electric ("FG&E") submitted its data and schedules used to calculate its annual transmission revenue requirement for Non-PTF Local Network Transmission Service, Firm Point-to-Point Transmission Service and Non-Firm Point-to-Point Transmission Service as set forth in Schedule 21-FG&E covering the June 1, 2021 – May 31, 2022 period. FG&E reported that its annual revenue requirement reflected in FG&E's rates effective June 1, 2021, is $1,439,133. The FERC will not notice this filing for public

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[53] *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.

[54] 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.

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

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.

- **Schedule 21-GMP Annual True Up Calculation Informational Filing (ER12-2304)**

On June 1, 2021, pursuant to Section 4 of Schedule 21-GMP, Green Mountain Power ("GMP") submitted its annual informational filing containing the true-up calculation of its actual (rather than estimated) costs for the January 1, 2020 through December 31, 2020 time period. The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-NSTAR Annual Informational Filing (ER09-1243; ER07-549)**

On May 28, 2021, NSTAR submitted an informational filing containing the true-up of billings under Schedule 21-NSTAR for the period January 1, 2020 through December 31, 2020. NSTAR stated that the filing complied with the requirements of Section 4 and Attachment D of Schedule 21-NSTAR, as well as the Settlement Agreement approved previously by the FERC.[56] On June 30, 2021, NSTAR supplemented its May 28 annual informational filing with additional information regarding its Construction-Work-In-Progress ("CWIP") in accordance with Section 4.1(i) and (ix) of Schedule 21-NSTAR ("CWIP Supplement"). The CWIP Supplement was provided primarily on a project-specific basis, and included NSTAR's 2020 long-range construction forecast. The FERC will not notice either of these filings 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).

- **Schedule 21-CMP Annual Info. Filing (ER09-938)**

On June 30, 2021, Central Maine Power ("CMP") submitted its annual update to the formula rates contained in Schedule 21-CMP. CMP indicated that the informational filing reflected actual cost data for the 2020 calendar year plus estimated cost data for the 2021 calendar year associated with CMP's forecasted transmission plant additions and Maine Power Reliability Program CWIP as well as the annual true-up and associated interest. CMP referred to Section 10.2 of Schedule 21-CMP for specific procedures for review and challenges to the informational report. 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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[56] *See NSTAR Elec. Co.*, 123 FERC ¶ 61,270 at P 5 (2008).

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

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

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

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

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

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

- **LFTR Implementation: 51st Quarterly Status Report (ER07-476; RM06-08)**

ISO-NE filed the 51st of its quarterly status reports regarding LFTR implementation on July 15, 2021. ISO-NE reported that it implemented monthly reconfiguration auctions (accepted in ER12-2122) beginning with the month of October 2019. ISO-NE further reported that, while it will continue to evaluate its as-filed LFTR design and financial assurance issues, including an ongoing evaluation of the FTR market and risk associated with FTRs and LFTRs, it is currently focused on higher priority market-design initiatives. These status reports are not noticed for public comment.

- **IMM 2020 Annual Markets Report (ZZ21-4)**

On June 11, 2021, the IMM filed its 2020 Annual Markets Report, which covers the 2020 calendar year period.[59] The report addresses the development, operation, and performance of the New England Markets and presents an assessment of each market based on market data, performance criteria, and independent studies, providing the information required under Section 17.2.4 of Appendix A to Market Rule 1. On the basis of its review of market outcomes and related information, the IMM concluded, as it has for many years in a row, that the New England Market operated competitively in 2020. The IMM reported that the restrictions implemented to curb the spread of COVID-19 posed unprecedented operational challenges, most notably in terms of the level and predictability of electricity demand as consumption behavior changed, the temporary deferral of equipment outages, and measures taken to protect key personnel operating the grid, but that ISO-NE successfully managed these challenges. No major reliability issues occurred in 2020 due to COVID-19 or other factors, and there were no periods in the Real-Time Energy Market when a shortage of energy and reserves resulted in very high energy prices or reserve scarcity pricing. In 2020, the average wholesale energy price was at its lowest level in New England since the implementation of Standard Market Design, driven by record low natural gas prices and wholesale electricity demand, both of which have trended downwards in recent years due to long-term factors such as cheaper shale gas, energy efficiency programs and growth in behind-the-meter photovoltaic generation. For the seventh consecutive year, the forward capacity auction procured surplus capacity. Other highlights included:

- 2020 total wholesale costs ($8.1 billion) were $1.7 billion lower than 2019, driven by lower energy and capacity costs; with the exception of transmission costs (up by $0.2 billion), each component of the wholesale cost of electricity declined in 2020.

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

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

59 Please note that Annual Markets Reports filings are not noticed for public comment by the FERC.

- 2020 Energy costs totaled $3.0 billion, down $1.1 billion or 27% from 2019 (Day-ahead LMPs averaged $23.32/MWh, down 25% (or by $7.90/MWh) on 2019), with the decrease driven by lower natural gas prices, which averaged $2.10/MMBtu, down 36% from 2019 prices.
- Capacity costs comprised 1/3 of total wholesale costs, totaling $2.7 billion, down by 22% (or $0.7 billion) on 2019. The costs were driven by lower combined clearing prices in FCAs 10 and 11.

In light of its review, the IMM, in Section 1.6 (pp. 38-41) of the Report, made a number of recommendations for Market Rule changes and identified areas for additional analysis in 2021. These recommendations will be discussed in more detail at the Participants Committee's August 5 meeting.

IX. Membership Filings

- **August 2021 Membership Filing (ER21-2552)**

On July 28, 2021, NEPOOL requested that the FERC accept (i) the memberships of In Commodities US LLC (Supplier Sector); and Jupiter Power (Provisional Member); (ii) the termination of the Participant status of GenOn Energy Management and GenOn Canal; and (iii) the name change of Rivercrest Power-SOUTH, LLC (f/k/a BioUrja Power LLC). Comments on this filing are due on or before August 19, 2021.

- **July 2021 Membership Filing (ER21-2267)**

On June 30, 2021, NEPOOL requested that the FERC accept (i) the memberships of Gridmatic Isotria LLC (Supplier Sector); InBalance, Inc. (Supplier Sector); North East Offshore, LLC [Related Person to Deepwater Wind and Eversource]; and NEPGA (Fuels Industry Participant); (ii) the termination of the Participant status of Priogen Power LLC; and (iii) the name change of WP&G Holdings, LLC (f/k/a Mega Energy Holdings, LLC). Comments on this filing were due on or before July 21, 2021; none were filed. This July 2021 membership filing is pending before the FERC.

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

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

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

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

- ♦ FAC-011-4 (System Operating Limits Methodology for the Operations Horizon)
- ♦ FAC-014-3 (Establish and Communicate System Operating Limits)
- ♦ FAC-003-5 (Transmission Vegetation Management)
- ♦ IRO-008-3 (Reliability Coordinator Operational Analyses and Real-time Assessments)
- ♦ PRC-002-3 (Disturbance Monitoring and Reporting Requirements)
- ♦ PRC-023-5 (Transmission Relay Loadability)
- ♦ PRC-026-2 (Relay Performance During Stable Power Swings)
- ♦ TOP-001-6 (Transmission Operations)

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

- **Revised Reliability Standards (Cold Weather Reliability Standards): EOP-011-2; IRO-010-4; and TOP-003-5 (RM21-16)**

On June 17, 2021, NERC filed for approval proposed changes to the following Reliability Standards to require generators to implement plans for cold weather preparedness and to enhance the ability of Balancing Authorities, Transmission Operators and Reliability Coordinators to plan and operate the grid reliably during cold weather conditions by requiring the exchange of information related to generators' capability to operate ("together, the "Cold Weather Reliability Standards"):

- ♦ EOP-011-2 (Emergency Preparedness and Operations)
- ♦ IRO-010-4 (Reliability Coordinator Data Specification and Collection)
- ♦ TOP-003-5 (Operational Reliability Data)

The Cold Weather Reliability Standards address recommendations arising from FERC and NERC Staff's report on the causes of the January 17, 2018 cold weather event affecting the south central United States. NERC asked that revised Reliability Standards become effective (and the currently effective versions be retired) on the first day of the first calendar quarter that is 18 months following FERC approval. The Cold Weather Reliability Standards have not yet been noticed for public comment.

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

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

Comments were filed by NERC, the ISO/RTO Council ("IRC"), 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.[60] On March 25, 2020, Joint Associations[61] 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,

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

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

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 to the comments filed, the FERC, in a December 17, 2020 order,[62] 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,[63] 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."[64] 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.[65]

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*[66] (the "MOD A Reliability Standards"). The FERC intends to coordinate the effective dates for the retirement of the MOD A Reliability Standards with successor North American Energy Standards Board ("NAESB") business practice standards (v. 003.3) that include Modeling business practices, which were just accepted in *Order 676-J* (*see* Section XII below).

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

On June 1, 2021, NERC filed comparisons of actual to budgeted costs for 2020 for NERC and the six Regional Entities operating in 2020, including NPCC. The Report includes comparisons of actual funding received and costs incurred, with explanations of significant actual cost-to-budget variances, audited financial statements, and tables showing metrics concerning NERC and Regional Entity administrative costs in their 2020 budgets and

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

[63] *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).

[64] *Order 873* at P 2.

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

[66] *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.

actual results. Comments on this filing were due on or before June 22, 2021; none were filed. This matter is pending before the FERC.

- **5-Year ERO Performance Assessment Report (RR19-7-002)**

On May 19, 2021, the FERC submitted a further compliance filing in response to the requirements of the January 19, 2021 *Order on Compliance Filings*[67] (i) to further clarify information sharing between NERC and the Electricity Information Sharing and Analysis Center[68] ("E-ISAC") as it relates to the development of Reliability Standards; and (ii) to revise NERC's Rules of Procedure to explicitly require that NERC share all Points Bulletins ("APBs") with the FERC no later than at the time of issuance. Comments on the further compliance filing were due on or before June 9, 2021; none were filed. This matter is pending before the FERC.

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

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

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

On July 8, 2021, FERC Staff, together with staff from NERC and its regional entities issued a report outlining recommendations for real-time assessments of grid operating conditions.[69] The report concluded that system operators are prepared to manage limited impairments of their primary assessment tools or data through system redundancy and redundant data sources. However, infrequent events involving significant real-time data loss or the failure of primary analysis tools lasting more than two hours require the development of alternative data sources, tools, and analyses work to mitigate the potential loss of visibility and control resulting from the impairment of their primary tools. The report addressed the following seven technical areas related to real-time assessments, including observations, conclusions, and recommendations for each: (i) Real-time Assessment Tools Under Normal Operating Conditions; (ii) Real-time Data and Data Quality; (iii) Real-time Data Loss Management; (iv) Alternative Real-time Assessment and Study Tools; (v) Model Management; (vi) Control Center Hardware Configuration; and (vii) Major System Upgrades/Vendor Changes. View the Report here.

XI. Misc. - of Regional Interest

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

On May 4, 2021, PPL Corporation and The Narragansett Electric Company ("Narragansett") requested authorization for a transaction pursuant to which a wholly-owned subsidiary of PPL will acquire 100% of the outstanding shares of common stock of Narragansett. The transaction is expected to close in the fourth quarter of 2021. Since the last Report, the Rhode Island ("RI") Division of Public Utilities and Carriers ("RI DPU") and RI Attorney General intervened out-of-time and filed comments. On July 7, PPL and Narragansett jointly answered

[67] *N. Am. Elec. Rel. Corp.*, 174 FERC ¶ 61,030 (2021) ("*Order on Compliance Filings*") (accepting NERC's compliance filings submitted in response the FERC's *2020 Five Year Order* (*N. Am. Elec. Rel. Corp.*, 170 FERC ¶ 61,029 (Jan. 23, 2020)). and directing the further compliance filing).

[68] The EISAC, created in 1999 pursuant to a U.S. presidential directive, provides its member utilities and partners with resources to prepare for and reduce cyber and physical security threats to the North American electricity industry

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

the RI AG comments. This matter remains pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On June 14, 2021, the FERC authorized a transaction pursuant to which the ultimate upstream ownership of Seneca Energy II ("Seneca"), among others, 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").[70] 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, for the time being, a Related Person to Generation Sector member Kleen Energy. Pursuant to the June 14 order, notice must be filed within 10 days of consummation of the transaction, which as of the date of this Report has not yet occurred. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On April 6, 2021, Certain NRG project companies, including Connecticut Jet Power LLC ("Connecticut Jet"), Devon Power LLC ("Devon"), Middletown Power LLC ("Middletown"), and Montville Power LLC ("Montville"), requested authorization for a transaction pursuant to which 100% of the membership interest in the NRG project companies will be sold to Generation Bridge Acquisition, LLC ("Purchaser"), a wholly-owned, indirect subsidiary of ArcLight Fund VI, which is itself affiliated with Great River Hydro. Workpapers supporting approval of the proposed transaction were filed on June 24, 2021. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **203 Application: 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[71] 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, Public Citizen, and out-of-time by LIPA and the Delaware Public Advocate. 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 were due on or before May 13, 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).

- **LGIA: National Grid / New England Wind (Hoosac) (ER21-2548)**

On July 29, 2021, National Grid and ISO-NE ("Filing Parties") filed a First Revised LGIA between the Filing Parties and New England Wind to include details regarding the Direct Assignment Facilities charge omitted from the original LGIA and to update the Capacity Network Resource Capability ("CNRC") of the 28.5 MW Hoosac wind farm. Going forward, the Filing Parties will report the conforming First Revised LGIA in their

[70] *Seneca Energy, II LLC et al.*, 175 FERC ¶ 62,170 (June 14, 2021).

[71] "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.

respective Electric Quarterly Reports. A March 19, 2021 effective date (the date the revised LGIA was signed) was requested. Comments on this filing are due on or before July 19, 2021. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

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

On July 23, 2021, Versant Power filed proposed revisions to Section 4 of the Versant Power Open Access Transmission Tariff For Maine Public District (the "MPD OATT") to incorporate by reference certain of the revisions required by *Order 676-I* and requested waiver of certain of those standards that are not applicable to MPD and/or the MPD OATT. Comments on this filing are due on or before August 13, 2021. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Versant Waiver Request: Unreserved Transmission Use Penalty Policy (ER21-2447)**

On July 16, 2021, Versant Power requested a limited waiver of the application of its posted policy statement regarding penalties for unreserved transmission use that was in effect from January through March 2021 to Black Bear SO, LLC and Black Bear Hydro Partners, LLC (jointly, "Black Bear"). Instead, Versant proposes to charge Black Bear penalties for unreserved use based on Versant Power's revised policy statement as published May 11, 2021, avoiding the imposition of a penalty on Black Bear that is nearly seven times what it would have incurred had it reserved and scheduled annual or monthly transmission service appropriately, but still requiring Black Bear to pay an unreserved use penalty for service used without the appropriate reservations. Comments, if any, on Versant's waiver request are due on or before August 6, 2021. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement: NSTAR/Hingham Municipal Light Plant (ER21-2281)**

On June 30, 2021, NSTAR filed an Agreement for Design, Engineering and Construction services (the "D&E Agreement") between itself and Hingham Municipal Light Plant ("Hingham"). The D&E Agreement sets forth the terms and conditions under which NSTAR would undertake certain design and engineering activities for the construction of a new 115 kV station to permit NSTAR's Line #478-502 to be sectionalized and Hingham's Hobart Street Substation to be serviced to address a reliability concern for the town of Hingham. NSTAR requested that the D&E Agreement be accepted for filing as of July 1, 2021. Comments on this filing were due on or before July 21, 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/Medway Grid (ER21-2273)**

Also on June 30, 2021, NSTAR filed a D&E Agreement between itself and Medway Grid, LLC ("Medway"). The Medway D&E Agreement sets forth the terms and conditions under which NSTAR would undertake certain preliminary design and engineering activities related to Qualified Transmission Upgrades identified in the FCA15 Post-Auction Overlapping Impact Restudy for Medway's request to interconnect to NSTAR's 3445 kV West Medway Substation (queue position #844). NSTAR requested that the Medway D&E Agreement be accepted for filing as of July 1, 2021. Comments on this filing were due on or before July 21, 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).

- **Amended and Restated IRH Support and Use Agreements eTariff Compliance Filings (ER21-2163 et al.)**

As noted above, in its May 20, 2021 order[72] approving the settlement that amended and restated four Support Agreements and an Agreement with Respect to Use of Québec Interconnection ("Use Agreement"),[73]

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[72] *New England Hydro-Transmission Electric Company, Inc. et al.*, 175 FERC ¶ 61,140 (May 20, 2021).

[73] 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

the FERC directed the Filing Parties[74] to make a compliance filing with revised tariff records in eTariff format reflecting the FERC's action. On June 18, 2021, the Filing Parties submitted their respective compliance filings with revised tariff records in eTariff format (IRH Management Committee (Use Agreement) (ER21-2163); National Grid Asset Owners (Phase I New Hampshire Transmission Line Support Agreement) (ER21-2162); New England Hydro Transmission Corporation (Phase II New Hampshire Transmission Facilities Support Agreement) (ER21-2161); New England Hydro Transmission Electric Company (Phase II Massachusetts Transmission Facilities Support Agreement) (ER21-2160); and VETCO (Phase I Vermont Transmission Line Support Agreement) (ER21-2158)). Comments, if any, on those compliance filings were due on or before July 12, 2021; none were filed. The Filing Parties intervened in each of the other Filing Parties compliance filing dockets. This matter is pending before the FERC. If you have any questions concerning these matters, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

In accordance with *Order 864*[75] and *Order 864-A,*[76] 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

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. The term of the Support Agreements (and thereby the Use Agreement) was extended for another 20 years, until October 31, 2040.

[74] "Filing Parties" were the 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").

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

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

Jul 30, 2020	ER20-2572 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

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

- ***ER20-2429-001 (CMP)***. On July 27, 2021, the MPUC protested CMP's July 6 deficiency letter response.

XII. Misc. - Administrative & Rulemaking Proceedings

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

On June 17, 2021,the FERC established a Joint Federal-State Task Force on Electric Transmission ("Transmission Task Force").[77] The Transmission Task Force will be comprised of all FERC Commissioners as well as representatives from 10 state commissions (two from each NARUC region). State commission representatives will serve one-year terms from the date of appointment by FERC and in no event will serve on the Task Force for more than three consecutive terms. The Transmission Task Force will convene multiple formal meetings annually, with FERC issuing orders fixing the time and place and agenda for each meeting, and will be open to the public for listening and observing and on the record. The Transmission Task Force will focus on "topics related to efficiently and fairly planning and paying for transmission, including transmission to facilitate generator interconnection, that provides benefits from a federal and state perspective."[78]

On July 19, 2021, NARUC nominated the 10 state commissioners to the Transmission Task Force, including New England Commissioners Riley Allen (VT PUC) and Matt Nelson (Chair, MA DPU). Those nominations are pending. The inaugural public meeting of the Transmission Task Force is expected to be held this Fall and will be publicly noticed by the FERC.

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

[78] Topics that the Task Force may consider include: (i) identifying barriers that inhibit planning and development of optimal transmission necessary to achieve federal and state policy goals, as well as potential solutions to those barriers; (ii) exploring potential bases for one or more states to use FERC-jurisdictional transmission planning processes to advance their policy goals, including multi-state goals; (iii) exploring opportunities for states to voluntarily coordinate in order to identify, plan, and develop regional transmission solutions; (iv) reviewing FERC rules and regulations regarding planning and cost allocation of transmission projects and potentially identifying recommendations for reforms; (v) examining barriers to the efficient and expeditious interconnection of new resources through the FERC-jurisdictional interconnection processes, as well as potential solutions to those barriers; and (vi) discussing mechanisms to ensure that transmission investment is cost effective, including approaches to enhance transparency and improve oversight of transmission investment including, potentially, through enhanced federal-state coordination.

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

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

- **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. On May 17, the FERC issued a notice inviting the submission of post-technical conference comments, on or before July 1, 20201, addressing issues raised during the technical conference and/or identified in the April 14, 2021 Supplemental Notice of Technical Conference. Nearly 20 sets of comments were filed, including comments by: AGA, CAISO, EEI, IL ICC, MISO, MISO TOs, Organization of MISO States, NEMA, NRECA, Chargepoint, CTC Global, Electrify America, Entergy, Environmental Defense Fund, ITC Holdings, Prairie Power, and National Grid. This matter is pending before the FERC.

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

March 23 Tech Conf (PJM). The FERC convened a Commissioner-led technical conference was on March 23, 2021 to provide input to the Commission on resource adequacy in the evolving electricity sector. Speaker materials from the March 23 technical conference have been posted to eLibrary. On March 29, Ohio PUC Commission Dan Conway submitted written comments. On April 5, the FERC issued a notice inviting post-technical conference comments on specific PJM-specific questions. Initial comments were due on or before April 26, 2021; reply comments must be submitted on or before May 10, 2021. More than 45 sets of comments were filed, including by: AEE, Calpine, Cogentrix, Dominion, Exelon, FirstLight, LS Power, NESCOE, NEPGA, NRG, PSEG, Shell, Vistra, CT DEEP, EEI, EPSA, and NRECA/APPA, some of which addressed issues to be discussed in the May 25 New England technical conference (identified immediately below). On May 10, 2021, reply comments were filed by the American Clean Power Association ("ACPA"), AEP, EPSA, Exelon, Joint Consumer Advocates, LS Power, Old Dominion Electric Cooperative ("ODEC"), PJM Power Providers ("P3"), Public Interest Organizations ("PIOs"), and the Retail Electric Supply Association ("RESA").

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

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

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

On July 19, 2021, the FERC issued a notice that it will convene two staff-led technical conferences by WebEx addressing ISO/RTO energy and ancillary services markets. The technical conferences will discuss potential energy and ancillary services market reforms, such as market reforms to increase operational flexibility, that may be needed as the resource fleet and load profiles change over time. The first technical conference will be held on Tuesday, September 14, 2021; the second, Tuesday, October 12, 2021. Each conference is scheduled to run from 9-5 p.m.

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

On June 24, 2021, the FERC issued a report in which it detailed the forthcoming creation of the Office of Public Participation ("OPP"), which it intends to grow over the course of a four-year period before OPP reaches its full operating status by the close of Fiscal Year ("FY") 2024. By the end of FY2021, the FERC plans to hire the OPP Director, as well as the Deputy Director and an administrative staff member. The FERC plans to assess OPP's workload and reevaluate needed resources for additional growth into and beyond FY2024 to ensure meaningful and consistent compliance with FPA section 319.

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

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

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

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

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

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

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

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

On January 19, 2021, the FERC issued an order directing each ISO/RTO to submit, within 6 months (or before July 19, 2021), a report that provides: (a) a description of its current practices related to each of the following four hybrid resource issues: (1) terminology; (2) interconnection; (3) market participation; and (4) capacity valuation (collectively, the "Issues"); (b) an update on the status of any ongoing efforts to develop reforms related to each of the Issues; and (c) responses to the specific requests for information contained in the order. The ISO/RTO Reports, including ISO-NE's, were filed on July 19, 2021. Public comments in response to the ISO/RTO reports are due August 18, 2021, although the Energy Storage Association requested a 30-day extension of time, to September 20, 2021, to file comments in response to the ISO/RTO reports (ESA's request is pending as of the date of this Report). The FERC will use the reports and comments to determine whether further action is appropriate.

Hybrid Resources White Paper. On May 26, 2021, the FERC issued a white paper that discusses the hybrid resources technical conference, as well as information learned in post-technical conference comments. Interested persons were invited to submit comments on the white paper and encouraged to jointly respond to both the white paper and RTO/ISO informational reports where applicable to avoid duplicate comments. Comments on the white paper are also due August 18, 2021.

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

On March 18, 2021, the FERC issued a NOI[79] seeking comments on whether to revise its Demand Response ("DR") Opt-Out regulations established in *Orders 719 and 719-A.* Those regulations require an ISO/RTO not to accept bids from an aggregator of retail customers ("ARC") that aggregates DR of the customers of utilities that distributed more than 4 million MWh in the previous fiscal year, where the relevant electric retail regulatory authority prohibits such customers' DR to be bid into ISO/RTO markets by an ARC. The FERC now seek information to help it examine the potential costs/burdens and benefits, both quantitative and qualitative, of removing the DR Opt-Out, as well as other changes relating to DR since the FERC issued *Orders 719 and 719-A*. The FERC is not seeking comment on the Small Utility Opt-In. Comments on the NOI, following an extension, were due on or

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

before July 23, 2021 and were filed by nearly 30 parties, including by AEE, Voltus, AEMA, APPA/NRECA, EEI, and NARUC. Reply comments are due on or before August 23, 2021.

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

On December 17, 2020, the FERC issued a NOPR[80] 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.,[81] Alliant, Anterix, Bureau of Reclamation, CA Dept of Water Resources State Water Project/CPUC, George Cotter, FRS, Hitachi ABB Power Grids, IECA, ITC, Joint Consumer Advocates, MI PUC, Org of MISO States, MISO TOs, PJM TOs, and Public Citizen. Reply comments were due May 6, 2021[82] and were filed by APPA/TAPS, EEI, SEIA, California Public Utilities Commission and California Department of Water Resources ("CA PUC/DWR"), and the Office of the Ohio Federal Energy Advocate ("Ohio FEA"). This matter remains pending before the FERC.

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

On November 19, 2020, the FERC issued a NOPR[83] 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.[84] 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,[85] 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)**

Supplemental NOPR. In light of comments already received in this proceeding,[86] the FERC issued on April 15, 2021 a *Supplemental NOPR*[87] 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

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

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

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

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

[84] 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.

[85] "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.

[86] 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.

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

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*.[88] A more detailed summary of the NOPR was distributed to the Transmission Committee and discussed at the TC's March 25, 2020 meeting.

Comments on the *Supplemental NOPR* were due on or before June 25, 2021. Over 60 sets of comments were filed, including by the New England TOs, MMWEC/NHEC/CMMEC, NECOS, NESCOE, Potomac Economics, and CT PURA. Reply comments were due on or before July 26, 2021, with 28 sets of comments received, including by the New England TOs, NECOS, NESCOE, CT PURA/CT DEEP/MA AG, CT AG, and Public Interest Groups[89].

September 10, 2021 Workshop. The FERC will convene a workshop on September 10, 2021[90] 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.

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

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

- A shift from risks and challenges to a ***consumers'' benefits test*** that focuses on ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.
- ***ROEs incentive for Economic Benefits***. A 50-basis-point adder for transmission projects that meet an economic benefit-to-cost ratio in the top 75th percentile of transmission projects examined over a sample period and an additional 50-basis-point adder for transmission projects that demonstrate *ex post* cost savings that fall in the 90th percentile of transmission projects studied over the same sample period, as measured at the end of construction.
- ***ROE for Reliability Benefits***. A 50-basis-point adder for transmission projects that can demonstrate potential reliability benefits by providing quantitative analysis, where possible, as well as qualitative analysis.
- ***Abandoned Plant Incentive***. 100 percent of prudently incurred costs of transmission facilities selected in a regional transmission planning process that are cancelled or abandoned due to factors that are beyond the control of the applicant. Recovery from the date that the project is selected in the regional transmission planning process.
- ***Eliminate Transco Incentives***.
- ***Transmission Organization Incentive.*** A *50-basis-point increase* for transmitting utilities that turn over their wholesale facilities to a Transmission Organization and *only for the first three years after transferring operational control of its facilities.* The FERC seeks comment as to whether participation must be voluntary to receive the incentive, and if so, how the CFERC should determine whether the decision to join is voluntary.
- ***Transmission Technologies Incentives***. Eligible for both a stand-alone, 100-basis-point ROE incentive on the costs of the specified transmission technology project and specialized regulatory asset treatment. Pilot programs presumptively eligible (though rebuttable).
- ***250-Basis-Point Cap***. Total ROE incentives capped at 250 basis points in place of current "zone of reasonableness" limit.
- ***Updated Date Reporting Processes***. Information to be obtained on a project-by-project basis, information collection expanded, updated reporting process.

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

[90] 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).

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

Order 2222. On September 17, 2020, the FERC issued a final rule ("*Order 2222*")[91] adopting reforms to remove what it found were barriers to the participation of distributed energy resource ("DER")[92] 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;

(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.

ISO-NE Compliance. On May 24, 2021, the FERC approved the extension of time requested by ISO-NE, to February 2, 2022 (2/2/222), to comply with *Order 2222*.[93] In granting the extension of time, as it did for MISO, SPP and PJM, the FERC directed ISO-NE to submit an informational filing indicating any changes to the stakeholder process schedule provided in its extension request on or before June 23, 2021 and to submit status reports every 90 days thereafter until the date that ISO-NE submits its compliance filing.[94] ISO-NE submitted its first report on June 22, 2021. In that report, ISO-NE stated that the "stakeholder schedule included in ISO-NE's motion for an extension of time has not been modified. Various NEPOOL stakeholders provided feedback on the ISO-NE's draft

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[91] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, 172 FERC ¶ 61,247 (Sep. 17, 2020) ("*Order 2222*").

[92] 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."

[93] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Indep. Sys. Operators*, 175 FERC ¶ 61,156 (May 24, 2021) ("*ISO-NE Order 2222 Compliance Extension*").

[94] *Id.* at P 5.

compliance proposal in June. The ISO plans to respond to that feedback before presenting its final draft compliance design and initial Tariff redlines in September, leading, ultimately, to the filing of a compliance proposal on February 2, 2022." Materials associated with ISO-NE's *Order 2222* compliance process can be viewed on the ISO-NE website's Order 2222 Key Project page.

Order 2222-A. On March 18, 2021, the FERC issued *Order 2222-A*,[95] 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*. On May 14, AEE/AEMA answered ISO-NE's May 4 answer.

On May 20, 2021, the FERC issued a "Notice of Denial of Rehearings by Operation of Law and Providing for Further Consideration". The Notice confirmed that the 60-day period during which a petition for review of *Order 2222-A* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of *Order 2222-A*.[96] 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."[97]

Order 2222-B. On June 17, 2021, the FERC issued *Order 2222-B*,[98] which as permitted by FPA section 313(a), modified the discussion in *Order 2222-A* and set aside, in part, and clarified, in part, that decision. Specifically, *Order 2222-B* set aside the decision in *Order 2222-A* to decline to extend the opt-out and opt-in requirements of Order Nos. 719 and 719-A to demand response resources participating in heterogeneous distributed energy resource aggregations (finding that these issues are better addressed in Docket No. RM21-14). *Order 2222-B* also provides further clarification regarding appropriate restrictions to avoid double counting of services and the compensation of demand response resources that participate in heterogeneous distributed energy resource aggregations. *Order 2222-B* will become effective August 27, 2021.[99]

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[95] *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 2222-A*").

[96] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Indep. Sys. Operators*, 175 FERC ¶ 62,109 (May 20, 2021) ("*Notice of Denial of Rehearings By Operation of Law*").

[97] *Id.*

[98] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Indep. Sys. Operators*, Order No. 2222-B, 175 FERC ¶ 61,227 (June 17, 2021) ("*Order 2222-B*").

[99] *Order 2222-B* was published *Fed. Reg.* on June 28, 2021 (Vol. 86, No. 121) pp. 33,853-33,861.

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

As previously reported, *Order 860,*[100] issued three years after the FERC's *Data Collection NOPR,*[101] (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,[102] 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,[103] 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.[104] Specifically, the FERC proposes to update the MBR Data Dictionary and add the following three new attributes to the Entities table: the blanket authorization docket number, and the utility ID types and the utility IDs of the utilities whose securities were purchased under the corresponding blanket authorization docket number. Appropriate Sellers would be required to submit the docket number of the proceeding in which the FERC granted the section 203(a)(2) blanket authorization and the upstream affiliate whose securities were acquired pursuant to the section 203(a)(2) blanket authorization. Comments on the Notice were due on or before June 7, 2021,[105] and were

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[100] *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).

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

[102] 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.

[103] *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*").

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

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

filed by EEI, the Global LEI Foundation, TAPS, and XBRL US. In light of the proposed changes, the FERC deferred by three months the effective date of *Order 860* and its associated deadlines.

Effective Date: November 30, 2021. On March 18, 2021, the FERC issued a notice extending the effective and associated implementation dates of *Order 860* by an additional *three* months. The new *Order 860* effective date 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.

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

On May 20, 2021, the FERC issued Order 676-J,[106] which revises FERC regulations to incorporate by reference the latest version (Version 003.3) of the Standards for Business Practices and Communication Protocols for Public Utilities adopted by the Wholesale Electric Quadrant ("WEQ") of the North American Energy Standards Board ("NAESB"). The WEQ Version 003.3 Standards include, in their entirety, the WEQ-023 Modeling Business Practice Standards contained in the WEQ Version 003.1 Standards, which address the technical issues affecting Available Transfer Capability ("ATC") and Available Flowgate Capability ("AFC") calculation for wholesale electric transmission services, with the addition of certain revisions and corrections. The FERC also revised its regulations to provide that transmission providers must avoid unduly discriminatory and preferential treatment in the calculation of ATC. *Order 676-J* will become effective August 2, 2021.[107] Public utilities must make a compliance filing to comply with the requirements of this final rule through eTariff 12 months after implementation of the WEQ Version 003.2 Standards. Compliance filings for cybersecurity and Parallel Flow Visualization standards are due March 2, 2022.

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

On May 21, 2020, the FERC issued a Proposed Policy Statement that would clarify its policy regarding requests for waiver of tariff provisions.[108] The *Proposed Policy Statement* sets forth the approach the FERC would take going forward to ensure compliance with the filed rate doctrine and the rule against retroactive making. The proposed policy will both clarify and modify waiver standards, and in some instances, make it harder to obtain waivers.

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

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

2. *Form of Filing*. When the entity requesting remedial relief is the entity that acted (or believes it may have acted) in a manner inconsistent with the tariff, such requests should be filed as petitions for declaratory order under Rule 207 of the FERC's Rules of Practice and Procedure.

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

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

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

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[109] 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,[110] to the extent that entities seek an effective date no earlier than the day *after* the date a rate change is submitted to the FERC.

Comments on the Proposed Policy Statement were due on or before June 18, 2020 and were filed by the IRC, AEE, APPA, AWEA/SEIA, EEI, EPSA, Indicated Generators,[111] 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,[112] KEPC, and the Sustainable FERC Project. The proposed Policy Statement remains pending before the FERC.

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[109] 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.

[110] *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.

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

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

- **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*.[113] 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").[114] 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.[115] 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[116] answered the New England TO's May 10 supplemental comments. On June 15, 2020, Joint Parties[117] 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.[118] WIRES submitted supplemental comments on June 18, 2020 requesting that the FERC take further action in this proceeding to "resolve the uncertainty surrounding its base ROE methodology and establish a policy consistent with the recommendations made in these comments" (recommending a framework that employs all four of the previously proposed ROE models, including the Expected Earnings model, along with certain modifications, to ensure that ROEs attract capital investment in needed transmission infrastructure). On June 24, EEI and WIRES requested the FERC issue a NOI regarding the FERC's policy for determining base ROE applicable to the electric industry as a whole. Six Cities answered Joint Parties on June 30. APPA answered EEI and WIRES' June 24 motion.

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

As previously reported, the FERC's February 18, 2021 notice of inquiry ("*2021 NOI*") sought new information and additional stakeholder perspectives to help the FERC explore whether it should revise its approach under the currently effective policy statement on the certification of new natural gas transportation facilities to determine whether a proposed natural gas project is or will be required by the public convenience and necessity, as that standard is established in NGA section 7.[119] The *2021 NOI* is to provide an opportunity for stakeholders to refresh the record and provide updated information and additional viewpoints to help the

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[113] *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*").

[114] 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.[114] 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).

[115] 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.

[116] 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.

[117] "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.

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

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

FERC assess its policy.[120] Comments on the *2021 NOI* were due May 26, 2021. In all, more than 130 sets of comments were filed, including a large number from concerned private citizens. This matter is pending before the FERC.

XIII. FERC Enforcement Proceedings

Electric-Related Enforcement Actions

- ***Terra-Gen (IN21-7)***

On August 2, 2021, the FERC approved a Stipulation and Consent Agreement with Terra-Gen, LLC[121] ("Terra-Gen") that resolved OE's investigation into whether Terra-Gen submitted false or misleading information to the California Independent System Operator ("CAISO") about the physical capabilities of Cameron Ridge[122] and whether Terra Gen violated the CAISO Tariff by deviating its wind farm's output from CAISO's dispatch instructions. Under the Settlement, in which Terra-Gen neither admits nor denies the alleged violations, Terra-Gen must ***disgorge $117,231*** plus interest,[123] and ***pay a $510,962 civil penalty*** to the United States Treasury. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **PacifiCorp (IN21-6)**

On April 15, 2021, in the FERC's first-ever Show Cause Order addressing alleged violations of NERC Reliability Standards,[124] 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***.

Since the last Report, on July 16, 2021, PacifiCorp answered the PacifiCorp Show Cause Order, denying the alleged violations of FAC-009. Enforcement's reply is due 60 days from the filing of PacifiCorp's answer, or September 14, 2021. Should the FERC choose to pursue a civil penalty against PacifiCorp for the alleged

120 *Id.* at P 3.

121 *Terra-Gen, LLC*, 176 FERC ¶ 61,071 (Aug. 2, 2021).

122 Cameron Ridge is a wind-powered electric generation facility owned by Terra-Gen's subsidiary Cameron Ridge, LLC. Terra-Gen represented that more than 50% of the resource was comprised of technology that was physically unable to curtail output, and could not be made to do so without significant investment. However, Terra-Gen formulated and implemented a practice to curtail Cameron Ridge's output in response to negative prices, as opposed to not being able to perform due to physical limitations, e.g., changes in wind speed, and therefore violated the CAISO Tariff each time it curtailed its resource in response to negative pricing.

123 Shell's disgorgement is to be allocated to National Trading II ($13,391), Enstor Energy Services ($10,166), Macquarie Energy ($9,073), Noble Americas Gas & Power Corp. ($8,636), and ConocoPhillips Co. ($7,051).

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

violations, PacifiCorp has already exercised its right to adjudicate these allegations in federal district court. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **GreenHat (IN18-9)**

On May 20, 2021, the FERC directed GreenHat Energy, LLC ("GreenHat"), John Bartholomew, Kevin Ziegenhorn, and [Luan Troxel as the Executor for] the Estate of Andrew Kittell ("Kittell Estate") (collectively, "Respondents") to show cause why they should not be found to have violated FPA section 222, along with section 1c.2 of the FERC's regulations, PJM Tariff Attachment Q, Section B and section 15.1.3 of PJM's Operating Agreement, by engaging in a manipulative scheme in PJM's Financial Transmission Rights ("FTR") market which generated more than $13 million in unjust profits for Respondents and imposed approximately $179 million in losses on PJM Members.[125] The FERC directed GreenHat, Bartholomew, Ziegenhorn, and the Kittell Estate to show cause why they should not be required, jointly and severally, to disgorge unjust profits of just ***over $13 million***, plus interest, and directed GreenHat, Bartholomew, and Ziegenhorn (but not the Kittell Estate) to show cause why they should not be assessed civil penalties of ***$179 million***, ***$25 million***, and ***$25 million***, respectively.

Since the last Report, on July 6, 2021, Respondents answered the *GreenHat Show Cause Order*. On July 27, Enforcement Litigation Staff answered Respondents' July 6 answers. This matter is again before the FERC. A previously reported, should the FERC choose to pursue a civil penalty against Respondents for the alleged violations, Respondents have already exercised their right to adjudicate these allegations in federal district court. 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[126] 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).[127] The FERC directed Respondents to show cause why they should not be assessed civil penalties in the amount of ***$20.16 million***. On April 5, 2021, the FERC extended by 60 days, to June 18, 2021, the deadline for Respondents' answer. On June 18, 2021, Rover and ETP answered the *Rover/ETP Show Cause Order*, asserting that the FERC should dismiss this matter and decline to initiate an enforcement action. On July 21, 2021, Enforcement Staff answered Rover/ETP's answer, stating the evidence supports a finding that Rover violated the FERC's Regulations and should be assessed the civil penalty identified in the *Rover/ETP Show Cause Order*. This matter is pending before the FERC.

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

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

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

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

On December 17, 2020, the FERC issued *Opinion 549-A*,[128] a 159-page decision addressing arguments raised on rehearing requested of *Opinion 549.*[129] *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.[130] 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.[131]

On December 29, 2020, BP filed a notice that it intends to appeal *Opinion 549-A* to the Fifth Circuit Court of Appeals and paid the civil penalty amount on December 28, 2020, under protest and with full reservation of rights pending the outcome of judicial review of that Opinion. On January 19, BP filed a notice that it disgorged $250,295 ($207,169 principal plus interest), divided equally ($83,431.67) among the following 3 entities identified in the "2016 Comprehensive Energy Assistance Program Subrecipient List": Dallas County Dept. of Health and Human Services (serving Dallas); El Paso Community Action, Project Bravo (Serving El Paso); and Panhandle Community Services (serving Armstrong and numerous other counties), again under protest and with full reservation of rights pending the outcome of judicial review of *Opinion 549/549-A*.

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

On April 28, 2016, the FERC issued a show cause order[132] 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.[133]

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

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

[129] *BP America Inc.*, Opinion No. 549, 156 FERC ¶ 61,031 (July 11, 2016) ("*BP Penalties Order*") (affirming Judge Cintron's Aug. 13, 2015 Initial Decision finding that BP America Inc., BP Corporation North America Inc., BP America Production Company, and BP Energy Company (collectively, "BP") violated Section 1c.1 of the FERC's regulations ("Anti-Manipulation Rule") and NGA Section 4A (*BP America Inc.et al,* 152 FERC ¶ 63,016 (Aug. 13, 2015) ("*BP Initial Decision*")).

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

[131] *Id*. at P 319.

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

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

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

On July 15, 2021, the FERC issued and order establishing hearing procedures to determine whether Respondents violated the FERC's Anti-Manipulation Rule, and to ascertain certain facts relevant for any application of the FERC's Penalty Guidelines.[134] On July 27, Chief Judge Cintron designated Judge Suzanne Krolikowski as the Presiding ALJ and established an extended Track III Schedule[135] for the proceeding. Judge Krolikowski will convene a prehearing conference in this proceeding on or before September 10, 2021.

XIV. Natural Gas Proceedings

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

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

- ***Iroquois ExC Project (CP20-48)***
  - 125,000 Dth/d of incremental firm transportation service to ConEd and KeySpan by building and operating new natural gas compression and cooling facilities at the sites of four existing Iroquois compressor stations in Connecticut (Brookfield and Milford) and New York (Athens and Dover).
  - Three-year construction project; service request by November 1, 2023.
  - February 2, 2020 application for a certificate of public convenience and necessity pending; Iroquois requests on January 26, 2021 that the FERC act promptly and issue the certificate; National Grid and ConEd submit comments supporting Iroquois' application and request for action.
  - On May 27, 2021, FERC staff issued a notice that it will prepare an environmental impact statement ("EIS") for this Project, which will respond to comments filed on the Environmental Assessment, and plans to release that EIS on September 3, 3021.
  - On June 11, 2021, FERC staff issued a notice that it has prepared a draft EIS for this Project, which responds to comments on the September 30, 2020 Environmental Assessment, and with the exception of greenhouse gas ("GHG") emissions, concludes that approval of the proposed Project, with the mitigation measures recommended in the EIS, would not result in significant environmental impacts. FERC staff did not come to a determination of significance with regards to GHG emissions. Comments on the draft EIS are due on or before August 9, 2021. Thus far, over 200 sets of individual comments have been filed.

- ***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.[136] Rehearing of the *Authorization Order* was timely requested, but denied by operation of law.

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

[135] The hearing in this proceeding will be convened within 55 weeks (Aug. 15, 2022) and the initial decision issued within 76 weeks (January 9, 2023) of the issuance of the Chief Judge's order.

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

- *Briefing Order*. In a fairly unprecedented order issued February 18, 2021,[137] 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".[138] The Notice confirmed that the 60-day period during which a petition for review of its *Briefing Order* can be filed with an appropriate federal court was triggered when the FERC did not act on the requests for rehearing of the *Briefing Order*. The Notice also indicated that the FERC would address, as is its right, the rehearing requests in a future order, and may modify or set aside its orders, in whole or in part, "in such manner as it shall deem proper." On May 19, the FERC issued that order,[139] dismissing the requests for rehearing of the *Briefing Order*, noting, over the objection of Commissioner Danly, that the *Briefing Order* was an exercise of the FERC's continuing oversight of the Project (meaning the claimed harms would be speculative and premature) and Algonquin and Trade Associations will have an opportunity to submit, if they choose, in requests for rehearing of any final decision by the Commission in this proceeding. Algonquin petitioned the DC Circuit for review of the *Briefing Order* and the notice of denial by operation of law on May 3, 2021 (*see* Section XVI below).
  - Requests for rehearing of the *May 19 Order* were filed by Algonquin and INGAA. Algonquin also petitioned the DC Circuit for review of the *Briefing Order*, *April 19 Notice of Denial of Rehearings by Operation of Law*, and the *May 19 Order*.
- 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 were due on or before May 5, 2021; 12 sets of reply briefs were filed. Algonquin answered those reply briefs on May 14.
- 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:

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

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

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

- **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.[140] 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*.[141] Further, in an interesting twist, the FERC found that a December 5, 2017 "Renewed Motion for Expedited Action" filed by National Fuel Gas Supply Corporation and Empire Pipeline, Inc. (the "Companies"), in which the Companies asserted a separate basis for their claim that the NY DEC waived its authority under section 401 of the Clean Water Act ("CWA") to issue or deny a water quality certification for the Northern Access Project, served as a motion requesting a waiver determination by the FERC,[142] 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.[143] 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.[144] 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.

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

[141] *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).

[142] 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).

[143] *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*").

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

- On August 8, 2019, the NY DEC again denied Applicants request for a Water Quality Certification, and as directed by the Second Circuit,[145] 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.[146]
- 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, [147] finding the request premature. The FERC reiterated its encouragement that pipeline applicants requesting extensions "file their requests no more than 120 days before the deadline to complete construction", so that the FERC has the relevant information available to determine whether good cause exists to grant an extension of time and whether the FERC's prior findings remain valid.[148]

XV. State Proceedings & Federal Legislative Proceedings

- **New England States' Vision Statement**

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

Jan 13, 2021	Wholesale Market Reform
Jan 25, 2021	Wholesale Market Reform
Feb 2, 2021	Transmission Planning
Feb 25, 2021	Governance Reform
Mar 18, 2021	Equity and Environmental Justice

Written comments on the topics and discussions addressed in the on the equity and environmental justice topics and discussions were, following an extension, due by May 13, 2021. Comments submitted are posted on **NewEnglandEnergyVision.com**. Recordings of the technical forums, as well as draft notices, agendas, and additional information on these sessions, are also available on the New England States' Vision Statement website (https://newenglandenergyvision.com/).

Report to the Governors. On June 29, 2021, the NESCOE Managers published their Progress Report to the New England Governors Regarding "Advancing the New England Energy Vision". The Report will be further discussed at the August 5, 2021 Participants Committee meeting. View Report here.

145 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).

146 *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).

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

148 *Id.* at P 10.

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).

- **ISO-NE Implementation of Order 1000 Exemptions for Immediate Need Reliability Projects (20-1422)**
  Underlying FERC Proceeding: EL19-90[149]
  Petitioner: LS Power
  Status: Briefing Complete; Pending Court Action

On October 16, 2020, LSP Transmission Holdings II, LLC ("LS Power") petitioned the DC Circuit Court of Appeals for review of the FERC's orders addressing ISO-NE's implementation of the Order 1000 exemptions for immediate need reliability projects. Since the last Report, MMWEC filed on July 8 a notice that it would not submit a Reply Brief. On July 9, 2021, LSP Transmission filed Petitioner's Reply Brief. LSP Transmission filed a Joint Appendix on July 16. On July 28, 2021, MMWEC filed an Intervenor for Petitioner Final Brief. Final Briefs were filed on July 30. Briefing is now complete and this matter is pending before the Court

- **CIP IROL Cost Recovery Rules (20-1389)**
  Underlying FERC Proceeding: ER20-739[150]
  Petitioner: Cogentrix, Vistra
  Status: Briefing Complete; Pending Court Action

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. Since the last Report, Cogentrix and Vistra filed a Deferred Appendix (July 16, 2021) and Final Briefs (from Petitioners and the FERC) were submitted on July 26, 2021. Briefing is now complete and this matter is pending before the Court.

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

[150] *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*").

- **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[151]
  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.[152] The cases have been consolidated into Case No. 20-1343. On February 17 and 24, 2021, the Court consolidated with 20-1343 the most recent appeals in cases 21-1067 (NESCOE) and 21-1070 (CT Parties), respectively. On March 25, 2021, the Court issued an order returning this case to its active docket. On March 26, the Court granted the interventions by MMWEC/NHEC, NESCOE, and ENECOS. On April 16, 2021, the Court ordered the parties to file, and the parties did file, by May 17, 2021, proposed formats for the briefing of these cases.

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

- ***CASPR* (20-1333, 20-1331) (consolidated)****
  Underlying FERC Proceeding: ER18-619[153]
  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 the result. The Sierra Club, NRDC and CLF also requested rehearing of the November 19 order.

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

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

[152] 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.

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

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[154]
  Petitioners: TOs' (CMP et al.)
  Status: Being Held in Abeyance

On August 28, 2020, the TOs[155] 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*[156] decision. On September 22, 2020, the FERC submitted an unopposed motion to hold this proceeding in abeyance for four months to allow for the Commission to "a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the Commission." On October 2, 2020, the Court granted the FERC's motion, and directed the parties to file motions to govern future proceedings in this case by February 2, 2021. On January 25, 2021, the FERC requested that the Court continue to hold this petition for review in abeyance for an additional three months, with parties to file motions to govern future proceedings at the end of that period. The FERC requested continued abeyance because of its intention to issue a future order on petitioners' request for rehearing of the order challenged in this appeal, and the rate proceeding in which the challenged order was issued remains ongoing before the FERC. Petitioners consented to the requested abeyance. On February 11, 2021, the Court issued an order that that this case remain in abeyance pending further order of the court. On April 21, 2021, the FERC filed an unopposed motion for continued abeyance of this case *because* the Commission intends to issue a future order on Petitioners' request for rehearing of the challenged Order Rejecting Compliance Filing, and because the remand proceeding in which the challenged order was issued remains ongoing.

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

- **2013/14 Winter Reliability Program Order on Compliance and Remand (20-1289, 20-1366) (consol.)**
  Underlying FERC Proceeding: ER13-2266[157]
  Petitioner: TransCanada
  Status: Briefing Complete; Pending Court Action

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

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

[155] 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.

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

[157] 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*").)

the FERC's April 1, 2020 *2013/14 Winter Reliability Program Order on Compliance and Remand*.[158] 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 pending 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**[159]
  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; Pending Court Action

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 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 pending before the Court.

Other Federal Court Activity of Interest

- ***Order 872* (20-72788,* 21-70113; 20-73375, 21-70113) (consol.) (9th Cir.)**
  Underlying FERC Proceeding: RM19-15[160]
  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*.[161] On October 9, the FERC filed an unopposed motion for the Court to hold this appeal in abeyance, suspend filing of the certified index to the record, and issue a new briefing schedule after January 4, 2021. The abeyance was to permit the FERC to address the pending rehearing requests in a future order. On October 26, 2020, the Court granted the FERC's motion. On January 29, 2021, SEIA requested that this case be consolidated with the others, and that the abeyance period be extended to give the parties additional time to coordinate and develop a unified, efficient briefing schedule.

On March 25, 2021, the Court granted SEIA's unopposed March 5, 2021 motion to lift the stay in this proceeding. Briefing has resumed. On May 27, 2021, Petitioners' briefs were filed by SEIA and Other

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[158] 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.

[159] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

[160] *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).

[161] *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.

Petitioners.[162] On June 28, 2021, petitioner-intervenors filed their joint brief and (June 28, 2021); motions and associated briefs by amici curiae in support of petitioners were also filed on June 28, 2021. Since the last Report, NewSun Energy filed an Intervenor Brief on July 28. Next up will be 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[163]
  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")[164] 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 Court, the DC Circuit will not take up this case. The last Joint Status Report was filed on June 22, 2021, noting developments since the March 23, 2021 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) (consol.)**
  Underlying FERC Proceeding: EL14-12; EL15-45[165]
  Petitioners: MISO TOs, Transource Energy, Dec 23 Petitioners et al.
  Status: Briefing Underway

The MISO Transmission Owners (TOs), Transource and "Dec 23 Petitioners",[166] among others, have appealed *Opinion 569/569-A*. The MISO TOs' case has been consolidated with previous appeals that had been held in abeyance, with the lead case number assigned as 16-1325. The FERC filed a certified Index to the Record on December 3, 2020, the Parties filed a joint unopposed briefing schedule on December 23, 2020. Statements of issues were filed on February 8, 2021. Petitioners' Briefs were filed on March 10. On March 17, 2021, a motion to participate as amicus curiae was jointly filed by NEP, CPM, Eversource, Fitchburg and Unitil, NHT, VTransco,

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

[163] *PennEast Pipeline Co., LLC*, 162 FERC ¶ 61,053 (Jan. 19, 2018), *reh'g denied*, 163 FERC ¶ 61,159 (May 30, 2018).

[164] 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.

[165] *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).

[166] "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.

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[167] filed their Brief. FERC filed its Respondent brief on June 8 and Intervenors in Support of FERC their Joint Brief on June 22, 2021. Since the last Report, Petitioners' and Joint Petitioners' Reply Briefs were filed on July 8, 2021; Intervenors in Support of Petitioners Reply Briefs, July 22, 2021. The following deadlines remain: Joint Deferred Appendix, August 6, 2021; and Final Briefs, August 19, 2021.

- **Algonquin Atlantic Bridge Project Briefing Order (21-1115*, 21-1138, 21-1153, 21-1155) (consol.); Underlying FERC Proceeding: CP16-9-012[168]**
  Petitioners: LS Power, Algonquin, INGA
  Status: Briefing Not Yet Begun

On May 3, 2021, Algonquin petitioned the DC Circuit Court of Appeals for review of the *Briefing Order* and the *April 19 Notice of Denial of Rehearings by Operation of Law*. Appearances, docketing statements and a statement of issues were due and filed June 4, 2021. Also on June 4, 2021, the FERC filed an unopposed motion to hold this proceeding in temporary abeyance, until August 2, 2021, including the fling of the certified index to the record, because "the May 3 petition for review no longer reflects the [FERC]'s latest determination in this matter." On June 21, the Court granted the abeyance motion, directing the parties to file motions to govern future proceedings by August 6, 2021. Since the last Report, the Court consolidated Cases 21-1153 and 21-1155 with the lead Case (21-1115), with the consolidated cases being held in abeyance pursuant to the June 21 order.

[167] 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.

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

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