NEPOOL
NEW ENGLAND POWER POOL
David T. Doot
Secretary

April 30, 2020

VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of May 7, 2020 NEPOOL Participants Committee Teleconference Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the May meeting of the Participants Committee will be held **via teleconference on *Thursday*, May 7, 2020, at 10:00 a.m.** for the purposes set forth on the attached agenda and posted with the meeting materials at http://nepool.com/NPC_2020.php.

For your information, the May 7 meeting will be recorded, as are all the NEPOOL Participants Committee meetings. NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, consumer advocates that are not members, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those in attendance or participating in the meeting are required to identify themselves and their affiliation during the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.

The dial-in number for the meeting, to be used only by those members, alternates and welcomed guests who otherwise attend NEPOOL meetings, is **866-803-2146; Passcode: 7169224**.

Please note that, given the COVID-19 situation and guidance from the Governor of Maine, a decision has been made NOT to hold the June 23-25 Participants Committee Summer Meeting in person. We are planning a virtual meeting for June 24 for the promised educational session associated with future grid discussions. We are working now to schedule virtual Sector meetings with the ISO Board panels for late June or July, with timing and format yet to be worked out. We are working on how best to handle the remainder of the business planned for the summer meeting and will advise as those plans are finalized.

We hope all of you are staying safe and healthy.

Respectfully yours,

/s/
David T. Doot, Secretary

NEPOOL PARTICIPANTS COMMITTEE
MAY 7, 2020 MEETING

FINAL AGENDA

1. To approve the draft minutes of the Participants Committee meeting held on April 2, 2020, which are marked to show the changes made since the minutes were circulated with the initial notice.

2. To adopt and approve the action recommended by the Reliability Committee set forth on the Consent Agenda included with this notice.

3. To receive an ISO Chief Executive Officer Report.

4. To receive an ISO Chief Operating Officer Report.

5. To consider and take action, as appropriate, on revisions to Schedule 24 to the OATT to incorporate by reference updated versions of the North American Electric Standard Board's Wholesale Electric Quadrant's Business Practice Standards, as recommended by the Transmission Committee. Background materials and a draft resolution are included and posted with this supplemental notice.

6. To consider and take action, as appropriate, on miscellaneous and clean-up changes to the ISO New England Billing Policy. These revisions were reviewed and discussed by the Budget & Finance Subcommittee. Background materials and a draft resolution are be included and posted with this supplemental notice.

7. To receive a report on current matters relating to regional wholesale power and transmission arrangements that are pending before the regulators and the courts. The litigation report will be 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
    - GIS Agreement Working Group
    - Joint Nominating Committee
    - Others

9. Administrative matters.

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

Electronic Participation Guidelines
May 7, 2020 Participants Committee Teleconference

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, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those in attendance or participating, either in person or by phone, are required to identify themselves and their affiliation at the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.

BEFORE THE MEETING

- **Download meeting materials** from the NEPOOL or ISO-NE websites**.** Will minimize disruptions WebEx or internet service interruptions.

PROXIES

- If unable to participate for any portion of the meeting, members and alternates are encouraged to designate a temporary alternate or proxy by e-mail to pmgerity@daypitney.com.

JOIN THE TELECONFERENCE
866-803-2146; 7169224#

- 866-803-2146; access code 7169224#.
- Slowly state your name and the Participant you are representing, followed by the # key.
- Audio by phone only. No computer-based audio available.

Join Meeting

JOIN THE WEBEX
WebEx Link

- Click <Classic View> on right side of menu. Do not use <Modern View>.
- Enter first name, last name and e-mail address.
- Enter meeting password: **nepool.**
- Click <Join>.

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DURING THE MEETING

- **MUTE YOUR PHONE** (*6) when not speaking.
- **DO NOT PLACE THE CALL ON HOLD** – if taking another call, hang-up and rejoin when ready.
- **USE A HANDSET** when speaking. Use of headsets/speaker phones strongly discouraged.
- **ASK AND WAIT** to be recognized by the Chair.
- **IDENTIFY** yourself/your Participant once recognized and before continuing.

VOTING

- Voice Votes. Oppositions and Abstentions will be noted for the record.
- Roll Call Votes. Will be taken if and as (i) necessary or (ii) requested by any member.

SERVICE INTERRUPTIONS

- Report dropped calls by e-mail to the Chair or Secretary.
- If teleconference system has failed, stand by on e-mail for updates via NPC distribution list.
- PATIENCE. We thank you for your patience during these unprecedented times of remote workforce deployment and strain on teleconference and WebEx services.

Stay Safe and Healthy

PRELIMINARY

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held via teleconference beginning at 10:00 a.m. on Thursday, April 2, 2020. 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.

Ms. Nancy Chafetz, Chair, presided and Mr. David Doot, Secretary, recorded.

APPROVAL OF MARCH 5, 2020 MINUTES

Ms. Chafetz referred the Committee to the preliminary minutes of the March 5, 2020 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of the March 5, 2020 meeting were unanimously approved as circulated, with an abstention by Mr. Michael Kuser noted.

CONSENT AGENDA

Ms. Chafetz referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting, noting that the ISO had agreed to adopt and file if supported the changes identified in Consent Agenda Item 4 ~~if approved.~~ , which recommended Market Rule changes for treating the Capacity Supply Obligations of Energy Efficiency Resources during Scarcity Conditions. Following motion duly made and seconded, the Consent Agenda was approved, with Jericho and PSEG opposing the Consent Agenda because they disagreed with the changes identified in Consent Agenda Item 4~~, which recommended Market Rule changes for treating the Capacity Supply Obligations of Energy Efficiency Resources during Scarcity Conditions. Michael~~. Mr. Kuser and Enel X abstained on the vote to approve the Consent Agenda, with Enel X abstaining also because of disagreement with Item 4.

ECONOMIC LIFE DETERMINATION COMPLIANCE AND PROSPECTIVE REVISIONS

Ms. Chafetz referred the Committee to Tariff revisions that~~ were proposed by the ISO and had been unanimously recommended by the Markets Committee ~~, in response to a recent FERC order~~. That ~~, had been proposed by the ISO and unanimously recommended by the Markets Committee. The FERC order had rejected proposed changes to the Internal Market Monitor's (IMM) calculation of the economic life of existing generators in the FCM (called the Economic Life Revisions). She explained that this matter would have been on the Consent Agenda but for the timing of the Markets Committee's consideration and vote.

The following motion was duly made, seconded, and unanimously approved, with abstentions noted by VEIC, Maple Energy and ~~Michael~~Mr. Kuser:

> RESOLVED, that the Participants Committee supports the revisions to Market Rule 1 to address the directives set forth in the FERC's March 10, 2020 Order Granting Rehearing in Docket No. ER18-1770-002, as recommended by the Markets Committee at its March 24, 2020 meeting and as circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

ISO CEO REPORT

Ahead of the CEO report, Ms. Chafetz, on behalf of NEPOOL, expressed appreciation for the ISO's efforts ~~of the ISO ~~to maintain reliability and markets during these extraordinary times of the COVID-19 coronavirus outbreak. She also acknowledged and thanked the transmission, distribution and ~~generator~~generation operators for their service during the pandemic.

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), began his report describing the ISO's activities in response to the COVID-19 outbreak. He said the ISO had decided to activate its business continuity and pandemic response plan beginning on March 13, 2020, smoothly transitioning about 95 percent of its work force to work from home. The ISO's operators and dispatchers remained in the control room and back-up control center to maintain operations, and the ISO was prepared if needed to sequester personnel to minimize the risk of exposure to the pandemic. He explained how the broader region had come together to address the challenges from the pandemic, with frequent calls among local control centers, the control rooms in the Eastern Interconnection, the Northeast Power Coordinating Council, and the Electric Power Research Institute (EPRI). He noted that transmission, distribution and power plant operators had all performed well.

Mr. van Welie completed his remarks referring the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the March 5, 2020 Participants Committee meeting, which had been circulated and posted in advance of the meeting. There were no questions or comments on the summaries.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), reviewed highlights from the March COO report, which was circulated in advance of the meeting and posted on the NEPOOL and ISO websites. He began by summarizing his report on ISO operations during the COVID-19 pandemic. He noted that approximately 95 percent of the ISO workforce was working remotely but that a select number of ISO personnel were working in the main or back-up control centers. He summarized protective measures being used to minimize risk to control room staff. He expected this operational posture to continue at least through early- to mid-May. Dr. Chadalavada noted with appreciation the collaborative sharing of best practices within the industry, identifying numerous communication protocols implemented, including frequent conference calls organized by EPRI to provide experiences and measures undertaken in other control centers around the globe.

He then discussed the impact of COVID-19 on system loads. He explained that system-wide demand was down by about ~~3~~three to ~~5~~five percent with the load curve more characteristic of loads on snow days when many New Englanders stay home and businesses operate at less than full capacity. He referenced load charts that showed loads ramping a few hours later in the morning and peaking later in the afternoon and evening. Load forecasts were less accurate given the changes, but the ISO was working to train the computer models to improve forecasting during and following these times. He expected it would be at least late April before the bulk of this work could be undertaken. He explained in response to a question that the ISO expected load to be impacted also by the projected recession once employees could return to their workplaces. He committed to keep the Committee appraised of corresponding changes in load forecasts as a result of developments during and after the business shutdowns for COVID-19.

In response to follow-up questions, Dr. Chadalavada opined that the region may see more negative prices with lower loads. He also explained that transmission owners had deferred or canceled non-critical outages during this time so there would be less spring maintenance with which to contend.

Dr. Chadalavada then continued with his regular operations report. He noted that, based on data through March 25, 2020 (except where otherwise noted): (i) Energy Market value was $142 million, down $90 million from February 2020 and down $267 million from March 2019; (ii) average natural gas prices over the period were 28 percent lower than February average values; (iii) average Real-Time Hub LMPs ($16.58/MWh) were 18 percent lower than February averages; (iv) average daily (peak hour) Day-Ahead cleared physical Energy, as a percent of forecasted load, was 98.8 percent in March, down from 99.9 percent in February; and (v) daily Net Commitment Period Compensation (NCPC) for March totaled $1.4 million, up $300,000 from February 2020 and down $900,000 from March 2019. March 2020 NCPC, which was 1.0

percent of total Energy Market value, was comprised of (a) $1.1 million in first contingency payments, up $200,000 from February, (b) $100,000 in second contingency payments, up $43,000 from February (but remaining low because the loads, particularly in SEMA, were not hitting the thresholds that typically trigger the need for second contingency payments), and (c) the remaining NCPC for distribution payments, compared to no such NCPC in February.

He noted that the April 23 Planning Advisory Committee (PAC) meeting would include discussion of economic studies, a transmission study, and the Marginal Emissions Analysis Report (expected to be published on April 14). The agenda also included PAC review of the 2020 load forecast. He said the 2020 Capacity, Energy, Loads, and Transmission (CELT) Report was scheduled to be released on May 1, 2020 and would include for the first time seasonal and annual demand from heating and transportation electrification. He also reported that the Order 1000 RFP for transmission for Boston in 2028 received 36 Phase One Proposals from ~~8~~eight Qualified Transmission Project Sponsors that ranged from $49 million to $745 million, with in-service dates ranging from March 2023 through December 2026. He said that the ISO was expediting its review of those proposals.

Dr. Chadalavada flagged for the Committee the current status of the Forward Capacity Market, highlighting specifically that the zones for the FCA15 would be the same as for FCA14.

Following his presentation, he responded to numerous questions and observations. He agreed that total energy market value may be at an all-time low, a fact that he would investigate following the meeting. He indicated that, based on early analysis, the ISO did not anticipate the need to enhance financial assurance or other risk mitigation measures as a result of COVID-19 or the recession, but monitoring and discussion would continue and additional changes or measures would be considered with stakeholders if and when appropriate. He noted that asset owners were not reporting supply chain issues. He confirmed that the ISO was working to analyze the Order

1000 RFP responses expeditiously with a goal of having selected projects in service for the FCA15 delivery period.

ISO ENERGY SECURITY IMPROVEMENTS (ESI) PROPOSAL

Ms. Chafetz began this item summarizing for the Committee the materials circulated in advance of the meeting and reviewing how she intended to conduct this portion of the teleconference meeting. She then invited Ms. Mariah Winkler, the Chair of the Markets Committee, to summarize that Committee's deliberations on this item. Ms. Winkler did so noting the three motions to amend the ISO's proposal that had been voted at the Markets Committee, once of which had passed and two that had failed. She then reported on the specific voting results, noting that the Markets Committee did not have enough votes in favor to recommend either the ISO proposal with the amendment that had passed~~,~~ or the ~~un-amended~~unamended ISO proposal.

Following this introduction, Ms. Chafetz explained that the ISO's base proposal would be the starting point for Committee deliberations. She acknowledged the substantial history and discussions leading up to the Markets Committee votes on this matter. She explained that, rather than repeating themselves for the Participants Committee, members if they wished could merely reference their positions at the Markets Committee if they were unchanged. The following main motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the revisions to the Tariff to effect the Energy Security Improvements (ESI) design, as proposed by ISO New England, and as circulated to this Committee in advance of this meeting, together with any changes agreed to by the Participants Committee at this meeting and such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee

Ms. Chafetz invited Mr. Jeff Bentz, Director of Analysis for the New England States Committee on Electricity (NESCOE), to describe the three amendments that had been sponsored by NESCOE and voted by the Markets Committee. Mr. Bentz began by explaining NESCOE's view that, without modifications, the ISO proposal puts consumers at great risk, especially during extended cold snaps and ~~will~~would impose unjustified costs on consumers. He said NESCOE was of the view that the ISO had failed to provide an assessment of the marginal reliability value attached with the substantial added costs from its proposal and elements of that proposal. He summarized NESCOE's understanding of the conclusion of the ISO's external market monitor that the proposal would result in load being required to pay for more incremental energy and operating reserves than are likely to be needed in Real-Time. He reminded the Committee that NESCOE had proposed other alternatives to more directly link quantities of purchases with incremental reliability gains, but those ~~are~~were not part of the ISO's proposal. Further, NESCOE questioned whether existing elements of markets, such as the FCM pay-for-performance rate and Reserve Constraint Penalty Factor values, needed to be reconsidered with the ISO's proposal. Failure to do so, he said, could potentially subject consumers to even more unjustified costs. He explained that NESCOE's three amendments were intended individually and collectively to reduce ESI costs to consumers without materially reducing reliability benefits.

NESCOE's first amendment would limit the provisions to acquire Replacement Energy Reserves (RER) solely to the winter months. Mr. Bentz reminded the Committee that, as discussed at the Markets Committee, this NESCOE amendment ~~is~~was designed specifically to support fuel security objectives, as there was no demonstrated need to procure RER for fuel security in non-winter months.

Referencing NESCOE's second amendment, Mr. Bentz explained NESCOE's view that the ISO's proposal to increase energy procured and related costs on account of potential load forecast error was not adequately justified or explained at the Markets Committee and, again, would increase costs without any material increase in reliability.

On NESCOE's third and final amendment, NESCOE proposed to increase the strike price by $10/MWh from levels proposed by the ISO. He explained such an adder would reduce risks and associated costs of the energy call option. He acknowledged that this change might weaken the financial incentive for some resources to acquire fuel to meet the call option but opined any reduction of such incentives would be very modest at best.

NESCOE Amendment No. 1 -- (Setting Day-Ahead RER to Zero for Non-Winter Months)

Following NESCOE's introduction, the Committee discussed each of the changes, beginning with NESCOE's Amendment No. 1 to amend the main motion so as to revise the ESI proposal so RER quantities would only be calculated for the months of December through February. Many commenters began their remarks by expressing appreciation for the ISO's efforts and willingness to consider many suggested changes. Other commenters, as suggested by the Chair, referred throughout the discussions to their positions at the Markets Committee rather than repeating them.

Focusing on the amendments themselves, beginning with comments from representatives of the Transmission Sector, one Participant representative explained that the Participant generally supported the new ancillary services as a good first step to improve the markets and agreed with NESCOE's amendments which would reduce customer costs that seemed to be unnecessary or unjustified while still allowing ESI to address demonstrated reliability concerns during the winter months. This Participant could not support and would abstain on a vote on the

ISO proposal at this time because it did not yet include a seasonal forward market and a strong market mitigation construct, both of which the ISO committed to consider in the future.

Continuing, all the representatives of the Publicly Owned Entity (POE) Sector expressed broad support for the NESCOE amendments, referring in some cases to supportive positions that had been expressed fully at the Markets Committee. They said that they could not support the ISO proposal because it included costs that they did not find to be needed.

The representatives of the End User Sector were called on next. Those who spoke expressed support for NESCOE Amendment No. 1 and the other proposed NESCOE amendments. They noted that the Commission had directed the region to address demonstrated fuel security concerns, which had only been for the winter months. They expressed the ~~views~~view that that there was no demonstrated need for RER to ensure reliability, especially during non-winter months. They objected to the substantial additional costs that would be imposed on consumers. One member cited analysis that suggested that the procurement of RER in non-winter months could impose an additional $51-61 million in costs on consumers that they believed to be unnecessary and unjustified. This Participant representative expressed support for the NESCOE amendments because they would reduce inappropriate costs ~~on~~to consumers.

Members of the Alternative ~~Resource~~Resources (AR) Sector who spoke were generally supportive of the NESCOE amendments for reasons previously identified in the discussion. The RER product was characterized in the discussion by one AR member as reserves for reserves and not a necessary product to preserve reliability. The member also expressed concern that the ISO did not analyze the impact ESI would have on the Forward Capacity Market. Another member suggested that the NESCOE amendments would properly remove optional costs from the ISO’s proposal that were not demonstrably necessary now, without prejudice to making those or similar changes in the future if they were to be demonstrated to be needed.

Representatives of the Generation Sector and Supplier Sector that spoke expressed general support for the ESI design and opposition to the amendments that were viewed as reducing necessary incentives to achieve the results sought by ESI. Referencing, for example, the $10 adder to the strike price proposed by NESCOE's third amendment, a member cited very recent operational challenges that resulted from the loss of a major nuclear generator that caused less than a $10/MWh increase in clearing prices. Consequently, he explained, the energy option would not have been available to address the drop in load. Another member similarly expressed concern that the $10 adder would reduce incentives that were necessary to ensure reliability. A member explained more broadly that the financial incentives from ESI, even without the amendments, at best provided marginal support for liquefied natural gas (LNG) for the winter months, and would be insufficient to support LNG arrangements with the amendments. One member explained that ESI more broadly addressed long-recognized problems with price formation in the energy market and should be supported for that reason. Another member, referring to NESCOE Amendment No. 1, expressed the view that RER was needed year round in order to address known issues that were resulting in ~~year round~~year-round uplift.

NESCOE, taking the opportunity to make closing comments, focused on the suggestion that ESI was addressing long-standing problems with the markets other than fuel security. Mr. Bentz opined that the issue before the group was to address winter fuel security concerns and this was not the right design to accomplish that objective.

Following that discussion, NESCOE Amendment No. 1 was voted in a roll call and passed with a 63.76% Vote in favor (Generation Sector – 0%; Transmission Sector – 16.79%; Supplier Sector – 5.60%; AR Sector – 7.79%; ~~Publicly Owned Entity~~POE Sector – 16.79%; and End User Sector – 16.79%). (See Vote 1 on Attachment 2).

NESCOE Amendment No. 2 (Remove Accounting for the Load Forecast Error)

With the once-amended main motion now before the Committee, a motion was duly made and seconded to further amend the ISO's ESI proposal to remove the language that permits the ISO to add to the RER purchased Day-Ahead for every hour of the Operating Day an amount to account for potential load forecast error. Discussion on this motion to amend began with the POE Sector. Representatives who spoke again expressed support for the amendment for the same reasons they supported the first amendment. Similarly, the End User members who spoke expressed their support for the amendment, with one summarizing analysis that suggested that allowing the ISO to include load forecast error in determining the RER to purchase could add anywhere from $16 million to $99 million in additional annual costs on consumers, even if RER were limited just to the winter period. Representatives from the other Sectors, to the extent they spoke, similarly referred back to their views expressed during the discussion of the first amendment.

Following discussion, the second NESCOE motion to amend was voted by roll call and passed with a 63.76% Vote in favor (Generation Sector – 0%; Transmission Sector – 16.79%; Supplier Sector – 5.60%; AR Sector – 7.79%; ~~Publicly Owned Entity~~POE Sector – 16.79%; and End User Sector – 16.79%). (See Vote 2 on Attachment 2).

NESCOE Amendment No. 3 (Strike Price $10 Adder)

With a twice-amended main motion now before the Committee, a motion was duly made and seconded for a third motion to amend the ISO's ESI proposal. This amendment would add $10/MWh in every hour to the strike price that the ISO proposed to use in that hour. Members who spoke in favor of this amendment argued that there was simply no support for the additional costs that an inappropriately low strike price would impose on consumers. There was some acknowledgement that the adder may reduce financial incentives to resources during certain hours, but they opined a higher strike price would achieve a more acceptable cost/benefit balance than the ISO's proposal. They also complained that the ISO failed to support its argument that a lower strike price was necessary. Members who spoke in opposition to the motion to amend reiterated the concern that the adder would effectively eliminate the availability of this option when needed.

The third NESCOE motion to amend was then voted and passed with a 61.27% Vote in favor (Generation Sector – 0%; Transmission Sector – 16.79%; Supplier Sector – 4.48%; AR Sector – 6.42%; ~~Publicly Owned Entity~~POE Sector – 16.79%; and End User Sector – 16.79%). (See Vote 3 on Attachment 2).

Thrice-Amended Main Motion

A motion to approve the thrice-amended main motion was then duly made and seconded. A number of members whose votes were going to be different on the amended motion than on the individual amendments described their positions. Some expressed concern that, while the amendments improved the ESI design, they would abstain when voting on the package because, in their view, the amended proposal, like the unamended ISO proposal, was still incomplete without a seasonal forward component and mitigation rules in place. More targeted revenues were needed to ensure available and flexible resources when needed. Others expressed support for the amendments as improving on a proposal but opposition to the amended proposal overall because, even with the amendments, the improved proposal was still unjust and unreasonable in their views, albeit less unreasonable than ISO's unamended ESI proposal.

Some who opposed the three amendments explained that they similarly would oppose the amended proposal, and would support the ISO's unamended ESI proposal even though they considered it only marginally sufficient to accomplish the necessary fuel security through LNG purchases. Others suggested that, particularly in the near term, but also as part of a transition to a system with a fundamentally-changed infrastructure, the region would be better-served, and operational reliability better achieved by, the increased reliability margin that the ISO's unamended proposal would provide, even if it proved to be somewhat more costly. Still others suggested that compensation for reliability services being provided was needed now and the amended package would limit if not eliminate the opportunity to be compensated for those services.

The thrice-amended main motion was then voted and passed with a 61.70% Vote in favor (Generation Sector – 0%; Transmission Sector – 16.79%; Supplier Sector – 3.54%; AR Sector – 7.79%; ~~Publicly Owned Entity~~POE Sector – 16.79%; and End User Sector – 16.79%). (See Vote 4 on Attachment 2).

ISO Unamended ESI Proposal

In response to a question from the Chair, ISO representatives requested that the Committee consider and vote on its unamended ESI proposal. Turning first to NESCOE, which had sponsored the successful amendments, the NESCOE representative explained the opposition by the six New England states to the ISO's ESI Proposal. NESCOE characterized the proposal as a bad bargain for consumers. NESCOE opposed the ISO's proposed year-round call option approach, which NESCOE considered to exceed the scope of FERC's 2018 order requiring the filing of longer-term market changes to better address regional winter fuel security. NESCOE argued that the ISO's ESI proposal would produce unjust and reasonable rates. In its view, the ISO's proposal would be vulnerable to producing uncompetitive outcomes absent effective mitigation, would procure Day-Ahead options for more reserves than the system needs in Real-Time at excessive consumer costs, relies on a flawed impact analysis, and deviates from more conventional approaches used by other RTOs to procure ancillary services at far less cost and risk to consumers.

A Generation Sector representative, notwithstanding his support for the ISO's proposed ESI design as innovative improvements to the region's overall market design, explained that the Participant could not support the ISO's unamended ESI proposal. In this ~~Participants~~Participant's view, the ISO's ESI proposal, as ultimately crafted, did not satisfy the compliance obligation imposed by the FERC to address fuel security.

Mr. Chadalavada on behalf of the ISO expressed understanding of and respect for the legitimate and well-articulated concerns with ESI. He noted that the ISO was focused on the longer term and was trying to implement markets that would work under almost all foreseeable circumstances and not just during the winter months. He said the ISO was mindful of consumer costs and believed its proposal achieved the right balance between costs and benefits. He recognized there was legitimate disagreement on this point and that the FERC would make the call. He expressed his appreciation for the stakeholder involvement, efforts and feedback. He committed the ISO to consistently evaluate its markets and propose adjustments if and as deemed desirable or necessary.

There being no further discussion, the unamended main motion was voted and failed to pass with a 39.59% Vote in favor (Generation Sector – 14.39%; Transmission Sector – 0%; Supplier Sector – 12.59%; AR Sector – 12.61%; ~~Publicly Owned Entity~~POE Sector – 0%; and End User Sector – 0%). (See Vote 5 on Attachment 2).

EARLIER SUNSET OF THE INVENTORIED ENERGY PROGRAM

The Committee then considered the ISO proposal to accelerate the sunset of the Inventoried Energy Program provisions so that they would not be effective for the commitment period covered by FCA-15 if the FERC ~~accepts~~accepted ESI. Referring to the materials circulated in advance of the meeting and without discussion, the following motion was moved, seconded, voted, and passed overwhelmingly with opposition noted by Exelon and abstentions by Dynegy, NextEra, NRDC, and ~~Michael~~Mr. Kuser:

> RESOLVED, that the Participants Committee supports the Tariff revisions for the early sunset of the Inventoried Energy Program, which is conditional upon the FERC's acceptance of the ESI design for the fifteenth Capacity Commitment Period, as recommended by the Markets Committee at its March 24, 2020 meeting, and as circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

LITIGATION REPORT

Mr. Doot referred the Committee to the March 31 Litigation Report that had been circulated and posted in advance of the meeting. He summarized for the Committee actions that were being taken by the FERC in light of the COVID 19 pandemic, noting that certain filing deadlines had been extended and other requirements relaxed. He encouraged members to check with FERC counsel for specifics. Related, he noted the ISO's filing early that day to have the FERC waive notarization requirements for financial assurance policy submissions that Market Participants were required to make with the ISO by the end of April.[*] He then highlighted the following items:

- The deadline the next day for comments on the FCA14 results filing;
- Developments regarding FCA15, including a limited waiver of the Delist Bid deadline, the rejection of the filing to remove the fuel security retention provisions for FCA15, and the continued but extended appellate proceedings concerning the Inventoried Energy Program;

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[*] Secretary's Note: This filing was made moot later that day when the FERC issued an order granting, among other things, a blanket waiver of notarization requirements imposed by all ISO/ RTO tariffs.

- The FERC's conditional acceptance of the region's filing in response to Order 845 on interconnection provisions, which required the region to make and file changes in further compliance on or before July 17, and which he said were to be reviewed with the Transmission Committee over the next several months;
- The FERC's Notice of Proposed Rulemaking (NOPR) on transmission incentives that also was planned to be reviewed with the Transmission Committee to consider whether NEPOOL should submit any comments; and finally
- The FERC's order the prior day confirming on remand that payments made under the 2013/14 winter program were just and reasonable.

COMMITTEE REPORTS

Before proceeding to committee reports, Ms. Chafetz provided an update on the plans for discussions on the future grid. Although the impacts of COVID-19 were delaying the planned kick-off for the process to define the study discussed at the March Participants Committee meeting, Ms. Chafetz noted that NESCOE would be offering its thoughts on the study at a joint meeting of the Markets Committee (MC) and Reliability Committee (RC) scheduled for April 7. A more fulsome kickoff was being planned for May, and plans for discussions on the second day of the June Summer Meeting were being developed.

Markets Committee. Mr. Bill Fowler, the MC Vice-Chair, reported that the MC was scheduled to meet the morning of April 7, with plans for a vote on changes to the Generation Information System (GIS) operating rules, discussion on changes to Manual M-11 and the Information Policy, and a presentation on the IMM's Fall 2019 quarterly report. The joint MC/RC meeting would convene later that day after a break for lunch.

Budget & Finance Subcommittee (B&F). Ms. Michelle Gardner, B&F Chair, reported that B&F was scheduled to meet on April 21, 2020, and would consider clean-up changes to the

Billing Policy and continue discussion of potential "know your customer" enhancements to the Financial Assurance Policy for new and existing Participants.

Reliability Committee. Mr. Robert Stein, the RC Vice-Chair, reported that, following the joint April 7 meeting with the MC, the next regularly-scheduled RC meeting would be April 22, 2020, at which the RC would discuss fuel security assumptions and the need to retain resources for fuel security in FCA15.

Transmission Committee (TC). Mr. José Rotger, the TC Vice-Chair, reported that the TC was scheduled to meet on April 28, 2020. The two key items planned for discussion were the ISO's plans in response to the FERC order conditionally accepting the Order 845 (interconnection reforms) compliance filing and whether NEPOOL should file comments on the FERC's transmission rate incentives NOPR.

Joint Nominating Committee (JNC). Mr. Doug Hurley reported that the JNC met telephonically on March 19, 2020 and had narrowed to approximately eight the list of candidates to be interviewed by the Committee. The Committee hoped to conduct those interviews in person, if possible, and Mr. Hurley committed to report at a future meeting on the status of those interviews.

OTHER BUSINESS

There being no further business, the meeting adjourned at 1:29 p.m.

Respectfully submitted,

David Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN APRIL 2, 2020 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User		Deborah Donovan	Jerry Elmer
American Petroleum Institute	Fuels Industry Part.	Zoe Cadore		
AR Small Load Response (LR) Group Member	AR-LR	Doug Hurley	Brad Swalwell	
AR Small Renewable Generation (RG) Group Member	AR-RG	Erik Abend		
American PowerNet Management	Supplier			Mary Smith, Michael Macrae
Ashburnham Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
Associated Industries of Massachusetts (AIM)	End User			R. Borghesani
AVANGRID: CMP/UI	Transmission		Alan Trotta	
Bath Iron Works Corporation	End User			William P. Short III
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned Entity		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		
C.N. Brown Electricity, LLC	Supplier			William P. Short III
Calpine Energy Services, LP	Supplier	Brett Kruse		
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Central Rivers Power	AR-RG		Dan Allegretti	
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield		
Competitive Energy Services, LLC	Supplier		Glenn Poole	
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw		
Connecticut Office of Consumer Counsel	End User		Dave Thompson	
Conservation Law Foundation (CLF)	End User	Jerry Elmer		
Consolidated Edison Energy, Inc.	Supplier	Norman Mah		
CPV Towantic, LLC	Generation	Dan Pierpont		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
DC Energy, LLC	Supplier	Bruce Bleiweis		
Direct Energy Business, LLC	Supplier	Nancy Chafetz		
Dominion Energy Generation Marketing, Inc.	Generation	Mike Purdie		
Durgin and Crowell Lumber Co., Inc.	End User			William P. Short III
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		Bill Fowler
EDF Trading North America, LLC	Supplier	Chris Armitage		
Elektrisola, Inc.	End User			William P. Short III
Emera (ENMAX) Maine	Transmission	Lisa Martin	David Norman	
Emera Energy Services	Supplier		Bill Fowler	
Enel X North America, Inc.	AR-LR		Herb Healy	
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		Pete Fuller
Environmental Defense Fund	End User	N. Jonathan Peress		
Eversource Energy	Transmission	James Daly		Dave Burnham, Vandan Divatia
Excelerate Energy LP	Fuels Industry Part.			Gary Ritter
Exelon Generation Company	Supplier	Steve Kirk	Bill Fowler	
FirstLight Power Management, LLC	Generation	Tom Kaslow		Nancy Chafetz
Galt Power, Inc.	Supplier	José Rotger		
Garland Manufacturing Company	End User			Michael Macrae

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN APRIL 2, 2020 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Generation Group Member	Generation			Ron Coutu
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.	Supplier	Louis Guibault	Bob Stein	
Hammond Lumber Company	End User			Michael Macrae
Harvard Dedicated Energy Limited	End User	Mary Smith	Michael Macrae	
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	
IDT Energy, LLC	Supplier		Glen Biren	
Industrial Energy Consumer Group (IECG)	End User			Alan Topalian
Ipswich Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Jericho Power LLC (Jericho)	AR-RG	Mark Spencer		
King Forest Industries, Inc.	End User			William P. Short III
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			Doug Hurley
Marble River, LLC	Supplier		John Brodbeck	
Marblehead Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Mass. Attorney General’s Office (MA AG)	End User	Tina Belew	Ben Griffiths	
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Brian Thomson		
Mercuria Energy America, LLC	Supplier			Jose Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Michael Kuser	End User	Michael Kuser		
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Moore Company	End User			William P. Short III
National Grid	Transmission	Tim Brennan	Tim Martin	
Natural Resources Defense Council	End User	Bruce Ho		Jerry Elmer
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski		B. Forshaw; D. Cavanaugh; B. Thomson
New Hampshire Office of Consumer Advocate	End User	Pradhip Chattopadhya		Jason Frost
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Power Marketing LLC	Generation		Pete Fuller	
Nylon Corporation of America	End User			William P. Short III
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN APRIL 2, 2020 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Paxton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Peabody Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PNE Energy Supply	Supplier			William P. Short III
PowerOptions, Inc.	End User	Heather Takle		
Princeton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Repsol Energy North America Company	Fuels Industry Part.		Nancy Chafetz	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Brian Thomson	
Saint Anselm College	End User			William P. Short III
Shipyard Brewing LLC	End User			William P. Short III
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Brian Thomson	
South Hadley Electric Light Department	Publicly Owned Entity		Brian Thomson	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Brian Thomson	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Pete Fuller
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
The Energy Consortium	End User	Roger Borghesani	Mary Smith	Michael Macrae
Verde Group, LLC	Provisional Member		Mike Bedley	
Vermont Electric Coop.	Publicly Owned	Craig Kieny		
Vermont Electric Power Co. (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned Entity			
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	
Z-TECH, LLC	End User			William P. Short III

ATTACHMENT 2

APRIL 2, 2020 PARTICIPANTS COMMITTEE MEETING
ROLL CALL VOTES

TOTAL

Sector	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5
GENERATION	0.00	0.00	0.00	0.00	14.39
TRANSMISSION	16.79	16.79	16.79	16.79	0.00
SUPPLIER	5.60	5.60	4.48	3.54	12.59
ALTERNATIVE RESOURCES	7.79	7.79	6.42	7.79	12.61
PUBLICLY OWNED ENTITY	16.79	16.79	16.79	16.79	0.00
END USER	16.79	16.79	16.79	16.79	0.00
% IN FAVOR	**63.76**	**63.76**	**61.27**	**61.70**	**39.59**

GENERATION SECTOR

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5
CPV Towantic, LLC	O	O	O	O	F
Dominion Energy Generation Mktg.	O	O	O	O	F
FirstLight Power Resources Mgmt.	O	O	O	O	F
Generation Group Member	O	O	O	O	F
Nautilus Power, LLC	O	O	O	O	F
NextEra Energy Resources, LLC	O	O	O	O	F
NRG Power Marketing, LLC	O	O	O	O	O
IN FAVOR (F)	0	0	0	0	6
OPPOSED (O)	7	7	7	7	1
TOTAL VOTES	7	7	7	7	7
ABSTENTIONS (A)	0	0	0	0	0

TRANSMISSION SECTOR

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5
Avangrid (CMP/UI)	F	F	F	A	O
Emera Maine	F	A	A	A	A
Eversource Energy	F	F	F	F	A
National Grid	F	F	A	F	A
Vermont Electric Power Co.	F	F	F	F	A
IN FAVOR (F)	5	4	3	3	0
OPPOSED	0	0	0	0	1
TOTAL VOTES	5	4	3	3	1
ABSTENTIONS (A)	0	1	2	2	4

SUPPLIER SECTOR

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5
American PowerNet Management	F	F	F	F	O
BP Energy Company	A	A	A	O	F
Brookfield Energy Marketing Inc.	O	O	O	O	F
C.N. Brown Electricity, LLC	F	F	F	F	O
Calpine Energy Services, LP	O	O	O	O	F
Castleton Comm. Merchant Trading	O	O	O	O	F
Competitive Energy Services, LLC	F	F	O	O	F
Consolidated Edison Energy, Inc.	A	A	A	O	A
Cross-Sound Cable Company	A	A	A	A	A
DC Energy, LLC	A	A	A	A	A
Direct Energy Business, LLC	O	O	O	O	F
Dynegy Marketing and Trade, LLC	O	O	O	O	F
Emera Energy Companies	O	O	O	O	F
Exelon Generation Company	O	O	O	O	A
Galt Power, Inc.	A	A	A	O	F
H.Q. Energy Services (U.S.) Inc.	O	O	O	O	F
IDT Energy, LLC	A	A	A	A	A
LIPA	A	A	A	A	A
Maine Power, LLC	F	F	F	F	O
Marble River, LLC	O	O	O	O	--
Mercuria Energy America, Inc	A	A	A	O	F
PNE Energy Supply LLC	F	F	F	F	O
PSEG Energy Resources & Trade	O	O	O	O	F
IN FAVOR (F)	5	5	4	4	12
OPPOSED	10	10	11	15	4
TOTAL VOTES	15	15	15	19	16
ABSTENTIONS (A)	8	8	8	4	6

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5
Renewable Generation Sub-Sector					
Central Rivers Power	O	O	O	O	F
ENGIE Energy Marketing NA	O	O	O	O	F
Great River Hydro	O	O	O	O	F
Jericho Power	O	O	O	O	F
Wheelabrator/Macquarie	O	O	O	O	F
Small RG Group Member	A	A	A	A	A
Distributed Gen. Sub-Sector					
CLEAResult Consulting, Inc.	A	A	A	A	A
Sunrun Inc.	F	F	F	F	F

ALTERNATIVE RESOURCES SECTOR (cont.)

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5
Load Response Sub-Sector					
Enel X North America, Inc.	F	F	O	F	A
Maple Energy	F	F	F	F	O
Vermont Energy Investment Corp.	F	F	F	F	O
Small LR Group Member	F	F	A	A	Split
Energy Federation Inc.					O
Tangent Energy Solutions, Inc.					F
IN FAVOR (F)	5	5	3	4	6.5
OPPOSED	5	5	6	5	2.5
TOTAL VOTES	10	10	9	9	9
ABSTENTIONS (A)	2	2	3	3	3

ATTACHMENT 2

APRIL 2, 2020 PARTICIPANTS COMMITTEE MEETING
ROLL CALL VOTES

END USER SECTOR

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5
Acadia Center	F	F	A	A	O
Associated Industries of Mass.	F	F	F	F	O
Bath Iron Works Corporation	F	F	F	F	O
Conn. Office of Consumer Counsel	F	F	F	F	O
Conservation Law Foundation	F	F	A	A	O
Durgin and Crowell Lumber Co.	F	F	F	F	O
Elektrisola, Inc.	F	F	F	F	O
Environmental Defense Fund	F	F	A	F	A
Garland Manufacturing Co.	F	F	F	F	O
Hammond Lumber Company	F	F	F	F	O
Harvard Dedicated Energy Limited	F	F	F	F	O
High Liner Foods (USA) Inc.	F	F	F	F	O
Industrial Energy Consumer Group	F	F	F	F	O
King Forest Industries, Inc.	F	F	F	F	O
Michael Kusar	A	A	A	A	A
Maine Public Advocate Office	F	F	F	F	O
Maine Skiing, Inc.	F	F	F	F	O
Mass. Attorney General's Office	F	F	F	F	O
Moore Company	F	F	F	F	O
Natural Resources Defense Council	F	F	A	A	O
NH Office of Consumer Advocate	F	F	F	F	O
Nylon Corporation of America	F	F	F	F	O
PowerOptions, Inc.	F	F	F	F	O
St. Anselm College	F	F	F	F	O
The Energy Consortium	F	F	F	F	O
Z-TECH, LLC	F	F	F	F	O
IN FAVOR (F)	25	25	21	22	0
OPPOSED	0	0	0	0	24
TOTAL VOTES	25	25	21	22	24
ABSTENTIONS (A)	1	1	5	4	2

PUBLICLY OWNED ENTITY SECTOR

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5
Ashburnham Municipal Light Plant	F	F	F	A	O
Belmont Municipal Light Dept.	F	F	F	F	O
Block Island Utility District	F	F	F	F	O
Boylston Municipal Light Dept.	F	F	F	A	O
Braintree Electric Light Dept.	F	F	F	F	O
Chester Municipal Light Dept.	F	F	F	F	O
Chicopee Municipal Lighting Plant	F	F	F	A	O
Concord Municipal Light Plant	F	F	F	F	O
Conn. Mun. Electric Energy Coop.	F	F	F	F	O
Danvers Electric Division	F	F	F	F	O
Georgetown Municipal Light Dept.	F	F	F	F	O
Groton Electric Light Dept.	F	F	F	A	O
Groveland Electric Light Dept.	F	F	F	F	O

PUBLICLY OWNED ENTITY SECTOR (cont.)

Participant Name	Vote 1	Vote 2	Vote 3	Vote 4	Vote 5
Hingham Municipal Lighting Plant	F	F	F	F	O
Holden Municipal Light Dept.	F	F	F	A	O
Holyoke Gas & Electric Dept.	F	F	F	A	O
Hull Municipal Lighting Plant	F	F	F	A	O
Ipswich Municipal Light Dept.	F	F	F	A	O
Littleton (MA) Electric Light Dept.	F	F	F	F	O
Littleton (NH) Water & Light Dept.	F	F	F	F	O
Mansfield Municipal Electric Dept.	F	F	F	A	O
Marblehead Municipal Light Dept.	F	F	F	A	O
Mass. Bay Transportation Authority	F	F	F	F	O
Mass. Mun. Wholesale Electric Co.	F	F	F	A	O
Merrimac Municipal Light Dept.	F	F	F	F	O
Middleborough Gas and Elec. Dept.	F	F	F	F	O
Middleton Municipal Electric Dept.	F	F	F	F	O
New Hampshire Electric Cooperative	F	F	F	F	O
Norwood Municipal Light Dept.	F	F	F	F	O
Pascoag Utility District	F	F	F	F	O
Paxton Municipal Light Dept.	F	F	F	A	O
Peabody Municipal Light Plant	F	F	F	A	O
Princeton Municipal Light Dept.	F	F	F	A	O
Reading Municipal Light Dept.	F	F	F	F	O
Rowley Municipal Lighting Plant	F	F	F	F	O
Russell Municipal Light Dept.	F	F	F	A	O
Shrewsbury's Elec. & Cable Ops.	F	F	F	A	O
South Hadley Electric Light Dept.	F	F	F	A	O
Sterling Municipal Electric Light Dept.	F	F	F	A	O
Stowe (VT) Electric Dept.	F	F	F	F	O
Taunton Municipal Lighting Plant	F	F	F	F	O
Templeton Municipal Lighting Plant	F	F	F	A	O
Vermont Electric Cooperative	F	F	F	F	O
Village of Hyde Park (VT) Elec. Dept.	F	F	F	F	O
VT Public Power Supply Authority	F	F	F	F	O
VT Public Power Supply Authority	F	F	F	F	O
Wakefield Mun. Gas and Light Dept.	F	F	F	A	O
Wallingford, Town of	F	F	F	F	O
Wellesley Municipal Light Plant	F	F	F	F	O
West Boylston Mun. Lighting Plant	F	F	F	A	O
Westfield Gas & Electric Light Dept.	F	F	F	F	O
IN FAVOR (F)	51	51	51	30	0
OPPOSED	0	0	0	0	51
TOTAL VOTES	51	51	51	30	51
ABSTENTIONS (A)	0	0	0	21	0

CONSENT AGENDA

Reliability Committee

From the previously-circulated notice of actions of the Reliability Committee's April 22, 2020 meeting, dated April 22, 2020:[1]

1. **OP-14 Revisions (Extend to January 1, 2021 the deadline for Settlement Only Resources >5 MW to comply with registration requirements of § II.A.2)**

Support revisions to ISO Operating Procedure (OP) No. 14 (Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources) to extend from June 1, 2020 to January 1, 2021 (due to supply chain issues associated with the coronavirus pandemic) the deadline for Settlement Only Resources above 5 MW to register as dispatchable generators and meet offer telemetry requirements, as recommended by the Reliability Committee at its April 22, 2020 meeting, with such further non-material changes as the Chair and Vice-Chair of the Reliability Committee may approve.

The motion to recommend Participants Committee support was approved unanimously.

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[1] Reliability Committee 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

May 7, 2020 Participants Committee Meeting

Since the last update, the Board of Directors met by teleconference on April 7, and the Markets Committee met by teleconference on April 30.

The Board of Directors received an update regarding the Company’s pandemic response and business continuity plans in light of the COVID-19 virus pandemic. The Board also discussed scenario analysis efforts in connection with strategic planning, and the critical uncertainties and possible outcomes identified that potentially impact the evolution of the markets and ISO’s ability to effectively and reliably manage the energy supply for the region.

The Markets Committee met in executive session to review highlights of the Internal Market Monitor’s draft annual markets report for the 2019 calendar year and discussed the methods used to evaluate the competitiveness of the markets, and the analysis of structural competitiveness and market outcomes. There was a general discussion concerning the recommendations in the draft Annual Report, and Committee members offered a variety of high level observations.

NEPOOL Participants Committee Report

May 2020

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

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COVID-19 – Summary Update

ISO Operations During COVID-19 Outbreak

- Effective March 14, ~95% of ISO workforce working remotely
- All reliability, market and planning functions are being operated in accordance with all applicable standards
- ISO remote deployment posture extended until at least June 1
- ISO has taken several measures to protect control room operators and on-site staff and is monitoring their safety continuously
- ISO is working on a measured re-entry plan, with a target date of June 1, that is
  - Subject to National, State, and Local criteria being met
  - Subject to on-site social distancing protocols
  - Phased over at least three months
  - Based on business needs and priorities
  - Flexible and adjusts to changing conditions
- The ISO will continue to monitor the situation and take all necessary steps to reliably operate the bulk power system
- The ISO greatly appreciates the support of all regional stakeholders

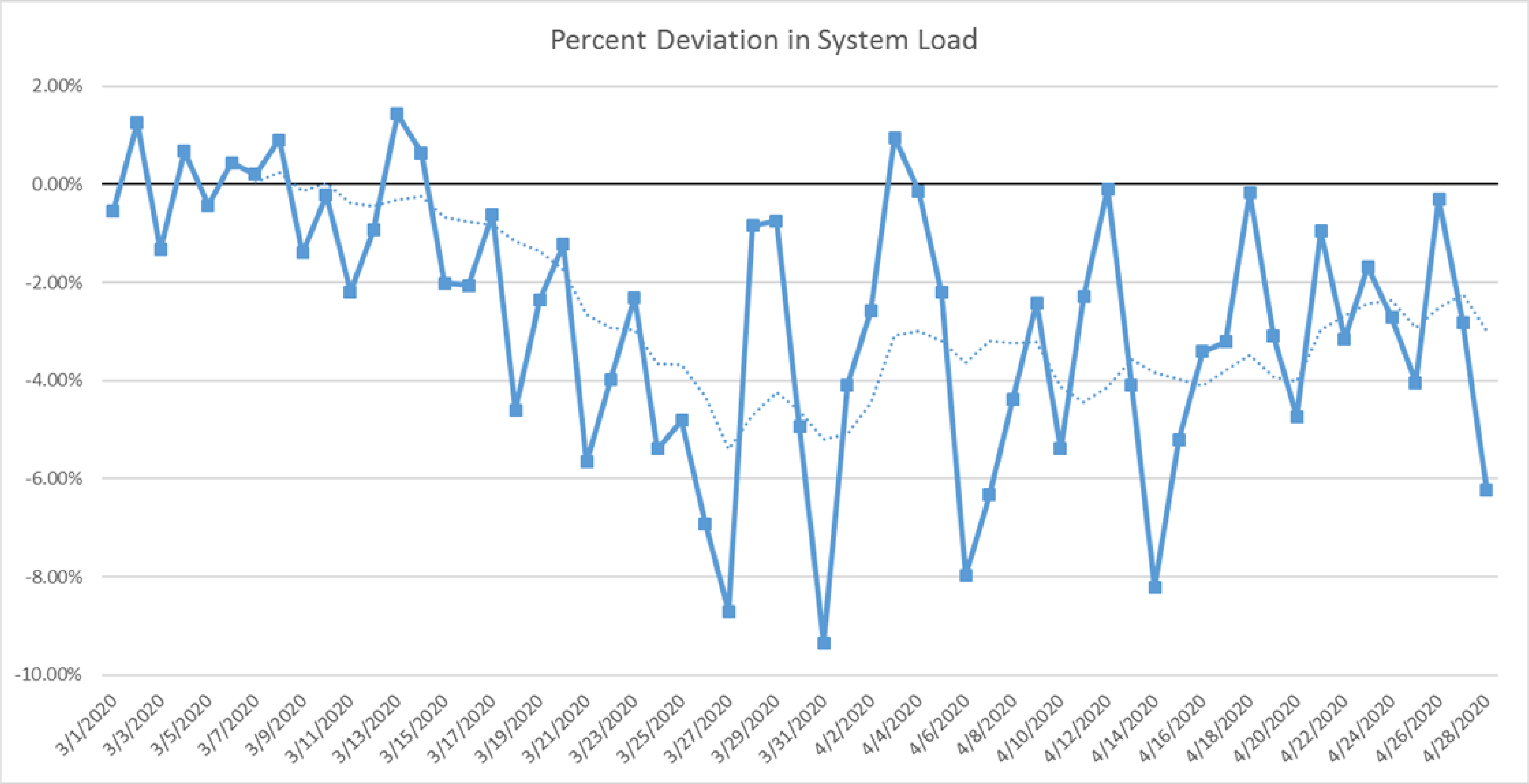
ISO Operations During COVID-19 Outbreak, contd.

- Operational Outreach with Designated Entities/Demand Designated Entities and Lead Market Participants for resources
  - Weekly teleconference to improve communications and readiness to maintain system reliability
  - Surveyed resources to understand their concerns, preparation plans and issues that ISO could provide assistance
  - Conducting pre-outage calls to understand risks and mitigation plans as additional input into development of reliable operating plan
  - Many Resources have deferred non-essential work, or have cancelled their outages completely
  - Increased publication of Annual Maintenance Schedule from monthly to weekly
  - Transmission owners have deferred non-essential work
- Calls with Local Control Centers and NPCC Reliability Coordinators
- Weekly calls with Electric Gas Operating Committee, includes NPCC, Northeast Gas Association, ISOs, pipelines, and LDCs

COVID-19 Impact on System Load

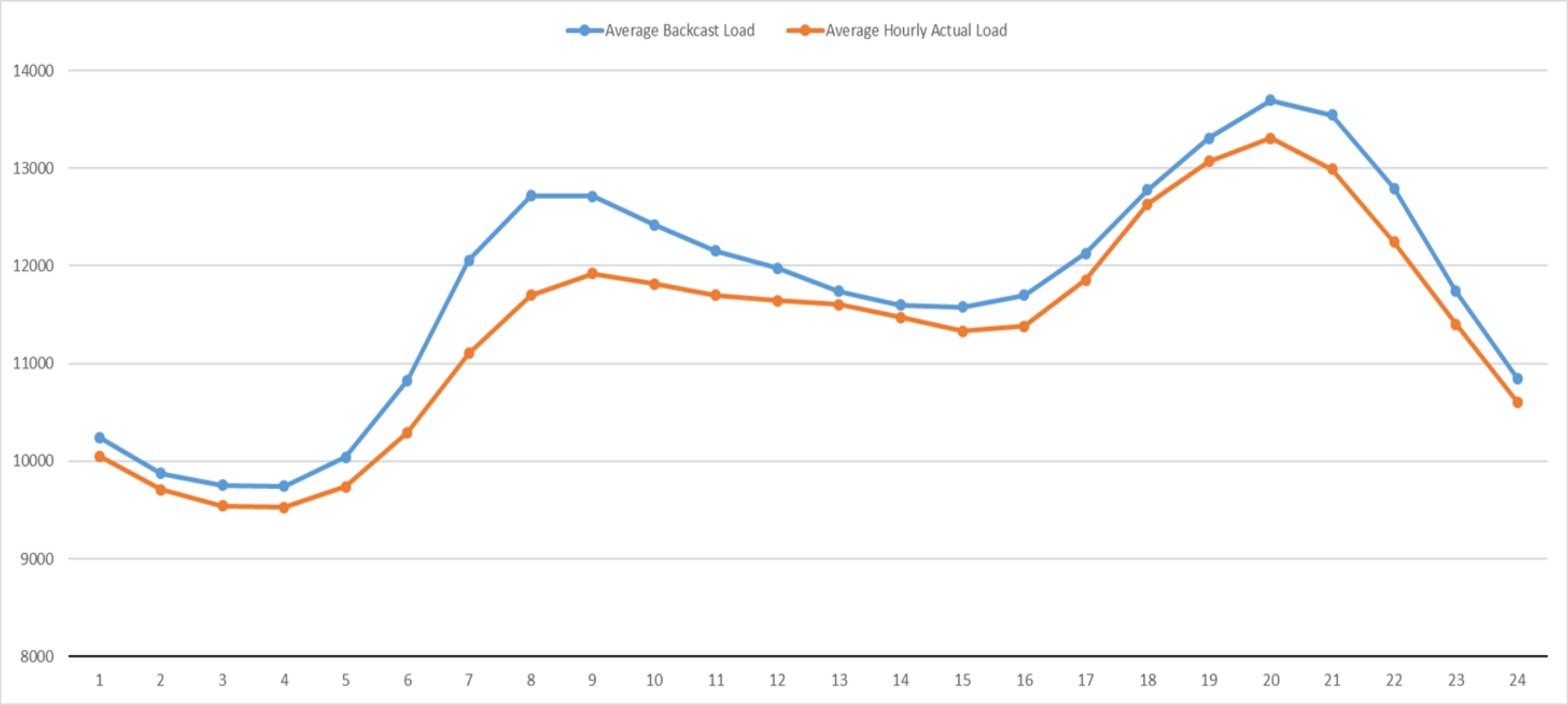
- Continuing to observe approximately 3% to 5% lower loads in April
- A backcast model was built to calculate what load would have been without the pandemic
  - The ‘backcast’ model is a load model that has not been retrained since the onset of the pandemic
  - Weather forecast inputs were replaced with actual weather, removing weather forecast variability from the calculation
- The backcast model provides a baseline of what loads should have been, absent the pandemic
- Conversely, comparing actual loads to the backcast model shows the deviation in load that can generally be attributed to the pandemic

Average Hourly Actual Load Deviations from Backcast Model



Comparison of Average Hourly Actual Loads to Backcast Loads

- ‘Average’ Load Curve created by averaging the hourly loads for each day from 3/1 through 4/28



General ‘Average’ Load Curve Observations

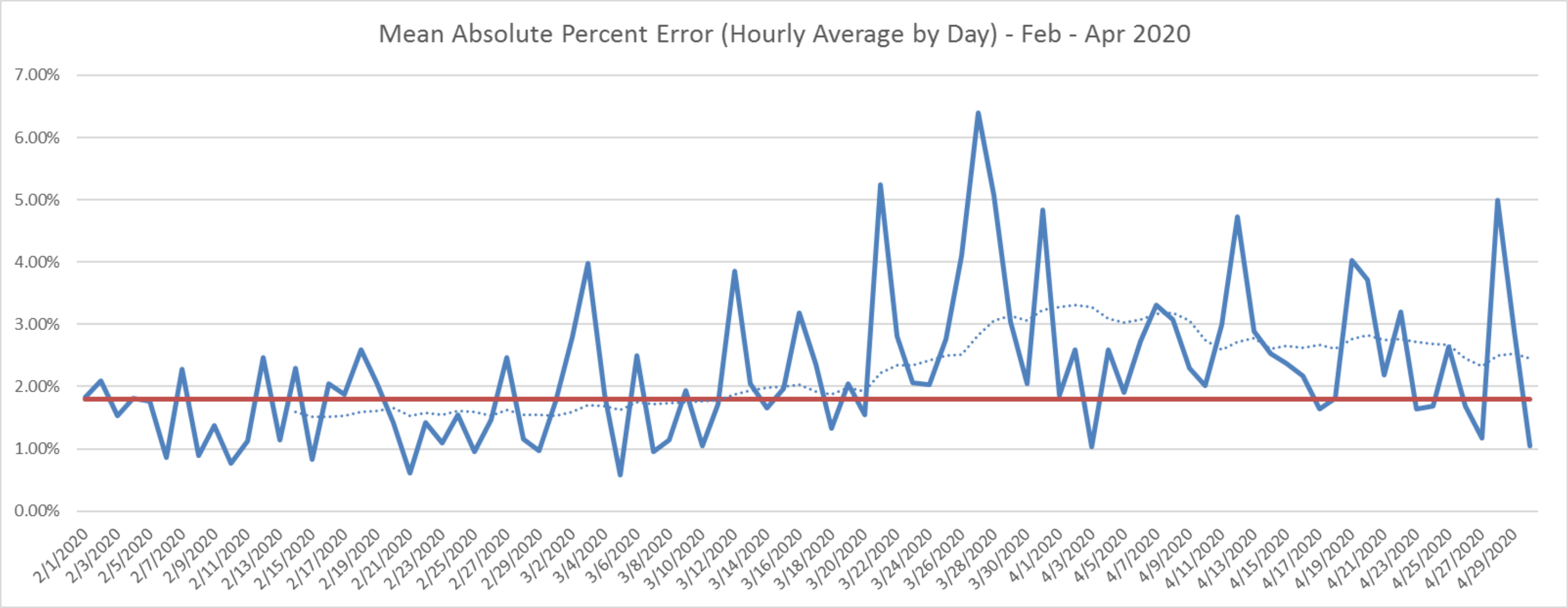
- Overnight loads, on average, are lower than would be expected using the actual weather observations
- Slower morning ramp, likely due to staggering schedules that conform more closely to individual tendencies than a set schedule
- Morning peak is lower and an hour later
- Mid-day loads lower with reduced economic activity
  - Load tends to drop off after lunchtime, more so on days with favorable weather
- Evening peaks are lower
- Transition to night loads is less steep, with fewer loads to shut down

March and April Loads – Comparing 2019 vs 2020

- Comparing 2020 loads to 2019, there is an ~6% reduction in average load
  - COVID-19 contributes between 3% and 5% lower load
  - Additional Energy Efficiency and PV installations likely make up a majority of the difference

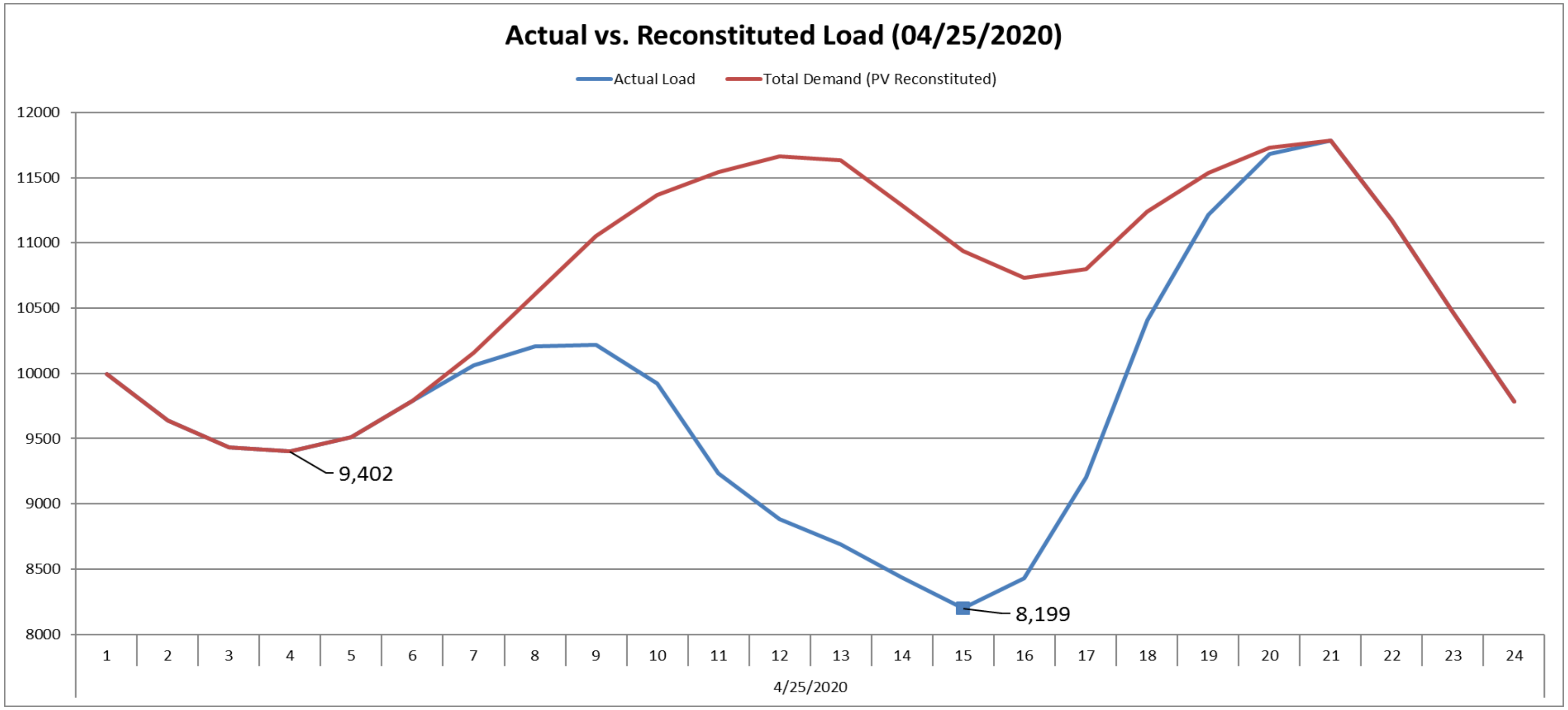
Load Forecast Accuracy

- Forecast challenges have reduced the overall accuracy of the load forecast
  - Forecasters and Modelers are working to retrain models to keep up with the changing trends; retraining every two days
  - Uncertainty about post-outbreak loads
  - Similar to a recovery from an economic recession, modeling will be challenging, but necessary



Mid-day April Minimum Load

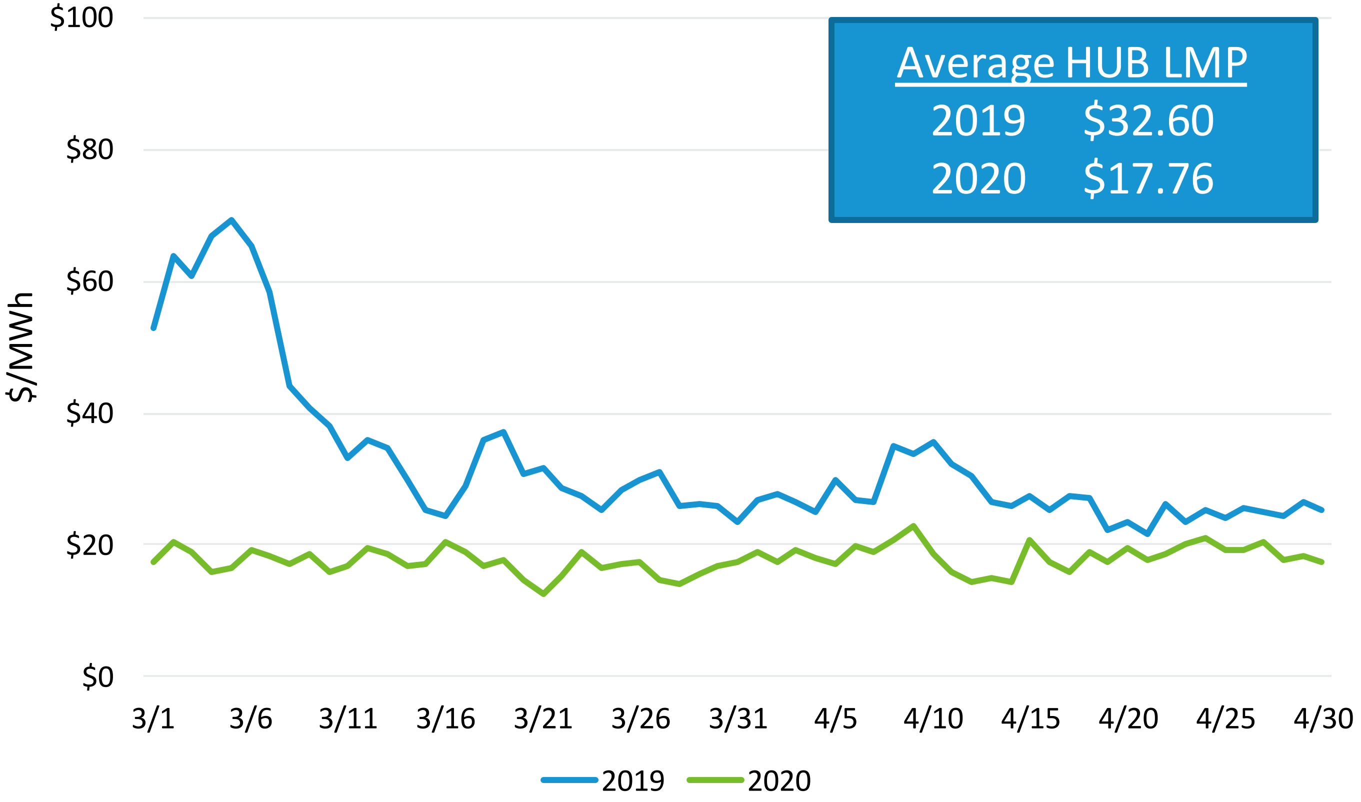
- On April 25, 2020, integrated hourly load for HE 15 was 8,199 MW versus an overnight minimum load of 9,402 MW
  - The April mid-day load was a record low until it was supplanted on May 2 with a minimum load of 8003 MWs



PRICING DURING COVID -19 PANDEMIC

March & April Comparison – 2019 to 2020

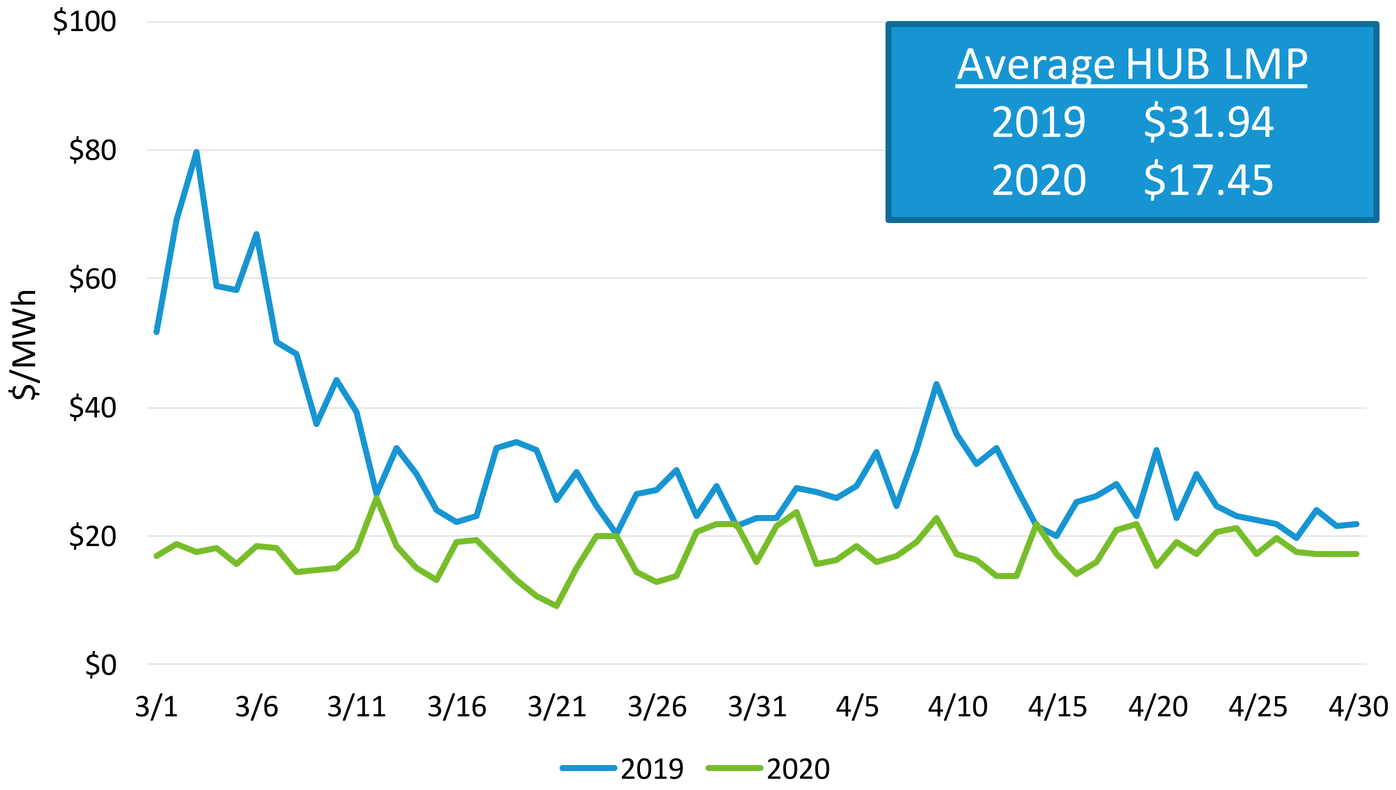
Daily Average Day-Ahead Hub LMPs – March and April, 2019 vs 2020



Average HUB LMP

2019	$32.60
2020	$17.76

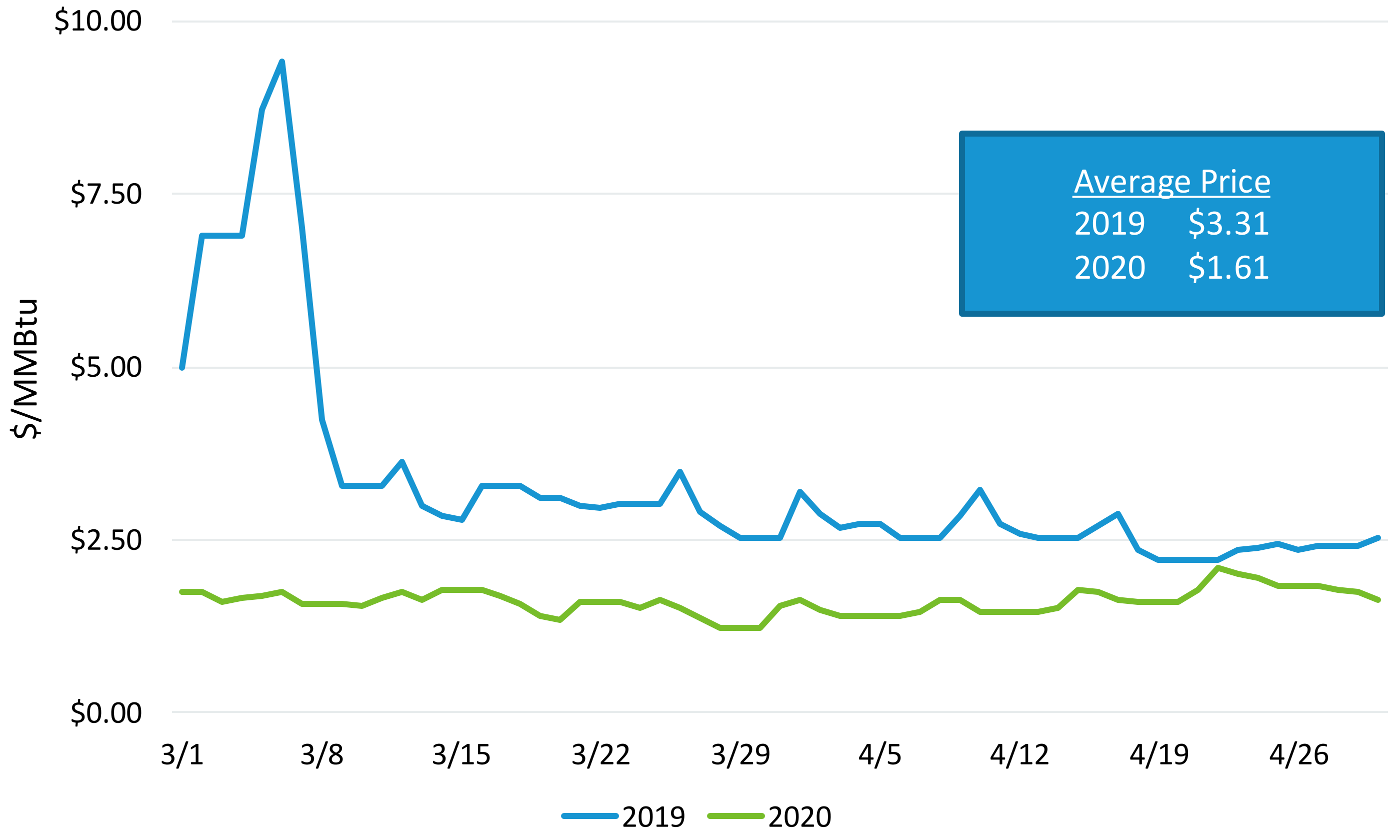
Daily Average Real-Time Hub LMPs – March and April, 2019 vs 2020



Average HUB LMP

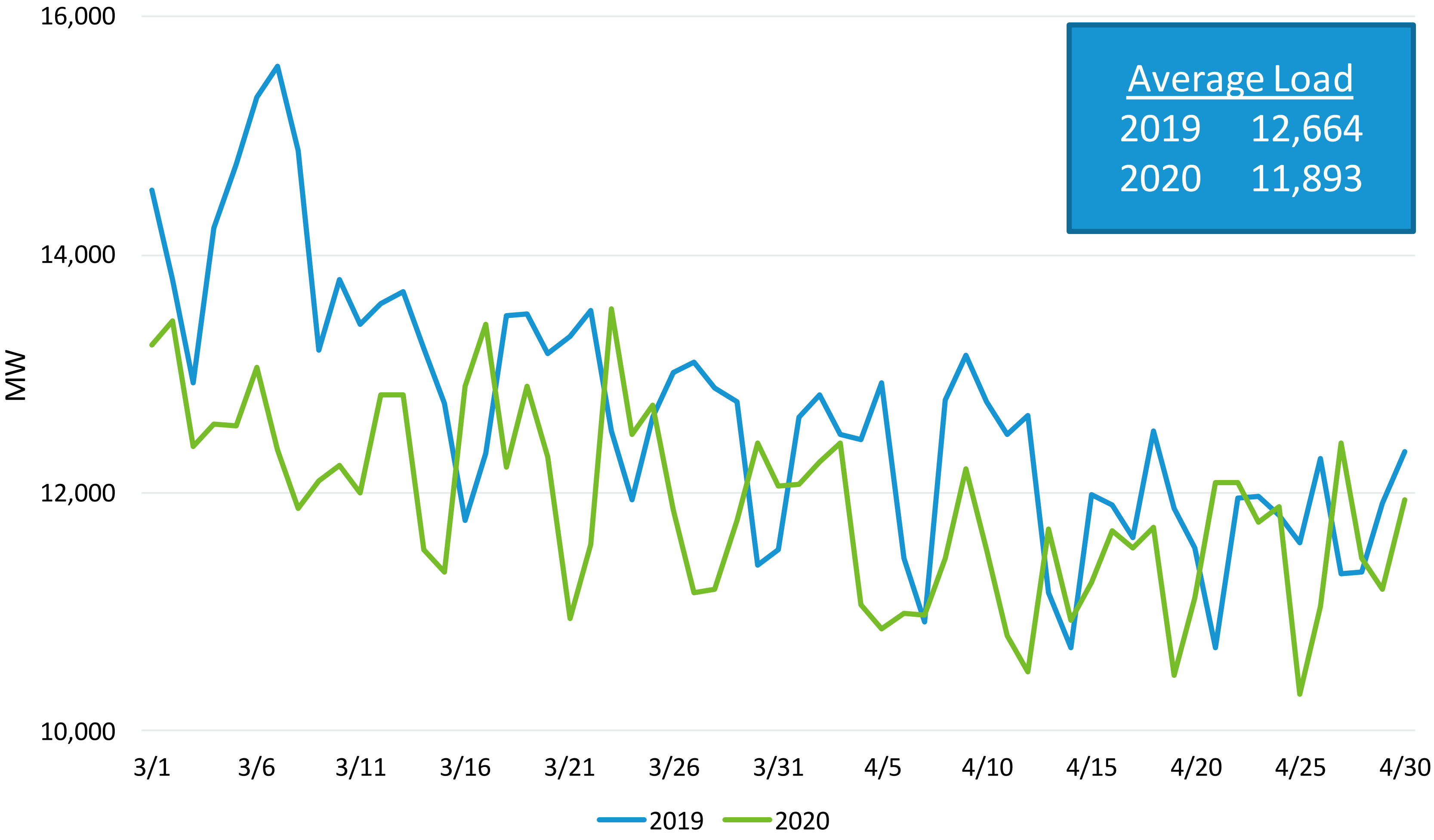
2019	$31.94
2020	$17.45

Daily Gas Price – MA Natural Gas Average – March and April, 2019 vs 2020



Average Price
2019 $3.31
2020 $1.61

Average Hourly System Load – March and April, 2019 vs 2020



Average Load

2019	12,664
2020	11,893

Regular Operations Report - Highlights

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - April 2020 Energy market value over the partial period was $154M down $18M from March and down $99M from April 2019
    - April natural gas prices over the period were 3.9% higher than March average values
    - Average RT Hub Locational Marginal Prices ($18.13/MWh) over the period were 7.8% higher than March averages
      - DA Hub: $18.40/MWh
    - Average April 2020 natural gas prices and RT Hub LMPs over the period were down 36% and 32%, respectively, from April 2019 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 97.6% during April, down from 98.7% during March*
      - The minimum value for the month was 93.8% on Thursday, April 2nd

DATA THROUGH April 29, EXCEPT WHERE NOTED.

Underlying natural gas data furnished by:

ice Global markets in clear view

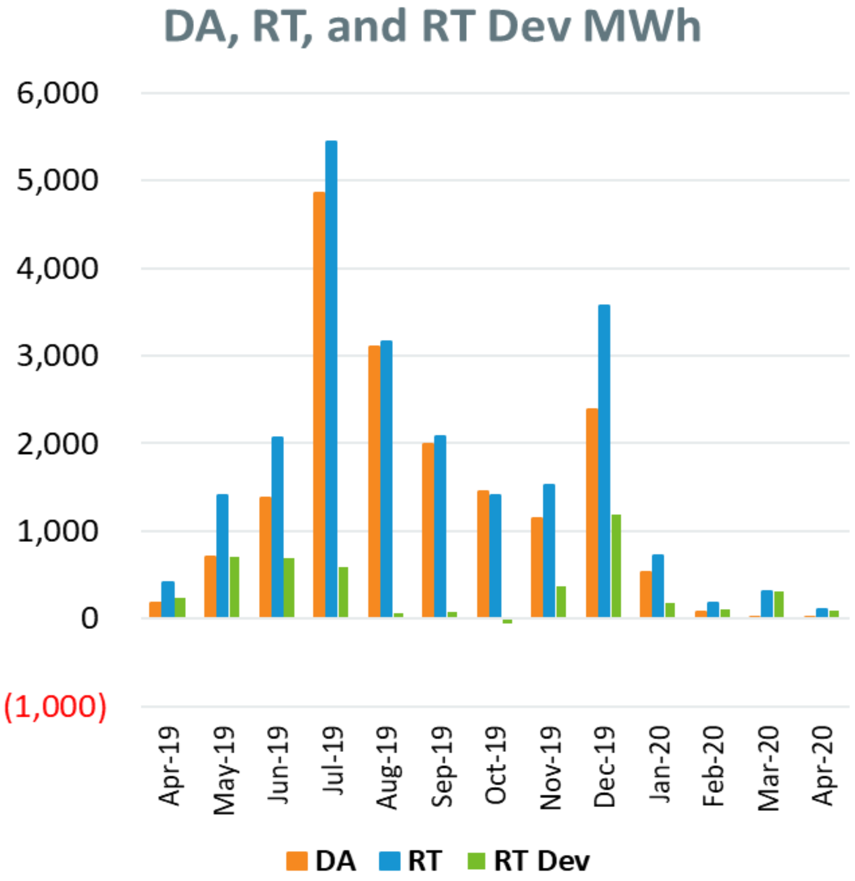
***DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market**

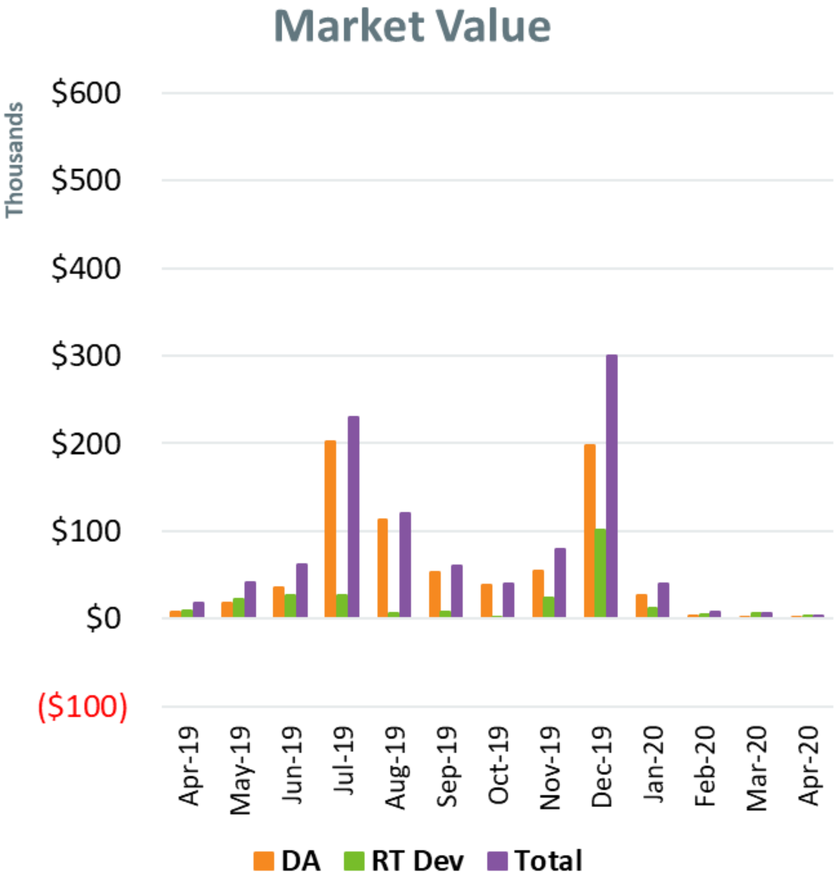
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - April 2020 NCPC payments totaled $1.3M over the period, down $0.4M from March 2020 and down $0.7M from April 2019
    - First Contingency* payments totaled $1.3M, down $0.2M from March
      - $1.2M paid to internal resources, down $0.2M from March
        - $492K charged to DALO, $292K to RT Deviations, $433K to RTLO
      - $67K paid to resources at external locations, down $9K from March
        - Charged to RT Deviations
    - Second Contingency payments totaled $45K, down $56K from March
  - NCPC payments over the period as percent of Energy Market value were 0.9%

*** NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $166K; Rapid Response Pricing (RRP) Opportunity Cost - $127K; Posturing - $8K; Generator Performance Auditing (GPA) - $132K**

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

- In response to the Boston 2028 RFP, 36 Phase One Proposals were received from 8 QTPSs
  - Review process ahead of schedule
- Show of Interest window closed on April 24
- 2020 CELT Report was issued on April 30 and included the new electrification forecasts
- Final 2019 Northeast Coordinated System Plan (NCSP) will be posted the week of May 4
- One 2020 economic study request from NGRID was received, and study approach will be discussed at the May PAC meeting
- Marginal Emissions Analysis Report has been posted for stakeholder review, and the final report will be issued in mid-May
- ICR & Related Values development discussions with the PSPC will begin on May 28
- 2019 Economic Studies are nearing completion and reports to be issued by early summer

Forward Capacity Market (FCM) Highlights

- CCP 10 (2019-2020)
  - Late, new resources (regardless of size) are being monitored closely
- CCP 11 (2020-2021)
  - Third and final annual reconfiguration auction (ARA3) was held March 2-4 and results were posted on April 1
- CCP 12 (2021-2022)
  - Second reconfiguration auction (ARA2) will be August 3-5 and results to be posted by September 2

CCP – Capacity Commitment Period

Forward Capacity Market (FCM) Highlights

- CCP 13 (2022-2023)
  - First reconfiguration auction (ARA1) will be June 1-3, and results to be posted by July 1
- CCP 14 (2023-2024)
  - Auction results were filed with FERC on February 18 and FERC accepted the filing on April 10

FCM Highlights, cont.

- CCP 15 (2024-2025)
  - FCA 15 will have the same zones as FCA 14
    - Export-constrained zones: Maine nested inside Northern New England
    - Import-constrained zones: Southeast New England and Connecticut
  - Existing capacity values were posted on March 6
  - Retirement and permanent delist bids and substitution auction demand bids summary was posted on March 18
  - Show of Interest window closed on April 24
  - ICR & Related Values development discussions with the PSPC will begin on May 28
    - Includes review of capacity zone determinations and load forecast assumptions, including anticipated BTM-PV by load zone

FCA – Forward Capacity Auction
ICR – Installed Capacity Requirement

Load Forecast

- The 2020 load forecast process is complete, and the final ten-year forecasts were issued as part of the 2020 CELT Report on April 30. Forecasts included are:
  - Summer and winter peak loads
  - Annual energy usage
  - Seasonal and annual load reductions from energy efficiency and behind-the meter photovoltaic (BTM PV)
  - Seasonal and annual demand from heating and transportation electrification (i.e., electric vehicles)
- Efforts continue to enhance load forecast models and tools to improve day-ahead and long-term load forecast performance.
  - Discussions are ongoing with industry experts regarding emerging technologies/trends and methods of incorporating these into the forecast.

FERC Order 1000

- Qualified Transmission Project Sponsor (QTPS)
  - 25 companies have achieved QTPS status
- The Public Policy Process was initiated on 1/14/2020
  - Stakeholder input on federal, state, and local Public Policy Requirements (PPRs) was required to be submitted by 2/28/2020
  - Two PPR submittals were received
  - NESCOE submitted a communication to the ISO regarding PPRs on 5/1/2020
  - Stakeholders may provide input to the ISO on NESCOE's communication regarding federal public policy requirements by 5/19/2020

Boston 2028 Request for Proposal (RFP)

- The ISO issued the Boston 2028 RFP on 12/20/2019, which is its first RFP for a competitively-selected transmission solution
  - Phase One Proposals were required to be submitted by 11:00 p.m. on 3/4/2020
  - 36 Phase One Proposals were received from 8 QTPSs
    - Installed cost estimates ranged from $49M to $745M
    - In-service dates ranged from March 2023 to December 2026
  - The ISO is working to expedite its reviews

Highlights

- The lowest 50/50 and 90/10 Spring Operable Capacity Margins are projected for week beginning May 16, 2020.

- The lowest 50/50 and 90/10 Summer Operable Capacity Margins are projected for week beginning September 12, 2020.

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Below Normal (3.6°F) Max: 62°F, Min: 31°F Precipitation: 4.33" – Above Normal Normal: 3.74" Snow: 0.7"	Hartford	Temperature: Below Normal (3.4°F) Max: 67°F, Min: 26°F Precipitation: 5.39" - Above Normal Normal: 3.72" Snow: 2.4"

Peak Load:	13,970 MW	April 27, 2020	18:00 (ending)

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

Procedure	Declared	Cancelled	Note
M/LCC 2	4/10/2020 10:30	4/11/2020 14:00	Severe Weather - Maine

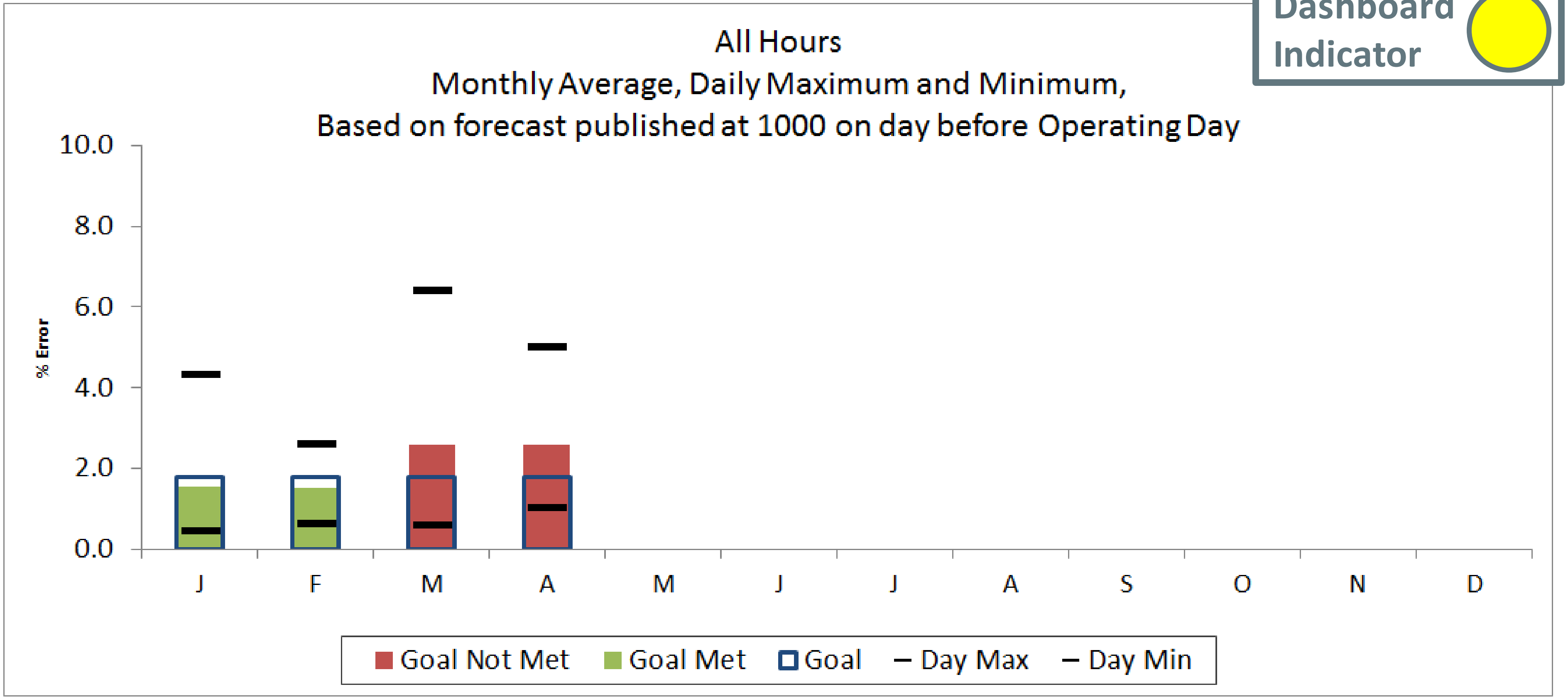
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
4/1	ISO-NE	1240
4/13	ISO-NE	1020
4/13	ISO-NE	700
4/29	IESO	900

2020 System Operations - Load Forecast Accuracy

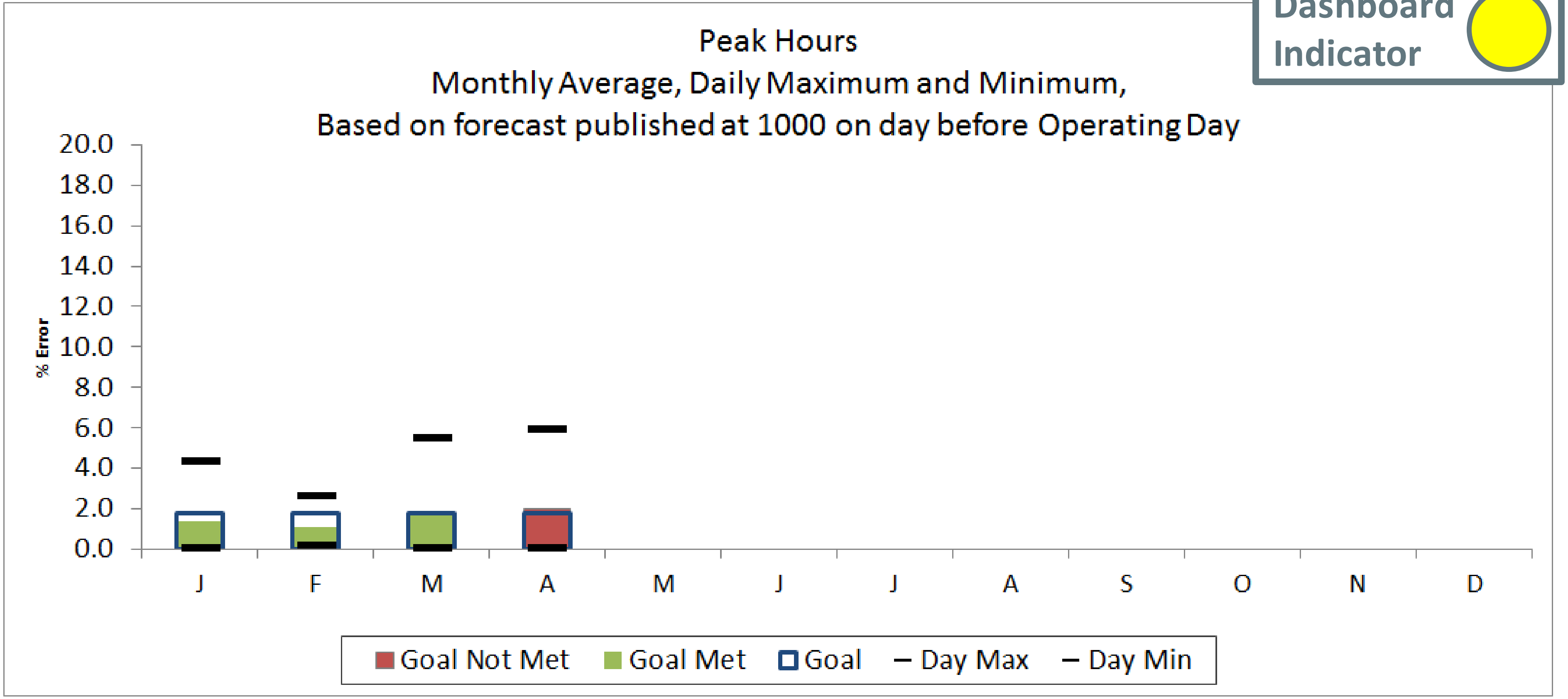
Dashboard Indicator 🟡



Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.31	2.59	6.40	5.00									6.40
Day Min	0.46	0.61	0.58	1.03									0.46
MAPE	1.57	1.54	2.60	2.58									2.08
Goal	1.80	1.80	1.80	1.80									

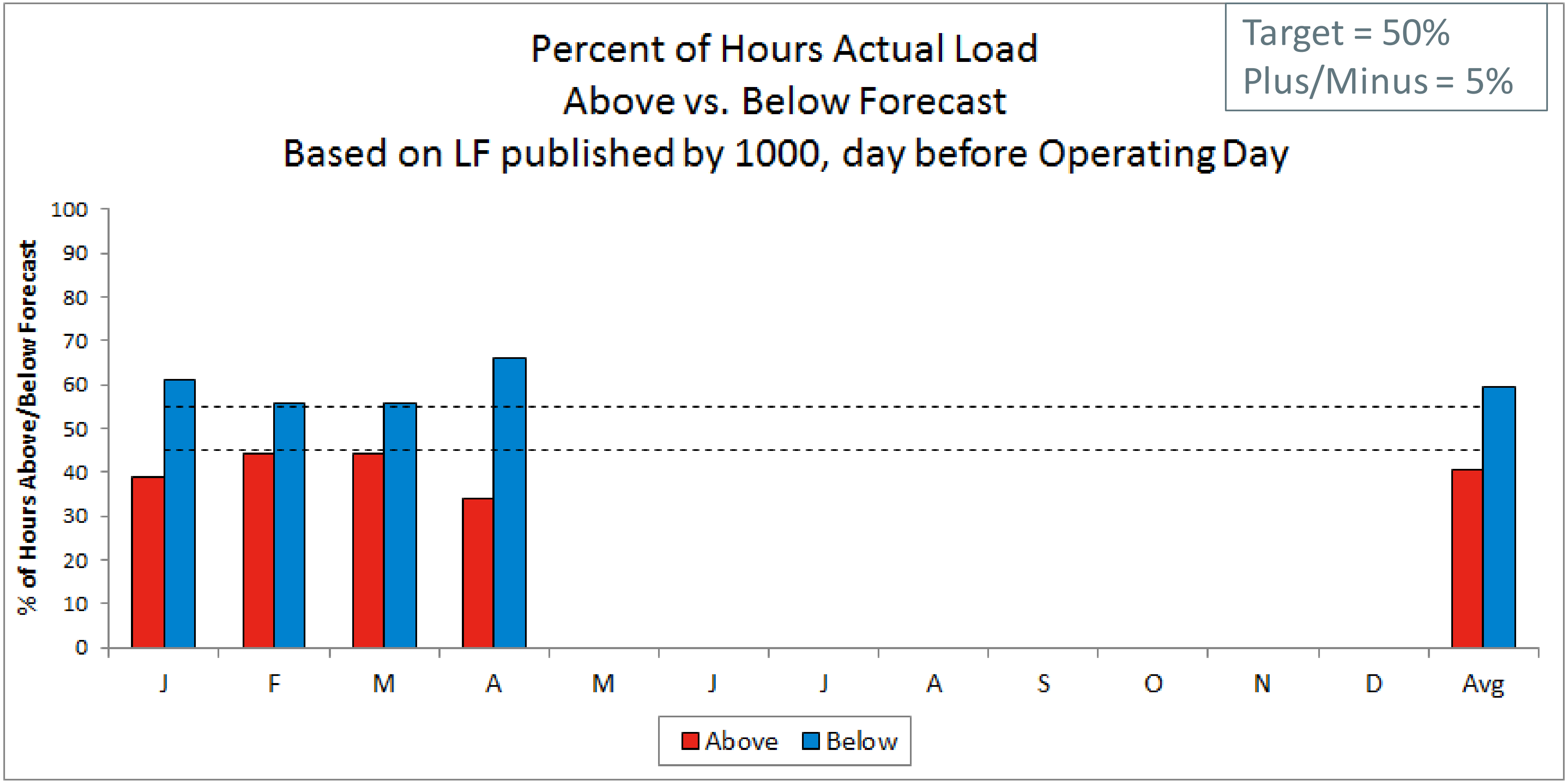
2020 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator ●



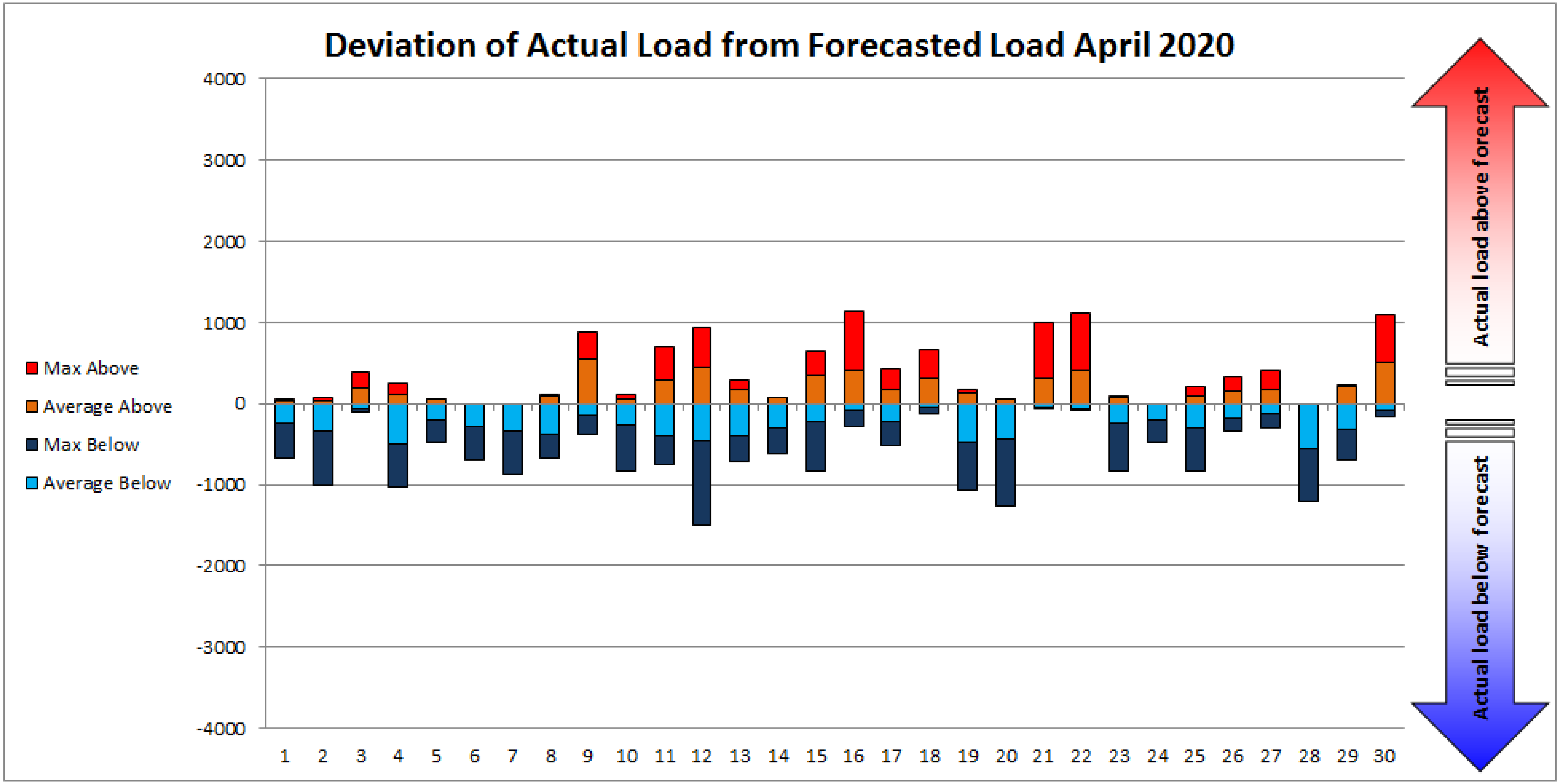
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.33	2.59	5.48	5.93									5.93
Day Min	0.07	0.19	0.01	0.00									0.00
MAPE	1.41	1.12	1.72	1.97									1.56
Goal	1.80	1.80	1.80	1.80									

2020 System Operations - Load Forecast Accuracy cont.

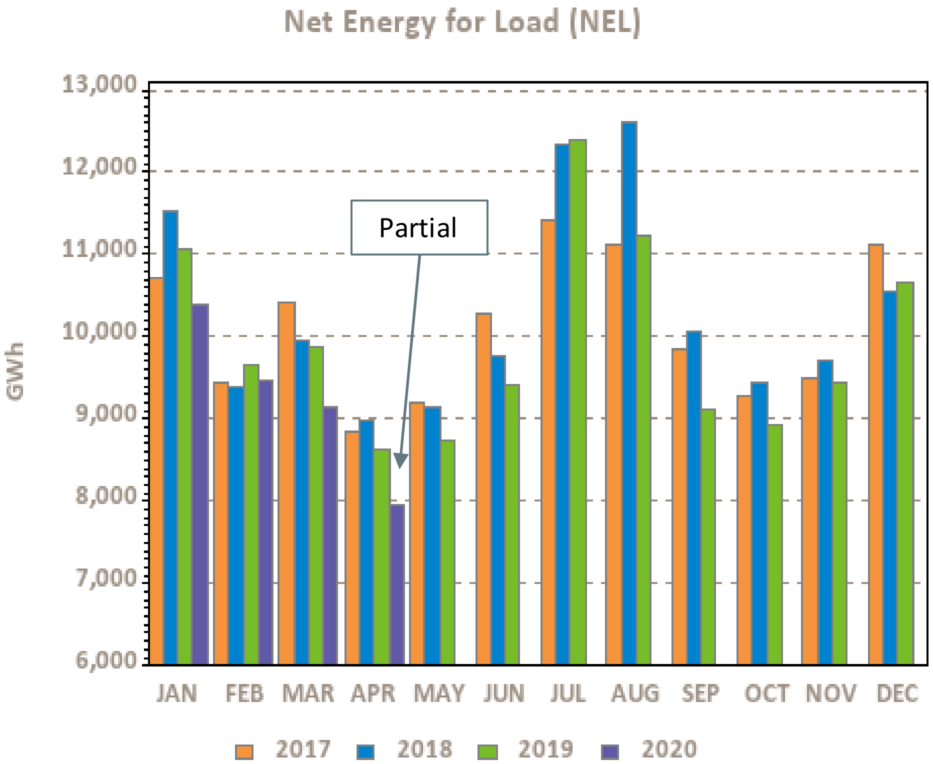


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	39	44.3	44.4	33.9									40
Below %	61	55.7	55.6	66.1									60
Avg Above	136.2	169.9	207	178.9									207
Avg Below	-192.4	-157.6	-263.9	-265.3									-265
Avg All	-65	-13	-56	-106									-60

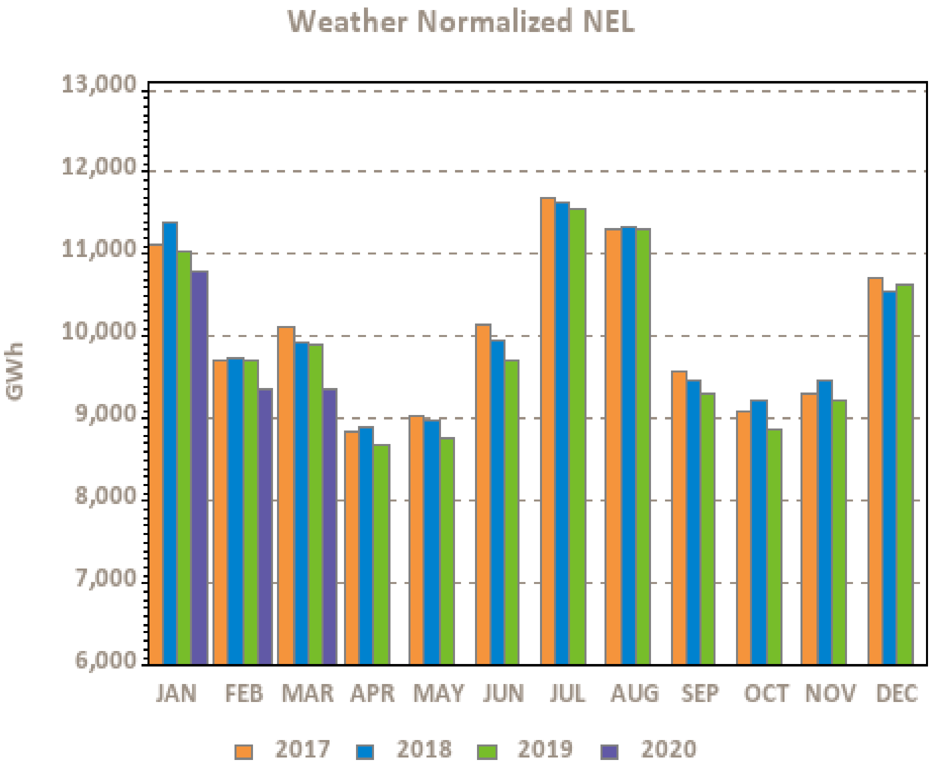
2020 System Operations - Load Forecast Accuracy cont.



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



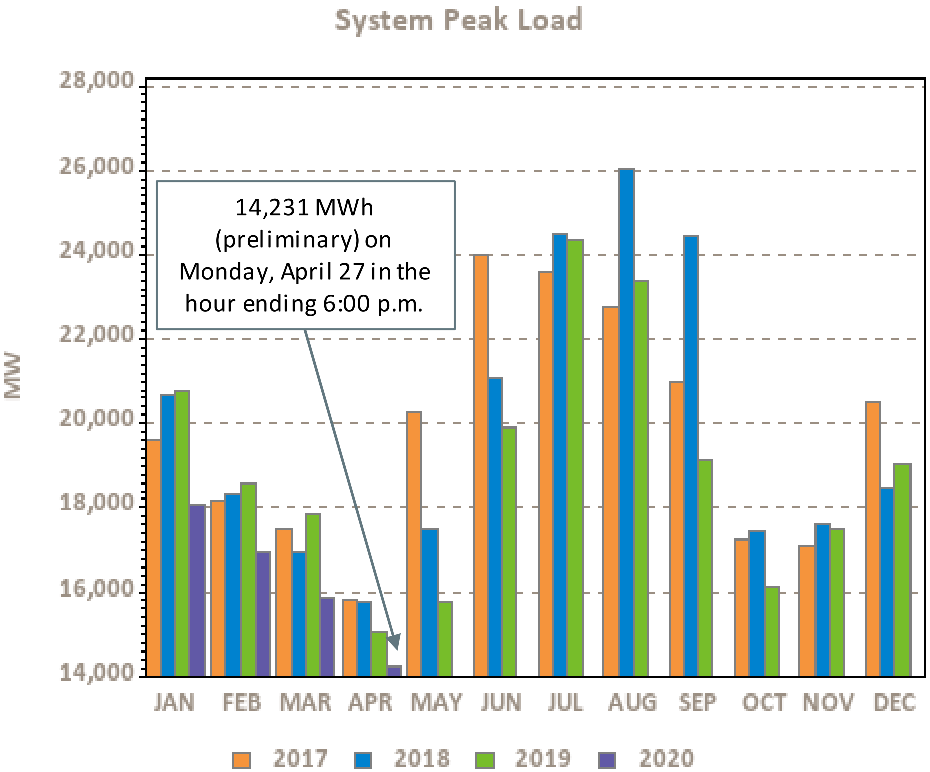
Ann Tot (TWh): 121.2 123.5 119.2 37.0



Ann Tot (TWh): 120.7 120.6 118.7 29.5

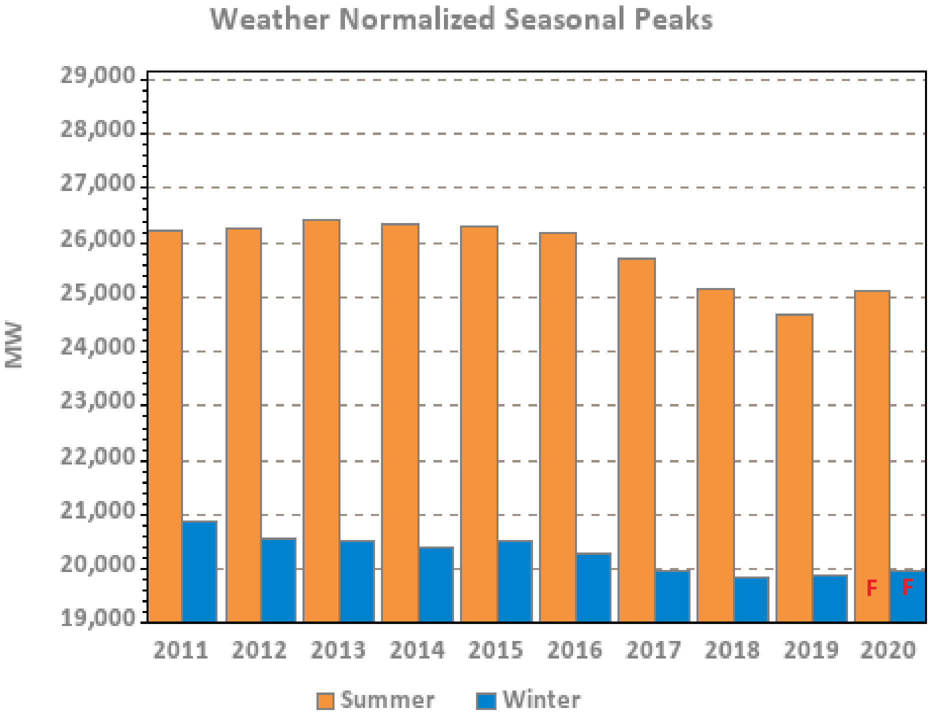
NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather normalized NEL may be reported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

Monthly Peak Loads and Weather Normalized Seasonal Peak History



14,231 MWh (preliminary) on Monday, April 27 in the hour ending 6:00 p.m.

Revenue quality metered value

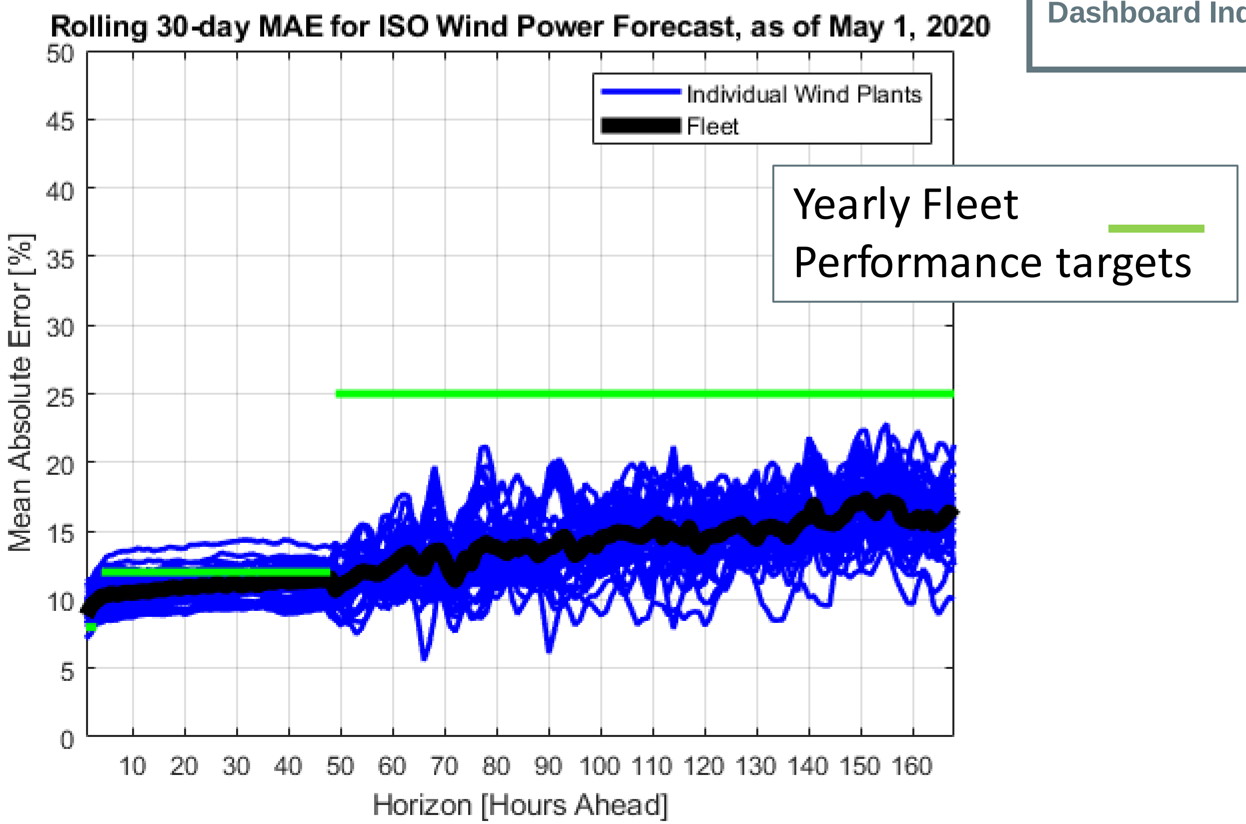


Winter beginning in year displayed

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

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

Dashboard Indicator 🟢

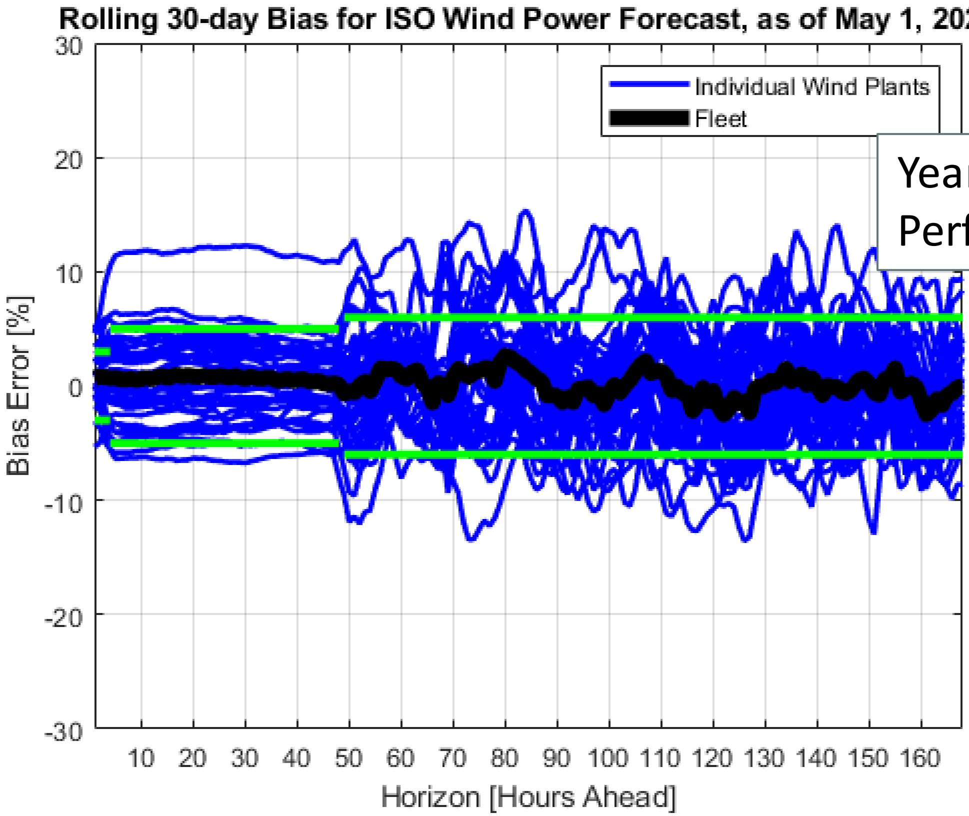


Yearly Fleet Performance targets 🟩

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

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

Dashboard Indicator ●

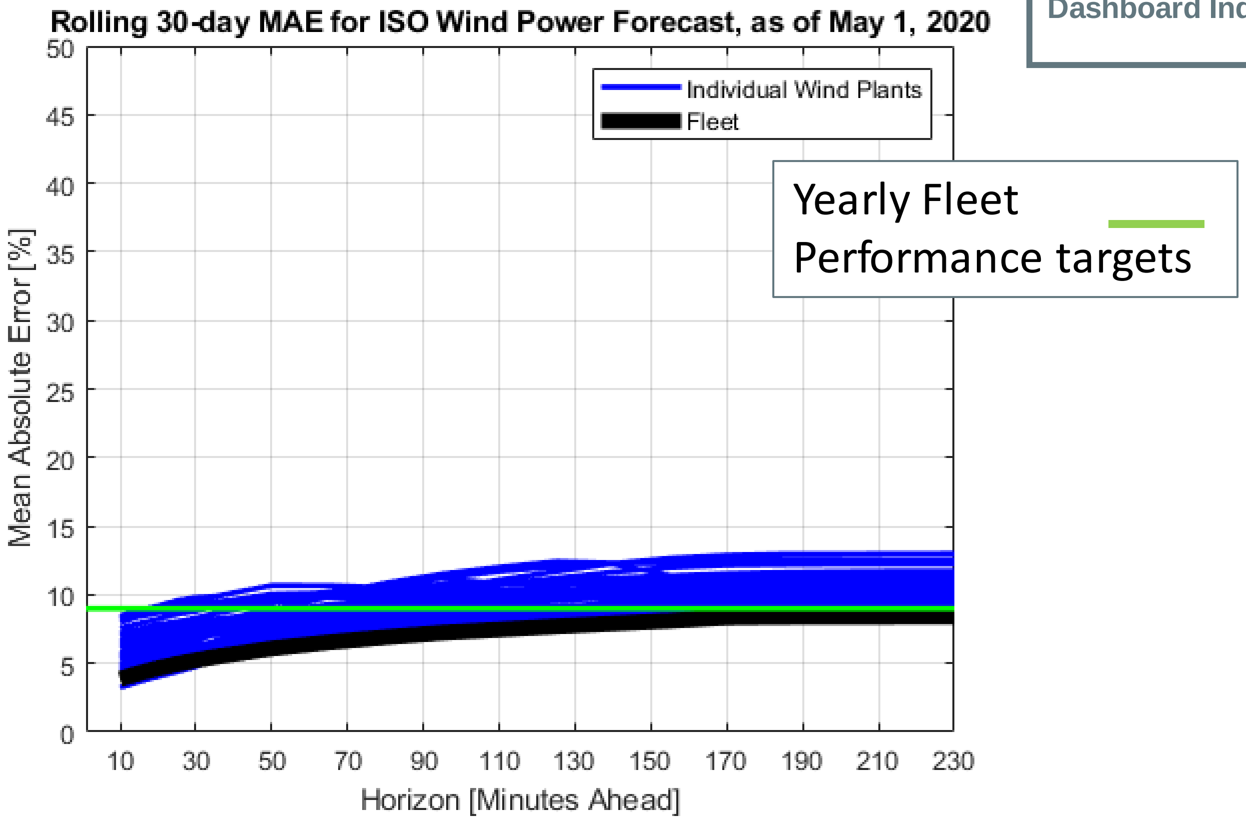


Yearly Fleet Performance targets

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-GL forecast compares well with industry standards, and monthly Bias is within yearly performance targets.

Wind Power Forecast Error Statistics: Short Term Forecast MAE

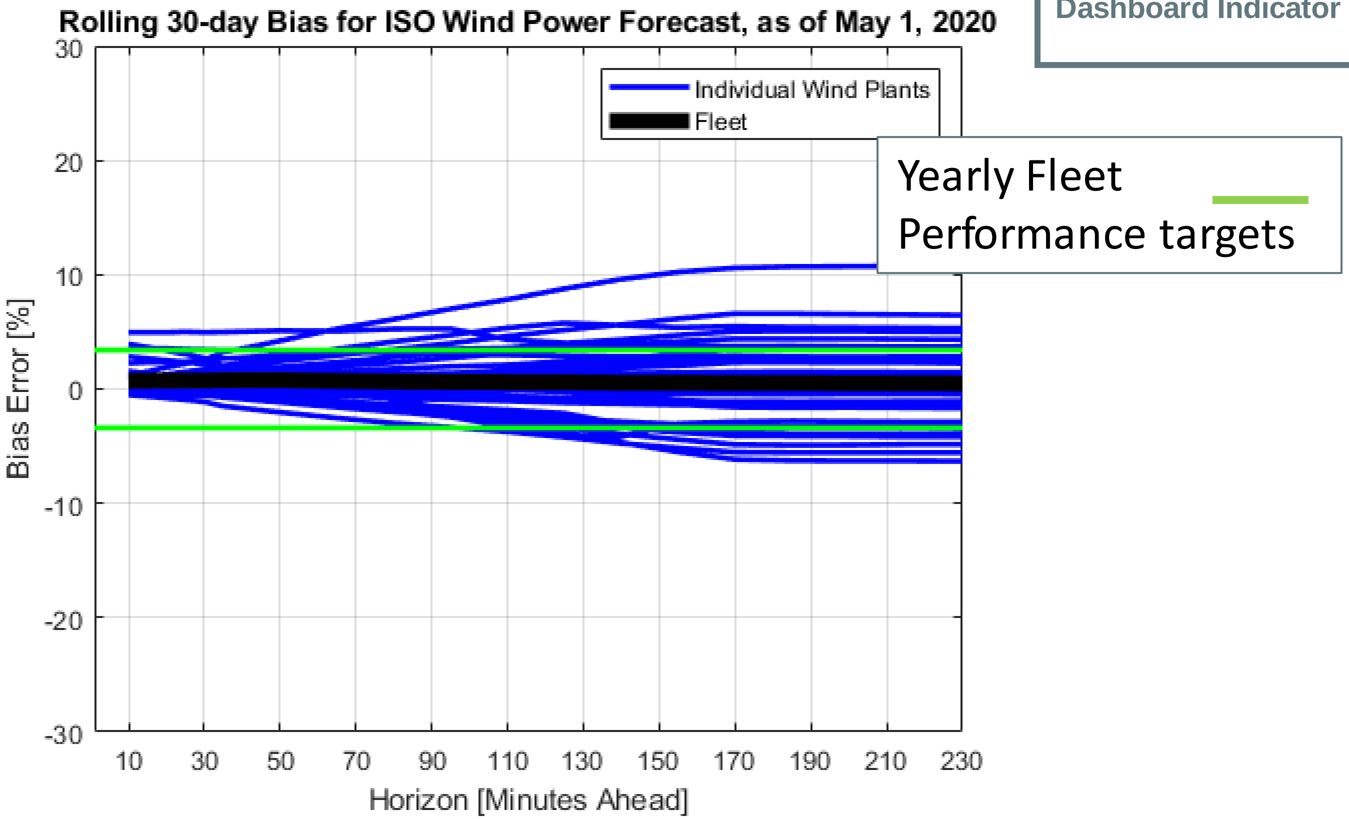
Dashboard Indicator ●



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

Wind Power Forecast Error Statistics: Short Term Forecast Bias

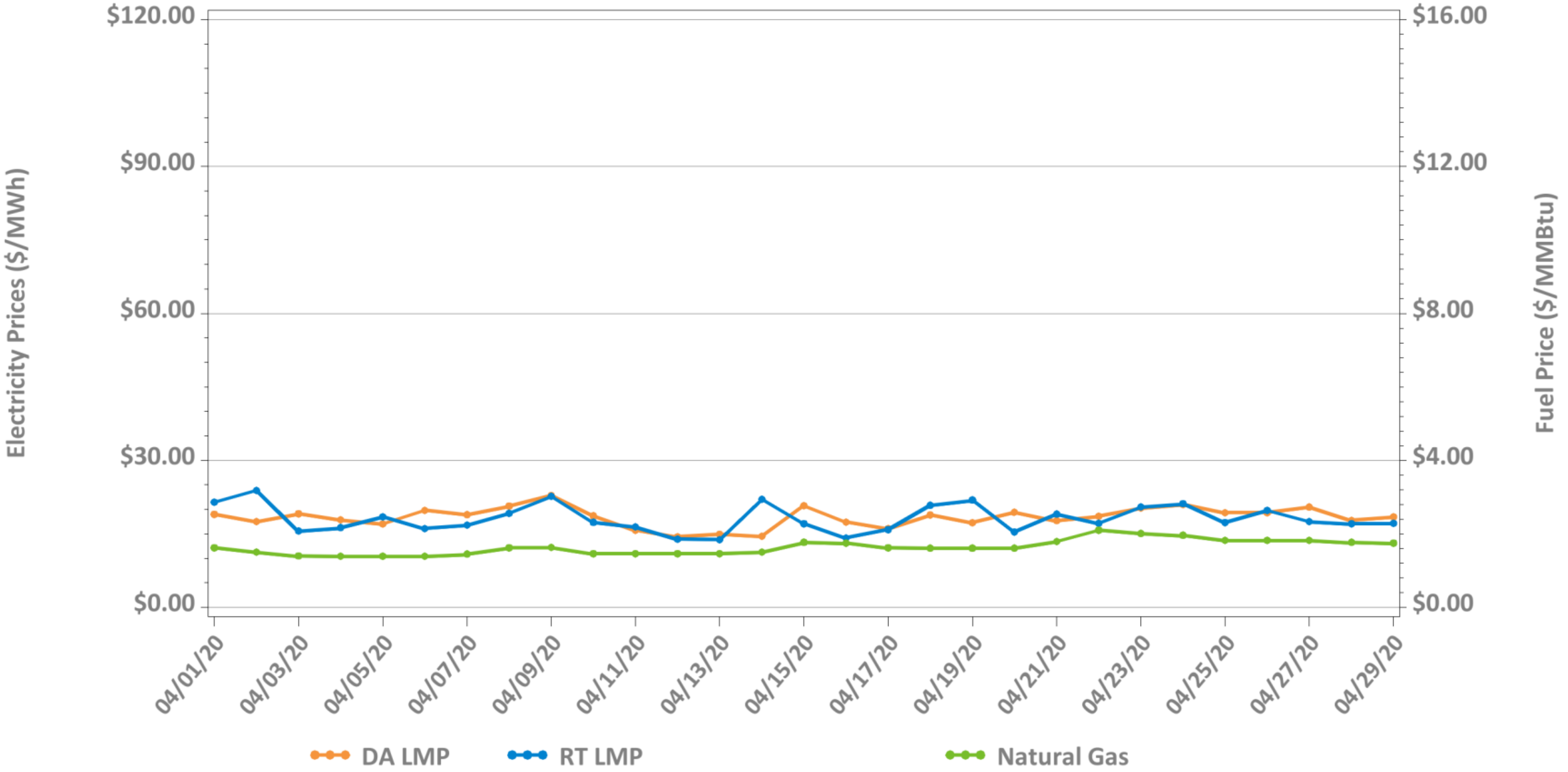
Dashboard Indicator ●



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

MARKET OPERATIONS

Daily Average DA and RT ISO-NE Hub Prices and Input Fuel Prices: April 1-29, 2020

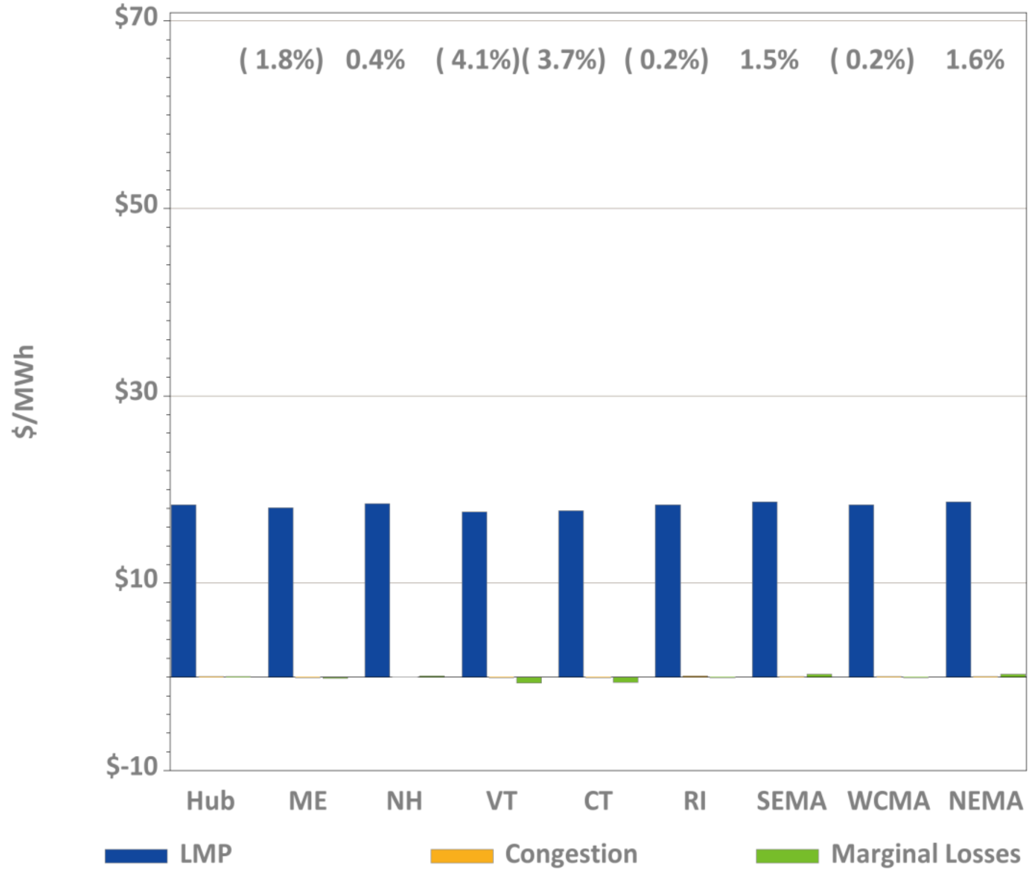


Underlying natural gas data furnished by:

ICE Global markets in clear view

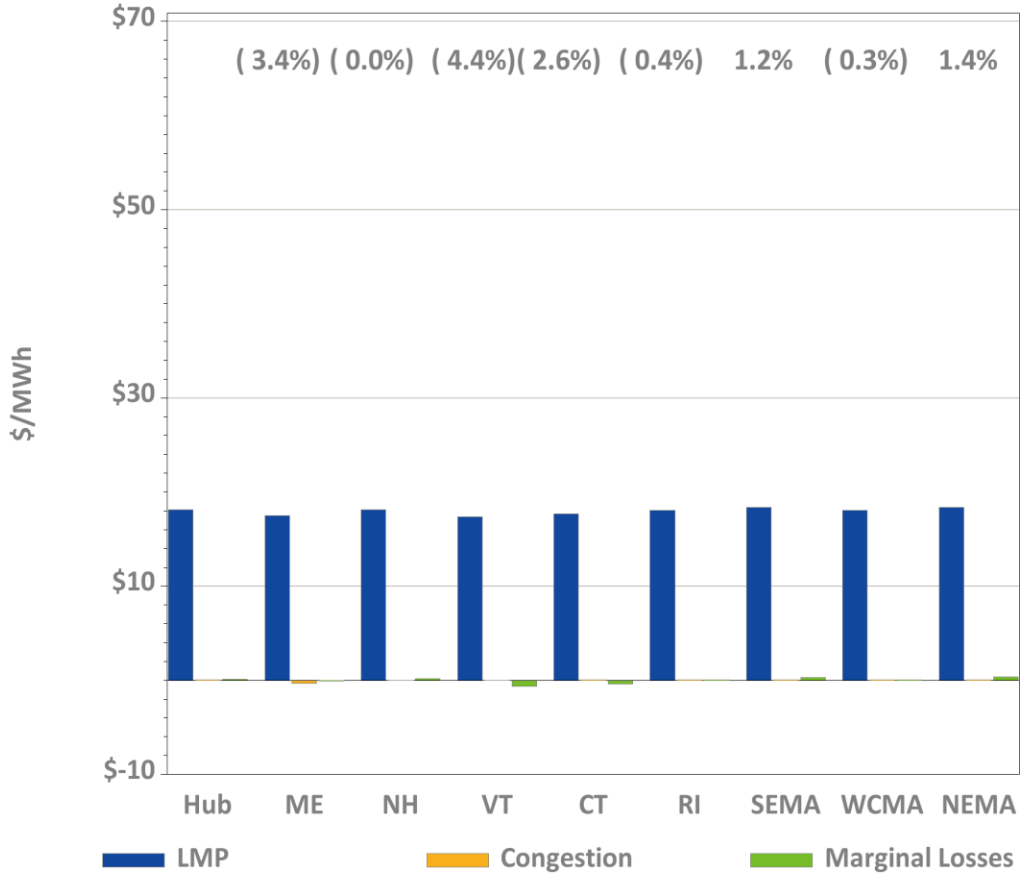
Average price difference over this period (DA-RT): $0.27
Average price difference over this period ABS(DA-RT): $2.15
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 12%
Gas price is average of Massachusetts delivery points

DA LMPs Average by Zone & Hub, April 2020



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

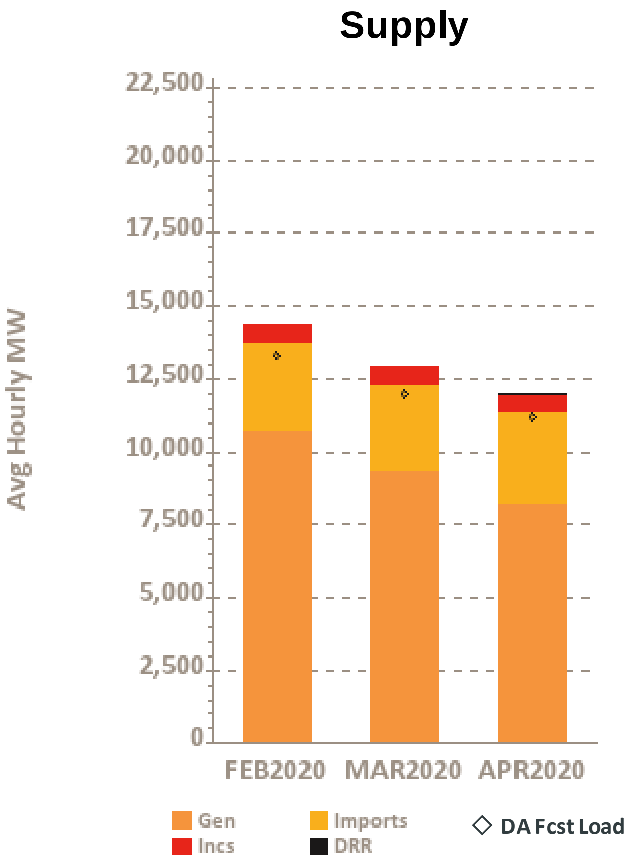
RT LMPs Average by Zone & Hub, April 2020

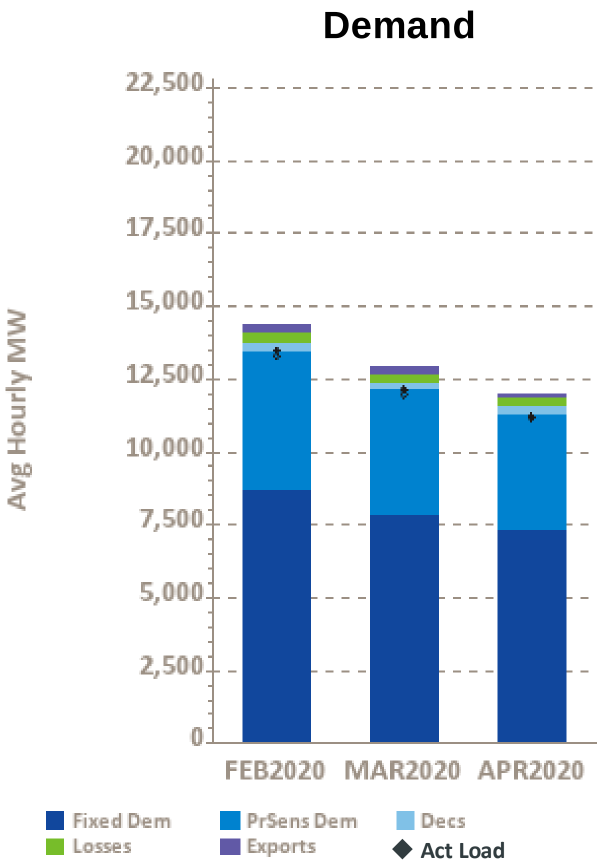


Definitions

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

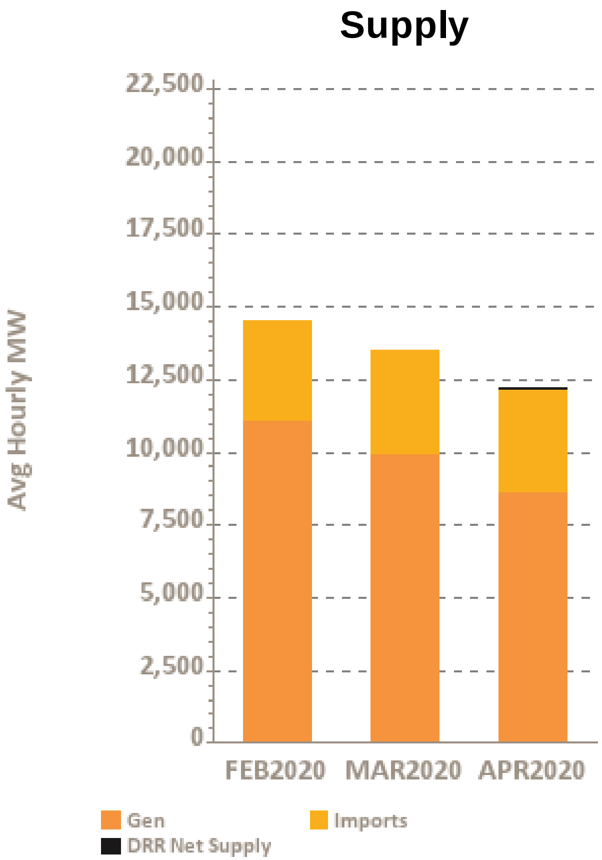


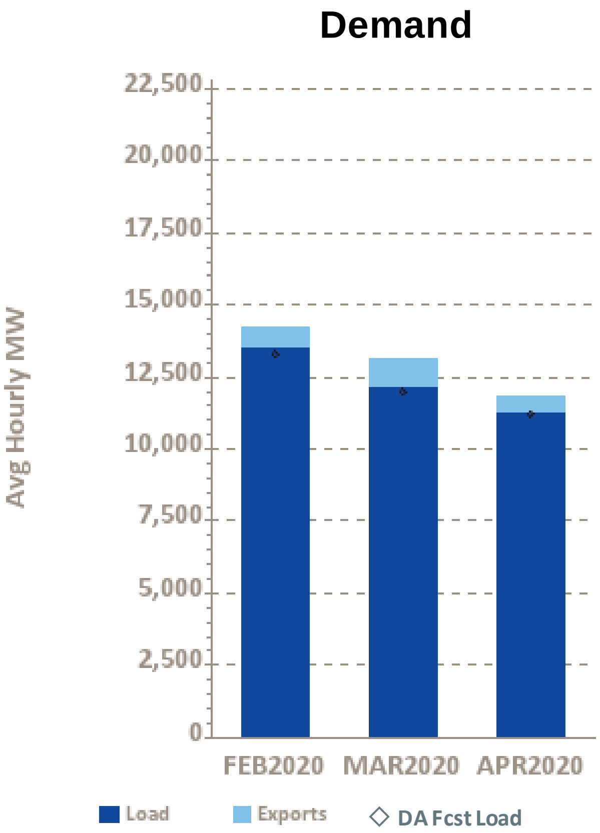


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load

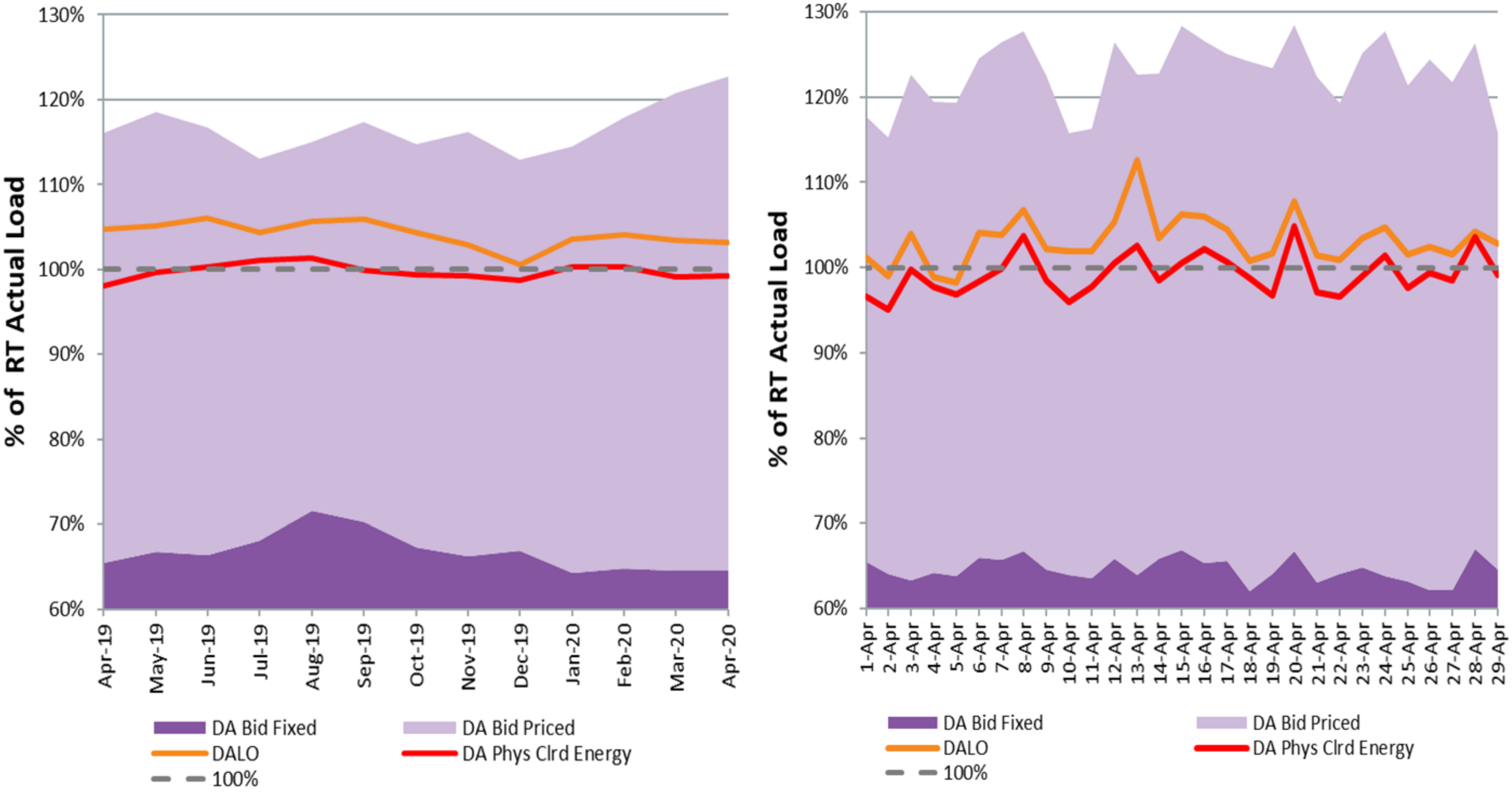
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

Components of RT Supply and Demand – Last Three Months



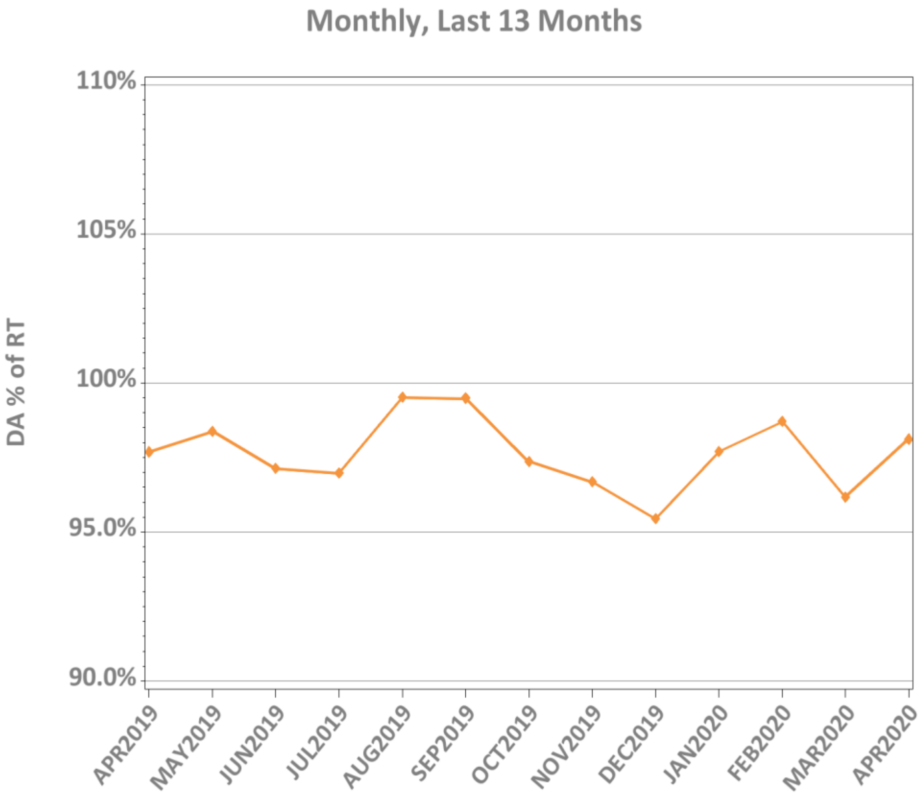


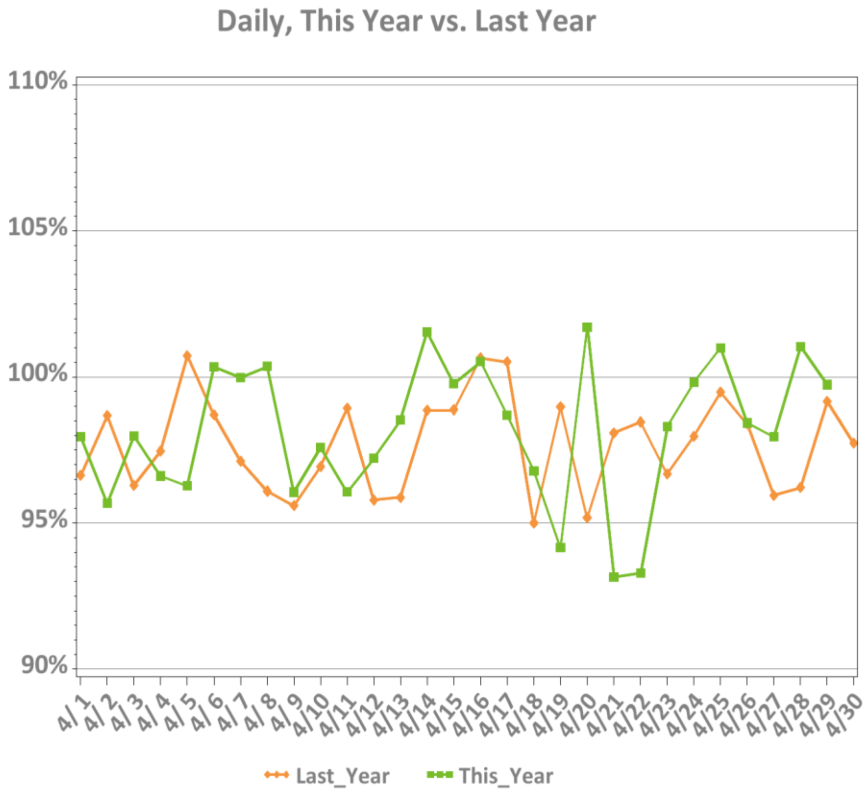
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)



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

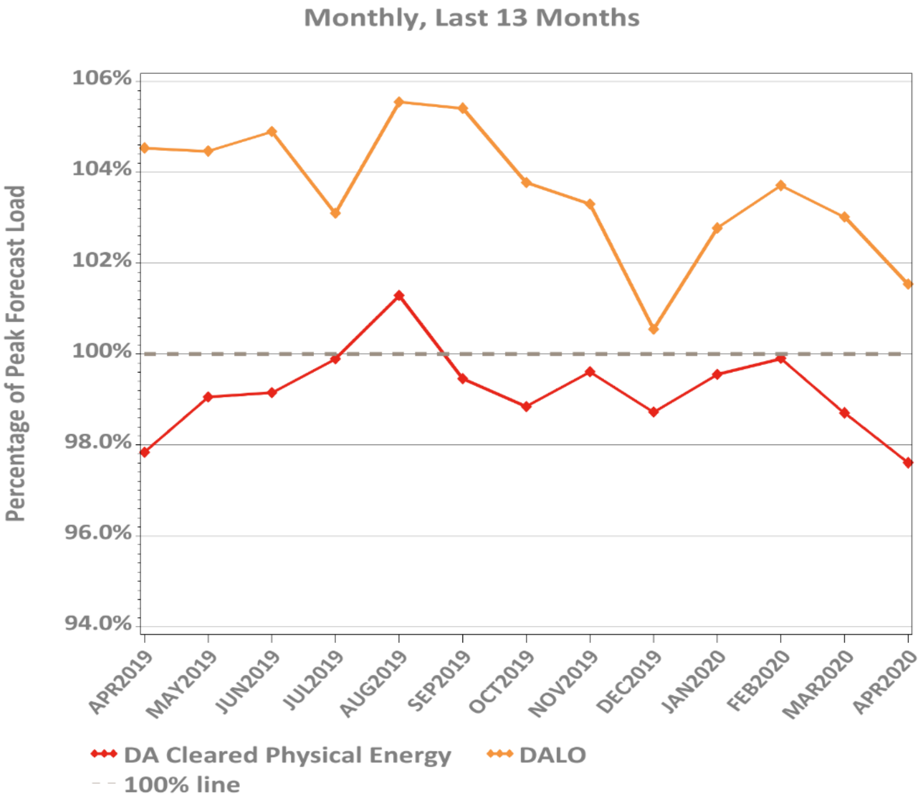
DA vs. RT Load Obligation: April, This Year vs. Last Year

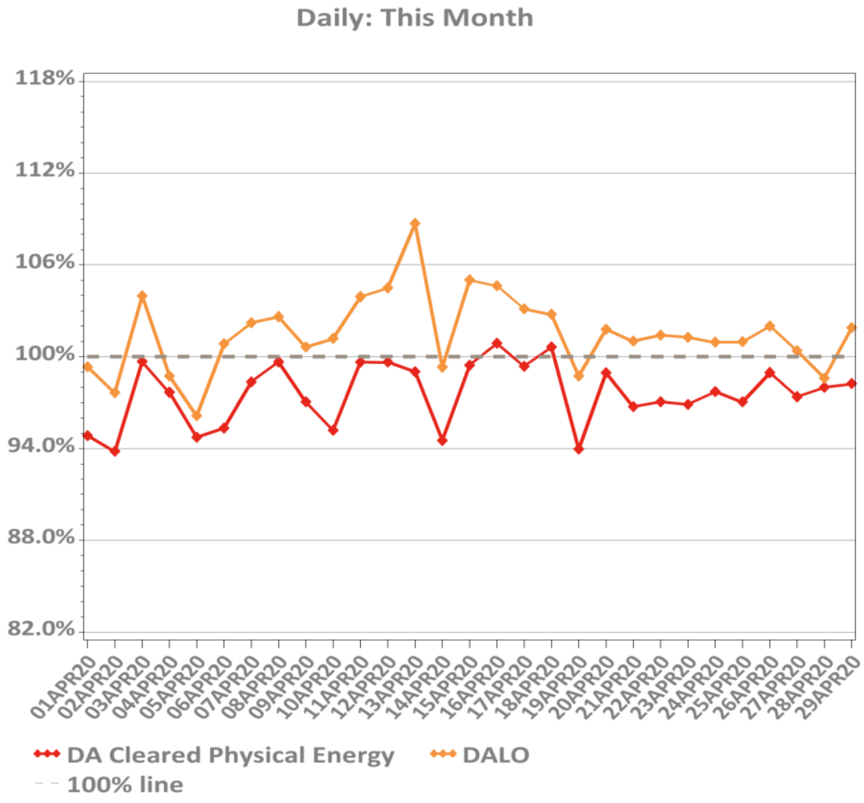




*Hourly average values

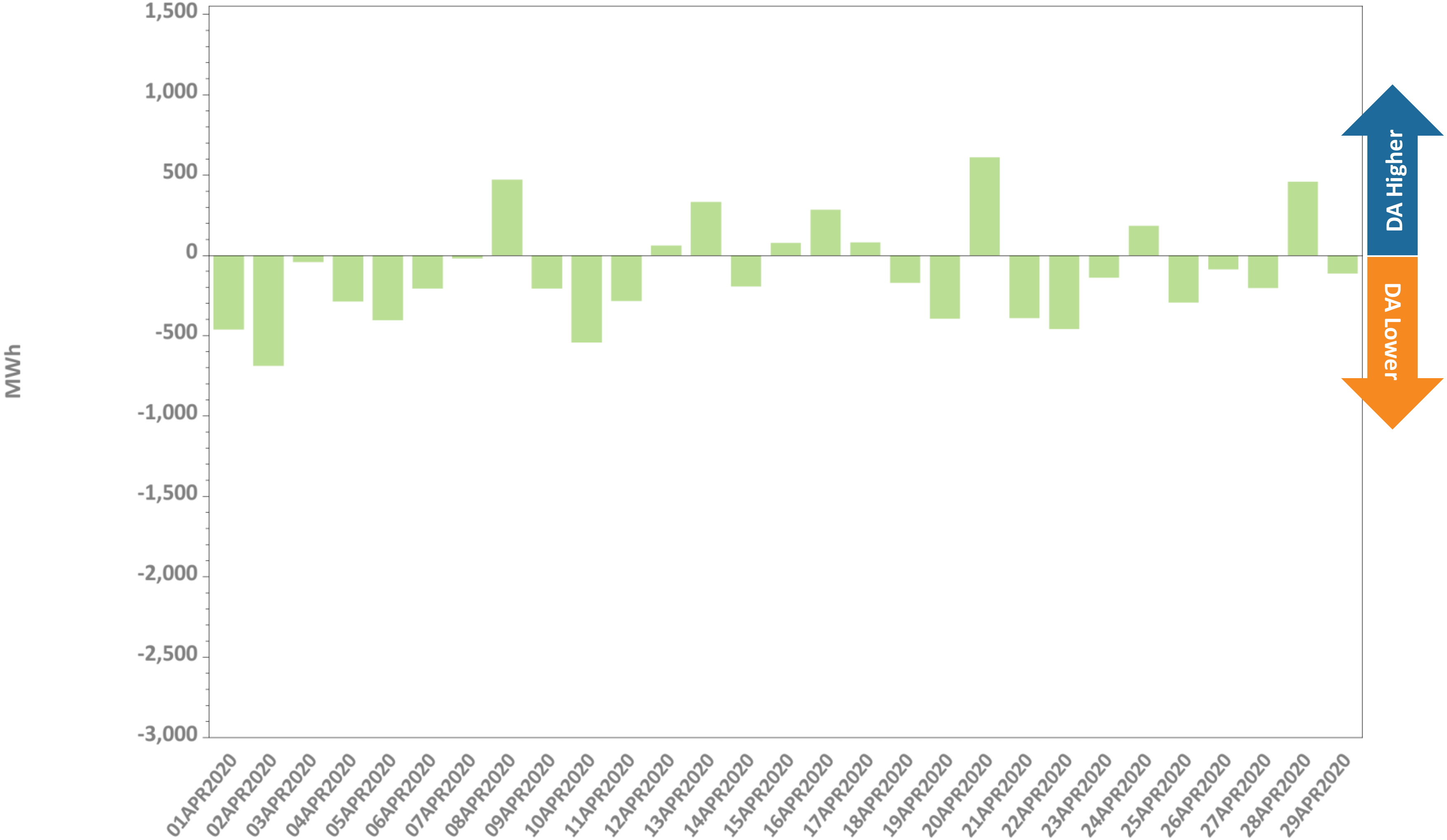
DA Volumes as % of Forecast in Peak Hour





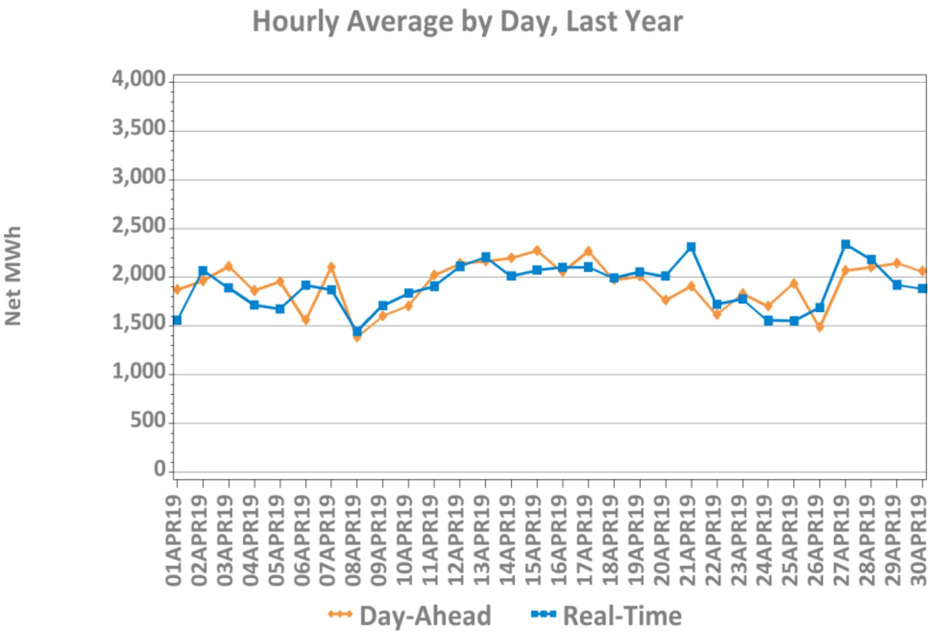
* There were *no* system-level supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during April.

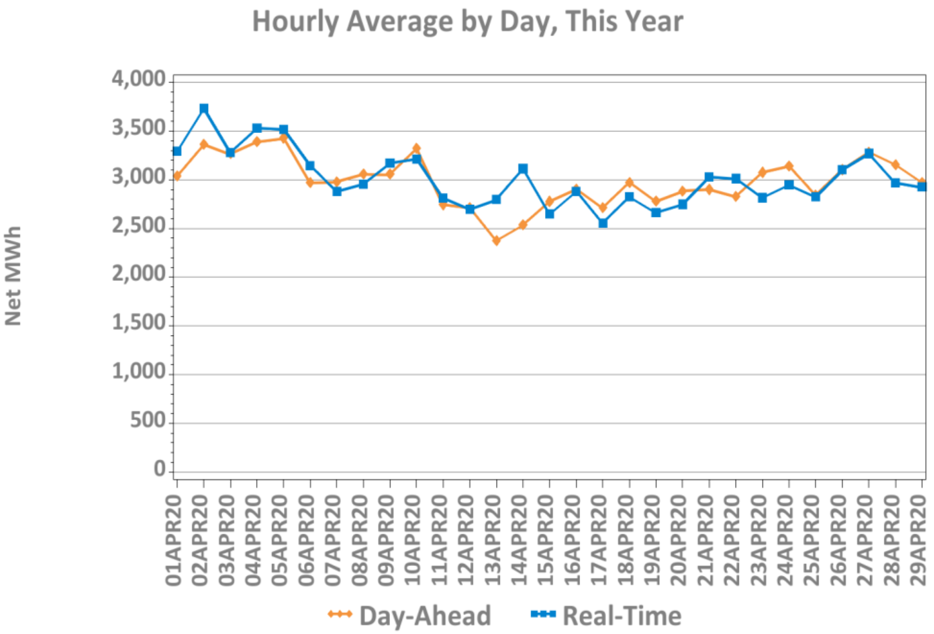
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

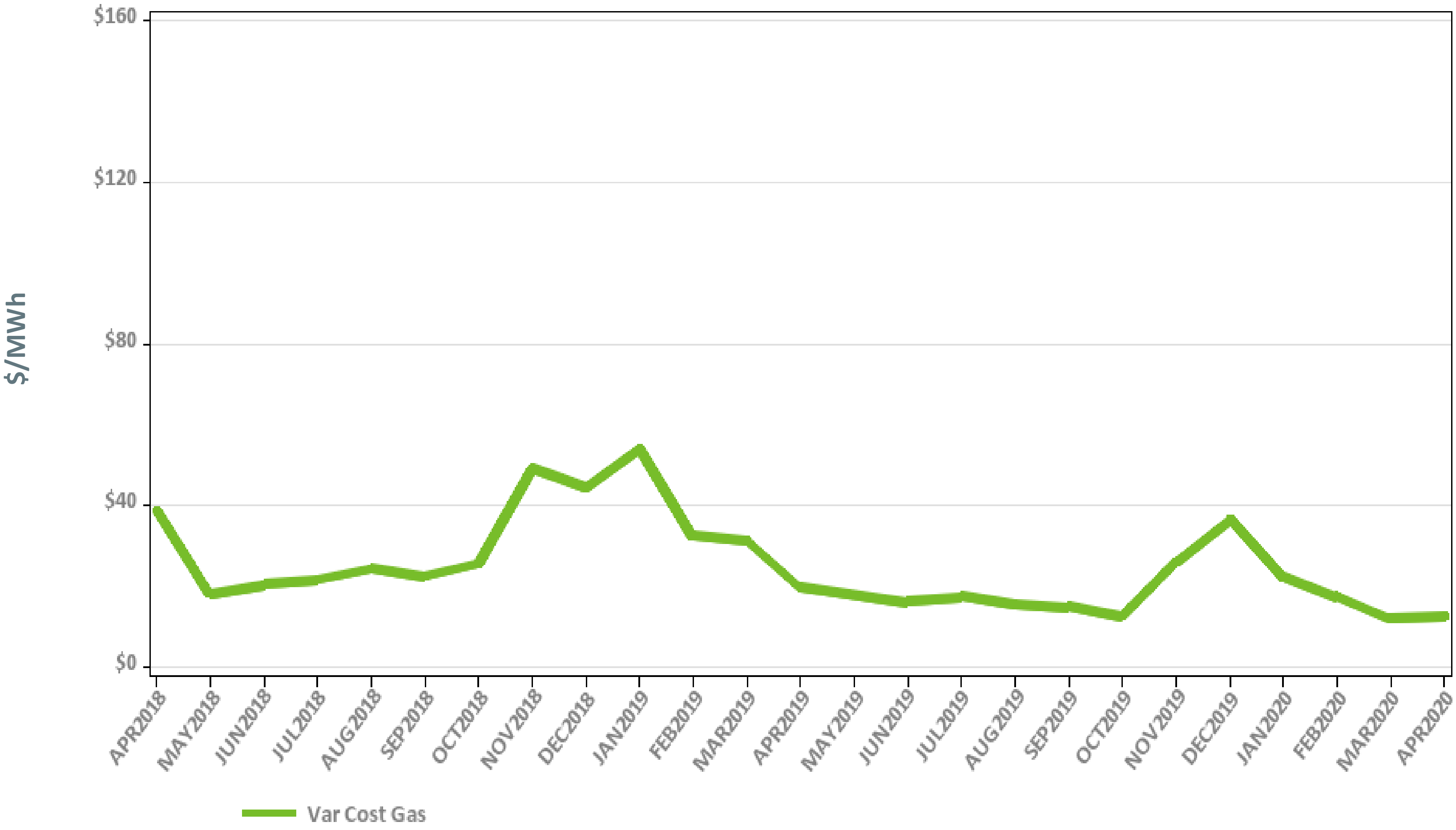
DA vs. RT Net Interchange April 2019 vs. April 2020





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

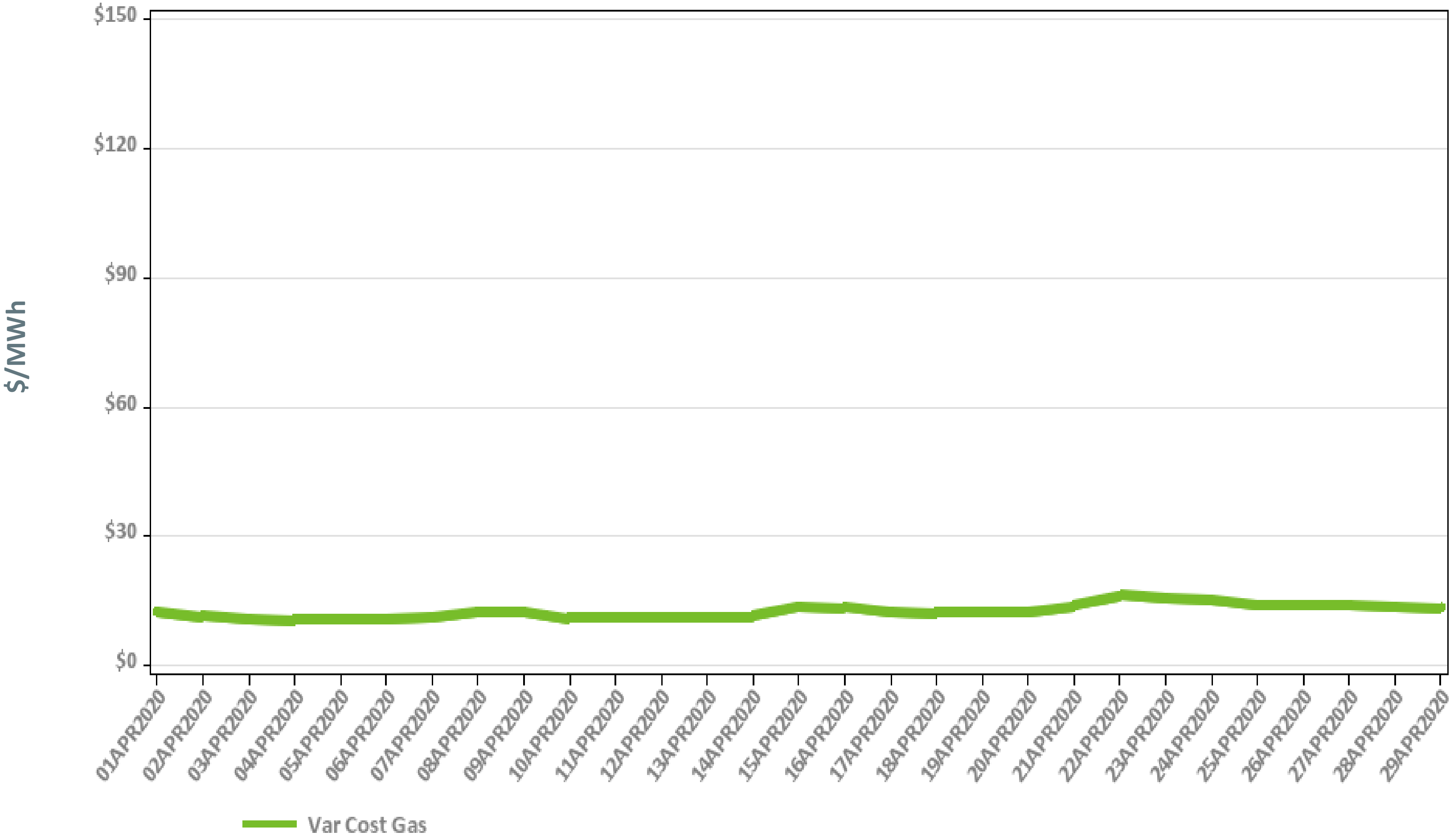
Variable Production Cost of Natural Gas: Monthly



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

Underlying natural gas data furnished by:

Variable Production Cost of Natural Gas: Daily

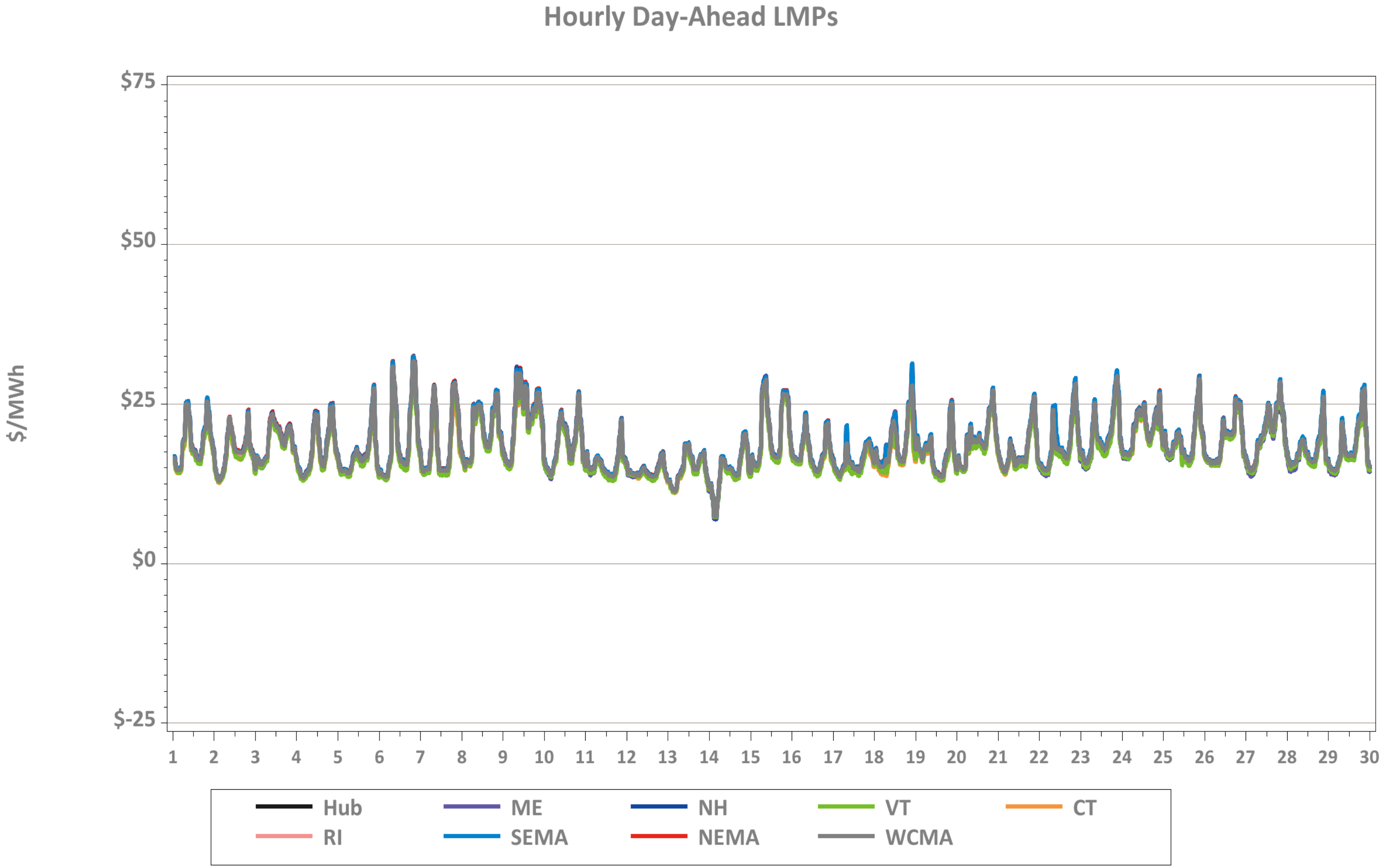


Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

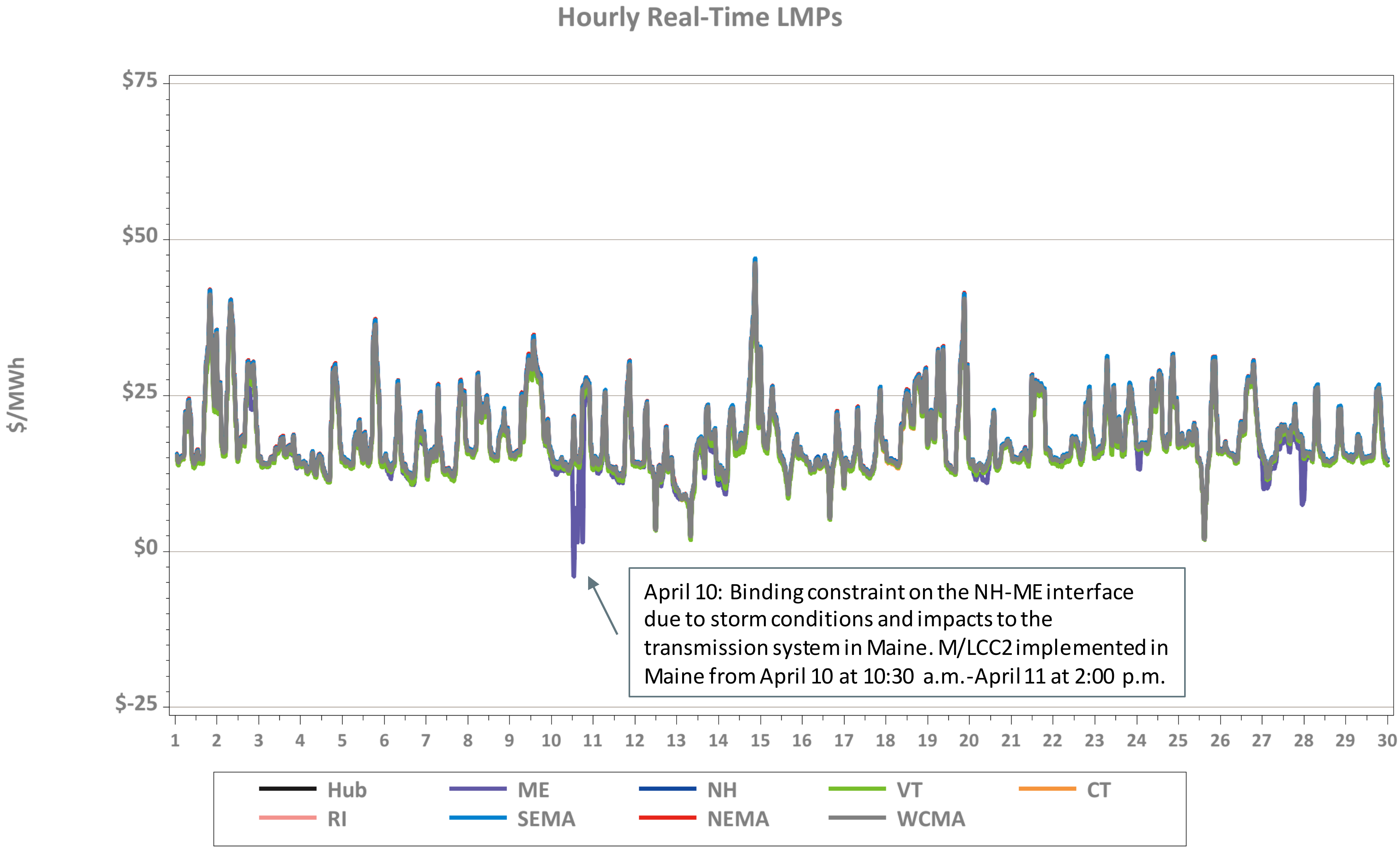
Underlying natural gas data furnished by:

ICE Global markets in clear view

Hourly DA LMPs, April 1-29, 2020



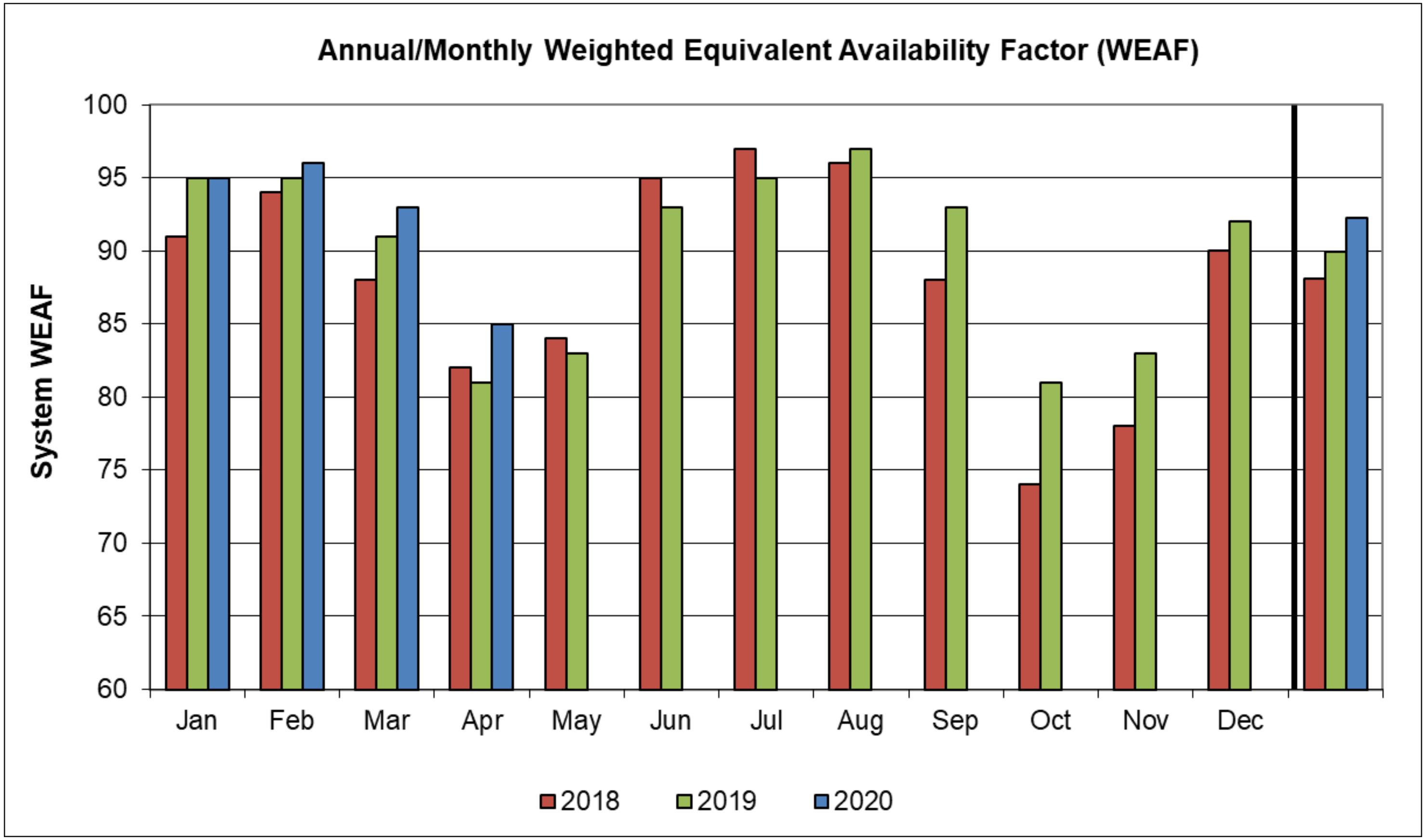
Hourly RT LMPs, April 1-29, 2020



April 10: Binding constraint on the NH-ME interface due to storm conditions and impacts to the transmission system in Maine. M/LCC2 implemented in Maine from April 10 at 10:30 a.m.-April 11 at 2:00 p.m.

- No Minimum Generation Emergencies were declared during April.

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2020	95	96	93	85									92
2019	95	95	91	81	83	93	95	97	93	81	83	92	90
2018	91	94	88	82	84	95	97	96	88	74	78	90	88

Data as of 4/29/2020

BACK-UP DETAIL

DEMAND RESPONSE

Capacity Supply Obligation (CSO) MW by Demand Resource Type for May 2020

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	100.9	186.1	0.0	287.0
NH	27.2	111.8	0.0	139.0
VT	29.3	120.0	0.0	149.2
CT	103.5	127.0	457.9	688.4
RI	33.2	215.5	0.0	248.7
SEMA	32.6	403.9	0.0	436.5
WCMA	60.5	401.1	49.6	511.2
NEMA	48.2	667.0	0.0	715.2
Total	**435.2**	**2,232.5**	**507.5**	**3,175.2**

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

NEW GENERATION

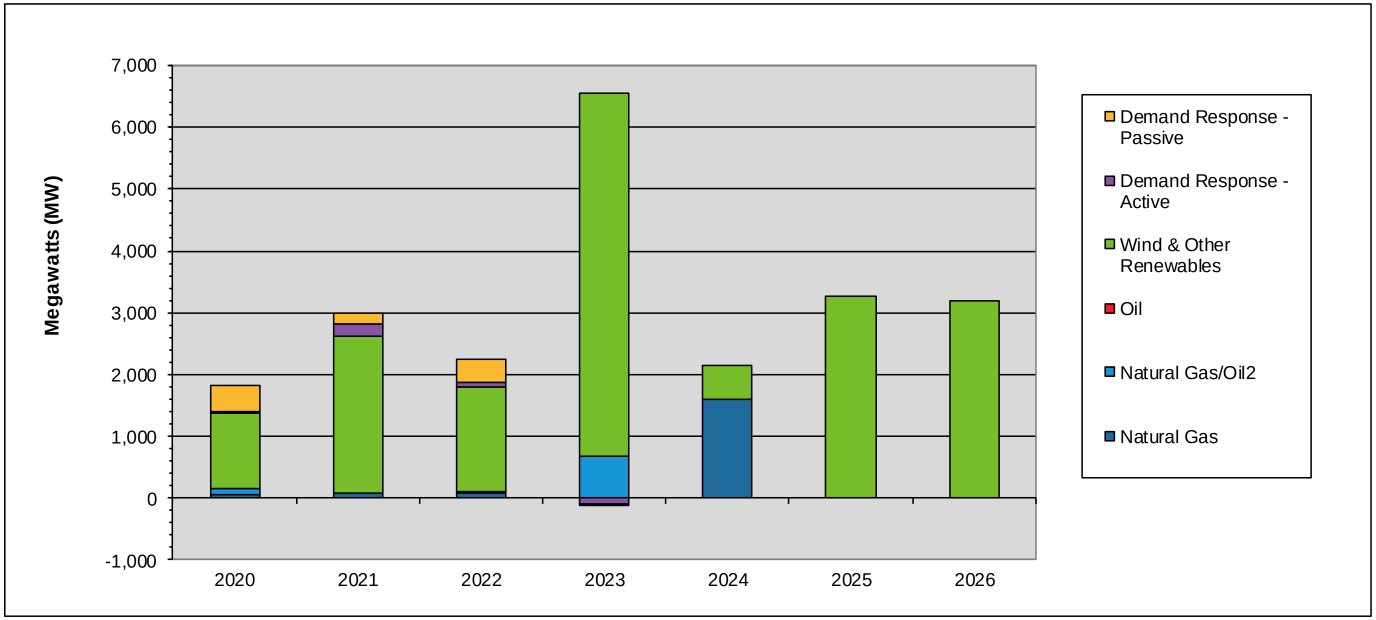
New Generation Update

Based on Queue as of 5/4/20

- 41 projects totaling 2,761 MW applied for interconnection study since the last update
- One project went commercial, four withdrew, and net increases in project capacities resulted in a net increase in new generation projects of 2,640 MW
- In total, 232 generation projects are currently being tracked by the ISO, totaling approximately 20,873 MW

Actual and Projected Annual Capacity Additions

By Supply Fuel Type and Demand Resource Type



	2020	2021	2022	2023	2024	2025	2026	Total MW	% of Total[1]
Demand Response - Passive	422	184	380	-28	0	0	0	958	4.3
Demand Response - Active	42	204	62	-94	0	0	0	214	1.0
Wind & Other Renewables	1,199	2,537	1,685	5,870	546	3,276	3,200	18,313	82.8
Oil	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	121	0	39	672	0	0	0	832	3.8
Natural Gas	43	76	73	0	1,600	0	0	1,792	8.1
Totals	**1,828**	**3,001**	**2,239**	**6,420**	**2,146**	**3,276**	**3,200**	**22,110**	**100.0**

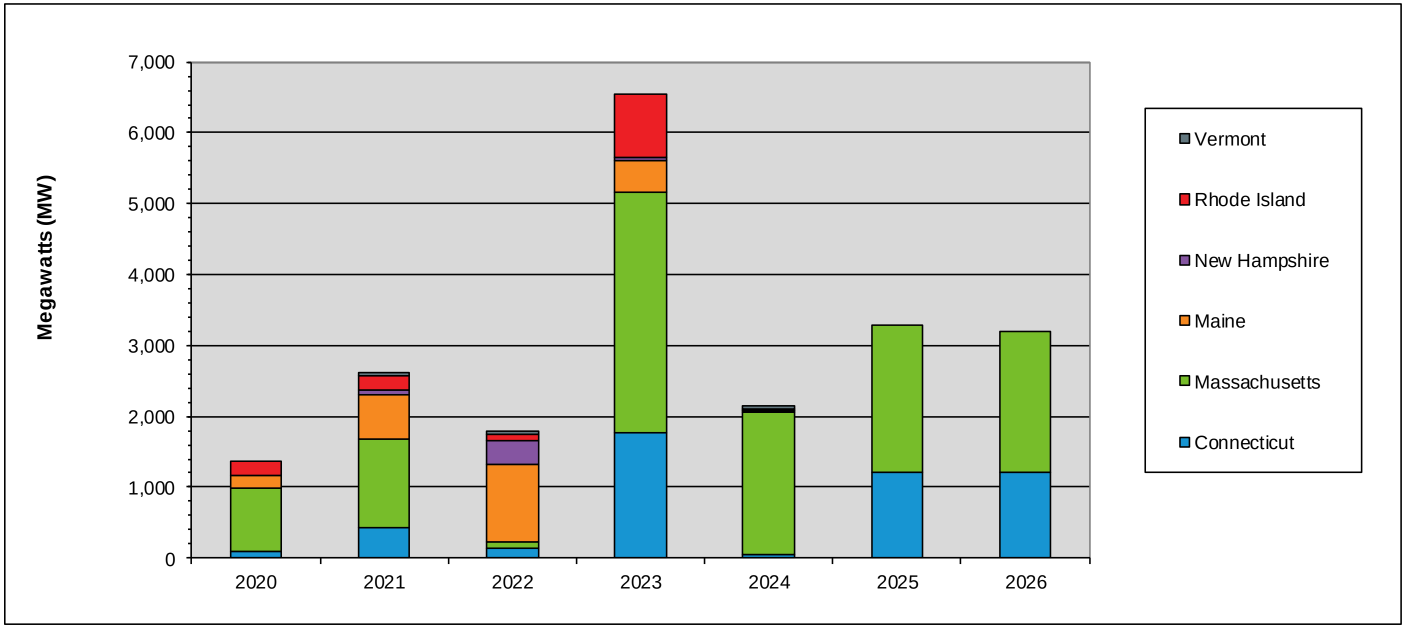
[1] **Sum may not equal 100% due to rounding**

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

- 2020 values include the 64 MW of generation that has gone commercial in 2020
- DR reflects changes from the initial FCM Capacity Supply Obligations in 2010-11

Actual and Projected Annual Generator Capacity Additions

By State



	2020	2021	2022	2023	2024	2025	2026	Total MW	% of Total[1]
Vermont	0	35	60	0	50	0	0	145	0.7
Rhode Island	206	196	73	880	0	0	0	1,355	6.5
New Hampshire	0	83	352	50	20	0	0	505	2.4
Maine	161	627	1,090	451	20	0	0	2,349	11.2
Massachusetts	896	1,232	87	3,384	2,016	2,076	2,000	11,691	55.8
Connecticut	100	440	135	1,777	40	1,200	1,200	4,892	23.4
Totals	**1,363**	**2,613**	**1,797**	**6,542**	**2,146**	**3,276**	**3,200**	**20,937**	**100.0**

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

- 2020 values include the 64 MW of generation that has gone commercial in 2020

New Generation Projection

By Fuel Type

	Total		Green		Yellow	
Fuel Type	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Biomass/Wood Waste	1	8	0	0	1	8
Battery Storage	15	1,839	0	0	15	1,839
Hydro	3	99	1	66	2	33
Landfill Gas	0	0	0	0	0	0
Natural Gas	13	1,792	0	0	13	1,792
Natural Gas/Oil	6	787	1	14	5	773
Nuclear	1	37	0	0	1	37
Oil	0	0	0	0	0	0
Solar	172	3,888	4	111	168	3,777
Wind	21	12,423	0	0	21	12,423
Total	232	20,873	6	191	226	20,682

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

New Generation Projection

By Operating Type

	Total		Green		Yellow	
Operating Type	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)	No. of Projects	Capacity (MW)
Baseload	8	133	0	0	8	133
Intermediate	12	2,433	1	14	11	2,419
Peaker	191	5,884	5	177	186	5,707
Wind Turbine	21	12,423	0	0	21	12,423
Total	232	20,873	6	191	226	20,682

- 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	
Fuel 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	1	8	1	8	0	0	0	0	0	0
Battery Storage	15	1,839	0	0	0	0	15	1,839	0	0
Hydro	3	99	2	33	0	0	1	66	0	0
Landfill Gas	0	0	0	0	0	0	0	0	0	0
Natural Gas	13	1,792	4	55	8	1,731	1	6	0	0
Natural Gas/Oil	6	787	0	0	4	702	2	85	0	0
Nuclear	1	37	1	37	0	0	0	0	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Solar	172	3,888	0	0	0	0	172	3,888	0	0
Wind	21	12,423	0	0	0	0	0	0	21	12,423
Total	232	20,873	8	133	12	2,433	191	5,884	21	12,423

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

FORWARD CAPACITY MARKET

Capacity Supply Obligation FCA 11

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*	419.928	441.221	21.293	594.551	153.33	584.35	-10.201
	Passive Demand	2,791.02	2,835.354	44.334	2,883.767	48.413	2,964.695	80.928
Demand Total		**3,210.95**	**3,276.575**	**65.625**	**3,478.318**	**201.743**	**3,549.045**	70.727
Generator	*Non-Intermittent*	30,494.80	30,064.23	-430.569	30,159.891	95.661	2,9678.995	-480.896
	Intermittent	894.217	823.796	-70.421	809.571	-14.225	689.524	-120.047
Generator Total		**31,389.02**	**30,888.027**	**-500.993**	**30,969.462**	**81.435**	**30,368.519**	**-600.943**
Import Total		**1,235.40**	**1,622.037**	**386.637**	**1,609.844**	**-12.193**	**1,124.6**	**-485.244**
****Grand Total**		**35,835.37**	**35,786.64**	**-48.731**	**36,057.624**	**270.984**	**35,042.164**	**-1015.46**
Net ICR (NICR)		**34,075**	**33,660**	**-415**	**33,520**	**-140**	**32,205**	**-1,315**

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** 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 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				
	Passive Demand	2,975.36	3,045.073	69.713				
Demand Total		**3,599.81**	**3,704.21**	**104.4**				
Generator	*Non-Intermittent*	29,130.75	29,244.404	113.654				
	Intermittent	880.317	806.609	-73.708				
Generator Total		**30,011.07**	**30,051.013**	**39.943**				
Import Total		**1,217**	**1,305.487**	**88.487**				
****Grand Total**		**34,827.88**	**35,060.710**	**232.83**				
Net ICR (NICR)		**33,725**	**33,550**	**-175**				

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

** 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 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						
	Passive Demand	3,354.69						
Demand Total		**4,040.244**						
Generator	*Non-Intermittent*	28,586.498						
	Intermittent	1,024.792						
Generator Total		**2,9611.29**						
Import Total		**1,187.69**						
****Grand Total**		**34,839.224**						
Net ICR (NICR)		**33,750**						

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

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

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

Capacity Supply Obligation FCA 14

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

* Real-time Emergency Generators (RTEG) CSO not capped at 600.000 MW

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

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

Active/Passive Demand Response

CSO Totals by Commitment Period

Commitment Period	Active/Passive	Existing	New	**Grand Total**
2019-20	Active	357.221	20.304	377.525
	Passive	2,018.20	350.43	2,368.63
	Grand Total	2,375.422	370.734	2,746.156
2020-21	Active	334.634	85.294	419.928
	Passive	2,236.73	554.292	2,791.02
	Grand Total	2,571.361	639.586	3,210.947
2021-22	Active	480.941	143.504	624.445
	Passive	2,604.79	370.568	2,975.36
	Grand Total	3,085.734	514.072	3,599.806
2022-23	Active	598.376	87.178	685.554
	Passive	2,788.33	566.363	3,354.69
	Grand Total	3,386.703	653.541	4,040.244
2023-24	Active	560.55	31.493	592.043
	Passive	3,035.51	291.565	3,327.07
	Grand Total	3,596.056	323.058	3,919.114

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

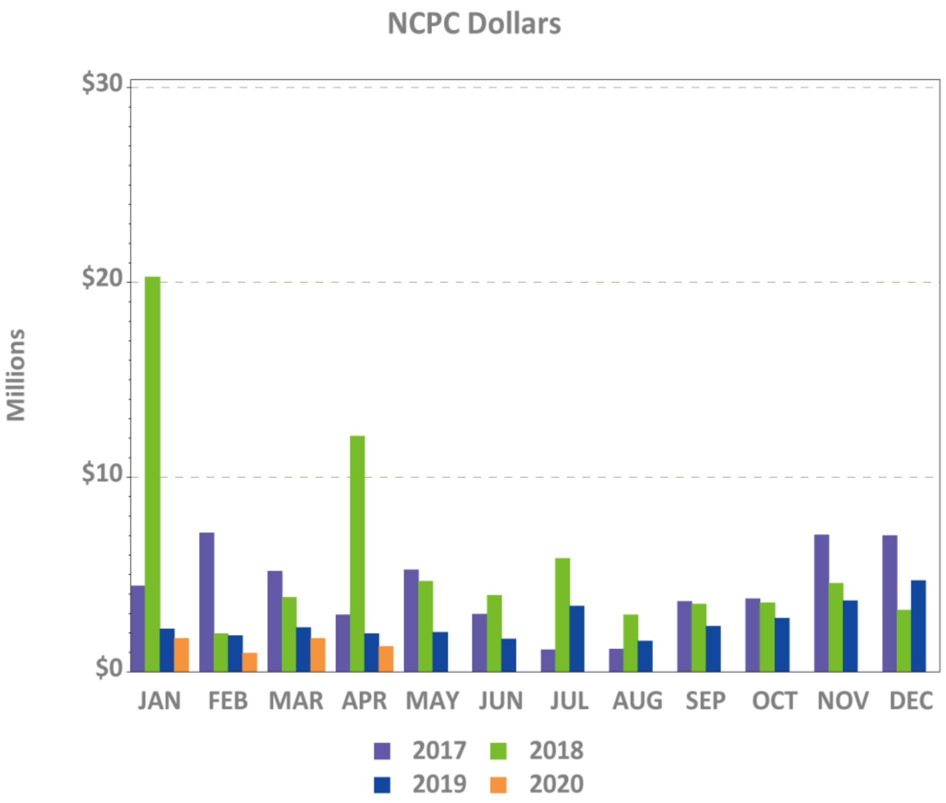
Definitions

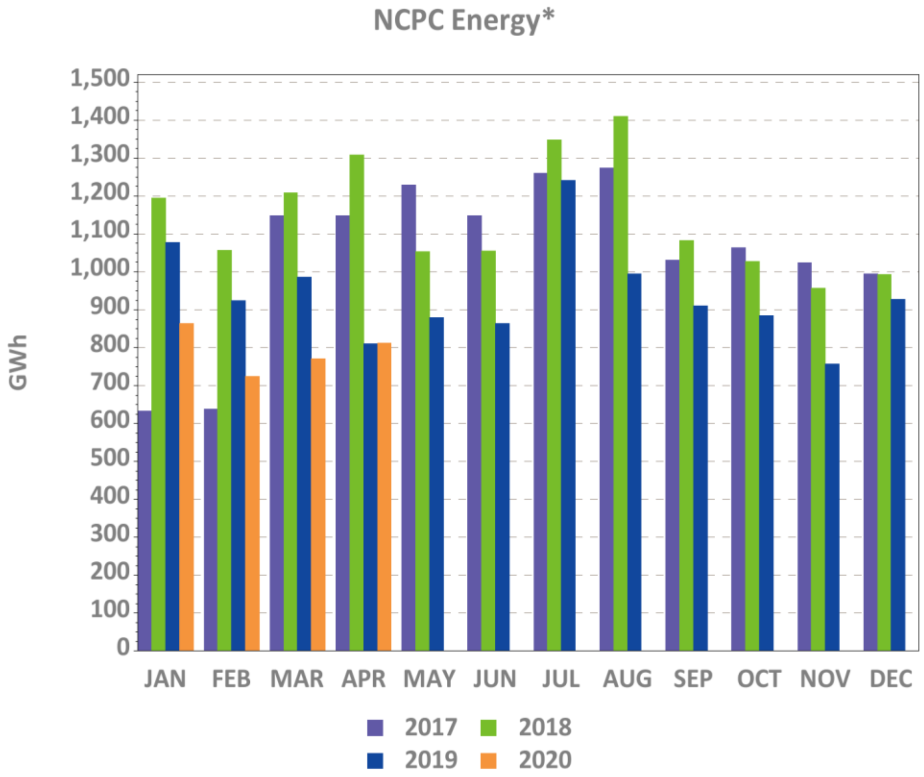
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing 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).

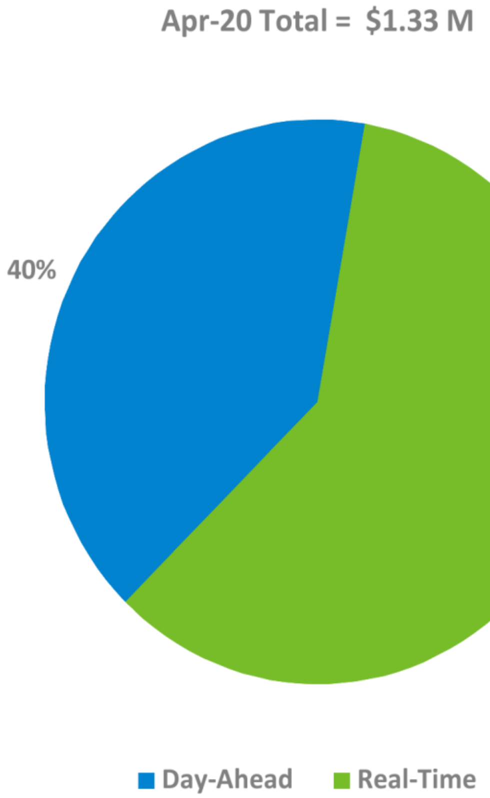
Year-Over-Year Total NCPC Dollars and Energy



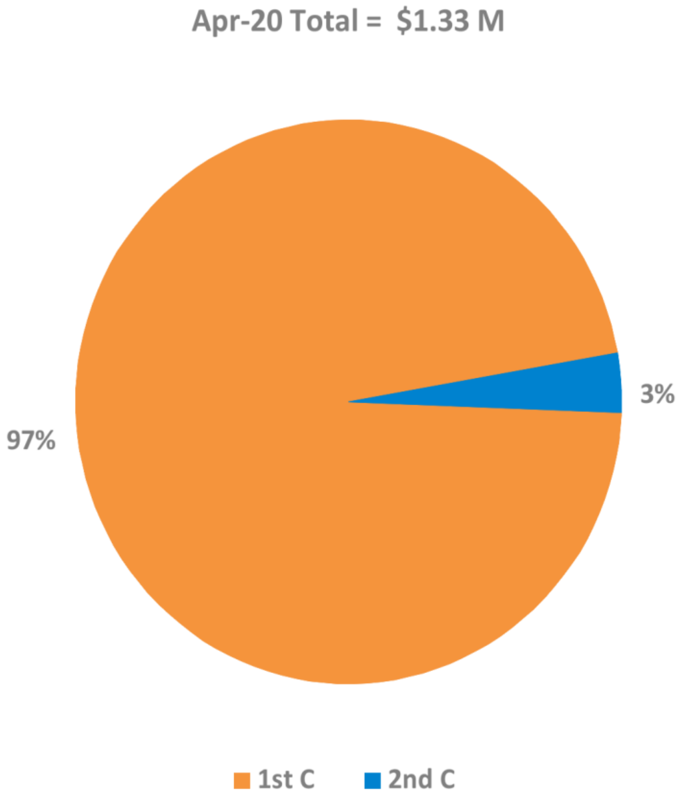


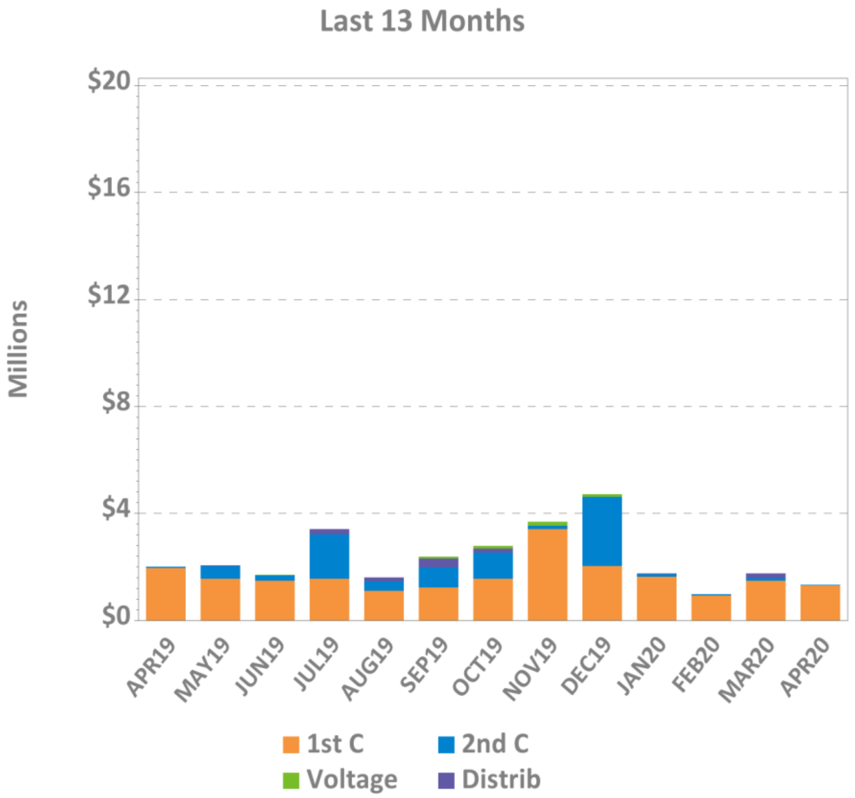
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

DA and RT NCPC Charges



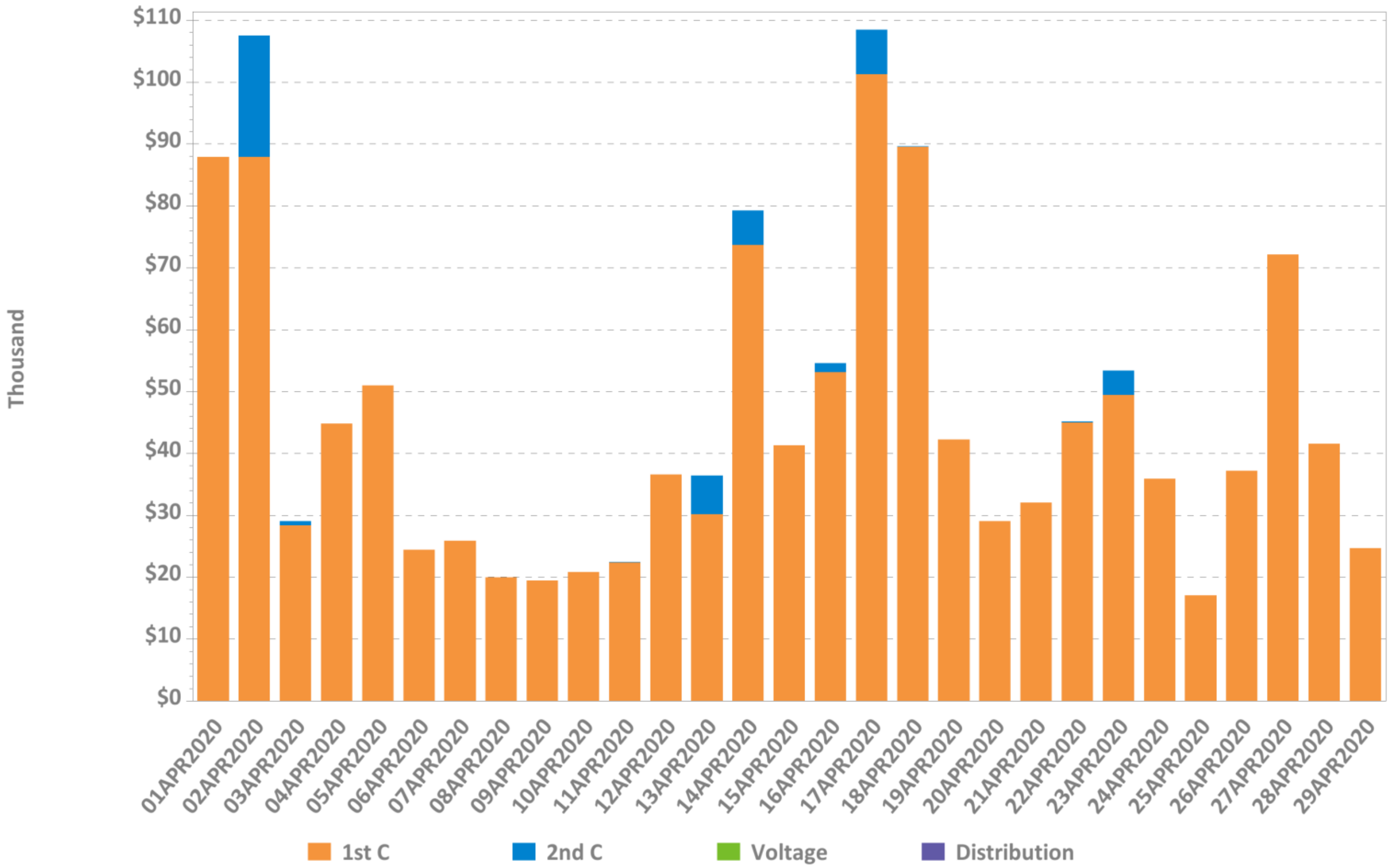
NCPC Charges by Type



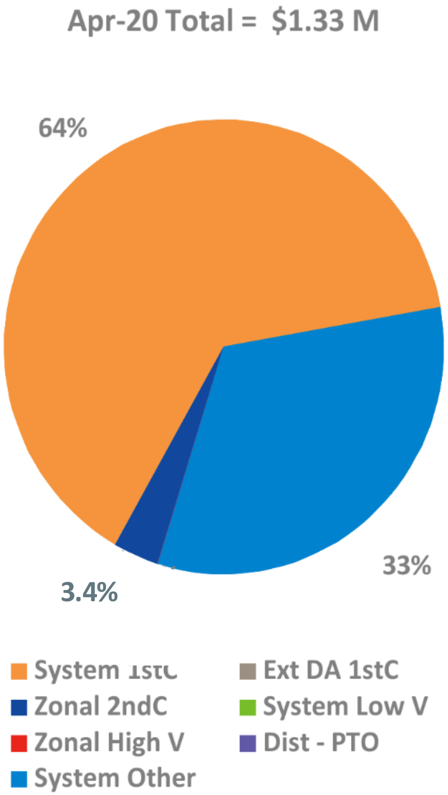


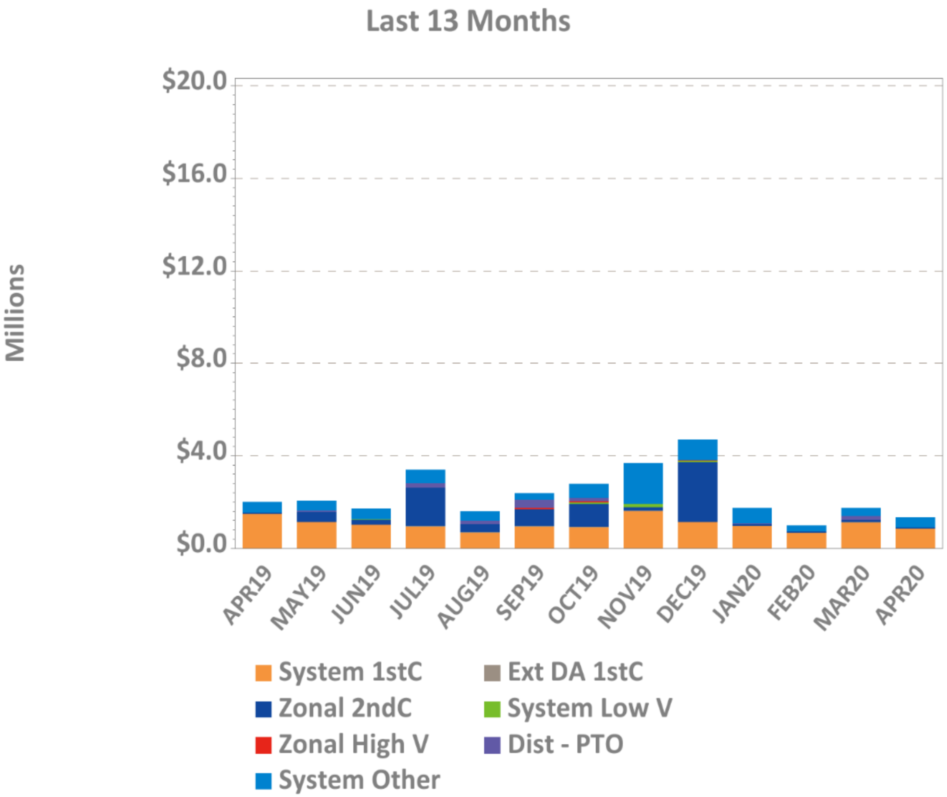
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



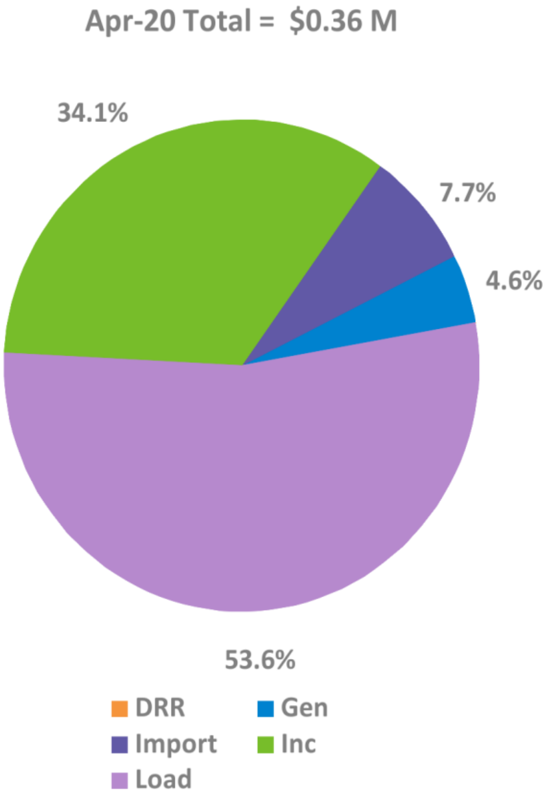
NCPC Charges by Allocation

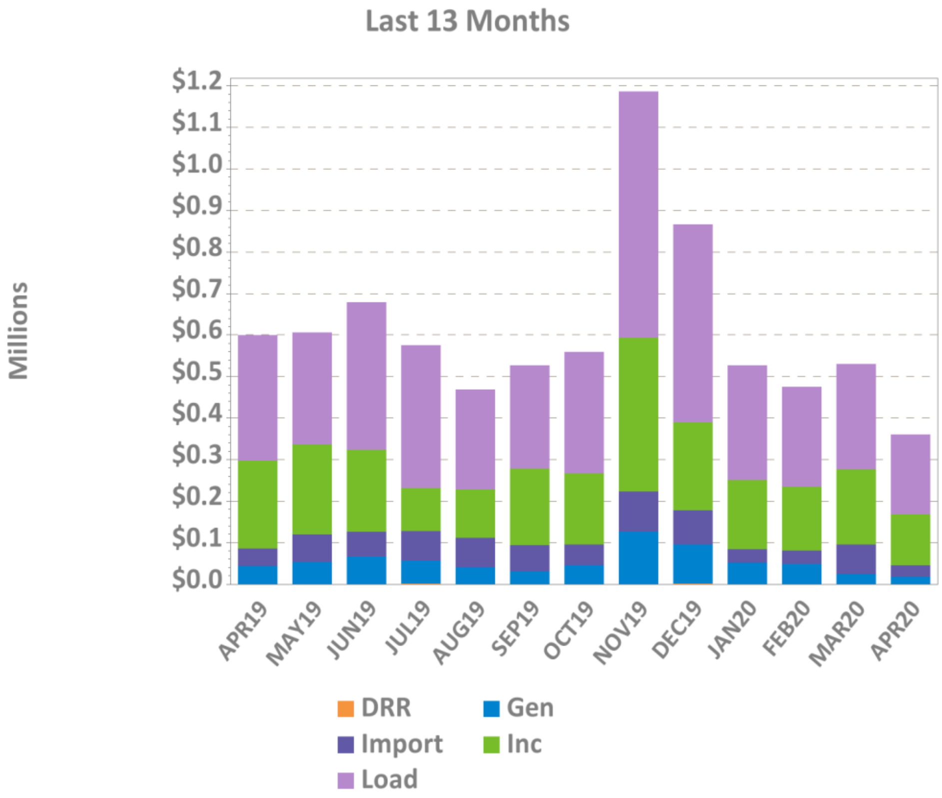




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

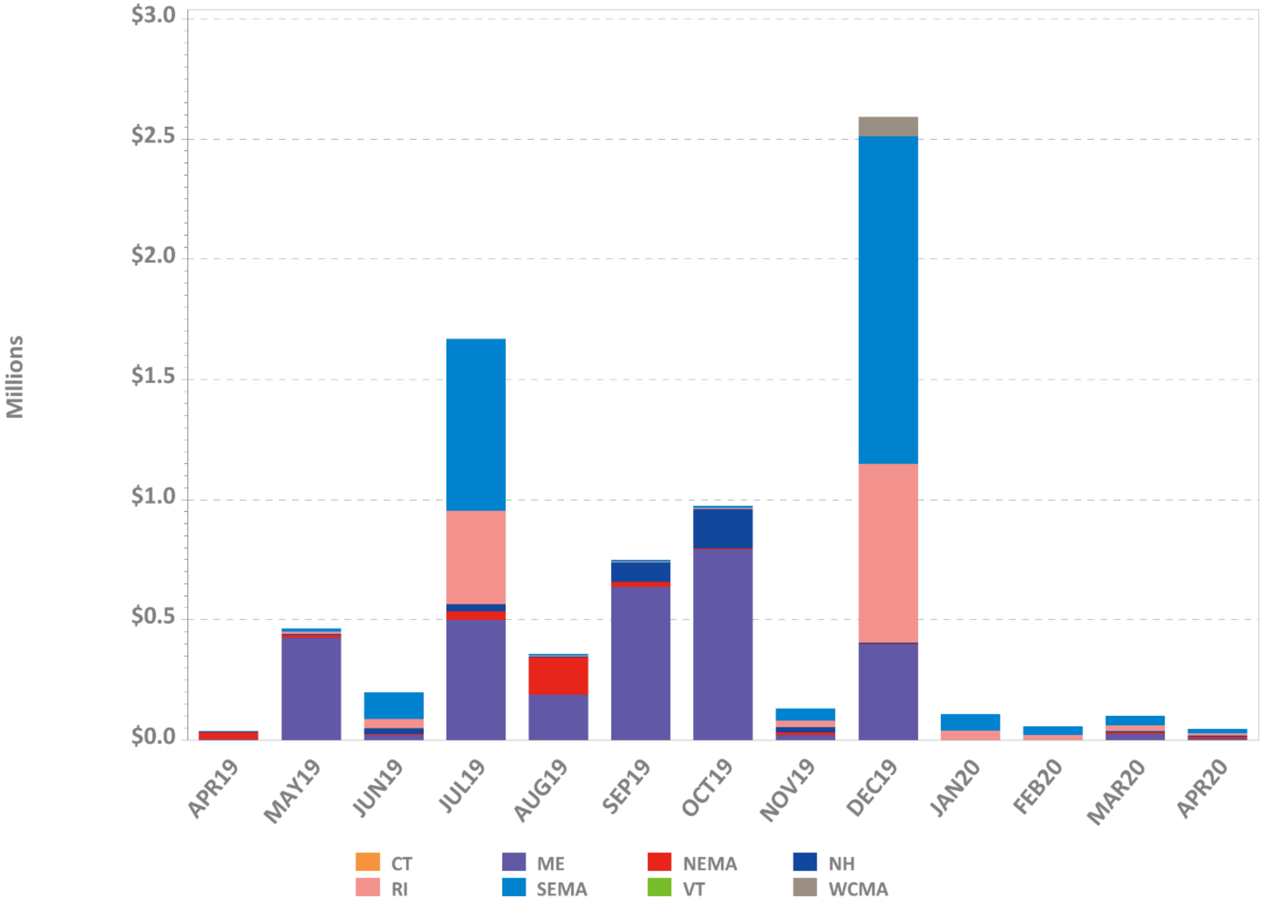
RT First Contingency Charges by Deviation Type





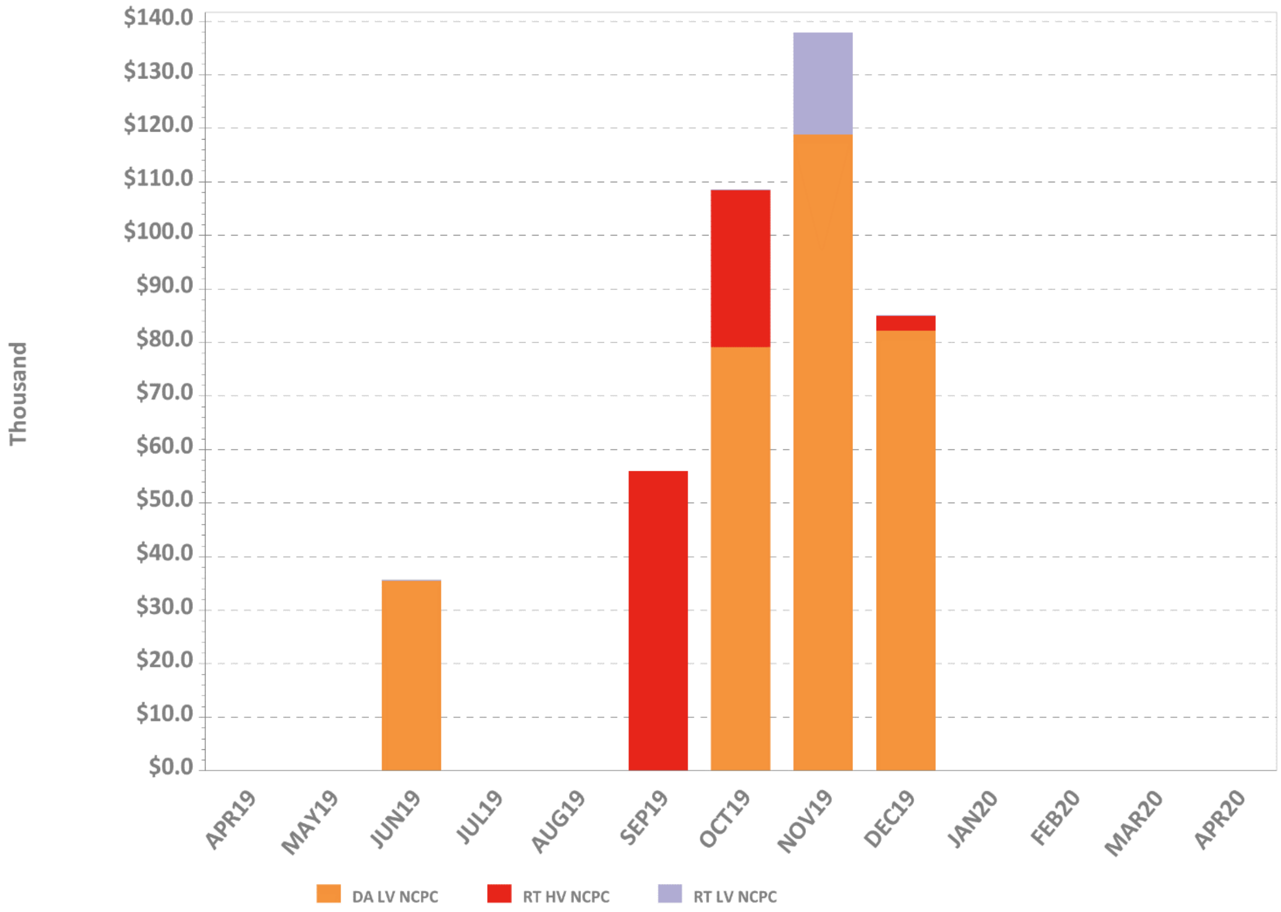
DRR – Demand Response Resource deviations
Gen – Generator deviations
Inc – Increment Offer deviations
Import – Import deviations
Load – Load obligation deviations

LSCPR Charges by Reliability Region

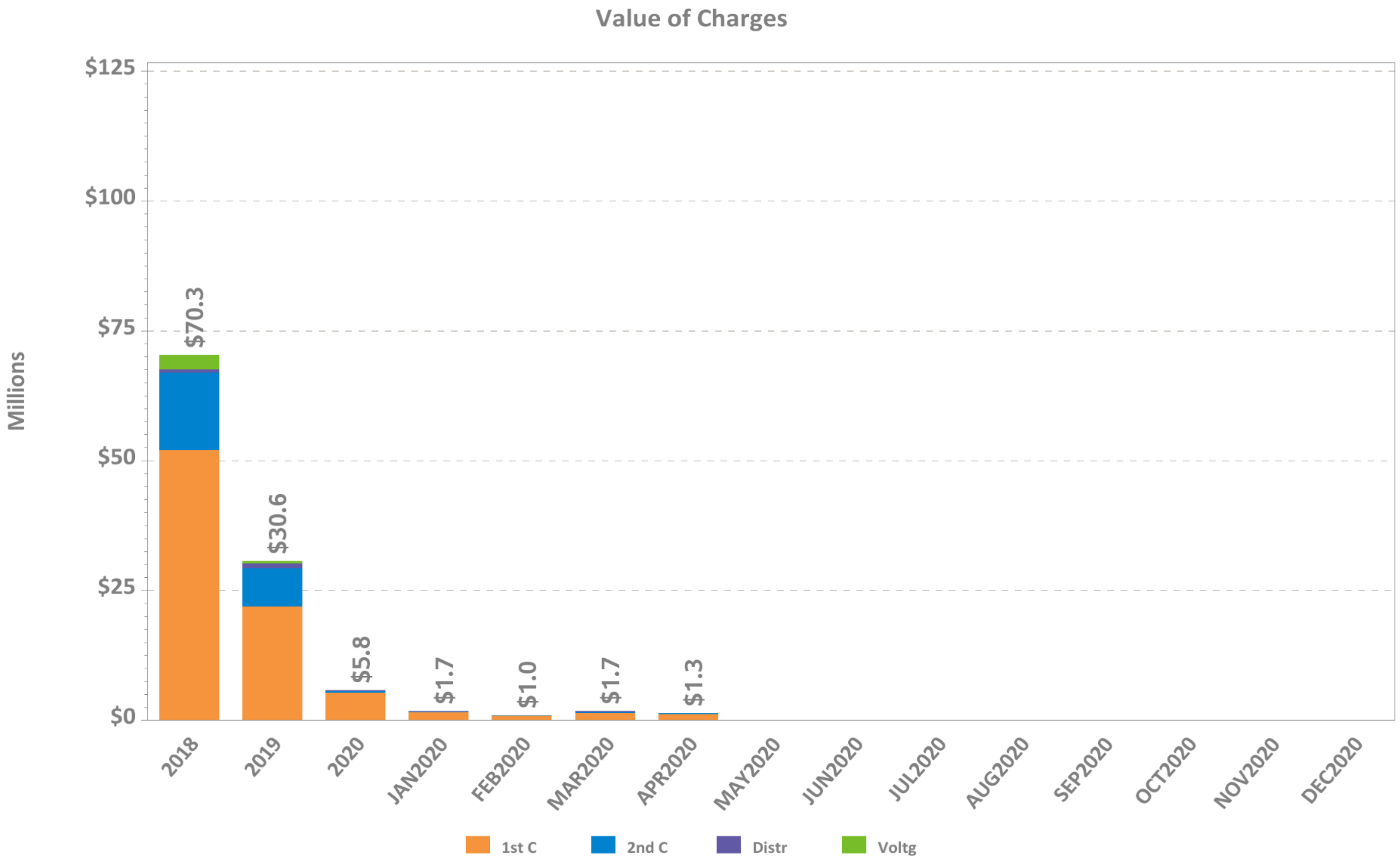


CT – Connecticut Region	SEMA – Southeast Massachusetts Region
ME – Maine Region	WCMA – Western/Central Massachusetts Region
NH – New Hampshire Region	NEMA – Northeast Massachusetts Region
RI – Rhode Island Region	EXT – External Locations
VT – Vermont Region	

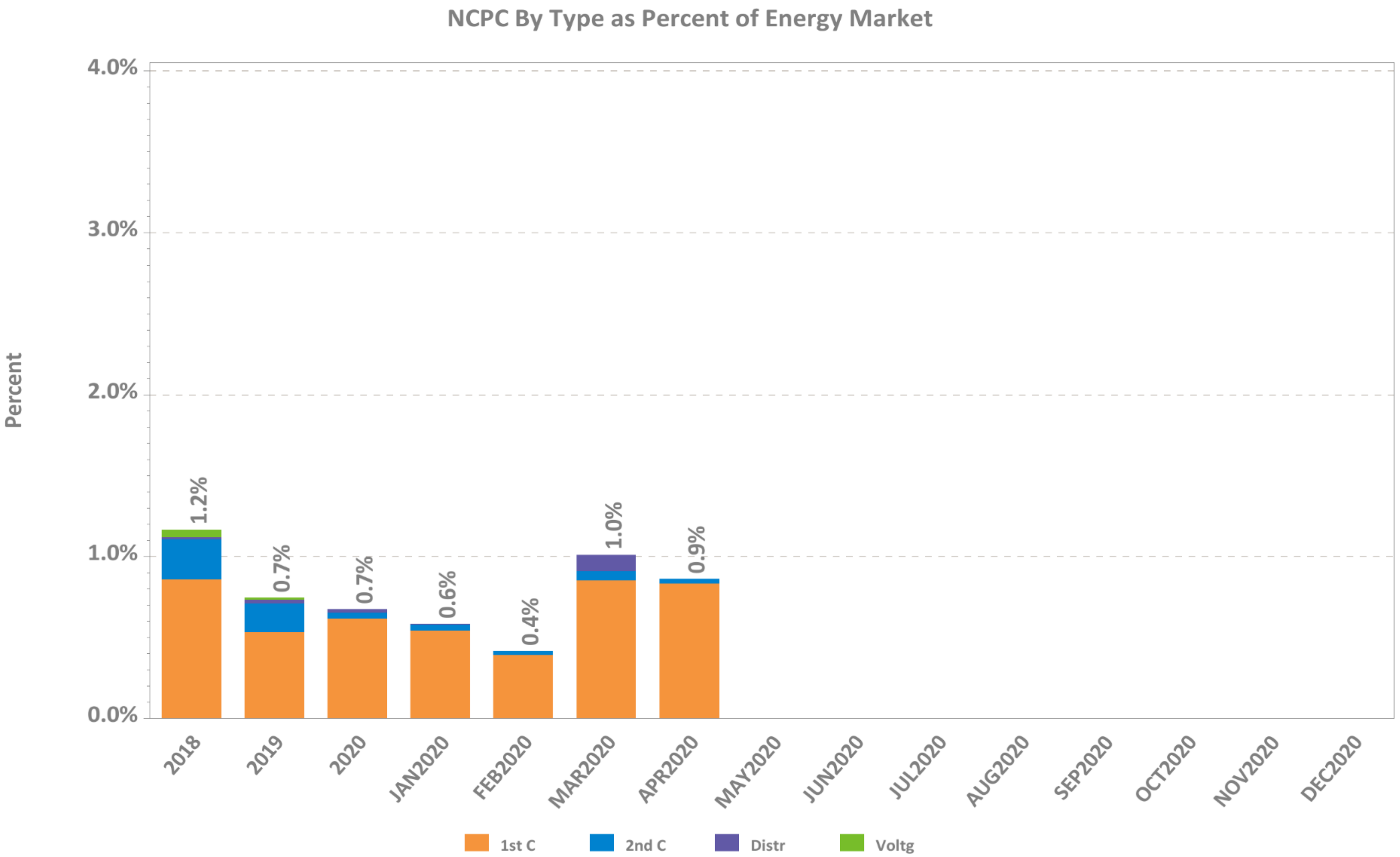
NCPC Charges for Voltage Support and High Voltage Control



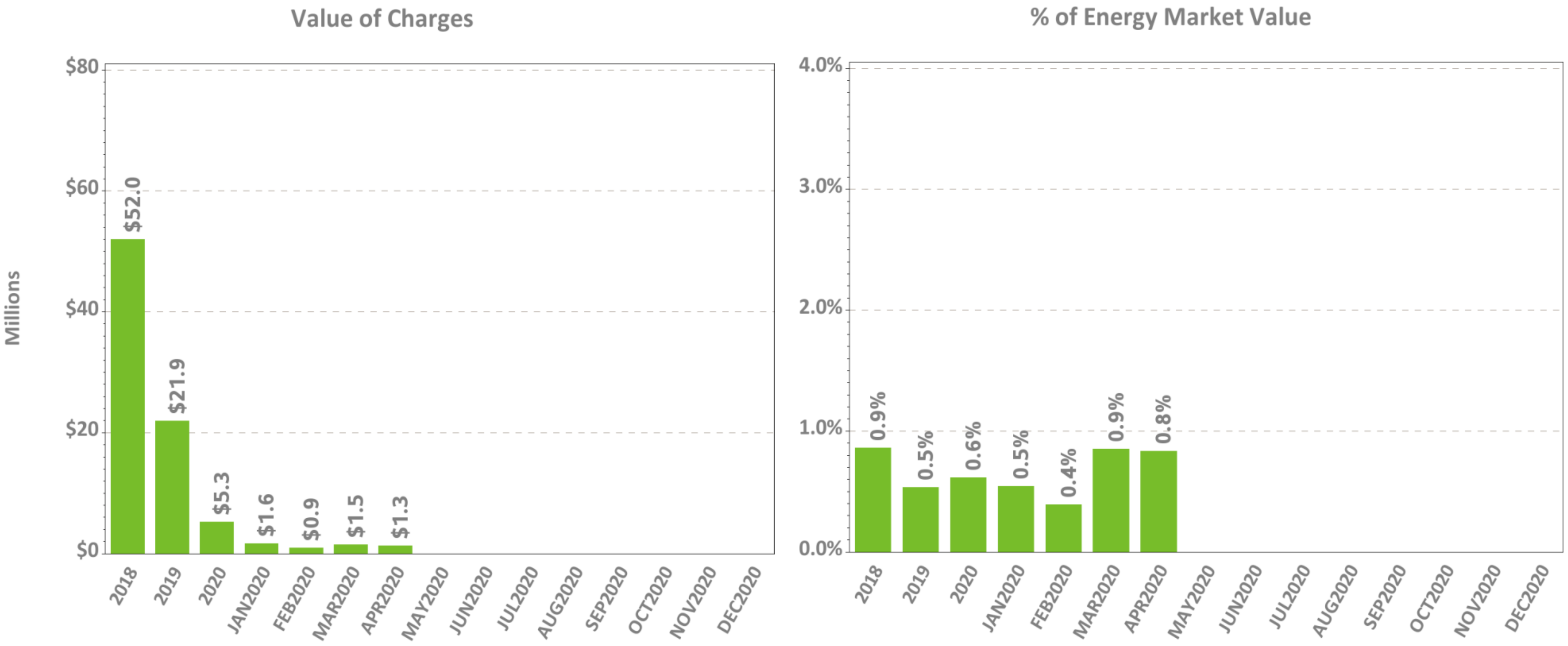
NCPC Charges by Type



NCPC Charges as Percent of Energy Market

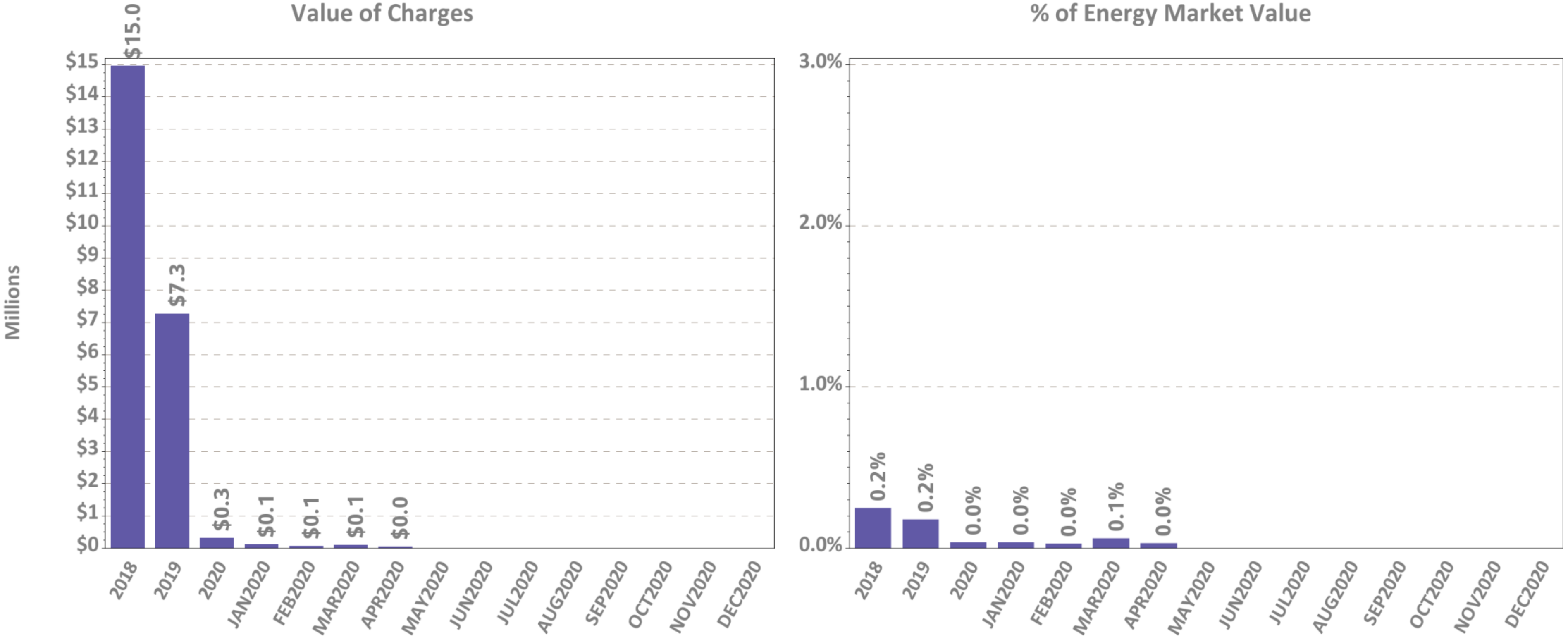


First Contingency NCPC Charges



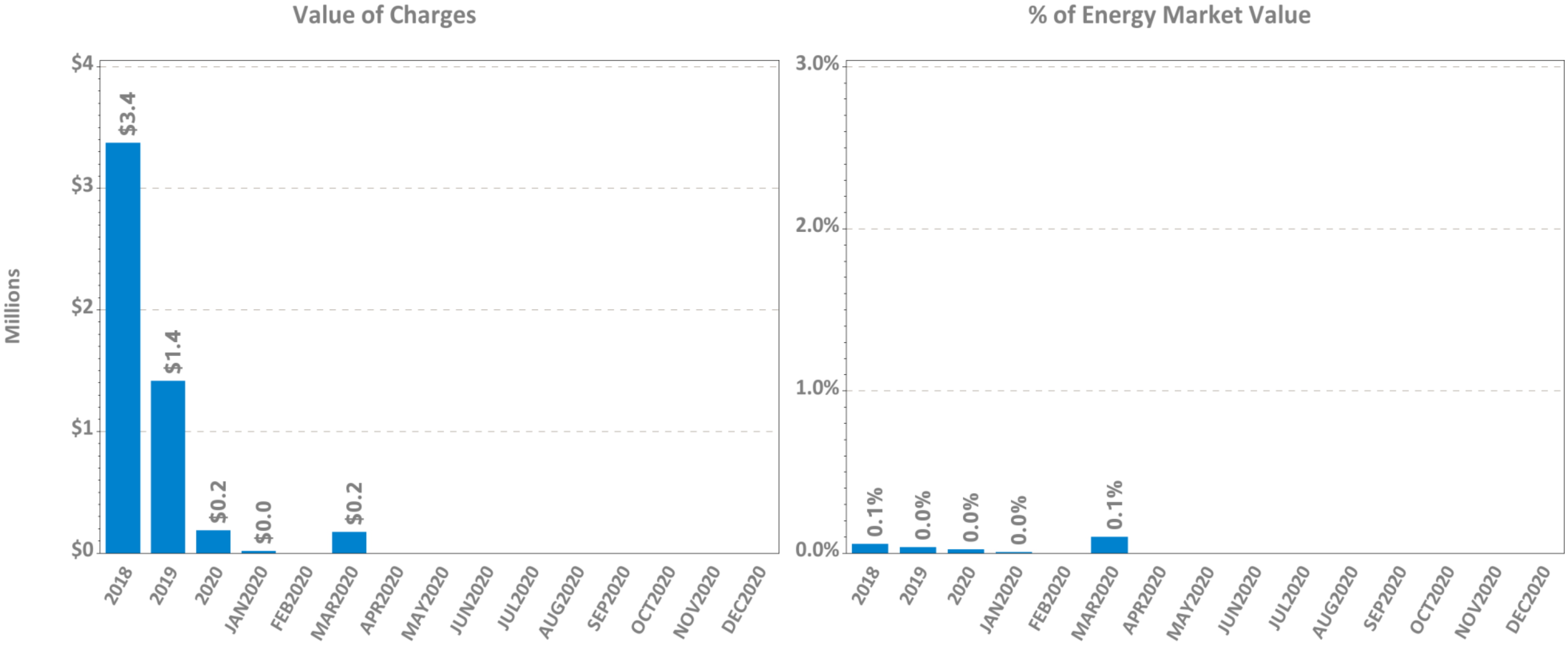
Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

Second Contingency NCPC Charges



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

Voltage and Distribution NCPC Charges



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

DA vs. RT Pricing

The following slides outline:

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

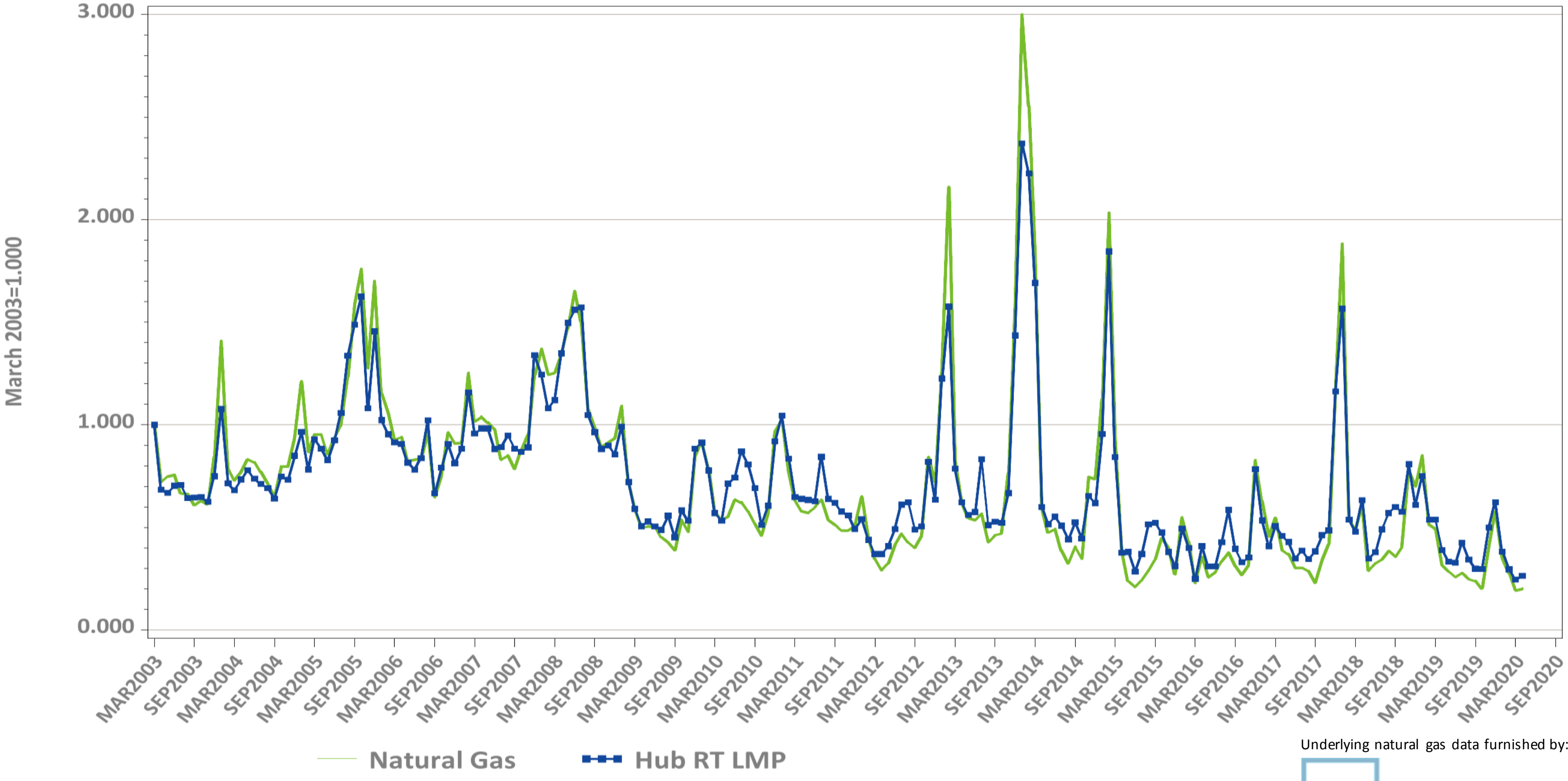
DA vs. RT LMPs ($/MWh)

Arithmetic Average

Year 2018	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$44.45	$43.60	$42.63	$44.04	$43.71	$44.11	$44.62	$44.19	$44.13
Real-Time	$43.87	$43.13	$41.03	$43.17	$42.83	$43.37	$43.68	$43.58	$43.54
RT Delta %	-1.3%	-1.1%	-3.8%	-2.0%	-2.0%	-1.7%	-2.1%	-1.4%	-1.3%
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%

April-19	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$27.03	$26.85	$26.31	$26.76	$26.27	$26.83	$26.97	$27.03	$26.97
Real-Time	$26.92	$26.72	$26.12	$26.64	$26.00	$26.67	$26.79	$26.84	$26.80
RT Delta %	-0.4%	-0.5%	-0.7%	-0.5%	-1.0%	-0.6%	-0.6%	-0.7%	-0.6%
April-20	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$18.69	$17.73	$18.06	$18.47	$17.65	$18.37	$18.68	$18.36	$18.40
Real-Time	$18.39	$17.66	$17.52	$18.12	$17.34	$18.06	$18.35	$18.08	$18.13
RT Delta %	-1.6%	-0.4%	-3.0%	-1.9%	-1.8%	-1.6%	-1.7%	-1.5%	-1.5%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-30.8%	-34.0%	-31.4%	-31.0%	-32.8%	-31.5%	-30.7%	-32.1%	-31.8%
Yr over Yr RT	-31.7%	-33.9%	-32.9%	-32.0%	-33.3%	-32.3%	-31.5%	-32.7%	-32.3%

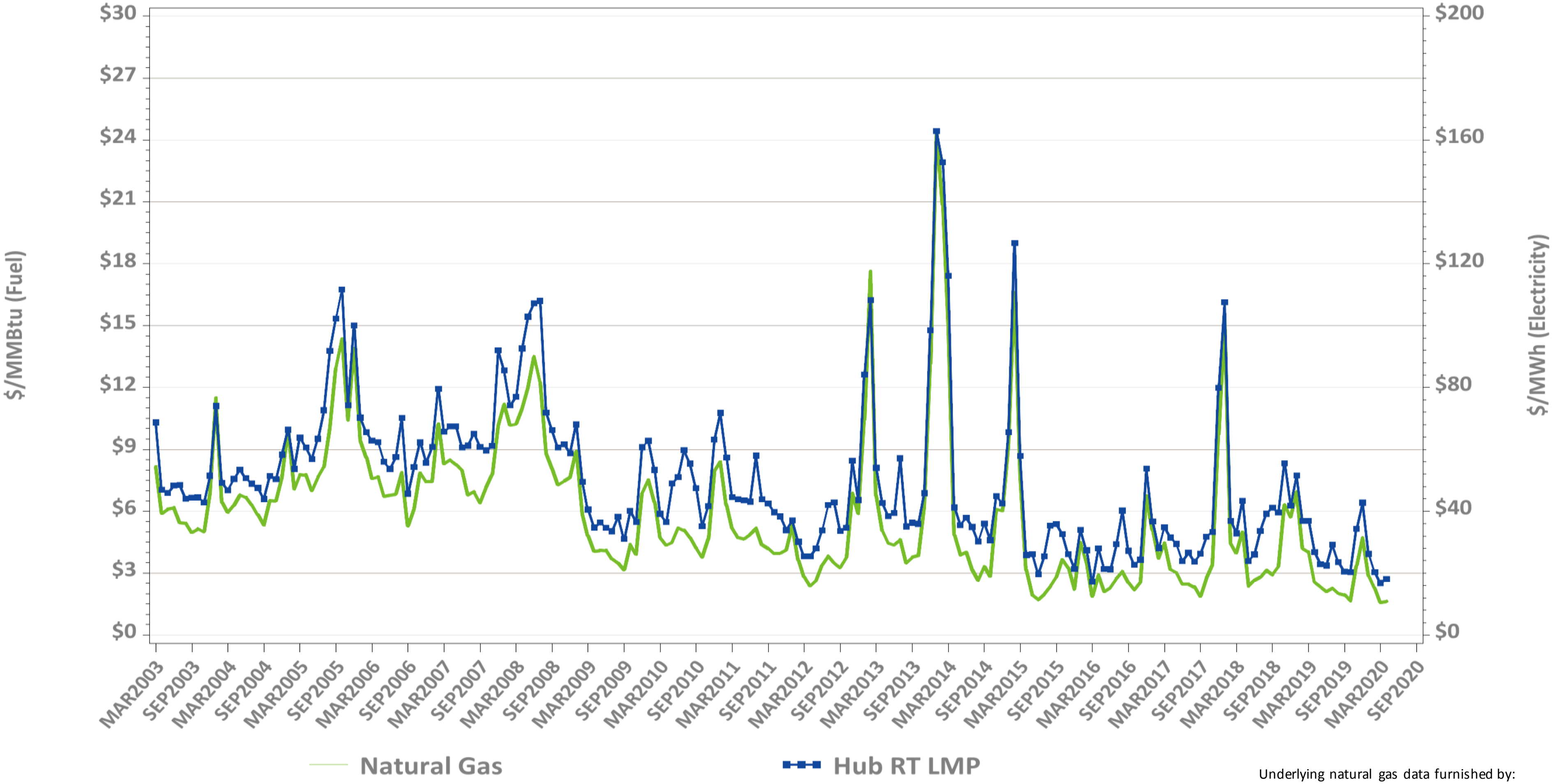
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ice Global markets in clear view

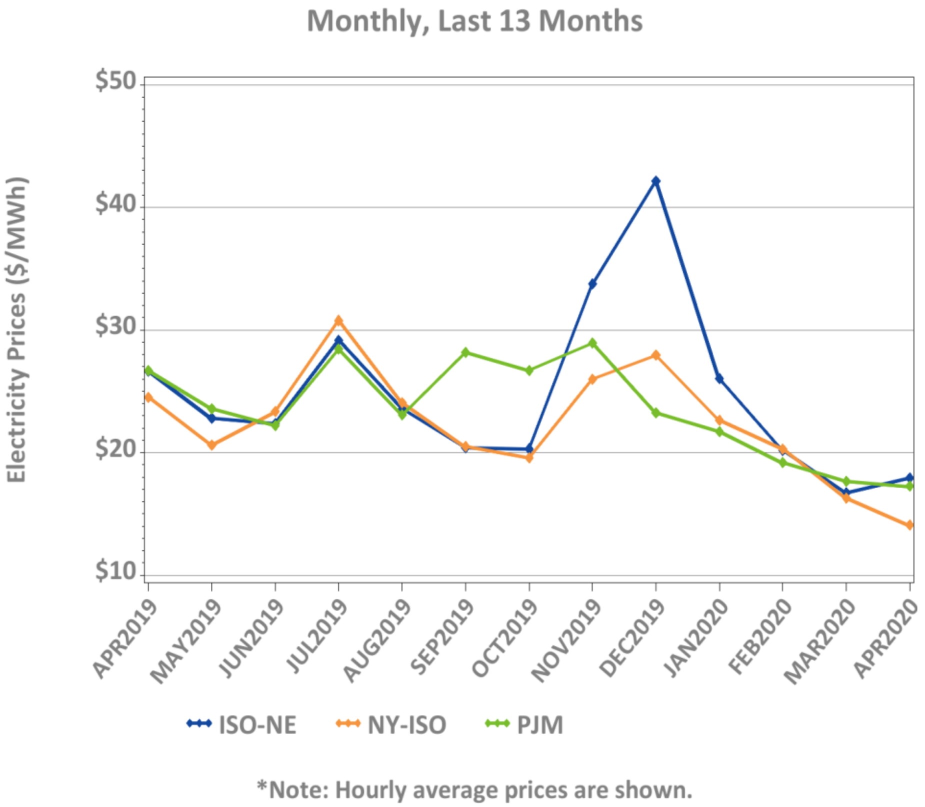
Monthly Average Fuel Price and RT Hub LMP



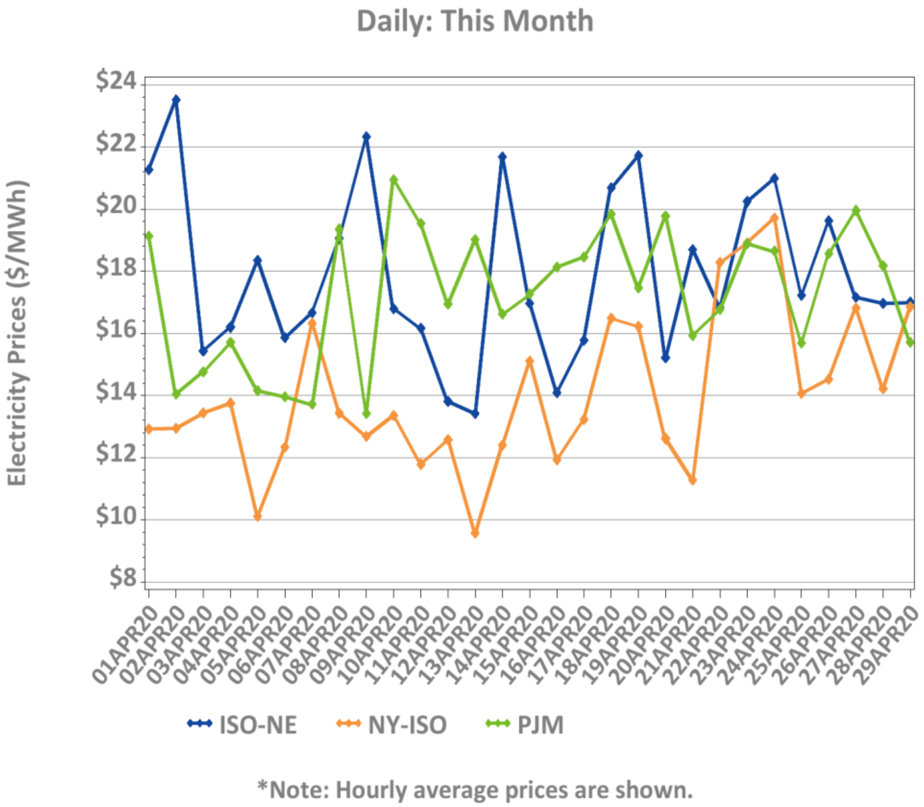
Underlying natural gas data furnished by:

ICE Global markets in clear view

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

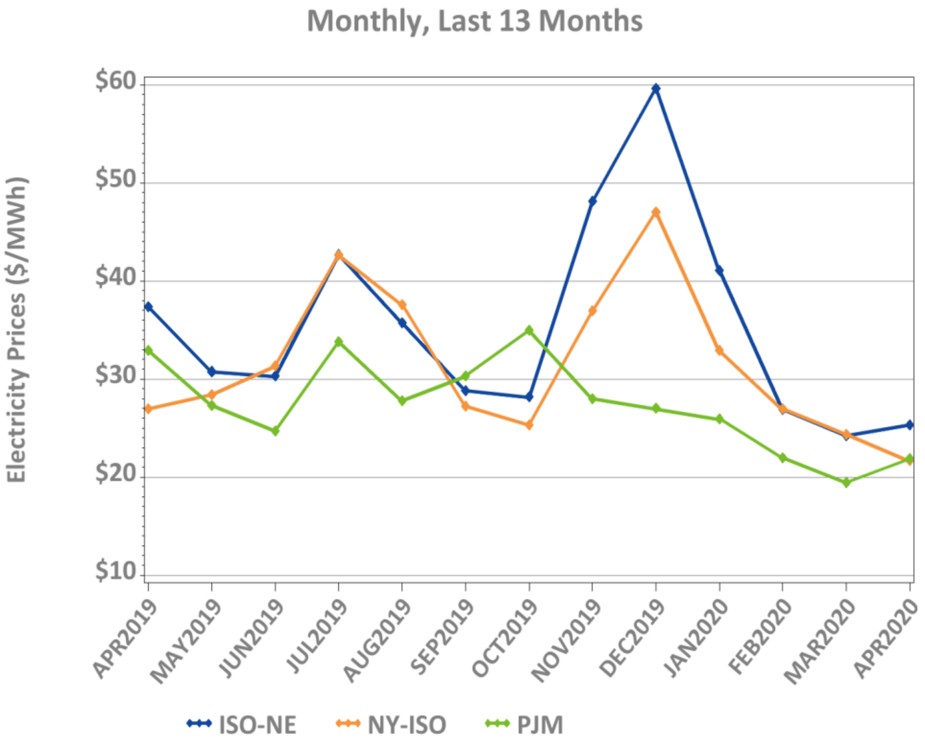


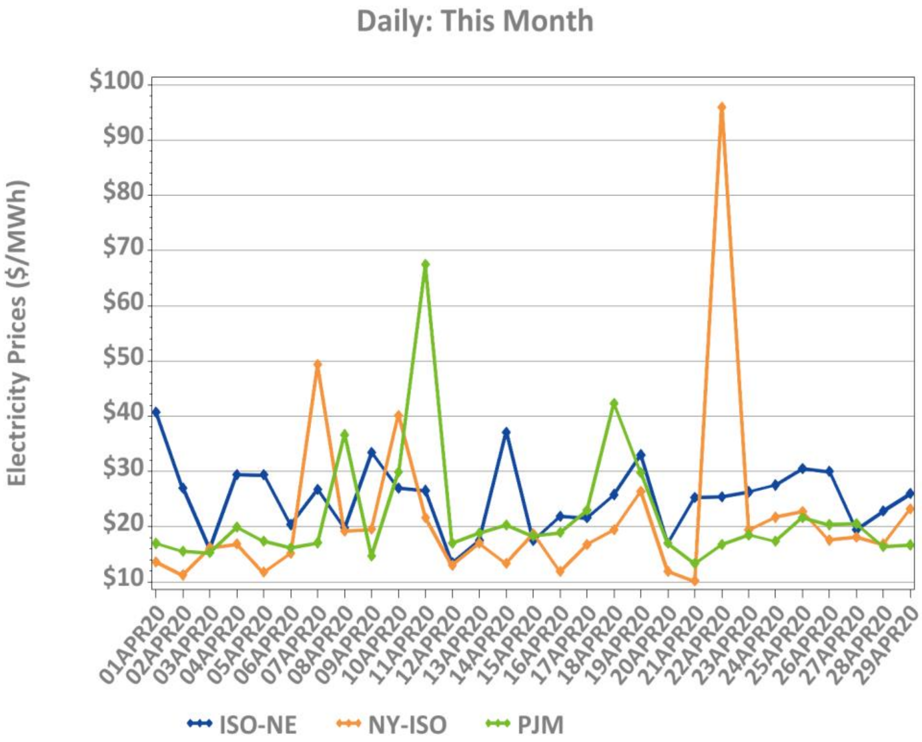
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





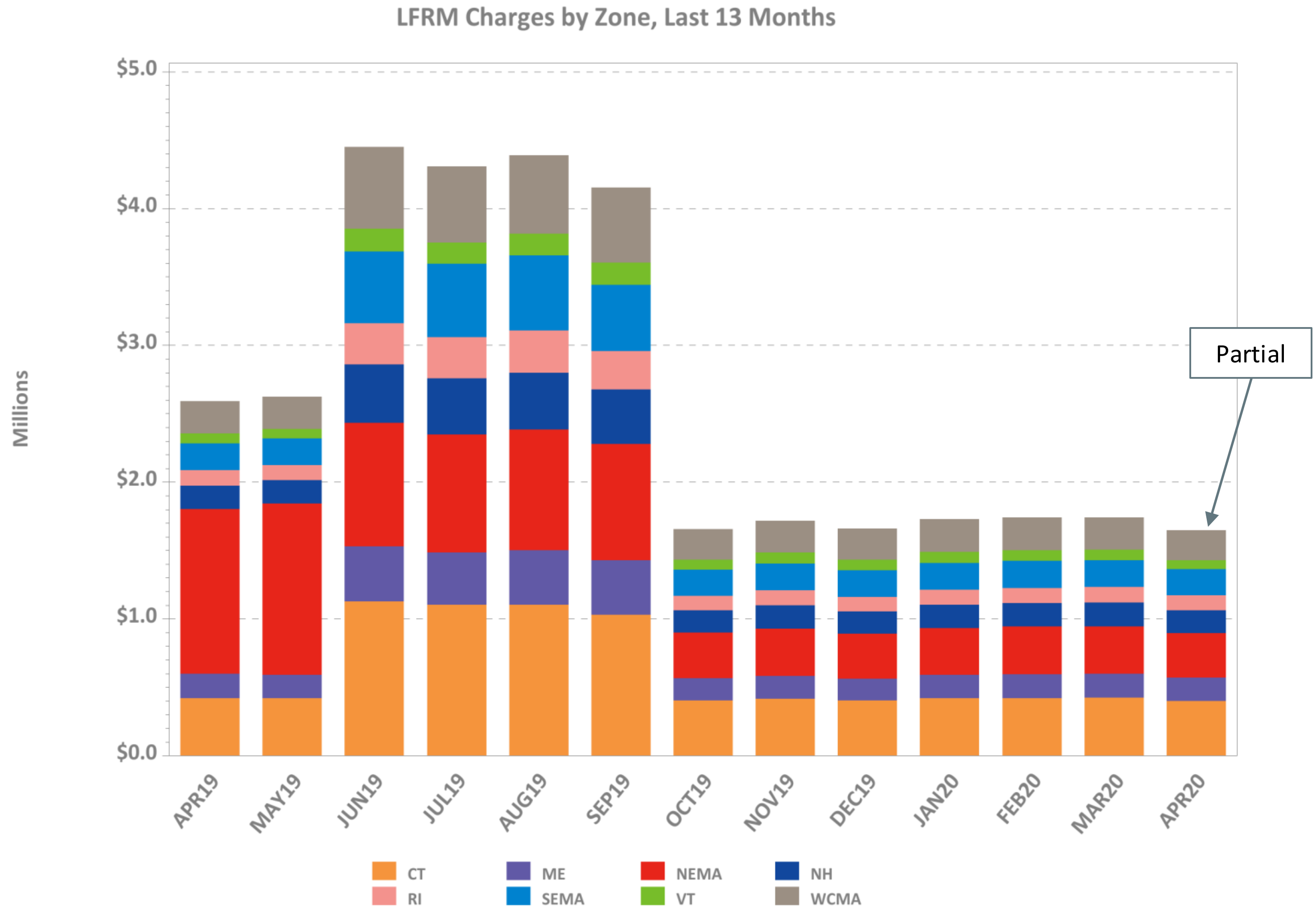
***Forecasted New England daily peak hours reflected**

Reserve Market Results – April 2020

- Maximum potential Forward Reserve Market payments of \$1.7M were reduced by credit reductions of \$8K, failure-to-reserve penalties of \$12K and no failure-to-activate penalties, resulting in a net payout of \$1.6M or 99% of maximum
  - Rest of System: \$1.25M/1.27M (99%)
  - Southwest Connecticut: \$0.05M/0.05M (100%)
  - Connecticut: \$0.34M/0.35M (99%)
- \$286K total Real-Time credits were not reduced by any Forward Reserve Energy Obligation Charges for a net of \$286K in Real-Time Reserve payments
  - Rest of System: 240 hours, \$197K
  - Southwest Connecticut: 240 hours, \$61K
  - Connecticut: 240 hours, \$20K
  - NEMA: 240 hours, \$9K

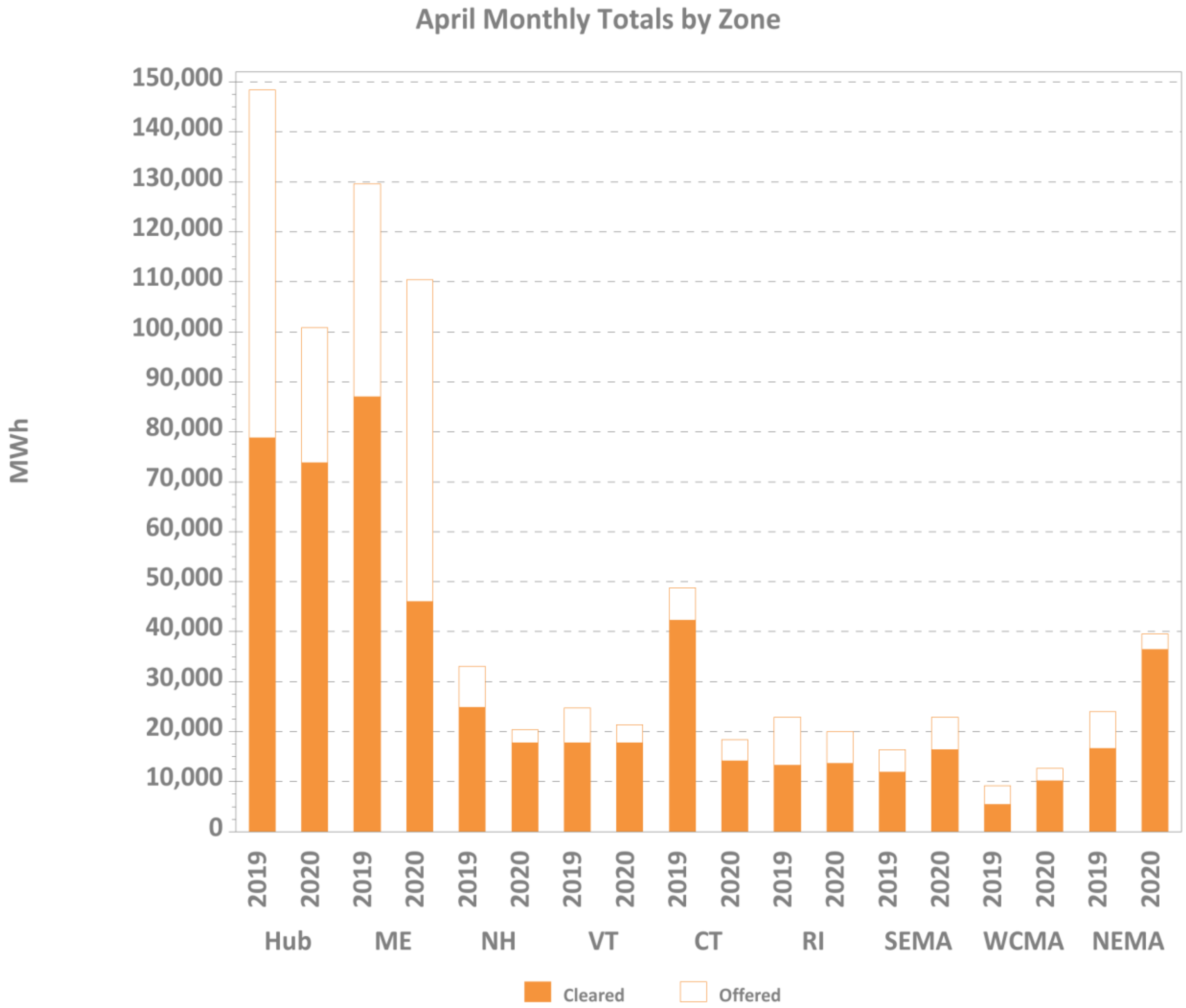
Note: "Failure to reserve" results in both credit reductions and penalties in the Locational Forward Reserve Market. While this summary reports performance by location, there were no locational requirements in effect for the current Forward Reserve auction period.

LFRM Charges to Load by Load Zone ($)

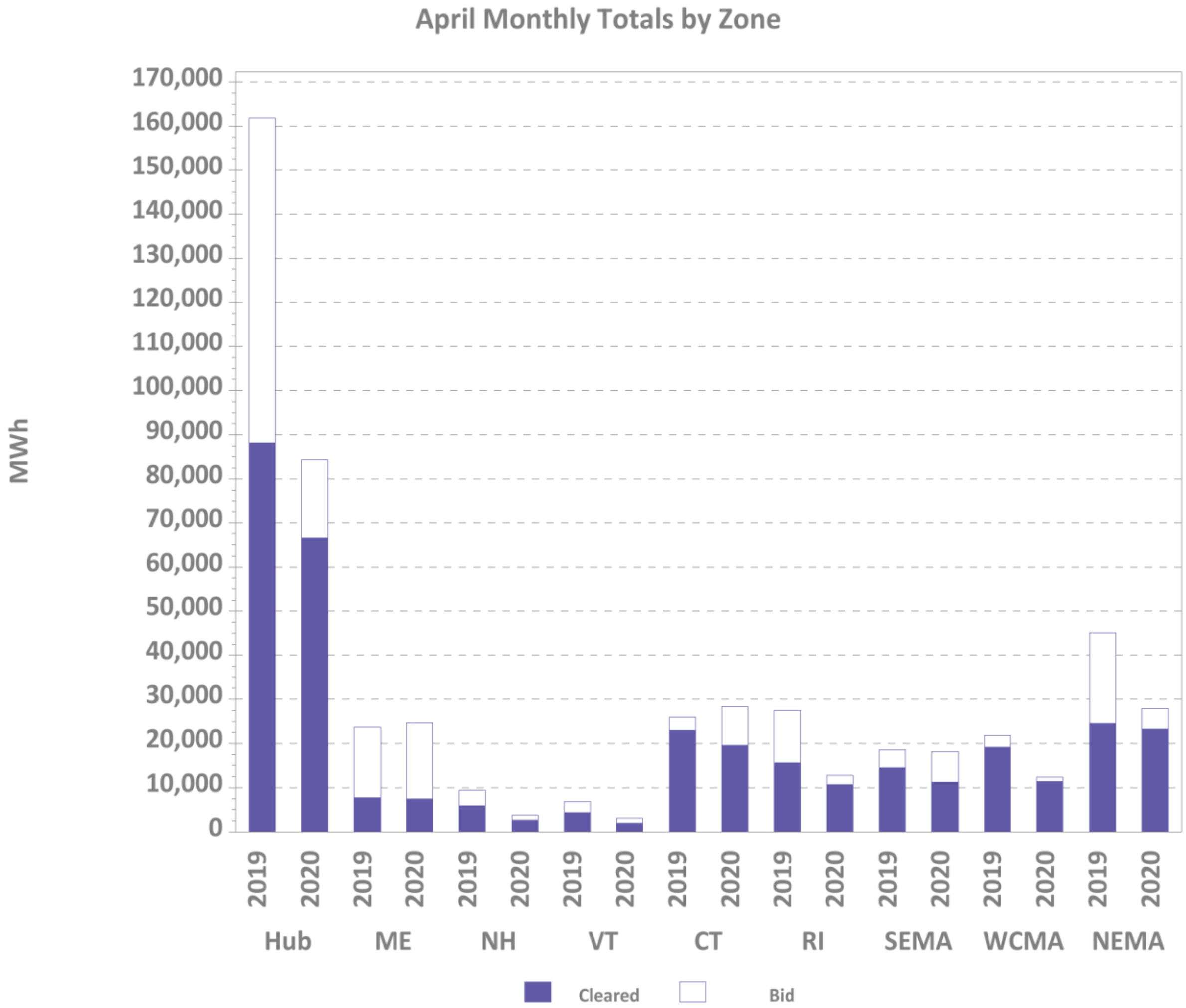


Partial

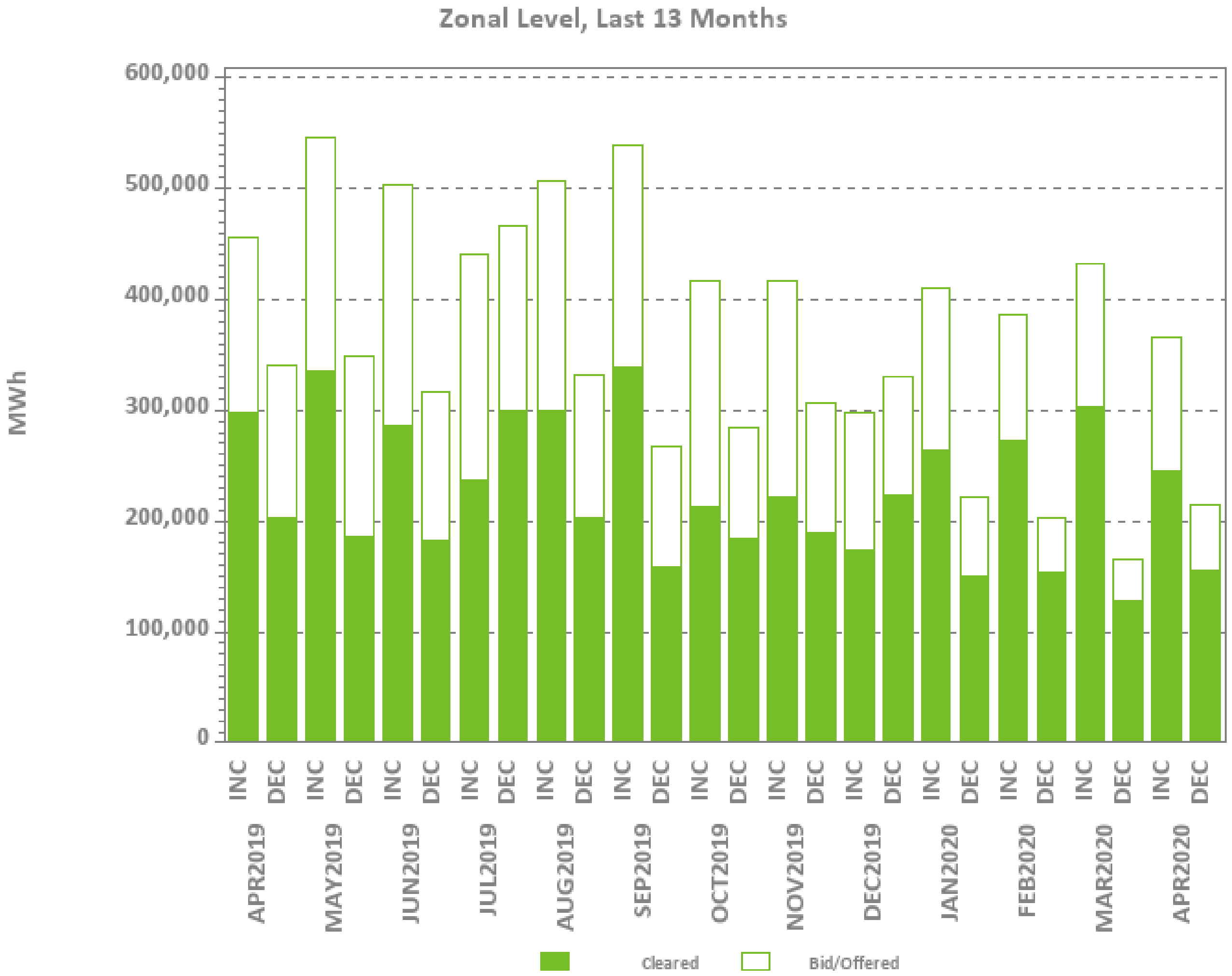
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

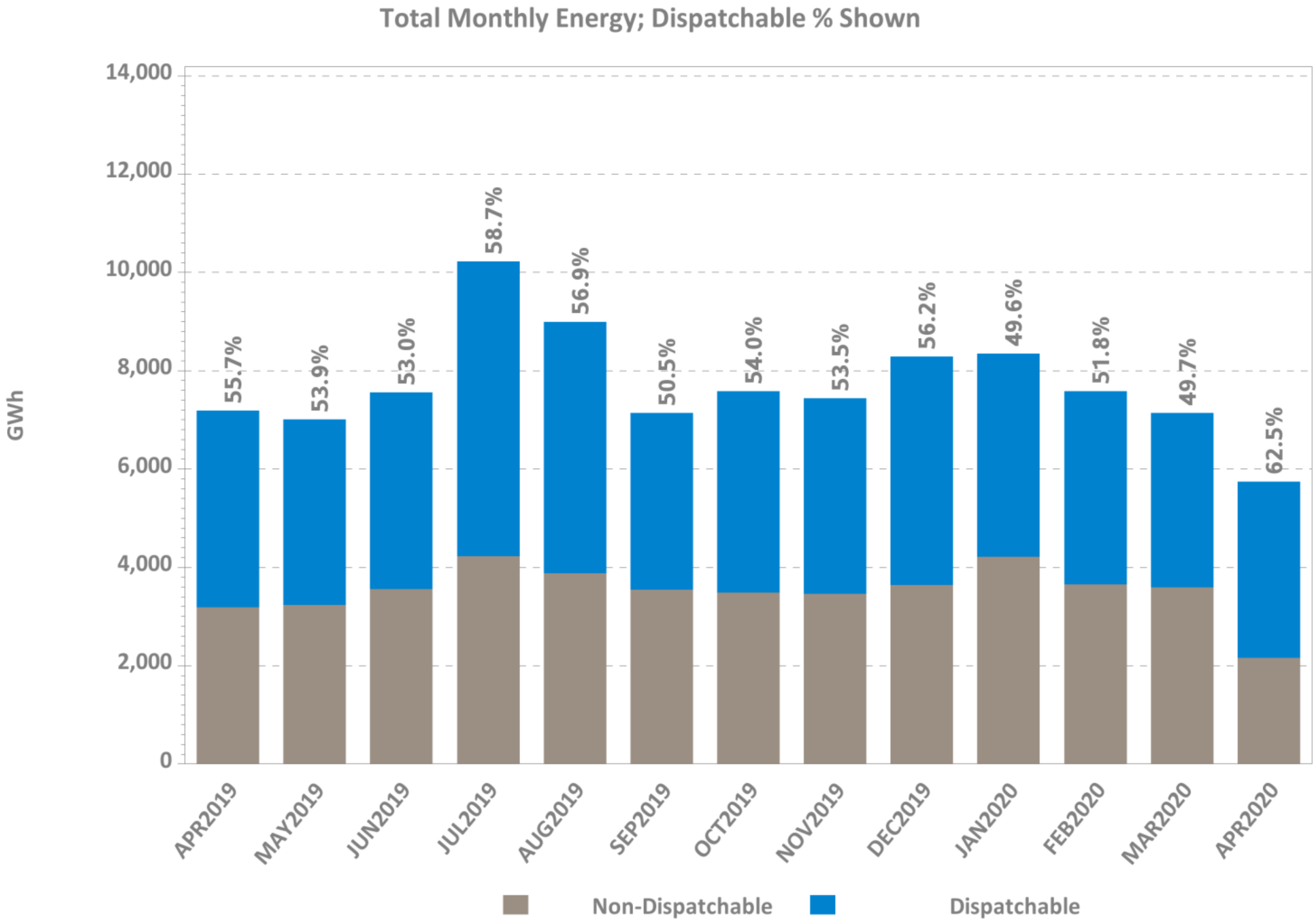


Total Increment Offers and Decrement Bids



Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



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

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- May 20 PAC Meeting Agenda Topics*
  - Interregional Planning/EIPC Update
  - ECT 2029 Preliminary Preferred Solution
  - National Grid Short Circuit Pre-fault Voltage Update
  - 2019 Economic Studies - NESCOE Ancillary Services
  - 2019 Economic Studies - Anbaric Follow-up from the March PAC
  - 2020 Economic Study - Draft Scope of Work and High-Level Assumptions

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

Interregional Planning

- Final 2019 Northeast Coordinated System Plan (NCSP) will be posted the week of May 4
- The next Inter-Area Planning Stakeholder Advisory Committee (IPSAC) meeting is scheduled for May 15 from 9:00am – 12:00pm and will include discussions of:
  - Regional Planning Needs and Solutions for PJM, ISO-NE, and NYISO
  - Interconnection Coordination - Interconnection Queue and Long-Term Firm Transmission Requests for NYISO, ISO-NE, and PJM
  - Review of Final NCSP19
  - Stakeholder Input and Outline Next Steps

Economic Studies

- NESCOE study results (up to 8,000 MW of offshore wind additions) were presented at the December and February PAC meetings. Preliminary results of the transmission interconnect analysis were presented to PAC in March and April. Additional results related to transmission interconnection costs and ancillary services to be presented in May, and report to be finalized by July 1.
- Anbaric study results (8,000 MW to 12,000 MW of offshore wind additions) were presented at the March PAC meeting. Supplemental study results to be presented in May, and report to be completed in July.
- RENEW study results were presented to PAC in April, and report to be completed in July.
- NGRID submitted a 2020 economic study request, and study assumption details and approach will be discussed at the May PAC meeting.

2018 Generator Emissions Report

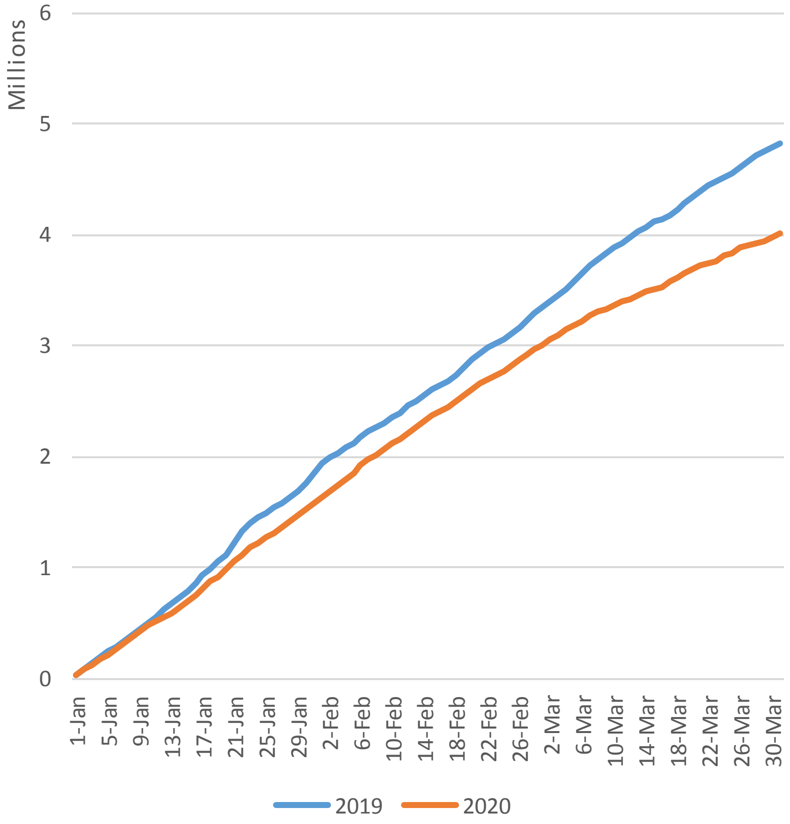
- The Annual Electric Generator Air Emissions Report (Marginal Emission Analysis (MEA)) has been posted for stakeholder review
  - Final report to be issued in mid-May, including results for the load-weighted and non-load-weighted marginal resource analyses
- At the April EAG meeting, stakeholders discussed obstacles to reporting emissions from imports, and what actions could be taken to overcome the lack of publically available information
  - Comments on the options presented by the ISO will be addressed at the next EAG meeting

Environmental Matters – Air Emissions from Native Generation (1/1 - 3/31)

Air Emissions Lower, Reflect Mix of Milder Weather, COVID-19

- EPA 1st Qtr. emissions data shows 2020 CO_2 emissions fell 16.2% compared to same period in 2019:
  - Native generation declined -5% in 1st Qtr. 2020 (23,579 GWh) compared to 1st Qtr. 2019 (24,891 GWh)
  - Natural gas generation increased 3%; coal (-79%) and oil (-31%) declined
  - Net imports declined -6%
- EPA issued various guidances responding to COVID-19 pandemic, temporarily waiving compliance and reporting requirements for regulated entities, including power plants, for air emissions and water discharges, but:
  - Limited in scope, conditional, discretionary for EPA, not binding on states, tribes, or localities, and temporary

Cumulative Carbon Dioxide (CO_2) Emissions (Million Metric Tons)

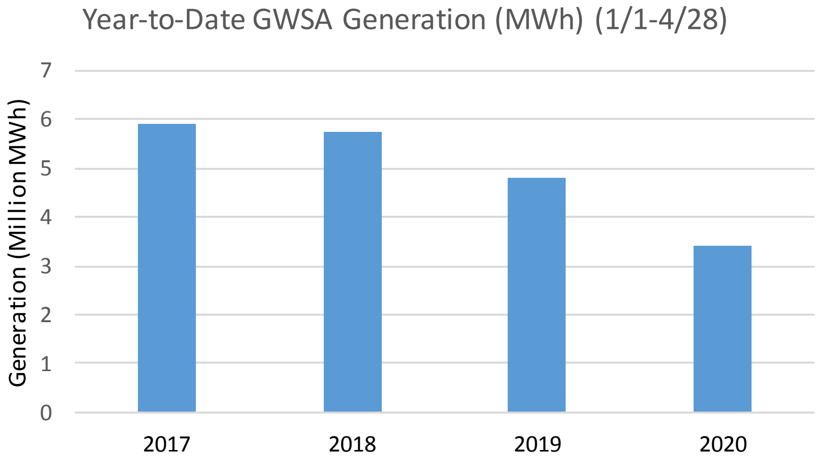


Environmental Matters – Massachusetts CO_2 Generator Emissions Cap

2020 YTD Emissions Declined 24%, Generation Declined 29% vs. 2019

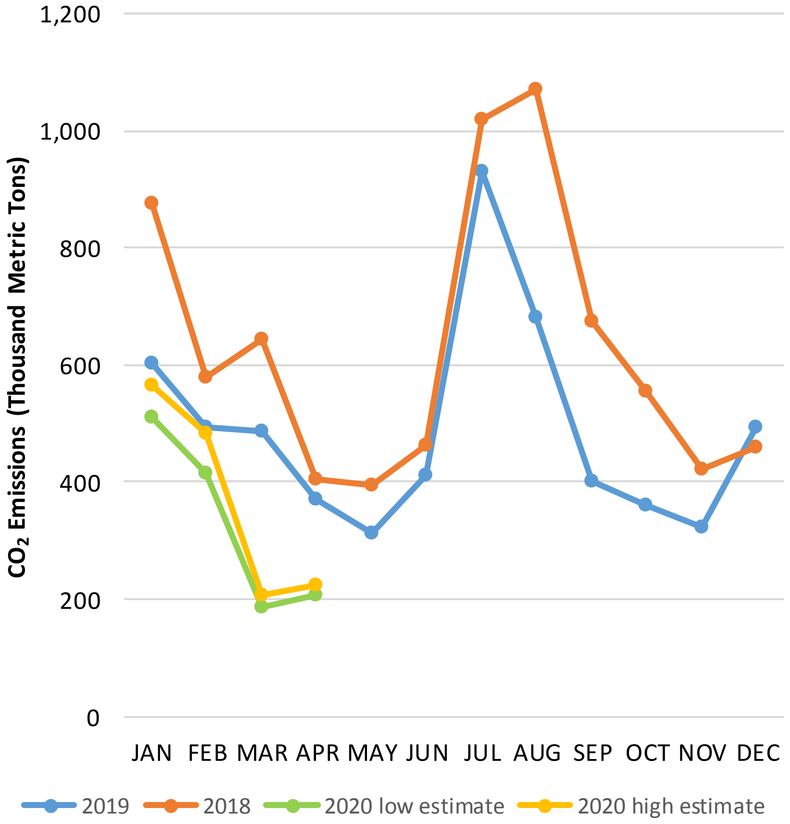
2020 CO_2 Estimated Emissions Below 2019 Trend line

- Year-to-date generation from affected generators declined 29%, while estimated emissions declined 24% compared to same period in 2019



GWSA - Global Warming Solutions Act

2020 Estimated, Past Monthly Emissions (Thousand Metric tons)



RSP Project Stage Descriptions

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

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

New Hampshire/Vermont 10-Year Upgrades

Status as of 4/24/20

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected/ Actual In-Service	Present Stage
Eagle Substation Add: 345/115 kV autotransformer	Dec-16	4
Littleton Substation Add: Second 230/115 kV autotransformer	Oct-14	4
New C-203 230 kV line tap to Littleton NH Substation	Nov-14	4
New 115 kV overhead line, Fitzwilliam-Monadnock	Feb-17	4
New 115 kV overhead line, Scobie Pond-Huse Road	Dec-15	4
New 115 kV overhead/submarine line, Madbury-Portsmouth	May-20	3
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	4

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 4/24/20

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected/ Actual In-Service	Present Stage
Saco Valley Substation - Add two 25 MVAR dynamic reactive devices	Aug-16	4
Rebuild 115 kV line K165, W157 tap Eagle-Power Street	May-15	4
Rebuild 115 kV line H137, Merrimack-Garvins	Jun-13	4
Rebuild 115 kV line D118, Deerfield-Pine Hill	Nov-14	4
Oak Hill Substation - Loop in 115 kV line V182, Garvins-Webster	Dec-14	4
Uprate 115 kV line G146, Garvins-Deerfield	Mar-15	4
Uprate 115 kV line P145, Oak Hill-Merrimack	May-14	4

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 4/24/20

Project Benefit: Addresses Needs in New Hampshire and Vermont

Upgrade	Expected/ Actual In-Service	Present Stage
Upgrade 115 kV line H141, Chester-Great Bay	Nov-14	4
Upgrade 115 kV line R193, Scobie Pond-Kingston Tap	Dec-14	4
Upgrade 115 kV line T198, Keene-Monadnock	Nov-13	4
Upgrade 345 kV line 326, Scobie Pond-NH/MA Border	Dec-13	4
Upgrade 115 kV line J114-2, Greggs - Rimmon	Dec-13	4
Upgrade 345 kV line 381, between MA/NH border and NH/VT border	Jun-13	4

Greater Hartford and Central Connecticut (GHCC) Projects*

Status as of 4/24/20

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected/ Actual In-Service	Present Stage
Add a 2nd 345/115 kV autotransformer at Haddam substation and reconfigure the 3-terminal 345 kV 348 line into two 2-terminal lines	Apr-17	4
Terminal equipment upgrades on the 345 kV line between Haddam Neck and Beseck (362)	Feb-17	4
Redesign the Green Hill 115 kV substation from a straight bus to a ring bus and add two 115 kV 25.2 MVAR capacitor banks	Jun-18	4
Add a 37.8 MVAR capacitor bank at the Hopewell 115 kV substation	Dec-15	4
Separation of 115 kV double circuit towers corresponding to the Branford – Branford RR line (1537) and the Branford to North Haven (1655) line and adding a 115 kV breaker at Branford 115 kV substation	Mar-17	4
Increase the size of the existing 115 kV capacitor bank at Branford Substation from 37.8 to 50.4 MVAR	Jan-17	4
Separation of 115 kV double circuit towers corresponding to the Middletown – Pratt and Whitney line (1572) and the Middletown to Haddam (1620) line	Dec-16	4

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 4/24/20

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected/ Actual In-Service	Present Stage
Terminal equipment upgrades on the 115 kV line from Middletown to Dooley (1050)	Jun-15	4
Terminal equipment upgrades on the 115 kV line from Middletown to Portland (1443)	Jun-15	4
Add a 3.7 mile 115 kV hybrid overhead/underground line from Newington to Southwest Hartford and associated terminal equipment including a 1.4% series reactor	Nov-20	3
Add a 115 kV 25.2 MVAR capacitor at Westside 115 kV substation	Jun-18	4
Loop the 1779 line between South Meadow and Bloomfield into the Rood Avenue substation and reconfigure the Rood Avenue substation	May-17	4
Reconfigure the Berlin 115 kV substation including two new 115 kV breakers and the relocation of a capacitor bank	Nov-17	4
Reconductor the 115 kV line between Newington and Newington Tap (1783)	Mar-20	4

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 4/24/20

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected/ Actual In-Service	Present Stage
Separation of 115 kV DCT corresponding to the Bloomfield to South Meadow (1779) line and the Bloomfield to North Bloomfield (1777) line and add a breaker at Bloomfield 115 kV substation	Dec-17	4
Separation of 115 kV DCT corresponding to the Bloomfield to North Bloomfield (1777) line and the North Bloomfield – Rood Avenue – Northwest Hartford (1751) line and add a breaker at North Bloomfield 115 kV substation	Dec-17	4
Install a 115 kV 3% reactor on the 115 kV line between South Meadow and Southwest Hartford (1704)	Nov-20	3
Replace the existing 3% series reactors on the 115 kV lines between Southington and Todd (1910) and between Southington and Canal (1950) with a 5% series reactors	Dec-18	4
Replace the normally open 19T breaker at Southington 115 kV with a normally closed 3% series reactor	Jun-19	4
Add a 345 kV breaker in series with breaker 5T at Southington	May-17	4

* Replaces the NEEWS Central Connecticut Reliability Project

Greater Hartford and Central Connecticut Projects, cont.*

Status as of 4/24/20

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Greater Hartford, Middletown, Barbour Hill and Northwestern Connecticut and increases western Connecticut import capability

Upgrade	Expected/ Actual In-Service	Present Stage
Add a new control house at Southington 115 kV substation	Dec-18	4
Add a new 115 kV line from Frost Bridge to Campville	Dec-17	4
Separation of 115 kV DCT corresponding to the Frost Bridge to Campville (1191) line and the Thomaston to Campville (1921) line and add a breaker at Campville 115 kV substation	Jun-18	4
Upgrade the 115 kV line between Southington and Lake Avenue Junction (1810-1)	Dec-16	4
Add a new 345/115 kV autotransformer at Barbour Hill substation	Dec-15	4
Add a 345 kV breaker in series with breaker 24T at the Manchester 345 kV substation	Dec-15	4
Reconductor the 115 kV line between Manchester and Barbour Hill (1763)	Apr-16	4

* Replaces the NEEWS Central Connecticut Reliability Project

Southwest Connecticut (SWCT) Projects

Status as of 4/24/20

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Add a 25.2 MVAR capacitor bank at the Oxford substation	Mar-16	4
Add 2 x 25 MVAR capacitor banks at the Ansonia substation	Oct-18	4
Close the normally open 115 kV 2T circuit breaker at Baldwin substation	Sep-17	4
Reconductor the 115 kV line between Bunker Hill and Baldwin Junction (1575)	Dec-16	4
Expand Pootatuck (formerly known as Shelton) substation to 4-breaker ring bus configuration and add a 30 MVAR capacitor bank at Pootatuck	Jul-18	4
Loop the 1570 line in and out the Pootatuck substation	Jul-18	4
Replace two 115 kV circuit breakers at the Freight substation	Dec-15	4

Southwest Connecticut Projects, cont.

Status as of 4/24/20

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Add two 14.4 MVAR capacitor banks at the West Brookfield substation	Dec-17	4
Add a new 115 kV line from Plumtree to Brookfield Junction	Jun-18	4
Reconductor the 115 kV line between West Brookfield and Brookfield Junction (1887)	Dec-20	2
Reduce the existing 25.2 MVAR capacitor bank at the Rocky River substation to 14.4 MVAR	Apr-17	4
Reconfigure the 1887 line into a three-terminal line (Plumtree - W. Brookfield - Shepaug)	May-18	4
Reconfigure the 1770 line into 2 two-terminal lines (Plumtree - Stony Hill and Stony Hill - Bates Rock)	May-18	4
Install a synchronous condenser (+25/-12.5 MVAR) at Stony Hill	Jun-18	4
Relocate an existing 37.8 MVAR capacitor bank at Stony Hill to the 25.2 MVAR capacitor bank side	May-18	4

Southwest Connecticut Projects, cont.

Status as of 4/24/20

Plan Benefit: Addresses long-term system needs in the four study sub-areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Relocate the existing 37.8 MVAR capacitor bank from 115 kV B bus to 115 kV A bus at the Plumtree substation	Apr-17	4
Add a 115 kV circuit breaker in series with the existing 29T breaker at the Plumtree substation	May-16	4
Terminal equipment upgrade at the Newtown substation (1876)	Dec-15	4
Rebuild the 115 kV line from Wilton to Norwalk (1682) and upgrade Wilton substation terminal equipment	Jun-17	4
Reconductor the 115 kV line from Wilton to Ridgefield Junction (1470-1)	Dec-19	4
Reconductor the 115 kV line from Ridgefield Junction to Peaceable (1470-3)	Dec-19	4

Southwest Connecticut Projects, cont.

Status as of 4/24/20

Plan Benefit: Addresses long-term system needs in the four study sub areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Add 2 x 20 MVAR capacitor banks at the Hawthorne substation	Mar-16	4
Upgrade the 115 kV bus at the Baird substation	Mar-18	4
Upgrade the 115 kV bus system and 11 disconnect switches at the Pequonnock substation	Dec-14	4
Add a 345 kV breaker in series with the existing 11T breaker at the East Devon substation	Dec-15	4
Rebuild the 115 kV lines from Baird to Congress (8809A / 8909B)	Dec-18	4
Rebuild the 115 kV lines from Housatonic River Crossing (HRX) to Barnum to Baird (88006A / 89006B)	Jun-21	3

Southwest Connecticut Projects, cont.

Status as of 4/24/20

Plan Benefit: Addresses long-term system needs in the four study sub areas of Frost Bridge/Naugatuck Valley, Housatonic Valley/Plumtree – Norwalk, Bridgeport, New Haven – Southington and improves system reliability

Upgrade	Expected/ Actual In-Service	Present Stage
Remove the Sackett phase shifter	Mar-17	4
Install a 7.5 ohm series reactor on 1610 line at the Mix Avenue substation	Dec-16	4
Add 2 x 20 MVAR capacitor banks at the Mix Avenue substation	Dec-16	4
Upgrade the 1630 line relay at North Haven and Wallingford 1630 terminal equipment	Jan-17	4
Rebuild the 115 kV lines from Devon Tie to Milvon (88005A / 89005B)	Nov-16	4
Replace two 115 kV circuit breakers at Mill River	Dec-14	4

Greater Boston Projects

Status as of 4/24/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install new 345 kV line from Scobie to Tewksbury	Dec-17	4
Reconductor the Y-151 115 kV line from Dracut Junction to Power Street	Apr-17	4
Reconductor the M-139 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
Reconductor the N-140 115 kV line from Tewksbury to Pinehurst and associated work at Tewksbury	May-17	4
Reconductor the F-158N 115 kV line from Wakefield Junction to Maplewood and associated work at Maplewood	Dec-15	4
Reconductor the F-158S 115 kV line from Maplewood to Everett	Jun-19	4
Install new 345 kV cable from Woburn to Wakefield Junction, install two new 160 MVAR variable shunt reactors and associated work at Wakefield Junction and Woburn*	Dec-21	3*
Refurbish X-24 69 kV line from Millbury to Northboro Road	Dec-15	4
Reconductor W-23W 69 kV line from Woodside to Northboro Road	Jun-19	4

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

Greater Boston Projects, cont.

Status as of 4/24/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Separate X-24 and E-157W DCT	Dec-18	4
Separate Q-169 and F-158N DCT	Dec-15	4
Reconductor M-139/211-503 and N-140/211-504 115 kV lines from Pinehurst to North Woburn tap	May-17	4
Install new 115 kV station at Sharon to segment three 115 kV lines from West Walpole to Holbrook	Oct-20	3
Install third 115 kV line from West Walpole to Holbrook	Oct-20	3
Install new 345 kV breaker in series with the 104 breaker at Stoughton	May-16	4
Install new 230/115 kV autotransformer at Sudbury and loop the 282-602 230 kV line in and out of the new 230 kV switchyard at Sudbury	Dec-17	4
Install a new 115 kV line from Sudbury to Hudson	Dec-23	2

Greater Boston Projects, cont.

Status as of 4/24/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Replace 345/115 kV autotransformer, 345 kV breakers, and 115 kV switchgear at Woburn	Dec-19	4
Install a 345 kV breaker in series with breaker 104 at Woburn	May-17	4
Reconfigure Waltham by relocating PARs, 282-507 line, and a breaker	Dec-17	4
Upgrade 533-508 115 kV line from Lexington to Hartwell and associated work at the stations	Aug-16	4
Install a new 115 kV 54 MVAR capacitor bank at Newton	Dec-16	4
Install a new 115 kV 36.7 MVAR capacitor bank at Sudbury	May-17	4
Install a second Mystic 345/115 kV autotransformer and reconfigure the bus	May-19	4
Install a 115 kV breaker on the East bus at K Street	Jun-16	4
Install 115 kV cable from Mystic to Chelsea and upgrade Chelsea 115 kV station to BPS standards	May-21	3
Split 110-522 and 240-510 DCT from Baker Street to Needham for a portion of the way and install a 115 kV cable for the rest of the way	Dec-20	3

Greater Boston Projects, cont.

Status as of 4/24/20

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

Upgrade	Expected/ Actual In-Service	Present Stage
Install a second 115 kV cable from Mystic to Woburn to create a bifurcated 211-514 line	Dec-21	3
Open lines 329-510/511 and 250-516/517 at Mystic and Chatham, respectively. Operate K Street as a normally closed station.	May-19	4
Upgrade Kingston to create a second normally closed 115 kV bus tie and reconfigure the 345 kV switchyard	Mar-19	4
Relocate the Chelsea capacitor bank to the 128-518 termination postion	Dec-16	4

Greater Boston Projects, cont.

Status as of 4/24/20

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

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

Pittsfield/Greenfield Projects

Status as of 4/24/20

Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts

Upgrade	Expected/ Actual In-Service	Present Stage
Separate and reconductor the Cabot Taps (A-127 and Y-177 115 kV lines)	Mar-17	4
Install a 115 kV tie breaker at the Harriman Station, with associated buswork, reconductor of buswork and new control house	Nov-17	4
Modify Northfield Mountain 16R Substation and install a 345/115 kV autotransformer	Jun-17	4
Build a new 115 kV three-breaker switching station (Erving) ring bus	Mar-17	4
Build a new 115 kV line from Northfield Mountain to the new Erving Switching Station	Jun-17	4
Install 115 kV 14.4 MVAR capacitor banks at Cumberland, Podick and Amherst Substations	Dec-15	4

Pittsfield/Greenfield Projects, cont.

Status as of 4/24/20

Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts

Upgrade	Expected/ Actual In-Service	Present Stage
Rebuild the Cumberland to Montague 1361 115 kV line and terminal work at Cumberland and Montague. At Montague Substation, reconnect Y177 115 kV line into 3T/4T position and perform other associated substation work	Dec-16	4
Remove the sag limitation on the 1512 115 kV line from Blandford Substation to Granville Junction and remove the limitation on the 1421 115 kV line from Pleasant to Blandford Substation	Dec-14	4
Loop the A127W line between Cabot Tap and French King into the new Erving Substation	Mar-17	4
Reconductor A127 between Erving and Cabot Tap and replace switches at Wendell Depot	Apr-15	4

Pittsfield/Greenfield Projects, cont.

Status as of 4/24/20

Project Benefit: Addresses system needs in the Pittsfield/Greenfield area in Western Massachusetts

Upgrade	Expected/ Actual In-Service	Present Stage
Install a 115 kV 20.6 MVAR capacitor at the Doreen substation and operate the 115 kV 13T breaker N.O.	Oct-17	4
Install a 75-150 MVAR variable reactor at Northfield substation	Dec-17	4
Install a 75-150 MVAR variable reactor at Ludlow substation	Dec-17	4
Construct a 115 kV three-breaker ring bus at or adjacent to Pochassic 37R Substation, loop line 1512-1 into the new three-breaker ring bus, construct a new line connecting the new three-breaker ring bus to the Buck Pond 115 kV Substation on the vacant side of the double-circuit towers that carry line 1302-2, add a new breaker to the Buck Pond 115 kV straight bus and reconnect lines 1302-2, 1657-2 and transformer 2X into new positions	Jun-20	3

SEMA/RI Reliability Projects

Status as of 4/24/20

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

Project 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	May-20	3
1742	Conduct remote terminal station work at the Wampanoag and Pawtucket substations for the new Grand Army GIS switching station	Nov-20	3
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	Jun-20	3
1716	Increase clearances on E-183E & F-184 lines between Brayton Point and Grand Army substations	Nov-19	4
1717	Separate the X3/W4 DCT and reconductor the X3 and W4 lines between Somerset and Grand Army substations; reconfigure Y2 and Z1 lines	Nov-19	4

SEMA/RI Reliability Projects, cont.

Status as of 4/24/20

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

Project 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-20	3
1719	Install 45.0 MVAR capacitor bank at Berry Street substation	Dec-20	2
1720	Separate the N12/M13 DCT and reconductor the N12 and M13 between Somerset and Bell Rock substations	Nov-21	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-21	2
1722	Extend the Line 114 from the Dartmouth town line (Eversource- NGRID border) to Bell Rock substation	Dec-21	2
1723	Reconductor L14 and M13 lines from Bell Rock substation to Bates Tap	Sep-21	2

SEMA/RI Reliability Projects, cont.

Status as of 4/24/20

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

Project 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	1
1727	Retire the Barnstable SPS	Dec-21	1
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-21	1

SEMA/RI Reliability Projects, cont.

Status as of 4/24/20

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

Project ID	Upgrade	Expected/ Actual In-Service	Present Stage
1731	Install 35.3 MVAR capacitors at High Hill and Wing Lane substations	Dec-21	1
1732	Loop the 201-502 line into the Medway substation to form the 201-502N and 201-502S lines	Jan-23	1
1733	Separate the 325/344 DCT lines from West Medway to West Walpole substations	Dec-21	1
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	Dec-20	3

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

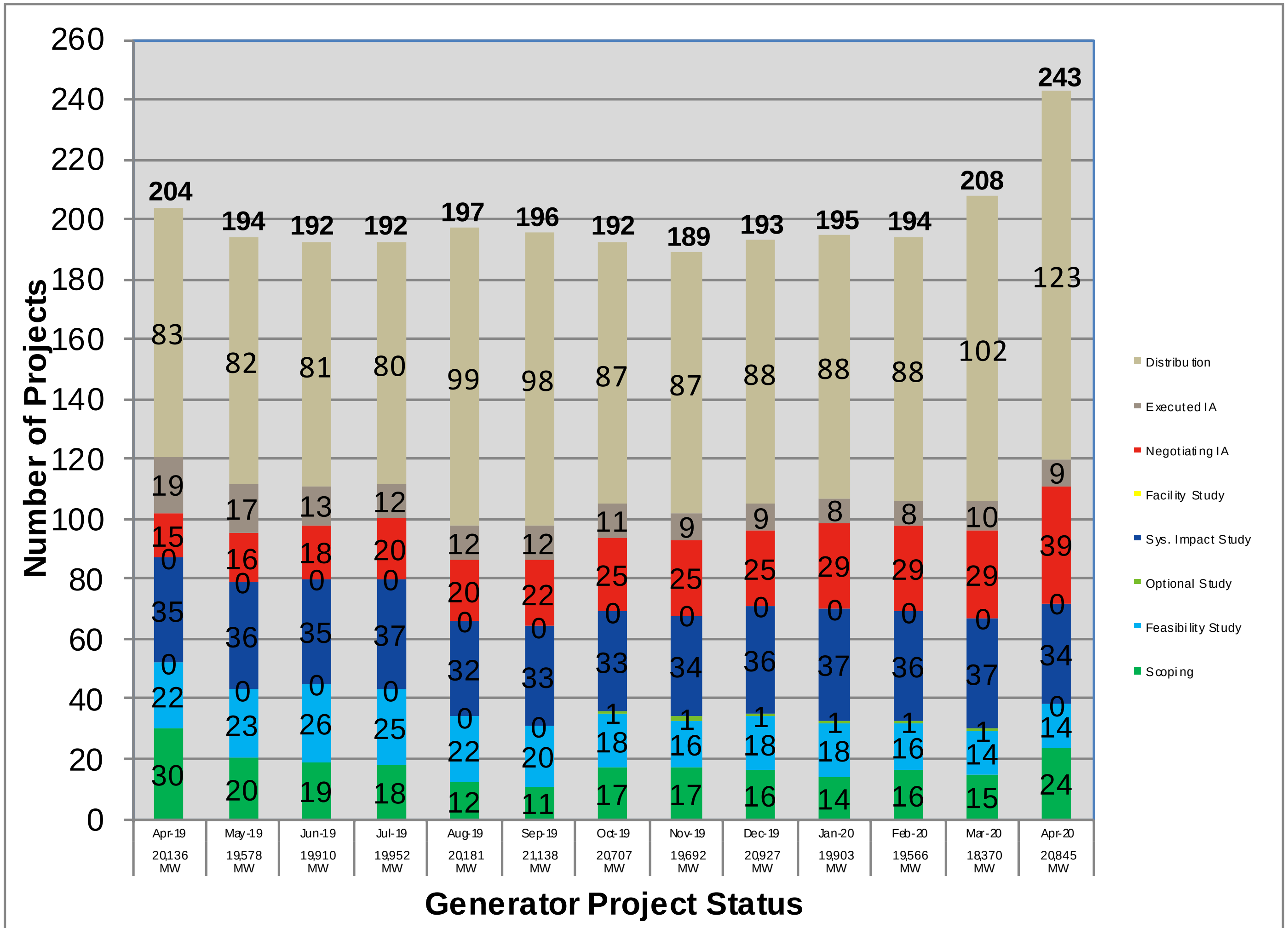
SEMA/RI Reliability Projects, cont.

Status as of 4/24/20

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

Project 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	Dec-21	2
1724	Replace the Kent County 345/115 kV transformer	Feb-21	2
1789	West Medway 345 kV circuit breaker upgrades	Dec-21	3
1790	Medway 115 kV circuit breaker replacements	Dec-21	3

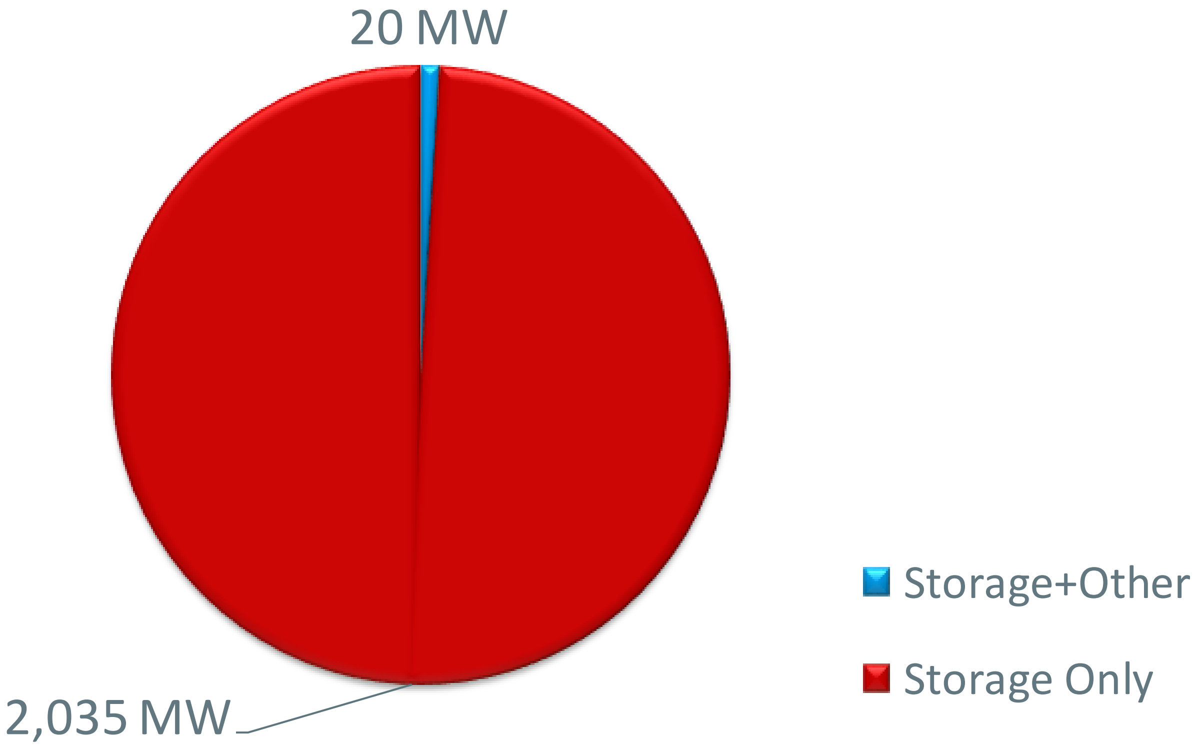
Status of Tariff Studies



Note: April 2020 based on partial data
As of April 2020, there are 4 ETU's in Scoping, 4 in FS, 4 in SIS, 0 in FAC, 0 Negotiating IA, and 1 with Executed IA
https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of April 27, 2020)

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



OPERABLE CAPACITY ANALYSIS

Spring 2020 Analysis

Spring 2020 Operable Capacity Analysis

50/50 Load Forecast (Reference)	**May - 2020[2] CSO (MW)**	**May - 2020[2] SCC (MW)**
Operable Capacity MW [1]	31,691	33,683
Active Demand Capacity Resource (+) [5]	403	447
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	450	450
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outage MW (-)	4,259	4,549
Gas Generator Outages MW (-)	1,504	1,518
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	23,381	25,113
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	20,358	20,358
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	22,663	22,663
Operable Capacity Margin	718	2,450

[1] Operable Capacity is based on data as of **April 28, 2020** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **April 28, 2020.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 16, 2020.**

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

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

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

Spring 2020 Operable Capacity Analysis

90/10 **Load Forecast** (Extreme)	**May - 2020[2] CSO (MW)**	**May - 2020[2] SCC (MW)**
Operable Capacity MW [1]	31,691	33,683
Active Demand Capacity Resource (+) [5]	403	447
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	450	450
Non Commercial Capacity (+)	0	0
Non Gas-fired Planned Outage MW (-)	4,259	4,549
Gas Generator Outages MW (-)	1,504	1,518
Allowance for Unplanned Outages (-) [4]	3,400	3,400
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	23,381	25,113
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	21,970	21,970
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	24,275	24,275
Operable Capacity Margin	-894	838

[1] Operable Capacity is based on data as of **April 28, 2020** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **April 28, 2020.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **May 16, 2020.**

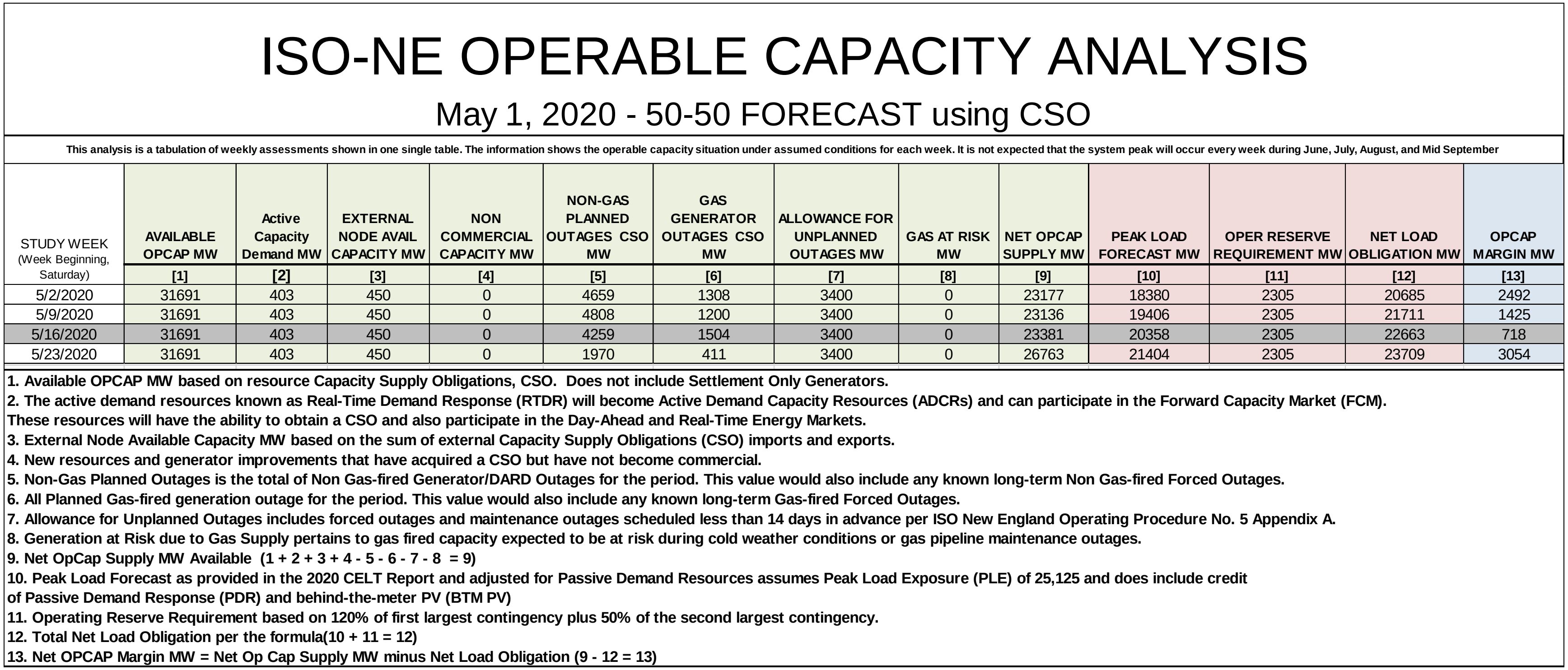
[3] Total of (Gas at Risk MW) – (Gas Gen Outages MW).

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

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

Spring 2020 Operable Capacity Analysis

50/50 Forecast (Reference)



ISO-NE OPERABLE CAPACITY ANALYSIS

May 1, 2020 - 50-50 FORECAST using CSO

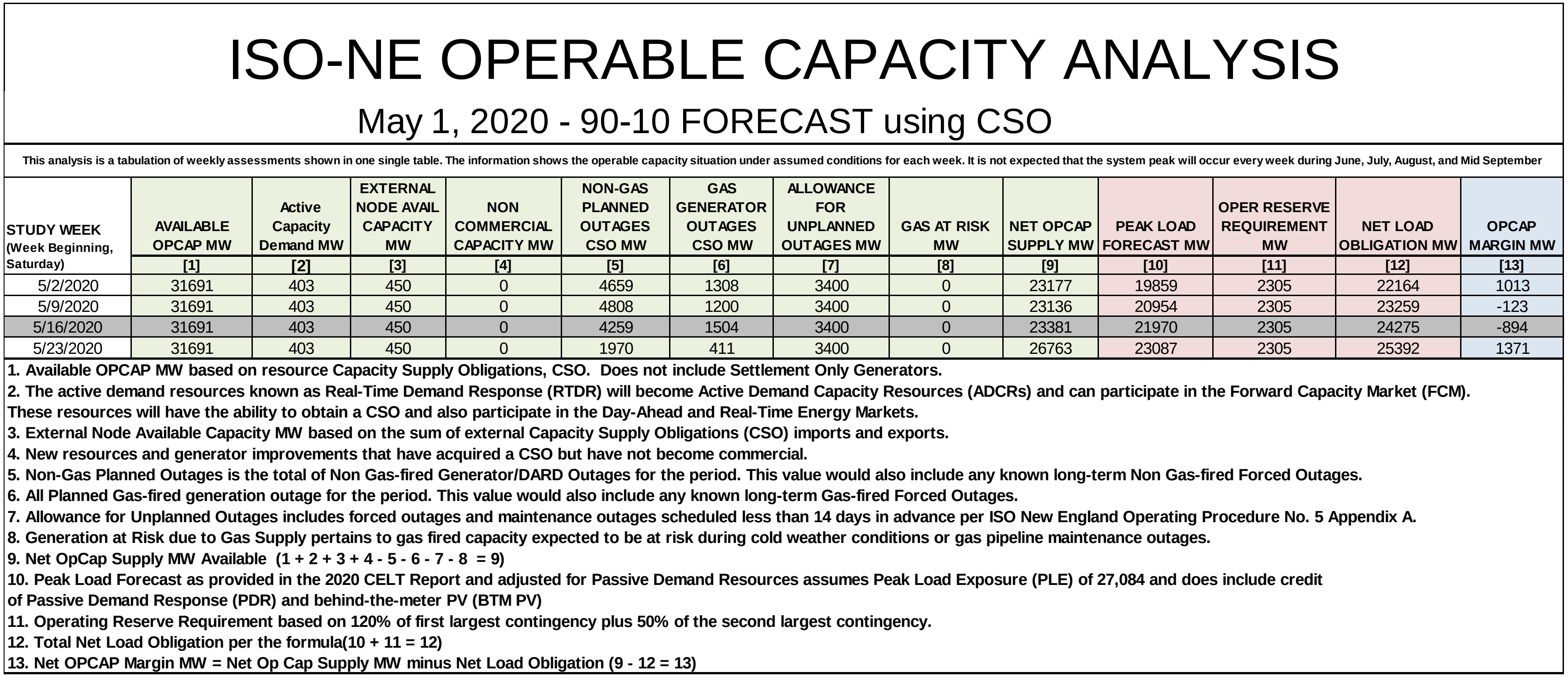
This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, August, and Mid September

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	Active Capacity Demand MW [2]	EXTERNAL NODE AVAIL CAPACITY MW [3]	NON COMMERCIAL CAPACITY MW [4]	NON-GAS PLANNED OUTAGES CSO MW [5]	GAS GENERATOR OUTAGES CSO MW [6]	ALLOWANCE FOR UNPLANNED OUTAGES MW [7]	GAS AT RISK MW [8]	NET OPCAP SUPPLY MW [9]	PEAK LOAD FORECAST MW [10]	OPER RESERVE REQUIREMENT MW [11]	NET LOAD OBLIGATION MW [12]	OPCAP MARGIN MW [13]
5/2/2020	31691	403	450	0	4659	1308	3400	0	23177	18380	2305	20685	2492
5/9/2020	31691	403	450	0	4808	1200	3400	0	23136	19406	2305	21711	1425
5/16/2020	31691	403	450	0	4259	1504	3400	0	23381	20358	2305	22663	718
5/23/2020	31691	403	450	0	1970	411	3400	0	26763	21404	2305	23709	3054

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active 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 participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. 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.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2020 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,125 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

Spring 2020 Operable Capacity Analysis

90/10 Forecast (Extreme)



ISO-NE OPERABLE CAPACITY ANALYSIS

May 1, 2020 - 90-10 FORECAST using CSO

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

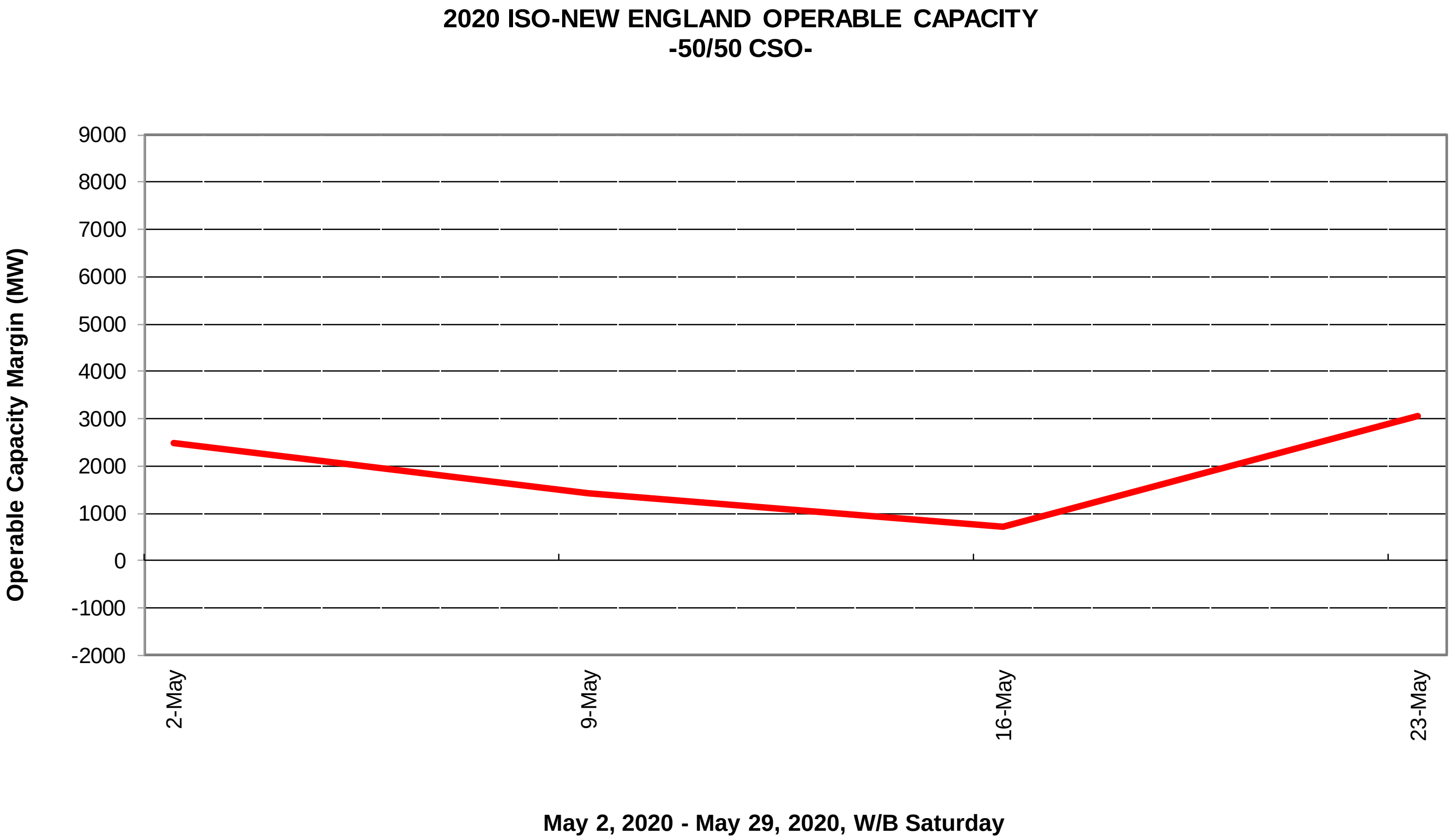
STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	Active Capacity Demand MW [2]	EXTERNAL NODE AVAIL CAPACITY MW [3]	NON COMMERCIAL CAPACITY MW [4]	NON-GAS PLANNED OUTAGES CSO MW [5]	GAS GENERATOR OUTAGES CSO MW [6]	ALLOWANCE FOR UNPLANNED OUTAGES MW [7]	GAS AT RISK MW [8]	NET OPCAP SUPPLY MW [9]	PEAK LOAD FORECAST MW [10]	OPER RESERVE REQUIREMENT MW [11]	NET LOAD OBLIGATION MW [12]	OPCAP MARGIN MW [13]
5/2/2020	31691	403	450	0	4659	1308	3400	0	23177	19859	2305	22164	1013
5/9/2020	31691	403	450	0	4808	1200	3400	0	23136	20954	2305	23259	-123
5/16/2020	31691	403	450	0	4259	1504	3400	0	23381	21970	2305	24275	-894
5/23/2020	31691	403	450	0	1970	411	3400	0	26763	23087	2305	25392	1371

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active 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 participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. 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.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2020 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 27,084 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

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

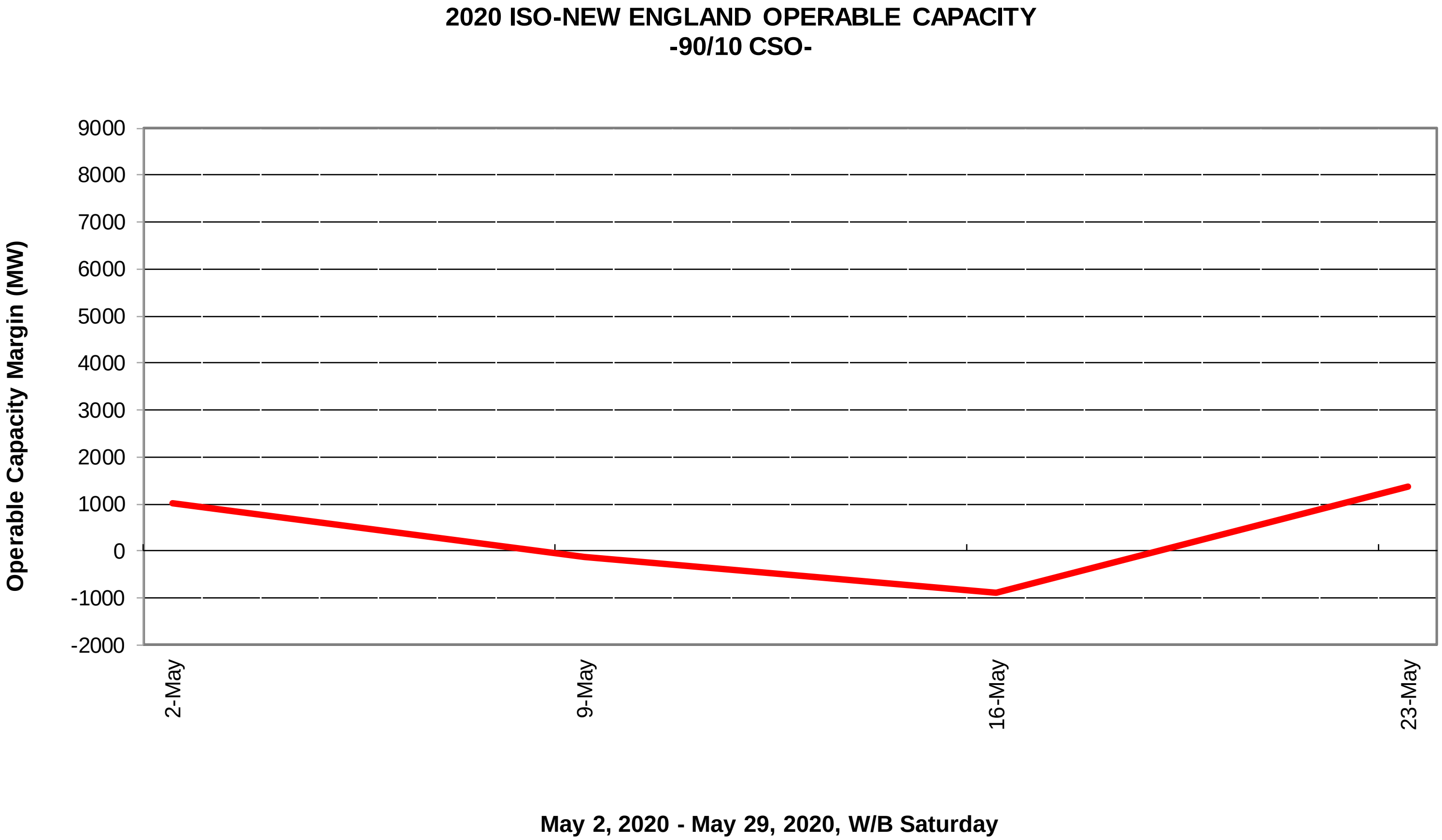
Spring 2020 Operable Capacity Analysis

50/50 Forecast (Reference)



Spring 2020 Operable Capacity Analysis

90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Summer 2020 Analysis

Summer 2020 Operable Capacity Analysis

50/50 **Load Forecast** (Reference)	**September - 2020[2] CSO (MW)**	**September - 2020[2] SCC (MW)**
Operable Capacity MW [1]	30,156	31,072
Active Demand Capacity Resource (+) [5]	524	447
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	584	584
Non Commercial Capacity (+)	7	7
Non Gas-fired Planned Outage MW (-)	2,646	2,651
Gas Generator Outages MW (-)	66	88
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)	26,459	27,271
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	25,125	25,125
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	27,430	27,430
Operable Capacity Margin	-971	-159

[1] Operable Capacity is based on data as of **April 28, 2020** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **April 28, 2020.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **September 12, 2020.**

[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 2020 Operable Capacity Analysis

90/10 **Load Forecast** (Extreme)	**September - 2020**[2] **CSO (MW)**	**September - 2020**[2] **SCC (MW)**
Operable Capacity MW [1]	30,156	31,072
Active Demand Capacity Resource (+) [5]	524	447
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	584	584
Non Commercial Capacity (+)	7	7
Non Gas-fired Planned Outage MW (-)	2,646	2,651
Gas Generator Outages MW (-)	66	88
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)	26,459	27,271
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	27,084	27,084
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	29,389	29,389
Operable Capacity Margin	-2930	-2118

[1] Operable Capacity is based on data as of **April 28, 2020** and does not include Capacity associated with Settlement Only Generators, Passive and Active Demand Response, and external capacity. The Capacity Supply Obligation (CSO) and Seasonal Claim Capability (SCC) values are based on data as of **April 28, 2020.**

[2] Load forecast that is based on the 2020 CELT report and represents the week with the lowest Operable Capacity Margin, week beginning **September 12, 2020.**

[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 2020 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

May 1, 2020 - 50-50 FORECAST using CSO

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

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
5/30/2020	30156	524	970	5	1355	259	2800	0	27241	25125	2305	27430	-189
6/6/2020	30156	524	1025	5	1149	530	2800	0	27231	25125	2305	27430	-199
6/13/2020	30156	524	1025	5	1027	479	2800	0	27404	25125	2305	27430	-26
6/20/2020	30156	524	1025	5	384	0	2800	0	28526	25125	2305	27430	1096
6/27/2020	30156	524	1025	5	345	0	2800	0	28565	25125	2305	27430	1135
7/4/2020	30156	524	1025	7	697	0	2100	0	28915	25125	2305	27430	1485
7/11/2020	30156	524	1025	7	359	0	2100	0	29253	25125	2305	27430	1823
7/18/2020	30156	524	1025	7	328	0	2100	0	29284	25125	2305	27430	1854
7/25/2020	30156	524	1025	7	364	0	2100	0	29248	25125	2305	27430	1818
8/1/2020	30156	524	1025	7	365	0	2100	0	29247	25125	2305	27430	1817
8/8/2020	30156	524	1025	7	354	0	2100	0	29258	25125	2305	27430	1828
8/15/2020	30156	524	1025	7	367	0	2100	0	29245	25125	2305	27430	1815
8/22/2020	30156	524	1025	7	367	0	2100	0	29245	25125	2305	27430	1815
8/29/2020	30156	524	1025	7	471	0	2100	0	29141	25125	2305	27430	1711
9/5/2020	30156	524	1025	7	1059	0	2100	0	28553	25125	2305	27430	1123
9/12/2020	30156	524	584	7	2646	66	2100	0	26459	25125	2305	27430	-971

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active 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 participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. 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.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2020 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 25,125 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

Summer 2020 Operable Capacity Analysis

90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

May 1, 2020 - 90-10 FORECAST using CSO

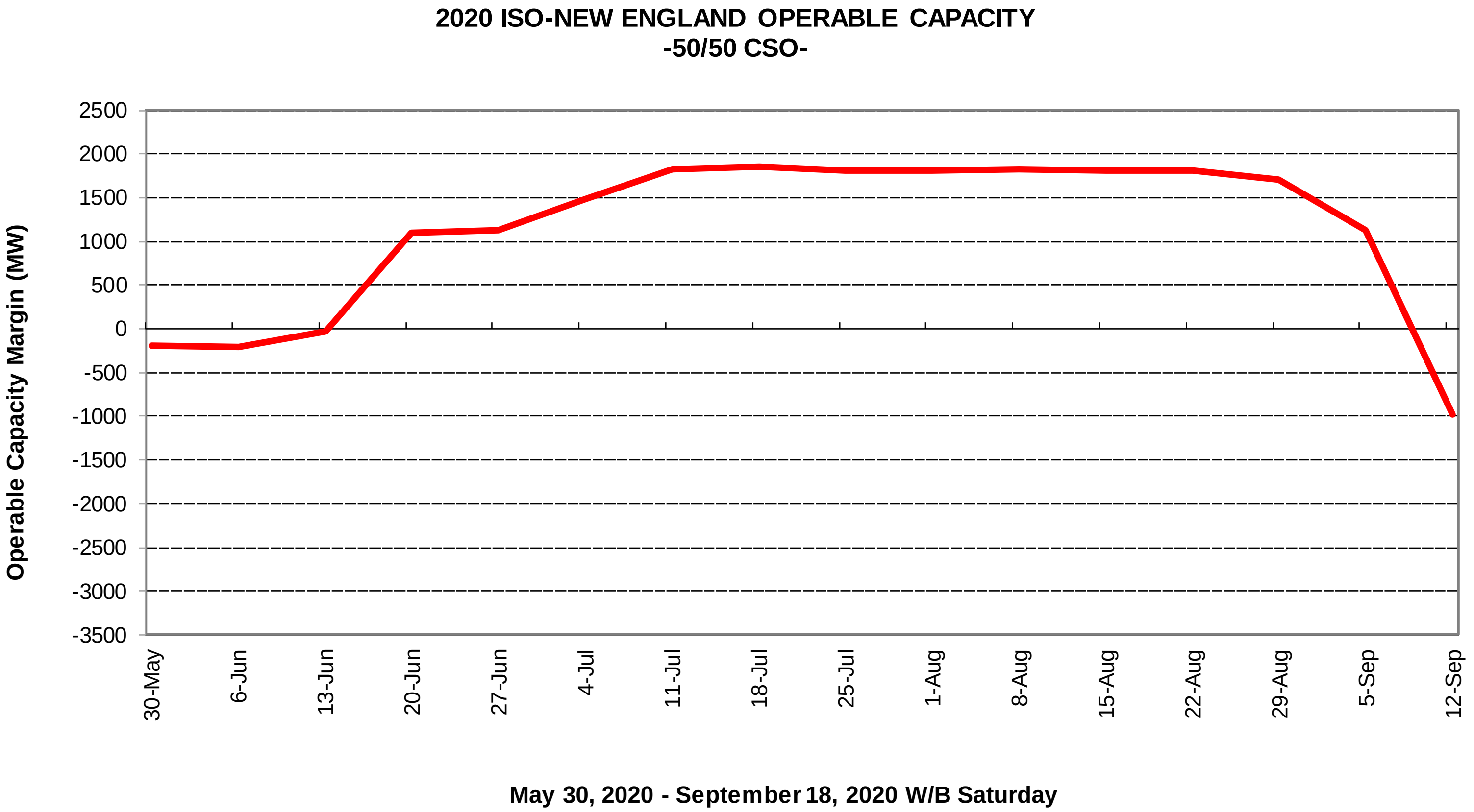
This analysis is a tabulation of weekly assessments shown in one single table. The information shows the operable capacity situation under assumed conditions for each week. It is not expected that the system peak will occur every week during June, July, August, and Mid September

STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
5/30/2020	30156	524	970	5	1355	259	2800	0	27241	27084	2305	29389	-2148
6/6/2020	30156	524	1025	5	1149	530	2800	0	27231	27084	2305	29389	-2158
6/13/2020	30156	524	1025	5	1027	479	2800	0	27404	27084	2305	29389	-1985
6/20/2020	30156	524	1025	5	384	0	2800	0	28526	27084	2305	29389	-863
6/27/2020	30156	524	1025	5	345	0	2800	0	28565	27084	2305	29389	-824
7/4/2020	30156	524	1025	7	697	0	2100	0	28915	27084	2305	29389	-474
7/11/2020	30156	524	1025	7	359	0	2100	0	29253	27084	2305	29389	-136
7/18/2020	30156	524	1025	7	328	0	2100	0	29284	27084	2305	29389	-105
7/25/2020	30156	524	1025	7	364	0	2100	0	29248	27084	2305	29389	-141
8/1/2020	30156	524	1025	7	365	0	2100	0	29247	27084	2305	29389	-142
8/8/2020	30156	524	1025	7	354	0	2100	0	29258	27084	2305	29389	-131
8/15/2020	30156	524	1025	7	367	0	2100	0	29245	27084	2305	29389	-144
8/22/2020	30156	524	1025	7	367	0	2100	0	29245	27084	2305	29389	-144
8/29/2020	30156	524	1025	7	471	0	2100	0	29141	27084	2305	29389	-248
9/5/2020	30156	524	1025	7	1059	0	2100	0	28553	27084	2305	29389	-836
9/12/2020	30156	524	584	7	2646	66	2100	0	26459	27084	2305	29389	-2930

1. Available OPCAP MW based on resource Capacity Supply Obligations, CSO. Does not include Settlement Only Generators.
2. The active 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 participate in the Day-Ahead and Real-Time Energy Markets.
3. External Node Available Capacity MW based on the sum of external Capacity Supply Obligations (CSO) imports and exports.
4. New resources and generator improvements that have acquired a CSO but have not become commercial.
5. 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.
6. All Planned Gas-fired generation outage for the period. This value would also include any known long-term Gas-fired Forced Outages.
7. Allowance for Unplanned Outages includes forced outages and maintenance outages scheduled less than 14 days in advance per ISO New England Operating Procedure No. 5 Appendix A.
8. Generation at Risk due to Gas Supply pertains to gas fired capacity expected to be at risk during cold weather conditions or gas pipeline maintenance outages.
9. Net OpCap Supply MW Available (1 + 2 + 3 + 4 - 5 - 6 - 7 - 8 = 9)
10. Peak Load Forecast as provided in the 2020 CELT Report and adjusted for Passive Demand Resources assumes Peak Load Exposure (PLE) of 27,084 and does include credit of Passive Demand Response (PDR) and behind-the-meter PV (BTM PV)
11. Operating Reserve Requirement based on 120% of first largest contingency plus 50% of the second largest contingency.
12. Total Net Load Obligation per the formula(10 + 11 = 12)
13. Net OPCAP Margin MW = Net Op Cap Supply MW minus Net Load Obligation (9 - 12 = 13)

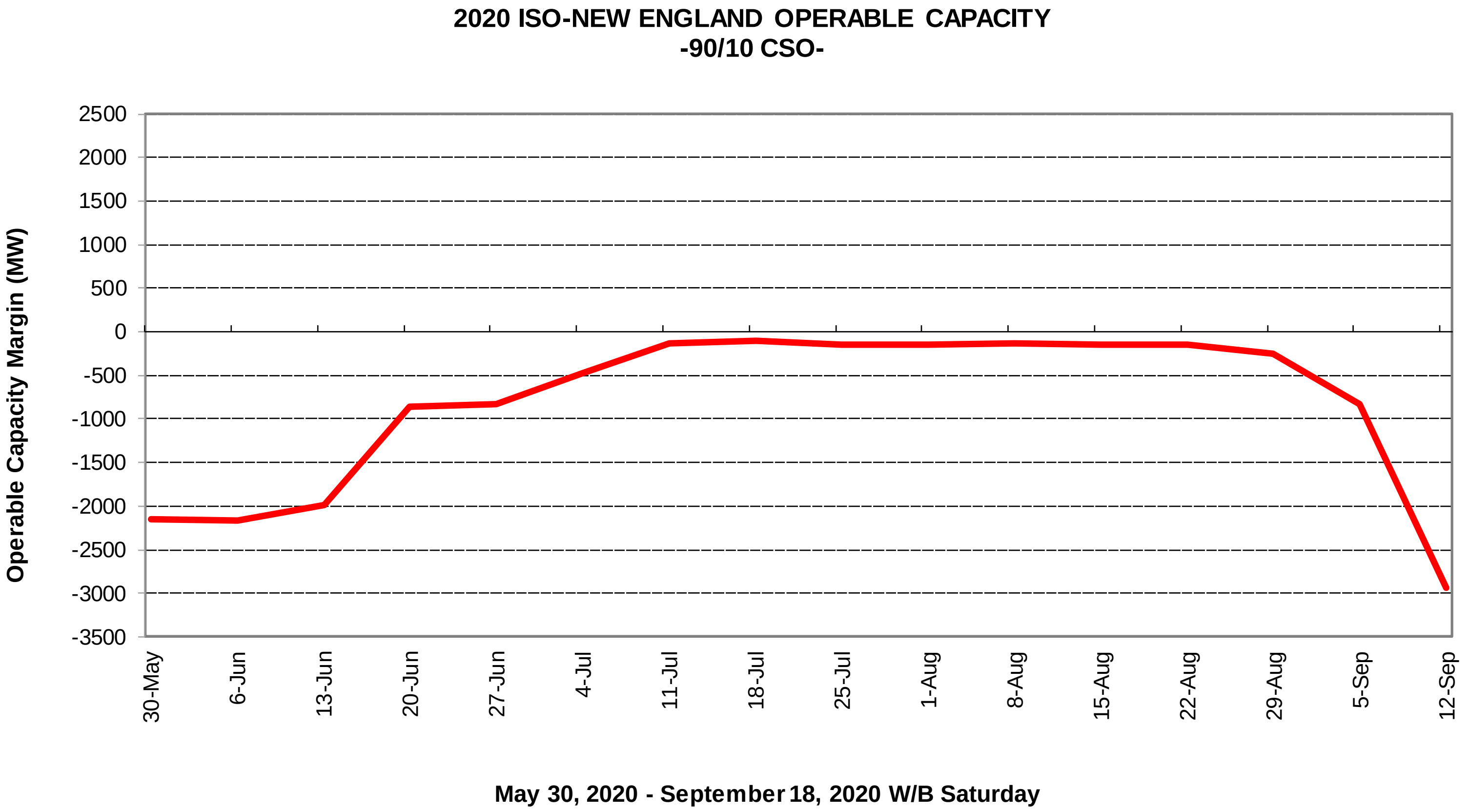
Summer 2020 Operable Capacity Analysis

50/50 Forecast (Reference)



Summer 2020 Operable Capacity Analysis

90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Appendix

Possible Relief Under OP4: Appendix A

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

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

Possible Relief Under OP4: Appendix A

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

NOTES:

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

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Eric Runge, NEPOOL Counsel

DATE: April 30, 2020

RE: **Vote on OATT Schedule 24 Revisions to Update NAESB Standards**

At the May 7, 2020 Participants Committee teleconference meeting, you will be asked to vote on revisions to Schedule 24 of the ISO-NE Open Access Transmission Tariff ("ISO-NE OATT") to incorporate updated Business Practice Standards from the North American Electric Standard Board ("NAESB") for the Wholesale Electric Quadrant ("WEQ") (the "Schedule 24 Revisions"). This matter received the unanimous support of the Transmission Committee at its April 28 meeting, and this item would have been on the May Participants Committee Consent Agenda but for timing.

The ISO is updating NAESB WEQ standards in Schedule 24 in compliance with FERC Order No. 671-I, which required incorporation of the updated NAESB WEQ standards by reference in applicable tariffs of public utilities.[1] Relevant background materials, including an ISO-NE presentation, have been included with this memo.[2]

The Participants Committee may use the following form of resolution for action on the Schedule 24 Revisions:

> RESOLVED, that the Participants Committee supports the Schedule 24 Revisions as recommended by the Transmission Committee and reflected in the materials posted for the May 7, 2020 Participants Committee teleconference meeting, together with [any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Transmission Committee.

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[1] The FERC issued Order No. 671-I on February 4, 2020. It can be accessed here: https://ferc.gov/whats-new/comm-meet/2020/012320/E-23.pdf. On April 3, the FERC extended the deadline for compliance to July 27, 2020. In its orders on compliance filings, the FERC will determine an implementation date for these changes.

[2] The ISO-NE presentation can also be accessed here: https://www.iso-ne.com/static-assets/documents/2020/04/a03_tc_2020_04_28_sched24_naesb_update.pptx

SCHEDULE 24

Incorporation By Reference of NAESB Standards

In accordance with paragraph 89 of Commission Order No. 676-I~~II~~, the following North American Electric Standard Board's ("NAESB") Whole Electric Quadrant's ("WEQ") Version 003.2 Business Practice Standards incorporated by reference below are implemented by the ISO in association with the transmission services – Regional Network Service and Through or Out Service – that the ISO offers over the Pool Transmission Facilities that are part of the New England Transmission System, except as described in Attachment A to this Schedule 24. The reference below to Version 003.2 of the WEQ Business Practice Standards and any future revisions shall not affect the transmission service products offered by the ISO.

- WEQ-000, Abbreviations, Acronyms, and Definition of Terms (WEQ Version 003.1, September 30, 2015) (including only the definitions of Interconnection Time Monitor, Time Error, and Time Error Correction);~~, WEQ Version 003, July 31, 2012, as modified by NAESB final actions ratified on Oct. 4, 2012, Nov. 28, 2012 and Dec. 28, 2012 (with minor corrections applied Nov. 26, 2013);~~

- WEQ-001, Open Access Same-Time Information Systems (OASIS), , [OASIS] Version 2.2 (WEQ Version 003.2, Dec. 8, 2017), excluding standards WEQ-001-9 preamble text, WEQ-001-10 preamble text; ~~OASIS Version 2.~~0~~, WEQ Version 003, July 31, 2012, as modified by NAESB final actions ratified on Dec. 28, 2012 (with minor corrections applied Nov. 26, 2013) excluding Standards 001-9.5, 001-10.5, 001-14.1.3, 001-15.1.2 and 001-106.2.5;~~

- WEQ-002, Open Access Same-Time Information Systems (OASIS) Business Practice Standards and Communication Protocols (S&CP), [OASIS] Version 2.2 (WEQ Version 003.2, Dec. 8, 2017); ~~OASIS Version 2.~~0~~, WEQ Version 003, July 31, 2012, as modified by NAESB final actions ratified on Nov. 28, 2012 and Dec. 28, 2012 (with minor corrections applied Nov. 26, 2013);~~

- WEQ-003, Open Access Same-Time Information Systems (OASIS) Data Dictionary Business Practice Standards, [OASIS] Version 2.2 (WEQ Version 003.2, Dec. 8, 2017) (with minor corrections applied July 23, 2019);~~ OASIS Version 2.0, WEQ Version 003, July 31, 2012, as modified by NAESB final actions ratified on Dec. 28, 2012 (with minor corrections applied Nov. 26, 2013);~~

- WEQ-004, Coordinate Interchange (WEQ Version 003.2, Dec. 8, 2017);~~, WEQ Version 003, July 31, 2012 (with Final Action ratified on December 28, 2012);~~

- WEQ-005, Area Control Error (ACE) Equation Special Cases (WEQ Version 003.2, Dec. 8, 2017);~~, WEQ Version 003, July 31, 2012;~~

- WEQ-006, Manual Time Error Correction (WEQ Version 003.1, Sept. 30, 2015);~~, WEQ Version 003, July 31, 2012;~~

- WEQ-007, Inadvertent Interchange Payback (WEQ Version 003.2, Dec. 8, 2017);~~, WEQ Version 003, July 31, 2012;~~

- WEQ-008, Transmission Loading Relief (TLR) – Eastern Interconnection (WEQ Version 003.2, Dec. 8, 2017);~~, WEQ Version 003, July 31, 2012 (with minor corrections applied November 28, 2012);~~

- WEQ-011, Gas / Electric Coordination (WEQ Version 003.2, Dec. 8, 2017);~~, WEQ Version 003, July 31, 2012;~~

- WEQ-012, Public Key Infrastructure (PKI) (WEQ Version 003.2, Dec. 8, 2017);~~, WEQ Version 003, July 31, 2012, as modified by NAESB final actions ratified on Oct. 4, 2012);~~

- WEQ-013, Open Access Same-Time Information Systems (OASIS) Implementation Guide, [OASIS] Version 2.2 (WEQ Version 003.2, Dec. 8, 2017);~~OASIS Version 2.0, WEQ Version 003, July 31, 2012, as modified by NAESB final actions ratified on Dec. 28, 2012 (with minor corrections applied Nov. 26, 2013);~~

- WEQ-015, Measurement and Verification of Wholesale Electricity Demand Response (WEQ Version 003.2, Dec. 8, 2017);~~, WEQ Version 003, July 31, 2012; and~~

- WEQ-021, Measurement and Verification of Energy Efficiency Products (WEQ Version 003.2, Dec. 8, 2017);~~, WEQ Version 003, July 31, 2012.~~

- WEQ–022, Electric Industry Registry Business Practice Standards (WEQ Version 003.2, Dec. 8, 2017); and

- WEQ-023, Modeling. The following standards are incorporated by reference: WEQ-023-5; WEQ-023-5.1; WEQ-023-5.1.1; WEQ-023-5.1.2; WEQ-023-5.1.2.1; WEQ-023-5.1.2.2; WEQ-023-5.1.2.3;

WEQ-023-5.1.3; WEQ-023-5.2; WEQ-023-6; WEQ-023-6.1; WEQ-023-6.1.1; WEQ-023-6.1.2; and WEQ-023-A Appendix A. (WEQ Version 003.2, Dec. 8, 2017).

ATTACHMENT A to SCHEDULE 24

NAESB Business Practice Standards Not Implemented by the ISO Given the Nature of Transmission Services Offered

The ISO does not offer the Point-To-Point Transmission Service or the Network Integration Transmission Service that are available under the Commission's *pro forma* open access transmission tariff. Under Sections II.B and II.C of the ISO OATT, the ISO offers Regional Network Service and Through or Out Service over the Pool Transmission Facilities that are part of the New England Transmission System. RNS and TOUT Service differ from the *pro forma* OATT Point-To-Point Transmission Service and Network Integration Transmission Service.

Because the ISO does not offer the *pro forma* Point-To-Point Transmission Service or the Network Integration Transmission Service, the ISO does not implement the WEQ Business Practice Standards that relate specifically to those services. Specifically, the ISO does not implement the WEQ-001, Open Access Same-Time Information Systems Business Practice Standards that are applicable to *pro forma* Point-To-Point Service and Network Integration Transmission Service and the WEQ-001 Coordination Of Requests For Service Across Multiple Transmission Systems-related Business Practice Standards for the coordination of the *pro forma* transmission services: 001-2.1 through 001-2.14; 001-2.2 through 001-2.2.2; 001-2.3 through 001-2.3.2; 001-4 through 001-4.27; 001-5 through 001-5.6; 001-8 through 001-8.3.2; 001-9 through 001-9.8.1; 001-10 through 001-10.8.7; 001-11 through 001-11.7.2.3~~1~~; 001-12 through 001-12.5.2; ~~001-18 through 001-18.2; 001-19 through 001-19.1.2;~~ 001-20 through 001-20.3; 001-21 through 001-21.5.5; 001-22 through 001-22.2; 001-23 through 23.3.9; 001-24 through 001-24.8.2; 001-25 through 001-25.4.7.3.1; 001-101 through 101.13.4; 001-102 through 102.5.3; 001-103 through 103.9.2; 001-104 through 104.5; 001-105 through 105.6.7.2; 001-106 through 106.2.7; 001-107 through 107.3.1; 001-INT2; and 001-D through 001-E.

Because of the geographical and electrical relationship of the ISO Control Area with other systems in the Eastern Interconnection, parallel flows associated with inter-Control Area transactions do not flow through the ISO Control Area in sufficient magnitude to require the use of Transmission Loading Relief or Transmission Loading Relief -like procedures. The ISO does not use Transmission Loading Relief procedures or initiate Transmission Loading Relief requests for inter-Control Area "interchange" transactions to manage parallel flows or to initiate curtailments. As such, the ISO does not implement the following NAESB Business Practice Standards within WEQ-008, Transmission Loading Relief (TLR) – Eastern Interconnection: 008-1 through 008-1.8.1~~7.1.2~~; 008-2 through 008-2.4.4; 008-3 through 008-3.11.2.8, and 008-A through 008-D.

APRIL 28, 2020 | TELECONFERENCE

Schedule 24 Amendments to Incorporate Updated NAESB Standards for the Electric Sector

Graham Jesmer

REGULATORY COUNSEL

Proposed Revisions to Schedule 24

Proposed Effective Date: TBD By FERC

- Proposed modifications to Schedule 24 of the ISO OATT to incorporate by reference updated versions of the North American Electric Standard Board's ("NAESB") Whole Electric Quadrant's ("WEQ") Business Practice Standards
  - Order No. 676-I requires RTOs and ISOs to revise their respective OATTs to include the Version 003.2 Standards
  - Specifically, revised standards WEQ-000, -001, -002, -003, -004, -006, -008, -012, -013, and -015, as well new standards WEQ-022 and -023*
  - No new implementation by ISO-NE is anticipated as a result of these changes
- Pursuant to Order No. 676-I, the changes were originally required to be filed by May 26, 2020
- On April 3, 2020, the Commission extended the timeframe for compliance to July 2021 at the request of SPP and MISO
  - ISO-NE intends to file revisions to Schedule 24 later this year and will work with the PTOs and CSC with regard to their timeframes for implementation/filing.

* Note that the proposed changes to Schedule 24 also include updated references for WEQ-005, -007, -011, and -021, however no revisions were made to those standards.

Background on Order 676-I

- The new versions were filed with the Commission as a package by NAESB on December 8, 2017, and include minor clarifications and updates submitted by NAESB on June 5, 2019, and July 23, 2019
- FERC issued *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-I, on February 4, 2020
- Public utilities are required to modify their respective OATTs to include these by making a compliance filing through eTariff no later than July 27, 2021, using an indeterminate effective date, which will be set the Commission

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Transmission Committee March 25, 2020	Discussion of Proposed Schedule 24 Revisions
Transmission Committee April 28, 2020	Advisory Vote
Participants Committee May 7, 2020	Advisory Vote

Questions

Graham Jesmer

GJESMER@ISO-NE.COM

memo

To: Participants Committee

From: Jay Dwyer, Secretary, NEPOOL Transmission Committee

Date: April 28, 2020

Subject: Actions of the Transmission Committee

This memo is notification to the Participants Committee of the following actions taken by the Transmission Committee (TC) at its April 28, 2020 meeting. All sectors had a quorum.

1. **Agenda Item No.2: March 25, 2020 MEETING MINUTES**
   ACTION: APPROVED

   The Transmission Committee approved the minutes of the March 25, 2020 Transmission Committee meeting by a voice vote with no opposition and no abstentions recorded.

2. **Agenda Item No. 3: Proposed Modifications to Schedule 24 of the Open Access Transmission Tariff to Comply with FERC Order 676-I**

   The following motion was made and seconded by the Transmission Committee:

   > *Resolved*, that the Transmission Committee recommends that the Participants Committee support the revisions to Schedule 24 of Section II of the ISO New England Inc. (the “ISO”) Transmission, Markets, and Services Tariff (the “Tariff”) as proposed by the ISO and as circulated in the materials distributed for the April 28, 2020 meeting with those further changes recommended by this Committee and supported by the ISO and such further non-substantive changes as the Chair and Vice-Chair approve after the meeting.

   The motion was voted and passed on a voice vote with no opposition and no abstentions recorded.

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
413-535-4135
jdwyer@iso-ne.com

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval, NEPOOL Counsel

DATE: April 30, 2020

RE: Enhancements and Clean-Up Changes to ISO-NE Billing Policy

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At its May 7, 2020 meeting, the Participants Committee will be asked to consider clean-up changes and enhancements to the ISO New England Billing Policy ("Billing Policy"). The Billing Policy changes were raised by the ISO in conjunction with certain clean-up changes to the ISO Financial Assurance Policy that are still under review by the NEPOOL Budget and Finance Subcommittee (the "Subcommittee").[1] The changes to the Billing Policy were discussed by the Subcommittee at its March 26, 2020 and April 21, 2020 teleconferences, and no Subcommittee members objected to the changes. This memorandum describes the proposed changes to the Billing Policy, and those changes are included in Attachment 1 to this memorandum.

The following are the changes to the Billing Policy:

- *Section 1.3* – Addition of pass-through charges, including communications-related charges, OASIS charges and fees for the Shortfall Funding Arrangements, to the items that are included on the monthly statements. These charges are already included on those invoices, and this is a clean-up change to add their inclusion to the Billing Policy.
- *Section 2.2* – Moving the date on which monthly statements are issued from the first Monday after the tenth of each calendar month to the first Monday after the ninth of each calendar month. The ISO has determined it has all the information needed to issue invoices one day earlier, and this change reduces the time between when charges are incurred and when they are billed, thereby reducing default risk.
- *Sections 3.1(a), 3.2* – Changing references to the ISO *sending* Invoices and Remittance Advices to the ISO *issuing* Invoices and Remittance Advices to reflect the fact that the ISO issues those invoices electronically.
- *Section 3.1(c)* – Moving the time to provide instructions to the ISO for the ISO to draw on collateral or other account to pay an invoice from one Business Day before the invoice is issued to two Business Days before the Invoice is issued. The extra day will provide the ISO with the time needed to process the auto-debit instructions from the Market Participant.
- *Section 3.1(e)(i)* – Limiting prepayments of invoices to five such prepayments in any rolling 365-day period. The ISO proposed this change because certain Market Participants had been

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[1] The clean-up changes to the Financial Assurance Policy are being considered together with more significant changes related to applications by new Market Participants and annual compliance filings by existing Market Participants (a/k/a the "Know Your Customer Changes"). All of those FAP changes will be discussed again on the Subcommittee's next teleconference on May 14.

using prepayments to reduce certain amounts due in order to avoid increasing the financial assurance obligations that are based on multiples of those amounts, creating additional exposure for the rest of the Pool.

- *Sections 4.2(a), 4.2(b)* – Addition of language prohibiting Market Participants who are in payment default from receiving a distribution of excess funds from the Late Payment Account or the Transmission Late Payment Account.

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

> RESOLVED, that the Participants Committee supports revisions to the ISO New England Billing Policy to make certain enhancements and clean-up changes, as proposed by the ISO and as circulated to this Committee with the April 30, 2020 supplemental notice, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair of the Budget and Finance Subcommittee.

EXHIBIT ID

ISO NEW ENGLAND BILLING POLICY

Table of Contents

SECTION 1 –OVERVIEW
SECTION 2 -TIMING AND CONTENT OF STATEMENTS
SECTION 3 -PAYMENT PROCEDURES
SECTION 4 -LATE PAYMENT CHARGES; LATE PAYMENT ACCOUNTS
SECTION 5 -SHORTFALL FUNDING ARRANGEMENT; PAYMENT DEFAULT SHORTFALL FUND
SECTION 6 -BILLING DISPUTE PROCEDURES
SECTION 7 -WEEKLY BILLING PRINCIPLES FOR NON-HOURLY CHARGES

c) Where a Covered Entity’s total Charges exceed its total Payments for all amounts being billed together in a billing period, the ISO shall issue an “Invoice” for the net Charge owed by such Covered Entity.

d) Where a Covered Entity’s total Payments exceed its total Charges for all amounts being billed together in a billing period, the ISO shall issue a “Remittance Advice” for the net Payment owed to the Covered Entity. Invoices and Remittance Advices are collectively referred to herein as “Statements.”

Section 1.3 -General Process. Except for special billings, as described in Section 1.4 below, the billing process is performed (i) twice weekly for each complete-day settlement amount for the hourly charges and payments for Real-Time Energy and Day-Ahead Energy and for each complete-day settlement amount for the hourly charges and payments for Real-Time Operating Reserve, Forward Reserves, Regulation service, Emergency Sales, Emergency Purchases and Net Commitment Period Compensation (all such hourly charges and payments described in this clause (i) being referred to collectively as the “Hourly Charges”); (ii) monthly for all other charges and payments, including without limitation charges relating to the monthly markets, the Forward Capacity Market and other ancillary services, Participant Expenses, charges under Section IV of the ISO Transmission, Markets and Services Tariff, monthly meter adjustments, Qualification Process Cost Reimbursement Deposits (including the annual true-up of those Qualification Process Cost Reimbursement Deposits), state sales tax and related charges, any pass-through charges where the ISO acts as agent (including communications related charges, Open Access Same-Time Information System related charges, and fees related to the Shortfall Funding Arrangement), and charges under the OATT (*other than* charges arising under Schedules 1, 8, and 9 to the OATT, which charges are addressed in clause (iii) below) (all such charges and payments described in this clause (ii) being referred to collectively as (-“Non-Hourly Charges” and, together with Hourly Charges, as “ISO Charges”), except in the case of Covered Entities who have requested and received a weekly payment arrangement for Non-Hourly Charges under the ISO New England Financial Assurance Policy that is Exhibit IA to Section I of the ISO Transmission, Markets and Services Tariff (the “ISO New England Financial Assurance Policy”); and (iii) monthly for all charges and payments under Schedules 1, 8 and 9 to the OATT (all such charges and payments described in this clause (iii) being referred to collectively as “Transmission Charges”). There are two major steps in the billing process:

it becomes possible to catch up on the settled data. Statements will include contiguous month-to-month hourly market billing data and will have separate line items for any hourly market data that may cross calendar months. For example, if a Statement's billing period includes May 30 through June 2, and all of those days are fully settled, the June 8 Statement would have one line item for the period May 30 to May 31 and one line item for the period June 1 to June 2. The Job Aid on the ISO web site will be updated weekly for any information necessary to be distributed through that medium.

Section 2.2 -Monthly Statements for Non-Hourly Charges. The first Statement issued on a Monday after the ~~tenth~~ ninth of a calendar month will include both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month (hereinafter sometimes referred to as a "Monthly Statement"). Resettlements determined in accordance with the procedures set forth in Market Rule 1 will be included in the monthly Statement for Non-Hourly Charges.

Section 2.3 - Statements for Weekly Billing Non-Hourly Charges. The ISO shall implement any weekly billing arrangements for Non-Hourly Charges effected under the ISO New England Financial Assurance Policy in accordance therewith and with the procedures set forth in Section 7 below.

Section 2.4 -Contents of Statements. Each Statement for Hourly and Non-Hourly Charges will include all of the following line items that are applicable to the Covered Entity receiving such Statement for the period to which such Statement relates:

a) *Invoice or Remittance Advice Amount*. The net amount of all Charges and Payments owed by or due to a Covered Entity for the relevant Statement. The ISO shall issue an Invoice where the Covered Entity owes monies. The ISO shall issue a Remittance Advice where the Covered Entity is owed monies.

b) *OATT Charges and Payments.* The Charges owed by and the Payments owed to the Covered Entity under the OATT *other than* Transmission Charges, which are billed separately under Section 2.5 below.

billing shall be allocated to Schedule 1 of Section IV of the Transmission, Markets and Services Tariff.

c) *Adjustments Reflecting Compliance with an Order of the Commission or other Regulatory or Judicial Authority With Jurisdiction*. Adjustments required to effect compliance with an order of the Commission (or any other regulatory or judicial authority with jurisdiction to interpret and/or enforce the provisions of the Governing Documents) shall be completed by the ISO in compliance with such order. The costs of any such re-billing to the ISO shall be allocated among the Covered Entities in accordance with the provisions of the Transmission, Markets and Services Tariff.

d) Nothing in this Section 2.6 shall affect resettlements of the New England Markets under Market Rule 1.

SECTION 3 -PAYMENT PROCEDURES.

All Payments (including prepayments as described in Section 3.1(e) below) made by the ISO will in all instances be made by EFT or in immediately available funds payable to the account designated to the ISO by the Covered Entity to which such Payment is due. Payments made by Covered Entities shall be made by EFT to the account designated by the ISO.

Section 3.1 -Invoice Payments.

a) *Payment Date*. Except in the case of special billings, all Charges due shall be paid to and received by the ISO not later than the second (2nd) Business Day after the Invoice on which they appeared was issued (the "Invoice Date") so long as the ISO ~~sends~~ issues such Invoice to the Covered Entities by 11:00 a.m. Eastern Time on the Invoice Date. If the ISO ~~sends~~ issues an Invoice after 11:00 a.m. Eastern Time on the Invoice Date, the charges on such Invoice will be paid not later than the third (3rd) Business Day after such Invoice Date. Notwithstanding the foregoing, a Non-Market Participant Transmission Customer will in no event be required to make a payment on an Invoice any sooner than provided in Section II of the Transmission, Markets and Services Tariff.

b) *Right to Alter Payment Date*. The ISO may establish the dates on which payments are due in the case of a special billing; provided, however, that, (i) payment on any special billing invoice shall not be due prior to the second (2nd) Business Day after the Invoice is issued, and (ii) a Non-Market Participant Transmission Customer shall not be required to make a payment on an Invoice any sooner than provided in Section II of the Transmission, Markets and Services Tariff.

c) *Payments Received by the ISO*. Each Covered Entity owing monies to the ISO, either in the ISO's individual capacity, or as agent for NEPOOL, shall remit the amount shown on its Invoice no later than the date such payment is due. Disputed Amounts shall be paid in accordance with clause (d) below. All Invoices shall be paid by EFT, except that (i) Covered Entities (other than Unqualified New Market Participants and Returning Market Participants under the ISO New England Financial Assurance Policy that are not Provisional Members) may, and any Provisional Member must, pay any Invoice for ISO Charges (but not for Transmission Charges) by instructing the ISO (either on a case-by-case basis or pursuant to a standing instruction) in writing to draw on collateral maintained in a shareholder account created pursuant to the ISO New England Financial Assurance Policy provided by such Covered Entity under the ISO New England Financial Assurance Policy for such Invoice, provided that the failure of a Provisional Member to provide such an instruction to the ISO shall not, in and of itself, be deemed to be a default under the ISO New England Billing Policy and (ii) any Covered Entity may instruct the ISO to auto-debit an account identified by that Covered Entity to pay all Invoices issued by the ISO and in such case the Covered Entity will direct the bank or other institution holding that account to permit the ISO to auto-debit that account to pay all such Invoices on the date they are due. Any instruction to pay any Invoice by drawing on collateral maintained in a shareholder account or to auto-debit an account must be received by at least 5:00 p.m. (Eastern Time) on the day that is two ~~by no later than the first~~ Business Days prior to the Invoice Date~~following the date~~

~~of such Invoice~~. The amount of a Covered Entity's collateral maintained in a shareholder account will immediately be reduced by the amount drawn to pay an Invoice for ISO Charges pursuant to a standing instruction. Nothing set forth in this section will reduce the financial assurance obligation otherwise applicable to any Covered Entity that instructs the ISO to draw on collateral maintained in a shareholder account or to auto-debit an account to pay an Invoice, and the ISO is not liable for any default resulting from a draw on collateral maintained in a shareholder account to pay an Invoice or for any overdraft charges resulting from any auto-debit.

d) *Payments Pending Resolution of a Dispute.* Any Covered Entity that disputes the amount due, including an amount due for Participant Expenses, on any Invoice for service other than transmission service under Section II of the Transmission, Markets and Services Tariff shall pay to the ISO all amounts due on such Invoice, including any such Disputed Amounts. Such payment shall in no way prejudice the right of such Covered Entity to seek reimbursement of such Disputed Amounts, including accrued interest on such amounts at the Commission's standard rate, set forth in 18 C.F.R. Section 35.19, pursuant to the Billing Dispute Resolution Procedures provided in Section 6 below.

Any Covered Entity that disputes the amount due on any Invoice for transmission service under the Transmission, Markets and Services Tariff shall pay to the ISO all amounts not in dispute in accordance with the ISO New England Billing Policy and shall pay (or, in the case of an auto-debit payment or a payment for ISO Charges pursuant to a standing instruction, as described above, direct the ISO to pay) such Disputed Amounts into an independent escrow account designated by the ISO, which account shall be established at a banking institution acceptable to the ISO and the Covered Entity challenging the amount due and shall accrue interest at a prevailing market rate. Such amount in dispute shall be held in escrow pending the resolution of such dispute in accordance with the applicable Governing Document(s). The shortfall of funds available to pay Remittance Advices resulting from the amount in dispute being held in an escrow account shall be allocated among the Covered Entities according to the two-step allocation process described in Section 3.3 (for ISO Charges) and in Section 3.4

(for Transmission Charges) for the applicable type of Covered Entity disputing the Charges, subject to payment to all Covered Entities being allocated a portion of the shortfall, with applicable interest (if any), once the dispute is resolved with the funds in such escrow account or with other amounts provided by the Covered Entity losing such dispute.

e) *Prepayments*. A Covered Entity may prepay any Invoice, in whole or in part, according to the following procedures:

(i) only two such prepayments shall be made by any Covered Entity in any calendar week; only five such prepayments shall be made in any rolling 365-day period; ~~,~~ and no prepayments shall be made on a Friday;

(ii) each prepayment will be applied only to the next subsequent Invoice issued;

(iii) prepayments and payments for issued Invoices must be made in separate wire transfers;

(iv) for purposes of calculating a Covered Entity’s financial assurance obligations under the ISO New England Financial Assurance Policy, prepayments will be applied first to Hourly Charges, then any remaining prepayment will offset the Covered Entity’s financial assurance obligations on a dollar-for-dollar basis;

(v) if ISO Charges and Transmission Charges are billed on separate Invoices, then separate prepayments must be made for those ISO Charges and Transmission Charges (the ISO will account for each prepayment separately and will only apply each prepayment to the designated Charges);

(vi) if a prepayment exceeds the amount due on the next subsequent Invoice issued, then the prepayment will be applied to that Invoice first, and then to the extent any amount is left after paying that Invoice, the Covered Entity making that prepayment may direct at the time of the prepayment that the excess be deposited with its collateral maintained in a shareholder account created pursuant to the ISO New England Financial Assurance Policy, and if the Covered Entity does not direct the ISO to make that deposit, the excess will be returned to the Covered Entity. Under either circumstance, the deposit to the shareholder account or the return of excess funds will occur on the next date when the ISO pays Remittances; and

(vii) all prepayments will be held in the ISO's settlement account until the Invoice payments are due, and no interest will be paid to any Covered Entity on any prepayments provided by it.

Section 3.2 -ISO Payment of Remittance Advice Amounts. The Payment Date for a Remittance Advice shall be the fourth (4th) Business Day following the date on which the Remittance Advice was issued (the "Remittance Advice Date") so long as the ISO ~~sends~~ issues such Remittance Advice by 11:00 a.m. Eastern Time on the Remittance Advice Date. If the ISO ~~sends~~ issues a Remittance Advice after 11:00 a.m. Eastern Time on the Remittance Advice Date, the Payment Date for that Remittance Advice shall be the fifth (5th) Business Day after the Remittance Advice Date.

Section 3.3 -Payment Default for ISO Charges. If the ISO, in its reasonable opinion, believes that all or any part of any amount of ISO Charges due to be paid to the ISO by any Covered Entity will not or has not been paid when due (other than in the case of (i) a payment dispute for any amount due for transmission service under the OATT or (ii) any amounts due for NEPOOL GIS API Fees) (the "Default Amount"), then the following procedures shall apply:

a) *Priority of Payments*. The ISO shall use moneys received by it from Covered Entities for an Invoice for ISO Charges to pay all amounts due to the ISO under Section IV of the Transmission, Markets and Services Tariff, all amounts due to NEPOOL for Participant Expenses, and all amounts due to the ISO for acting as Project Manager for the generation information system (the "NEPOOL GIS") before making any payments to any Covered Entities. After paying all amounts due to the ISO and NEPOOL but prior to making any payments to any Covered Entities, the ISO shall use moneys received by it from Covered Entities for ISO Charges to pay all amounts due from NEPOOL to the entity or entities that develop, administer, operate and maintain the NEPOOL GIS (the "NEPOOL GIS Administrator") for those services (other than NEPOOL GIS API Fees). After paying all amounts due to the ISO and NEPOOL for Participant Expenses and all amounts due to the NEPOOL GIS Administrator for the development, administration, operation and maintenance of the NEPOOL GIS but prior to making any payments to any Covered Entities, the ISO shall use moneys received by it from Covered Entities for ISO Charges to pay any and all amounts including without limitation any late payment charges or rights to terminate or limit trading rights of the defaulting Covered Entity, to the extent such rights and remedies otherwise exist.

SECTION 4 – LATE PAYMENT CHARGE; LATE PAYMENT ACCOUNT

Section 4.1 -Late Payment Charge.

(a) If a Covered Entity is delinquent two or more times within any period of 12 months in paying on time its ISO Charges, such Covered Entity shall pay, in addition to interest on each such late payment, a late payment charge for its second failure to pay on time, and for each subsequent failure to pay on time within the same 12-month period (a “Late Payment Charge”) in an amount equal to the greater of (i) two percent (2%) of the total amount of such late payment or (ii) $500.00. In the case of a former Market Participant that applies again for membership in the ISO, a determination of delinquency shall be based on the Market Participant’s history of payment of its ISO Charges in its last 12 months of membership.

(b) If a Covered Entity is delinquent two or more times within any period of 12 months in paying on time its Transmission Charges, such Covered Entity shall pay, in addition to interest on each such late payment, a late payment charge for its second failure to pay on time, and for each subsequent failure to pay on time within the same 12-month period (a “Transmission Late Payment Charge”) in an amount equal to the greater of (i) two percent (2%) of the total amount of such late payment or (ii) $500.00. In the case of a former Market Participant that applies again for membership in the ISO, a determination of delinquency shall be based on the Market Participant’s history of payment of its Transmission Charges in its last 12 months of membership.

Section 4.2 -Late Payment Account; Transmission Late Payment Account.

(a) Interest collected on late payments of ISO Charges shall be allocated and paid to the Covered Entities to whom such late payments are due, pro rata in accordance with the amount due to each such Covered Entity. Late Payment Charges that are collected and not distributed to the Covered Entities under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy shall be deposited by the ISO into a segregated interest-bearing account (the "Late Payment Account") for disbursement in accordance with Section 3.3 of the ISO New England Billing Policy; provided, however, that in no event shall the amount in the Late Payment Account, including interest accrued thereon, at any time exceed $1,000,000 or other amount determined from time to time by the Participants Committee (the "Late Payment Account Limit"). Any amount in the Late Payment Account (including interest thereon) in excess of the Late Payment Account Limit shall be distributed to the Market Participants, no more frequently than quarterly, pro rata based on their ISO Charges in the month preceding the month in which such distribution is to be made; provided, however that no amount from the Late Payment Account shall be distributed to any Market Participant in payment default at the time of such distribution.

(b) Interest collected on late payments of Transmission Charges shall be allocated and paid to the Covered Entities to whom such late payments are due, pro rata in accordance with the amount due to each such Covered Entity. Transmission Late Payment Charges that are collected and not distributed to the Covered Entities under the ISO New England Billing Policy shall be deposited by the ISO into a segregated interest-bearing account (the "Transmission Late Payment Account") for disbursement in accordance with Section 3.4 of the ISO New England Billing Policy; provided, however, that in no event shall the amount in the Transmission Late Payment Account, including interest accrued thereon, at any time exceed $1,000,000 or other amount determined from time to time by the Participants Committee (the "Transmission Late Payment Account Limit"). Any amount in the Transmission Late Payment Account (including interest thereon) in excess of the Transmission Late Payment Account Limit shall be distributed to the Market Participants, no more frequently than quarterly, pro rata based on their Transmission Charges in the month preceding the month in which such distribution is to be made; provided, however that no amount from the Transmission Late Payment Account shall be distributed to any Market Participant in payment default at the time of such distribution.

EXECUTIVE SUMMARY
Status Report of Current Regulatory and Legal Proceedings
as of May 4, 2020

The following activity, as more fully described in the attached litigation report, has occurred since the report dated March 31, 2020 was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

COVID-19

	1	Blanket Waiver of ISO/RTO Tariff In-Person Meeting & Notarization Requirements (EL20-37)	Apr 2	FERC provides blanket waiver, eff. Apr 2 – Sep 1, 2020, of all jurisdictional agreement requirements for (i) document notarization and (ii) *in-person* meetings
	1	Remote ALJ Hearings (AD20-12)	Apr 23	All hearings before Administrative Law Judges will be hold remotely until further notice
	1	Extension of Filing Deadlines (AD20-11)	Apr 2	***to June 1, 2020***: deadlines for filing (i) 2020 Q1 EQRs, (ii) FERC Forms 60, 61 and 552; ***Upon Request***: Entities may still seek waiver of FERC orders, regulations, tariffs and rate schedules, as appropriate, to address needs resulting from steps taken in response to COVID-19

I. Complaints/Section 206 Proceedings

*	2	NERA Petition: FERC Jurisdiction Over Customer-Side-of-the-Retail-Meter Energy Sales (EL20-42)	Apr 14	New England Ratepayers Association asks the FERC to assert jurisdiction over energy sales from facilities located on the customer side of the retail meter (rooftop solar and other DG) (i) whenever the DG output exceeds customer demand or (ii) where the energy from the DG is designed to bypass the customer's load and therefore is not used to serve demand behind the customer's meter, and ensure the output is priced accordingly
			Apr 16-May 4	Entities intervene
			Apr 28-May 4	NARUC, NRECA/APPA, State Entities, Org of MISO States, Nat'l Assoc. of State Energy Officials request 90-day extension of time to comment
			Apr 29– May 4	NESCOE, Joint Parties, State Entities, PIOs, AEE, SEIA, KS Corp. Comm, among others, support requests for 90-day extension of time
			Apr 29	NERA opposes 90-day extension of time (does not oppose 30-60 days)
			May 4	FERC grants 30-day extension of time to intervene/comment; comment date ***Jun 15, 2020***
	4	Energy Security Improvements (Chapter 3) (EL18-182)	Apr 15	ISO-NE files ESI alternatives (see ER20-1567 in Section III below)
	5	206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19-002)	Apr 21	TOs request procedural schedule be suspended for an add'l 47 days
			Apr 22	Chief Judge Cintron grants request, proceeding to be held in abeyance until Jun 8, 2020; TOs next status report due on or before May 18, 2020

II. Rate, ICR, FCA, Cost Recovery Filings

	9	FCA14 Results Filing (ER20-1025)	Apr 10	FERC accepts results filing, eff. Jun 17, 2020
*	11	MPD OATT 2020 Annual Informational Filing (ER15-1429-000)	May 1	Emera Maine submits annual update of charges under the MPD OATT
	11	MPD OATT 2018 Annual Informational Filing Settlement Agreement (ER15-1429-012)	Apr 1	FERC Trial Staff files comments supporting Settlement
			Apr 14	Settlement Judge Dring certifies, and recommends approval of, Settlement to the Commission

	12	MPD OATT 2018 Annual Info. Filing (ER15-1429-010)	Apr 14	Settlement Judge Dring issues final report
			Apr 22	Chief Judge Cintron terminates settlement judge procedures

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

*	13	Waiver Request: Settlement Only Resources Definition -- GMP's Searsburg facility (ER20-1755)	May 1	Green Mountain Power requests limited waiver of Settlement Only Resources definition to allow its Searsburg facility to maintain its Settlement Only Resource/SOG registration; comment date May 22
			May 4	NEPOOL intervenes
*	13	Extension of Implementation Date: SOG Dispatchability Changes (ER20-1582)	Apr 16	ISO-NE requests deferral of effective date of previously-accepted revisions to Tariff § I.2 that require Settlement Only Resources (SOGs) above 5 MW to register as dispatchable generators and meet offer telemetry requirements, from Jun 1, 2020 to Jan 1, 2021, due to COVID-19 related impacts
			Apr 24, 27	NEPOOL, National Grid intervene
*	14	ESI Alternatives (ER20-1567)	Apr 15	ISO-NE files ESI Alternative; comment date May 15, 2020
			Apr 16-May 1	Avangrid, Brookfield RTM, Calpine, CT DEEP, CT OCC, Dominion, ENE, Eversource, Exelon, MA AG, National Grid, NEPGA, NESCOE, NRG, PSEG, MPUC, VT PUC, AWEA, EPSA, Helix Maine, Public Citizen intervene
			Apr 24	NEPOOL files comments supporting the NEPOOL Alternative
*	14	eTariff § III.13.6 Conforming Changes (ER20-1497)	Apr 3	ISO-NE submits a conformed § III.13.6 to be effective Jun 1, 2020
			Apr 24	NEPOOL intervenes
	14	NCPC Audit Eligibility Clean Up (ER20-1094)	Apr 20	FERC accepts changes, eff. May 1, 2020
	15	*Order 841* Compliance Filings (Electric Storage in RTO/ISO Markets) (ER19-470)	Apr 16	FERC denies ISO-NE's request for rehearing of Nov 22 order conditionally accepting New England *Order 841* compliance filing
	17	Economic Life Determination Compliance and Prospective Revisions (ER18-1770)	Apr 9	ISO-NE and NEPOOL jointly file changes in response to the FERC's directives in the order granting rehearing of its Nov 9, 2018 order
			Apr 30	NEPGA files comments supporting changes that eliminate the Economic Life Revisions as directed in the *Economic Life Revisions Rehearing Order*; National Grid intervenes
	20	2013/14 Winter Reliability Program Remand Proceeding (ER13-2266)	Apr 1	FERC accepts ISO-NE's Jan 23, 2017 compliance filing and finds that the bid results from the 2013/14 Winter Reliability Program were just and reasonable
			May 1	TransCanada requests rehearing of Apr 1 order

IV. OATT Amendments / TOAs / Coordination Agreements

	21	CIP IROL Cost Recovery Rules (ER20-739)	Apr 17	IROL-Critical Facility Owners file comments on ISO-NE's Mar 27 response to the FERC's Feb 26 deficiency letter
			Apr 24	NESCOE answers IROL-Critical Facility Owners Apr 17 comments
	22	ISO-NE *Order 845* Compliance Filing (ER19-1951)	Apr 20	ISO-NE seeks expedited clarification of two aspects of the *Order 845 Compliance Filing Order*
			May 4	NEPOOL answers ISO-NE's Apr 20 motion

V. Financial Assurance/Billing Policy Amendments

No Activity to Report

VI. Schedule 20/21/22/23 Changes

*	24	Schedule 21-NEP: NSTAR LSA (ER20-1692)	Apr 29	National Grid submits LSA between NEP and NSTAR; comment date May 20
*	24	Schedule 20A-NEP: NEP-Brookfield RTM Phase I/II HVDC-TF Service Agreement (ER20-1626)	Apr 21	National Grid files a new Phase I/II HVDC-TF Service Agreement between NEP and Brookfield RTM; comment date May 12
			Apr 29	Brookfield RTM submits comments
*	25	Schedule 21-VEC and 20-VEC: Annual Informational Filing (ER10-1181)	Apr 30	VEC submits its annual update to its Schedule 21-VEC and 20-VEC formula rates covering the Jul 1, 2020 – Jun 30, 2021 period

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

	26	Capital Projects Report - 2019 Q4 (ER20-973)	Apr 3	FERC accepts 2019 Q4 Report, eff. Jan 1, 2020
*	26	LFTR Implementation: 46th Quarterly Status Report (ER07-476)	Apr 15	ISO-NE files its 46th quarterly report
	27	Reserve Market Compliance (28th) Semi-Annual Report (ER06-613)	Apr 2	ISO-NE submits 28th semi-annual report
*	27	IMM Quarterly Markets Reports - 2020 Winter (ZZ20-4)	May 4	IMM files Winter 2020 Report
*	27	ISO-NE FERC Form 1 (not docketed)	Apr 15	ISO-NE files 2019 FERC Form 1
			Apr 16	ISO-NE files CPA Certification Statement for 2019 FERC Form 1
*	27	ISO-NE FERC Reporting Req. 582 (not docketed)	Apr 27	ISO-NE submits 2019 annual report of total MWh of transmission service (approx. 1.27 million MWhs)

IX. Membership Filings

*	27	May 2020 Membership Filing (ER20-1694)	Apr 30	***Membership***: RPA Energy Inc. d/b/a Green Choice Energy; ***Termination***: Empire Generating Co.; comment date May 20, 2020
	28	March 2020 Membership Filing (ER20-1130)	Apr 3	FERC accepts (i) the membership of SP Transmission (Provisional Member); (ii) the termination of the Participant status of QPH Capital (Supplier Sector); and (iii) the name change of Pixelle Energy Services

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

	28	Revised Reliability Standard: PRC-024-3 (RD20-7)	Apr 20	CAISO files comments supporting approval of Revised PRC-024
	29	CIP Standards Development: Virtualization and Cloud Computing Services Projects Informational Filings (RD20-2)	Apr 21, 27	B. Jones, VMware, Inc. submit comments
*	29	Reliability Standard Implementation Deferral (RD18-4; RM17-13; RM16-22; RM15-4)	Apr 6	NERC requests approval of deferral of several FERC-approved Reliability Standards that have effective dates or phased-in implementation dates in the second half of 2020
			Apr 7, 9	IRC, Joint Associations support deferral request
			Apr 10	Protect Our Power, M. Mabee protest deferral request
			Apr 17	FERC grants NERC's deferral request

	30	NOI: Virtualization and Cloud Computing Services in BES Operations (RM20-8)	Apr 2	FERC extends dates for comments and reply comments to Jul 1, 2020 and Jul 31, 2020, respectively
			Apr 20-28	Bureau of Reclamation, B. Jones, Siemens Energy Management, VMware, A2lA, Waterfall Security Solutions file comments
	30	NOPR - Retirement of Reliability Standard Reqs. (Standards Efficiency Review) (RM19-17; -16)	Apr 3-6	BPA, NERC, WAPA file comments

XI. Misc. - of Regional Interest

	31	PJM MOPR-Related Proceedings (EL18-178; EL16-49)	Apr 16	FERC issues an order granting, in part, and denying, in part, the requests for rehearing and clarification of the *Dec 2019 PJM MOPR Order;* directs PJM to submit a further compliance filing within 45 days
			Apr 20-30	Parties appeal *April 2020 PJM MOPR Rehearing Order* to DC Circuit
	34	PJM Clean MOPR Complaint (EL18-169)	Apr 16	FERC dismisses Complaint as moot
*	34	VTransco/VEC ShPA and O&M Agreements (ER20-1679)	Apr 29	VTransco files Agreements; comment date May 20, 2020
*	35	Phase II VT DMNRC Support Agreement *Order 864*-Related Filing (ER20-1480)	Apr 1	VELCO, as agent of Joint Owners, submits filing explaining why no changes to the Agreement are required to comply with *Order 864*
			Apr 3-13	IRH Management Committee, Eversource, National Grid intervene
			Apr 22	GMP intervene and submits comments
	35	IA Cancellations: NGrid/GRS, NGrid/Mini-Watt (ER20-1405/1406/1407)	Apr 28	FERC accepts notice of cancellation of superseded Mini-Watt Unit No. 1 SGIA, eff. May 27, 2020
	36	IA / TSA Cancellations: Emera Maine/ReEnergy Ashland (ER20-1172/1173)	Apr 22	FERC accepts notices of cancellation of Emera Maine's IA and TSA with ReEnergy Ashland, each eff. Feb 28, 2020
	36	IA / TSA Cancellations: Emera Maine/ReEnergy Fort Fairfield (ER20-1076/1077)	Apr 8	FERC accepts notice of cancellations, eff. Feb 24, 2020
	36	Northern Pass: TSA Cancellation / Cost Reimbursement (ER20-1030/1031)	Apr 14	FERC accepts TSA cancellation and cost reimbursement letter, eff. Sep 6, 2019 and Apr 19, 2020, respectively
	37	Amended and Restated CONVEX Services Agreement: CL&P/MMWEC (ER20-996)	Apr 6	FERC accepts amended and restated Agreement, eff. Feb 14, 2020

XII. Misc. - Administrative & Rulemaking Proceedings

*	38	Carbon Pricing in RTO/ISO Markets (AD20-14)	Apr 14	Industry associations/participants request FERC convene a tech. conf. or workshop to discuss integrating state, regional and national carbon pricing in RTO/ISO markets; comment date May 21, 2020
			Apr 21-27	PJM IMM, MA AG, Institute for Policy Integrity, Western Power Trading Forum support request
*	38	Hybrid Resources Technical Conference (AD20-9)	Apr 7	FERC issues notice of Jul 23, 2020 tech. conf.; panelist self-nominations due May 15
*	41	Increasing Market and Planning Efficiency Through Improved Software (AD10-12)	Apr 7	FERC issues sup. notice of Jun 23-25 tech. conf.

41	NOPR – Electric Transmission Incentives Policy (RM20-10)	Apr 27 Apr 29 May 4	Schulte Assoc. submits comments American Manufacturers request 90-day extension of Jul 1, 2020 comment deadline APPA/TAPS support extension; WIRES, EEI oppose extension
42	NOPR: QF Rates and Requirements; Implementation Issues under PURPA (RM19-15)	Apr 7 May 4	US Rep S. Casten (D-IL) submits comments opposing FERC action SEIA submits comments
43	*Orders 864/864-A*: Public Util. Trans. ADIT Rate Changes (RM19-5)	Apr 16	FERC denies reh'g and grants clarification in part of *Order 864*
45	Order 676-I: NAESB WEQ Standards v. 003.2 - Incorporation by Ref. into FERC Regs (RM05-5-027)	Apr 3 Apr 6	FERC extends compliance filing deadline from May 25, 2020, up to and including July 27, 2020 FERC issues tolling order affording it add'l time to consider requests for reh'g and clarification of *Order 676-I*

XIII. Natural Gas Proceedings

48	Constitution Pipeline (CP13-499) and Wright Interconnection Project (CP13-502)	Mar 31	Iroquois notifies the FERC that it will not be moving forward with the Wright Interconnection Project

XIV. State Proceedings & Federal Legislative Proceedings

51	Executive Order on Securing the United States Bulk-Power System	May 1	President Trump signs an Executive Order prohibiting Federal agencies and U.S. persons from "acquiring, transferring, or installing BPS equipment in which any foreign country or foreign national has any interest and the transaction poses an unacceptable risk to national security or the security and safety of American citizens."

XV. Federal Courts

	COVID-19 Response		***All in-person onsite oral arguments suspended pending further order of the court.*** Each panel scheduled to hear argument on a particular day will determine whether: (1) argument will proceed by teleconference; (2) argument will be postponed until a later date; or (3) the case(s) will be decided without oral argument
52	ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224) (consol.)***	Apr 13 Apr 14 Apr 21	The Court issues and order establishing briefing formats and schedule FERC requests the Court suspend the Apr 13 briefing schedule and grant voluntary remand of the agency record Court grants motion to suspend briefing and for voluntary remand; directs parties to file status reports at 90-day intervals beginning Jul 20, 2020
53	*Order 841* (19-1142, 19-1147) (consol.)	May 5	Oral argument before Judges Rogers, Garland and Wilkins held by teleconference
53	PG&E Bankruptcy (19-71615) (9th Cir.)	Apr 6	9th Circuit issues an order directing the case be calendared on Aug 12 or 14 in Pasadena; arguments to be held remotely if conditions dictate

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: May 5, 2020

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

We have summarized below the status of key ongoing proceedings relating to NEPOOL matters before the Federal Energy Regulatory Commission ("FERC"),[1] state regulatory commissions, and the Federal Courts and legislatures through May 4, 2020. If you have questions, please contact us.

COVID-19

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

On April 2, 2020, the FERC, pursuant to Section 206 of the Federal Power Act ("FPA"), provided a blanket waiver, effective April 2, 2020 and through September 1, 2020, of all jurisdictional agreement[2] requirements for (i) document notarization and (ii) *in-person* meetings (such meetings must still be held, but should be conducted by other means). The FERC, noting alternatives like electronic signatures and telephonic and web-based meeting capabilities, indicated that it was taking the action given the President's proclamation of a National Emergency, the unprecedented risk to health and safety currently presented by personal contact, and consistent with guidance from public health officials on social distancing. The blanket waiver made moot requests separately filed earlier by ISO-NE (ER20-1484) and NYISO (ER20-1419), among others.

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

On April 23, 2020, Chief Judge Cintron issued a notice that all hearings before Administrative Law Judges will be held remotely through video conference software until further notice. 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.

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

to June 1, 2020. On April 2, 2020, the FERC issued a blanket extension, until ***June 1, 2020***, for the deadlines for filing (i) 2020 Q1 EQRs, (ii) FERC Form Nos. 60 (Annual Report of Centralized Service Companies) and 61 (Narrative Description of Service Company Functions); and (iii) FERC Form 552 (Annual Report of Natural Gas Transactions).

Upon Request. In a March 19 notice, the FERC indicated that entities may seek waiver of FERC orders, regulations, tariffs and rate schedules, including motions for waiver of regulations that govern the form of

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

[2] This waiver applies to any tariff, rate schedule, service agreement, or contract subject to the FERC's jurisdiction under the FPA, the Natural Gas Act, or the Interstate Commerce Act.

filings, as appropriate, to address needs resulting from steps they have taken in response to the coronavirus. The FERC committed to take action on any such motions as expeditiously as possible.

The FERC's March 19 blanket extension of time, until ***May 1, 2020***, of deadlines to make filings required by the FERC that occur on or before May 1, 2020, for those entities unable to meet certain deadlines due to steps they have taken to meet the emergency conditions caused by COVID-19 has since expired.[3]

I. Complaints/Section 206 Proceedings

- **NERA Petition: FERC Jurisdiction Over Customer-Side-of-the-Retail-Meter Energy Sales (EL20-42)**

On April 14, 2020, the New England Ratepayers Association ("NERA") asked the FERC to assert jurisdiction over energy sales from facilities located on the customer side of the retail meter (rooftop solar and other DG) (i) whenever the DG output exceeds customer demand or (ii) where the energy from the DG is designed to bypass the customer's load and therefore is not used to serve demand behind the customer's meter, and ensure the output is priced accordingly. More than 100 Entities, including NEPOOL, have already intervened. A number of state-affiliated organizations, including NARUC, NRECA/APPA, State Entities,[4] the Organization of MISO States, and the National Association of State Energy Officials, requested a 90-day extension of time from the original comment date of May 14 to comment. Several parties, including NESCOE, Joint Parties,[5] PIOs,[6] Advanced Energy Economy ("AEE"), Solar Energy Industries Association ("SEIA"), and the Kansas Corporation Commission, supported the request for a 90-day extension of time. NERA opposed the requests for 90 days, suggesting instead an extension of between 30 and 60 days. On May 4, the FERC granted a 30-day extension of time to intervene/comment in this proceeding. Comments are now due on or before June 15, 2020.

- **Liberty Complaint – Eversource/ISO-NE Failure to Correct Nov 2018 Meter Data Error/Load Assignment (EL20-27)**

On February 28, 2020, Liberty Power Holdings, LLC ("Liberty") filed a complaint against Eversource Energy Company ("Eversource") and ISO-NE related to a November 2018 Meter Data Error ("Nov 2018 Error") for a load in Metering Domain #685 ("Nov 2018 Load"). Liberty asserted (i) that Eversource incorrectly assigned the Nov 2018 Load to Liberty (as it did with a December 2018 load, which was subsequently corrected via Meter Data Error ("MDE") request #12/18/02MD); and (ii) ISO-NE refused to correct the error for the Nov 2018 Load at Liberty's Request Billing Adjustment ("RBA") because the RBA was not received within three months of the date that the Invoice containing the Disputed Amount was issued. Liberty further asserted that the Tariff, in light of the facts and circumstances Liberty describes in the Complaint, provides a

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[3] Deadlines that occurred on or before May 1, 2020 that were extended for entities unable to meet deadlines due to steps taken to meet the emergency conditions included: (i) FERC Forms (other than FERC From 6 (Annual Report of Oil Pipeline Companies)); (ii) non-statutory deadlines (e.g. compliance filings, responses to deficiency letters, rulemaking comments, answers, interventions, protests, or comments to complaints, answers to orders to show cause, and initial and reply briefs in paper hearings before the FERC); and (iii) tariff or rate schedule-based deadlines.

[4] "State Entities" are: Massachusetts Attorney General Maura Healey ("MA AG"), the state attorneys general of Conn., the District of Columbia, Iowa, Maryland, Michigan, Minnesota, New Jersey, North Carolina, Rhode Island ("RI AG"), the Maine Office of the Public Advocate ("MOPA") , and the Pub. Util. Comm. of Oregon.

[5] "Joint Parties" are: the Conn. Pub. Utils. Regulatory Authority ("CT PURA"), the New Jersey Board of Pub. Utils. ("NJ BPU"), the Conn. Dept. of Energy and Environ. Protection ("CT DEEP"), the Conn. Office of Consumer Counsel ("CT OCC") and the New Jersey Division of Rate Counsel.

[6] "PIOs" are: the Center for Biological Diversity, Climate + Energy Project, Conservation Law Foundation ("CLF"), Environmental Law & Policy Center, Natural Resources Defense Council ("NRDC"), Public Citizen, Idaho Conservation League, RENEW Wisconsin, Sierra Club, Solar United Neighbors, Sustainable FERC Project, and Vote Solar.

basis for the correction beyond the three-month period for RBA submissions.[7] The amount in dispute is $191,440 plus interest ("Disputed Amount"). Liberty seeks an order directing Eversource to refund the Disputed Amount to ISO-NE and directing ISO-NE to refund the Disputed Amount to Liberty.

ISO-NE and Eversource responded to Liberty's Complaint on March 19 and 18, 2020, respectively. In its response, ***ISO-NE*** asserted that "Liberty's Complaint has no basis under the Tariff, law, or equity, and should be rejected" because Liberty "failed to take timely or appropriate action to detect the [Nov 2018 E]rror and request that it be corrected" pursuant to ISO Tariff procedures. ISO-NE reported that, "in the three months leading up to the applicable deadline, Liberty was given information on five separate occasions that should have alerted it … to the Nov[] 2018 [E]rror." ISO-NE stated that the "tolling provision that Liberty claims gives safe harbor where a party only discovers an error after the deadline has passed is taken from a set of billing procedures that explicitly do not apply in this case." ISO-NE added that the Liberty Complaint "also ignores the importance of settlement finality that underlies the correction procedures in the Tariff." ***Eversource*** argued for summary dismissal in its response by highlighting the opportunities Liberty had to timely identify the Nov 2018 Error, by explaining why denying the Complaint is consistent with and supportive of the filed-rate doctrine, as well as distinguishable from other instances in which the FERC has allowed the correction of billing errors. Eversource also explained that any correction would have been (or would need to be) paid by different retail supplier (not Eversource). NEPOOL submitted a doc-less motion to intervene.

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

- **206 Investigation: ISO-NE Implementation of Order 1000 Exemptions for Immediate Need Reliability Projects (EL19-90)**

As previously reported, the FERC instituted a proceeding under FPA Section 206 on October 17, 2019 to consider whether ISO-NE may be implementing exemptions for immediate need reliability projects in a manner that is inconsistent with what the FERC directed pursuant to *Order 1000*, and therefore may be unjust and unreasonable, unduly preferential and discriminatory.[8] The FERC noted that, "based on its review of the annual informational filings and materials provided in stakeholder processes as posted on the Responding RTOs' websites, we are concerned that the Responding RTOs may be implementing the exemption in a manner that is inconsistent with or more expansive than what the Commission directed."[9] The FERC directed ISO-NE to respond to questions in the *October 17 Order* to: (1) demonstrate how it is complying with the immediate need reliability project criteria; (2) demonstrate that the provisions in the Tariff, as implemented, containing certain exemptions to the requirements of *Order 1000* for immediate need reliability projects remain just and reasonable; and (3) consider additional conditions or restrictions on the use of the exemption for immediate need reliability projects to appropriately balance the need to promote competition for transmission development and avoid delays that could endanger reliability. ISO-NE's response was due and was filed on December 27, 2019. The FERC noted its expectation that it would issue a final order within six months of ISO-NE's response.[10] On October 18, the FERC issued a notice of the proceeding and of the refund effective date, which will be October 28, 2019 (the date the *October 17 Order* was published in the *Federal Register*).

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[7] *See* § 6.3.1 of the Tariff: A Disputing Party must submit its Requested Billing Adjustment within three months of the date that the Invoice or Remittance Advice containing the Disputed Amount was issued by the ISO unless the Disputing Party could not have reasonably known of the existence of the alleged error within such time.

[8] *ISO New England Inc. et al.*, 169 FERC ¶ 61,054 (Oct. 17, 2019) ("*October 17 Order*").

[9] *Id.* at P 7.

[10] *Id.* at P 23.

Those interested in participating in this proceeding were required to intervene on or before November 27, 2019.[11] Interventions were filed by: NEPOOL, ISO-NE, Anbaric, Avangrid, Calpine, CT AG, CT, OCC, CT PURA, ENE, Eversource, IECG, LSPower, MA AG, MA DPU, MMWEC, MS PSC, NESCOE, NHEC, NextEra, NRDC, NRG, PSEG, AK PSC, ATC, Developers Advocating Transmission Advancements, East TX Cooperative, EEI, IECA, LA PSC, MD PSC, Mid-Kansas Electric Co., NJ PBU, NY TOs, NY Transco, Northeast TX Electric Cooperative, PA PUC, Public Citizen, Sunflower Electric Cooperative, and Xcel Energy Services. As noted above, ISO-NE submitted its responses on December 27, 2019.

Comments on ISO-NE's response are due on or before January 27, 2020 and were filed by: NEPOOL, Avangrid, Eversource, LSP Transmission, MMEWC, National Grid, NESCOE, CT PURA, State Agencies,[12] Developers Advocating Transmission Advancements, and EEI. Reply comments were submitted by ISO-NE, Eversource and Avangrid and National Grid. On February 21, State Agencies answered National Grid's reply comments. On March 3, LSP Transmission replied to the replies submitted by ISO-NE, Eversource/Avangrid and National Grid. There has been no activity in this proceeding since the last Report.

As noted above, a FERC order in this proceeding is expected by the end of June 2020. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Energy Security Improvements (Chapter 3) (EL18-182)**

As previously reported, the July 2, 2018 *Mystic Waiver Order*[13] (reported on in more detail in ER18-1509 in Section III below) in part instituted this Section 206 proceeding in light of the FERC's preliminarily finding that the ISO-NE Tariff may be unjust and unreasonable in that it fails to address specific regional fuel security concerns identified in the record in ER18-1509 that could result in reliability violations as soon as 2022. Accordingly, the *Mystic Waiver Order* directed ISO-NE, in part, to submit permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns (the "Chapter 3 Proposal"). In response to that directive, and in accordance with the extensions of time previously granted, ISO-NE filed the Energy Security Improvements ("ESI") alternatives on April 15, 2020. That proceeding is summarized in Section III below (ER20-xxxx). request for an extension of time to file its Chapter 3 Proposal, the FERC issued a notice granting an extension of time, to and including October 15, 2019, a month earlier than requested, for the filing of that Proposal. The deadline has since been further extended – to ***April 15, 2020***.[14] Markets Committee consideration of ISO-NE's Energy Security Improvements ("ESI") project is on-going, with action by the Markets Committee scheduled for March 24 and by the Participants Committee on April 2, 2020.

Since the last Report, ISO-NE filed in this proceeding a copy of an e-mail sent to FERC staff transmitting links to ISO-NE's 2020 Regional Electricity Outlook and its presentation entitled "New England's Wholesale Electricity Markets: The Clean Energy Transition and Future Pathways." The e-mail was filed to mitigate any ex parte concerns that might otherwise be created given the discussion of Energy Security Improvements ("ESI") in both.

If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

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[11] The *October 17 Order* was published in the *Fed. Reg.* on Oct. 29, 2019 (Vol. 84, No. 208) pp. 57,726-57,727.

[12] "State Agencies" are: the CT and MA Attorneys General, CT DEEP, CT OCC, and MOPA.

[13] *ISO New England Inc.*, 164 FERC ¶ 61,003 (July 2, 2018), *reh'g requested* ("*Mystic Waiver Order*").

[14] Notice of Extension of Time, *ISO New England Inc.*, Docket No. EL18-182 (Aug. 30, 2019).

- **206 Proceeding: RNS/LNS Rates and Rate Protocols (EL16-19-002)**

As described below, the procedural schedule in this proceeding is now suspended until May 18, 2020 "with aim to finalize settlement."

2018 Settlement (Rejected). Concluding that the contested 2018 Joint Offer of Settlement (the "Settlement"),[15] filed to resolve all issues in the Section 206 proceeding instituted by the FERC on December 28, 2015,[16] lacked sufficient detailed information to enable it to apply any of the approaches available to it to approve a contested settlement,[17] the FERC rejected the Settlement and remanded this proceeding (EL16-19) to Chief Judge Cintron to resume hearing procedures.[18]

As previously reported, the Settlement was supported by ***NESCOE*** but opposed by Municipal PTF Owners[19] and FERC Trial Staff. The ***Municipal PTF Owners*** ("Munis") asserted that the Settlement would worsen, rather than improve, the issues of "lack of transparency, clarity and specificity that led the Commission [to] find the existing Attachment F formula unjust and unreasonable", discriminate against load directly connected to PTF and exempted by Section II.12(c) of the ISO-NE Tariff from paying costs associated with service across non-PTF facilities, contravened numerous settled rate principles without explanation or justification,[20] and would have imposed an unacceptable moratorium and burden on parties inclined to challenge Attachment F. ***FERC Trial Staff*** asserted that the Settlement, as filed, was not fair and reasonable nor in the public interest "because it would result in unreasonable rates and contains fundamental defects",[21] and opposed the Settlement terms which would

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[15] As previously reported, the Settling Parties filed the Settlement on Aug. 17, 2018, in ER18-2235. The Settlement proposed changes to Section II.25, Schedules 8 and 9, Attachment F (including the addition of Interim Formula Rate Protocols ("Interim Protocols")), and the Schedule 21s to the ISO-NE OATT. Had they been approved, the changes to Attachment F would have become effective mid-June, 2019, with the remaining changes to be effective January 1, 2020. The Interim Protocols, as well as the changes to Section II.25 and Schedules 8 and 9, were supported by the Participants Committee at its July 24, 2018 meeting.

[16] *ISO New England Inc. Participating Transmission Owners Admin. Comm.*, 153 FERC ¶ 61,343 (Dec. 28, 2015), *reh'g denied,* 154 FERC ¶ 61,230 (Mar. 22, 2016) ("*RNS/LNS Rates and Rate Protocols Order*"). The *RNS/LNS Rates and Rate Protocols Order* found the ISO-NE Tariff unjust, unreasonable, and unduly discriminatory or preferential because the Tariff "lacks adequate transparency and challenge procedures with regard to the formula rates" for Regional Network Service ("RNS") and Local Network Service ("LNS"). The FERC also found that the RNS and LNS rates themselves "appear to be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful" because (i) "the formula rates appear to lack sufficient detail in order to determine how certain costs are derived and recovered in the formula rates" and "could result in an over-recovery of costs" due to the "the timing and synchronization of the RNS and LNS rates". The FERC encouraged the parties to make every effort to settle this matter before hearing procedures are commenced. The FERC-established refund date is January 4, 2016.

[17] The FERC outlined in a seminal case the following four alternative approaches for approving contested settlements: (1) where the FERC can render a binding merits decision on each contested issue, (2) where the FERC can approve the settlement based on a finding that the overall settlement *as a package* is just and reasonable, (3) where the FERC can determine that the benefits of the settlement outweigh the nature of the objections and the interests of the contesting party are too attenuated, and (4) where the FERC can approve the settlement as uncontested for the consenting parties, and can sever the contesting parties to allow them to litigate the issues raised. *See Trailblazer Pipeline Co.*, 85 FERC ¶ 61,345, at 62,342-44 (1998).

[18] *ISO New England Inc. Participating Transmission Owners Admin. Comm., et al.*, 167 FERC ¶ 61,164 (May 22, 2019) ("*RNS Rate/Rate Protocol Settlement Order*").

[19] "Municipal PTF Owners" are: Braintree, Chicopee, Middleborough, Norwood, Reading, Taunton, and Wallingford.

[20] The elements of the Settlement that Municipal PTF Owners assert contravene settled rate principles include: provision for a fixed accrual for Post-Employment Benefits Other than Pension ("PBOPs"); continued TO use of net proceeds of debt, rather than gross proceeds of debt, in establishing capital structures under their proposed revenue requirement formula; inappropriate allocation of rental revenues from secondary uses of transmission facilities; the addition of miscellaneous intangible plant (Account 303), and depreciation and amortization of intangibles, to rate base; and the creation of a Regulatory Asset for an unspecified Massachusetts state tax rate change (without explanation).

[21] Included in the "fundamental defects" of the Settlement identified by FERC Trial Staff are that it: (1) enables the TOs to conduct extra-formulaic, ad hoc ratemaking for all externally-sourced inputs every year; (2) enables certain PTOs to over-recover certain plant costs; (3) enables certain PTOs to recover greater than 50% of Construction Work in Progress ("CWIP") in rate base (4) violates prior FERC orders about which customer groups can be made to pay incentive returns; (5) fails to appropriately calculate federal and state income taxes and,

bind non-settling parties to the terms of the Settlement and establish a standard of review for changes to the Settlement. FERC Trial Staff suggested that these defects could be corrected in a comprehensive compliance filing. ***Reply comments*** were submitted by NEPOOL, NESCOE and the MA AG. In its limited comments, ***NEPOOL*** noted that it supported the Interim Protocols and that it had no objection to the Settlement. ***NESCOE*** reiterated its support for the Settlement in its reply comments, urging the FERC to reject any arguments that consumer-interested parties "were not familiar with the issues relating to the Settlement or that they reached a settlement for any reason other than their view that it is in the best interests of consumers."[22] ***MA AG*** urged the FERC to approve the Settlement as submitted, despite the objections of FERC Trial Staff and Municipal PTF Owners, because it complies with the *RNS/LNS Rates and Rate Protocols Order* and represents a carefully negotiated resolution to numerous complex ratemaking and transparency issues.[23]

Hearings. On May 23, 2019, Chief Judge Cintron designated Judge David H. Coffman as the Presiding Judge for the purpose of hearings and issuance of an initial decision within Track III procedural time standards.[24] A prehearing conference was held on June 6, 2019. Following that conference, orders establishing a procedural schedule and adopting rules of conduct for the hearing were issued. That schedule has since been extended three times by a total of 85 days and is currently suspended (*see* immediately below).

Procedural Schedule Further Suspended Until June 8, 2020. On April 21, 2020, the TOs requested a further 47-day suspension of the procedural schedule. Chief Judge Cintron issued an order on April 22, 2020 granting that request, with the proceedings to be held in further abeyance until June 8, 2020. The TOs must file a status report with the Chief Judge and Presiding Judge by May 18, 2020. As previously noted, if the current suspension period concludes without a settlement filed, the Chief Judge and Presiding Judge will take action to re-establish a procedural schedule absent good cause provided for a further suspension.

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,[25] set the TOs' Base ROE at 10.57% (reduced from 11.14%), capped the TOs' total ROE (Base ROE *plus* transmission incentive adders) at 11.74%, and required implementation effective as of October 16, 2014 (the date of *Opinion 531-A*).[26] However, the FERC's orders were challenged, and in *Emera Maine,*[27] the DC Circuit Court

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in particular, fails to account for excess Accumulated Deferred Income Taxes ("ADIT") created by the Tax Cuts and Jobs Act; (6) does not contain a fixed and stated ROE; and (7) does not contain a fixed and stated PBOPs expense.

[22] Reply Comments of NESCOE, Docket Nos. ER18-2235 and EL16-19, at p. 2 (filed Sep. 28, 2018).

[23] Reply Comments of the Mass. Att'y General in Support of Settlement, Docket Nos. EL16-19 and ER18-2235 (filed Sep. 28, 2018).

[24] Track III time standards require a hearing be convened within 42 weeks and an initial decision issued within 63 weeks.

[25] The TOs' 11.14% pre-existing Base ROE was established in *Opinion 489*. *Bangor Hydro-Elec. Co.*, Opinion No. 489, 117 FERC ¶ 61,129 (2006), *order on reh'g*, 122 FERC ¶ 61,265 (2008), *order granting clarific.*, 124 FERC ¶ 61,136 (2008), *aff'd sub nom.*, Conn. Dep't of Pub. Util. Control v. FERC, 593 F.3d 30 (D.C. Cir. 2010) ("*Opinion 489*")).

[26] *Coakley Mass. Att'y Gen. v. Bangor Hydro-Elec. Co.*, 147 FERC ¶ 61,234 (2014) ("*Opinion 531*"), *order on paper hearing*, 149 FERC ¶ 61,032 (2014) ("*Opinion 531-A*"), *order on reh'g*, 150 FERC ¶ 61,165 (2015) ("*Opinion 531-B*").

[27] *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017) ("*Emera Maine*"). *Emera Maine* vacated the FERC's prior orders in the Base ROE Complaint I proceeding, and remanded the case for further proceedings consistent with its order. The Court agreed with both the TOs (that the FERC did not meet the Section 206 obligation to first find the existing rate unlawful before setting the new rate) and "Customers"

vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the FERC remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.

- ***Base ROE Complaints II & III (EL13-33 and EL14-86) (consolidated)***. The second (EL13-33)[28] and third (EL14-86)[29] ROE complaint proceedings were consolidated for purposes of hearing and decision, though the parties were permitted to litigate a separate ROE for each refund period. After hearings were completed, ALJ Sterner issued a 939-paragraph, 371-page *Initial Decision*, which lowered the base ROEs for the EL13-33 and EL14-86 refund periods from 11.14% to 9.59% and 10.90%, respectively.[30] The *Initial Decision* also lowered the ROE ceilings. Parties to these proceedings filed briefs on exception to the FERC, which has not yet issued an opinion on the ALJ's *Initial Decision*.

- ***Base ROE Complaint IV (EL16-64)***. The fourth and final ROE proceeding[31] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[32] The *Base ROE IV Initial Decision* concluded that the currently-filed base ROE of 10.57%, which may reach a maximum ROE of 11.74% with incentive adders, was ***not*** unjust and unreasonable for the Complaint IV period, and hence was not unlawful under section 206 of the FPA.[33] Parties in this proceeding filed briefs on exception to the FERC, which has not yet issued an opinion on the *Base ROE IV Initial Decision*.

October 16, 2018 Order Proposing Methodology for Addressing ROE Issues Remanded in Emera Maine and Directing Briefs. On October 16, 2018, the FERC, addressing the issues that were remanded in *Emera Maine,* proposed a new methodology for determining whether an existing ROE remains just and reasonable.[34] The FERC indicated its intention that the methodology be its policy going forward, including in

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(that the 10.57% ROE was not based on reasoned decision-making, and was a departure from past precedent of setting the ROE at the midpoint of the zone of reasonableness).

[28] The 2012 Base ROE Complaint, filed by Environment Northeast (now known as Acadia Center), Greater Boston Real Estate Board, National Consumer Law Center, and the NEPOOL Industrial Customer Coalition ("NICC", and together, the "2012 Complainants"), challenged the TOs' 11.14% ROE, and seeks a reduction of the Base ROE to 8.7%.

[29] The 2014 Base ROE Complaint, filed July 31, 2014 by the Massachusetts Attorney General ("MA AG"), 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.

[30] *Environment Northeast v. Bangor Hydro-Elec. Co. and Mass. Att'y Gen. v. Bangor Hydro-Elec. Co,* 154 FERC ¶ 63,024 (Mar. 22, 2016) ("*2012/14 ROE Initial Decision*").

[31] The 4th ROE Complaint asked the FERC to reduce the TOs' current 10.57% return on equity ("Base ROE") to 8.93% and to determine that the upper end of the zone of reasonableness (which sets the incentives cap) is no higher than 11.24%. The FERC established hearing and settlement judge procedures (and set a refund effective date of April 29, 2016) for the 4th ROE Complaint on September 20, 2016. Settlement procedures did not lead to a settlement, were terminated, and hearings were held subsequently held December 11-15, 2017. The September 26, 2016 order was challenged on rehearing, but rehearing of that order was denied on January 16, 2018. *Belmont Mun. Light Dept. v. Central Me. Power Co.*, 156 FERC ¶ 61,198 (Sep. 20, 2016) ("*Base ROE Complaint IV Order*"), *reh'g denied*, 162 FERC ¶ 61,035 (Jan. 18, 2018) (together, the "*Base ROE Complaint IV Orders"*). *The Base ROE Complaint IV Orders*, as described in Section XV below, have been appealed to, and are pending before, the DC Circuit.

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

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

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

the four currently pending New England proceedings. The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[35]

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%.[36] 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[37] 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. 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.

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[35] *Id.* at 19.

[36] *Id.* at P 59.

[37] 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*[38] 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, 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

- **FCA14 Results Filing (ER20-1025)**

On April 10, 2020, the FERC accepted the results of the fourteenth FCA ("FCA14"), effective June 17, 2020, as requested.[39] As previously reported:

- ♦ FCA14 Capacity Zones were the Southeastern New England ("SENE") Capacity Zone (the Northeastern Massachusetts ("NEMA")/Boston, Southeastern Massachusetts, and Rhode Island Load Zones), the Northern New England ("NNE") Capacity Zone (the Maine, New Hampshire and Vermont Load Zones), and the Rest-of-Pool Capacity Zone (the Connecticut and Western/Central Massachusetts Load Zones). NNE was modeled as an export-constrained Capacity Zone. The Maine Load Zone was modeled as a separate nested export-constrained Capacity Zone within NNE.
- ♦ FCA14 commenced with a starting price of $13.099/kW-mo. and concluded for all Capacity Zones after five rounds.
- ♦ All Resources will be paid the same Capacity Clearing Price -- $2.001/kW-mo. – including imports at the NY AC Ties (510.7 MW), Highgate (64 MW), Phase I/II HQ Excess external interface (412 MW), and New Brunswick (72 MW).
- ♦ There were no active demand bids for the substitution auction and, accordingly, the substitution auction was not conducted.
- ♦ No resources cleared as Conditional Qualified New Generating Capacity Resources.
- ♦ No Long Lead Time Generating Facilities secured a Queue Position to participate as a New Generating Capacity Resource.
- ♦ No de-list bids were rejected for reliability reasons.

Unless the April 10 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

Final actions by the FERC in this proceeding remain pending. As previously reported, the FERC conditionally accepted the Cost-of-Service Agreement ("COS Agreement")[40] among Constellation Mystic

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[38] *Ass'n of Buss. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569, 169 FERC ¶ 61,129 (2019) ("*MISO ROE Order*").

[39] *ISO New England Inc.*, Docket No. ER20-1025 (Apr. 10, 2020) (unpublished letter order).

[40] 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

Power ("Mystic"), Exelon Generation Company ("ExGen") and ISO-NE.[41] The COS Agreement will provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024. The *Mystic Order* directed Mystic to submit a compliance filing (intended to modify aspects of the COS Agreement that FERC rejected or directed be changed) on or before February 18, 2019, and established a paper hearing to ascertain whether and how the ROE methodology that FERC proposed in *Coakley* should apply in the case. Requests for clarification and/or rehearing of the *Mystic Order* were filed by Constellation Mystic Power, CT Parties, EDF, ENECOS, MA AG, NESCOE, NextEra, and Repsol. CT Parties answered Constellation's request for rehearing. Constellation answered the other parties' requests for rehearing. NESCOE answered Constellation's answer. On February 15, 2019, the FERC issued a tolling order affording it additional time to consider the requests for clarification and/or rehearing, which remain pending.

Mystic's Compliance Filing. On March 1, 2019, Mystic submitted its required compliance filing. The compliance filing included the following modifications:

- Modification to Section 2.2 (Termination) which provides ISO-NE will be required to seek FERC authorization to extend the term of the COS Agreement beyond May 31, 2024; deletion of Section 2.2.1 in its entirety;
- Inclusion of a clawback provision;
- Modification to Section 4.4 related to settlement of over- and underperformance credits;
- A clarification that fuel opportunity costs will not be included as part of the Stipulated Variable Costs used to calculate the revenue credits;
- Modifications to information access provisions (§ 6.2) both to allow ISO-NE full access to information and to support verification of third-party sales;
- Modifications to Schedule 3 supporting multiple compensation-related directives (e.g. cost of capital/cost of service, fuel supply charge, settlement of over- and under-performance credits);
- Schedule 3A modifications related to Mystic's true-up process; and
- Non-substantive conforming changes.

In addition, Mystic's compliance filing included for informational purposes changes to the Fuel Supply and Terminal Services Agreements. Comments on Mystic's compliance filing were due on or before March 22, 2019. Protests and comments were filed by CT Parties, ENECOS, MA AG, National Grid, Public Systems (MMWEC/NHEC), and NESCOE. Mystic answered the March 22 protests on April 8. Also, on March 22, Concord, Reading and Wellesley moved for the release from Protective Order a documentary response regarding the net book value of Mystic 8 and 9 from the 2006 Mystic 8/9 RMR proceeding (ER06-427). Mystic's compliance filing and the pleadings related thereto remain pending before the FERC.

ROE Paper Hearing. The *Mystic Order* established a paper hearing to determine the just and reasonable ROE to be used in setting charges under Mystic's COS Agreement. On April 19, Mystic, Connecticut Parties, ENECOS, MA AG, and FERC Trial Staff filed initial briefs. On July 18, 2019, Constellation Mystic Power, CT Parties, ENECOS, MA AG, National Grid, FERC Trial Staff filed reply briefs. The ROE Paper Hearing is now pending before the FERC.

July Mystic COS Agreement Order. Rehearing remains pending of the FERC's July order. As previously reported, the FERC issued an initial order regarding the COS Agreement, accepting the COS Agreement but suspending its effectiveness and setting it for accelerated hearings and settlement discussions.[42] The *Mystic*

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.

[41] *Constellation Mystic Power, LLC*, 165 FERC ¶ 61,267 (Dec. 20, 2018) ("*Mystic Order*").

[42] *Constellation Mystic Power,* 164 FERC ¶ 61,022 (July 13, 2018) ("*July Mystic COS Agreement Order*"), *reh'g requested*.

COS Agreement Order was approved by a 3-2 vote, with dissents by Commissioners Powelson and Glick. Challenges to the *July Mystic COS Agreement Order* were filed by NESCOE, ENECOS, MA AG, and the NH PUC. Constellation answered the NESCOE request for reconsideration on August 21. On September 10, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

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

- **MPD OATT 2020 Annual Informational Filing (ER15-1429-000)**

On May 1, 2020, Emera Maine submitted its annual informational filing setting forth, for the June 1, 2020 to May 31, 2021 rate year, the charges for transmission service under the MPD OATT ("MPD Charges") and an updated transmission real power loss factor. Although this filing will not be noticed for public comment, it 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 (*see, e.g.*, 2019 and 2018 filings below below). If there are questions on this latest MPD OATT Informational Filing, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **MPD OATT 2019 Annual Informational Filing (ER15-1429-000)**

On May 1, 2019, as corrected by its filing on May 16, 2019, Emera Maine submitted its 2019 annual informational filing setting forth, for the June 1, 2019 to May 31, 2020 rate year, the charges for transmission service under the MPD OATT ("MPD Charges") and an updated transmission real power loss factor. Although this filing and the May 16 correction were not noticed for public comment, it will nevertheless 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 (*see, e.g.*, ER15-1429-010 below). On June 11, Maine Customer Group ("MCG") moved to strike a portion of Emera Maine's May 1 filing. Specifically, MCG moved to strike the trueup to actuals portion of Emera's Annual Update filing to the extent that true-up proposes a change in the formula rate from a direct assignment of Maine Public District ("MPD") post- retirement benefits other than pensions ("PBOPs") to an allocation of company-wide PBOPs (which MCG argued would be a retroactive change to Emera Maine's formula rate, otherwise required to effect only prospectively). On June 26, Emera Maine answered MCG's June 11 motion to strike. This matter remains pending before the FERC. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **MPD OATT 2018 Annual Informational Filing Settlement Agreement (ER15-1429-012)**

On March 12, 2020, Emera Maine submitted an uncontested Joint Offer of Settlement between itself, MPUC and the MCG to resolve all the issues set for hearing by the FERC in its *2018 Challenge Order*[43] (*see* ER15-1429-010 immediately below). On March 17, Emera Maine requested authorization to implement on an interim basis its "revised rates and charges to wholesale network and point-to-point transmission customers" that are "in accordance with" the Settlement ("Settlement Rates"), effective as of February 1, 2020. On March 18, 2020, Chief Judge Cintron authorized Emera Maine to implement the Settlement Rates as of February 1, 2020, subject to refund or surcharge, with interest, pending the outcome of the FERC's consideration of the Settlement Agreement.[44] Initial comments and reply comments were due on April 1, 2020 and April 13, 2020, respectively. On April 1, FERC Trial Staff filed comments supporting the Settlement; no other comments were

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[43] *Emera Maine*, 167 FERC ¶ 61,090 (Apr. 30, 2019) ("*2018 Challenge Order*").

[44] *Emera Maine*, 170 FERC ¶ 63,028 (Mar. 18, 2020) ("*Settlement Rates Order*").

filed. The Settlement is uncontested, was certified to the FERC (and recommended for approval) by Settlement Judge Dring on April 14, 2020,[45] and is pending before the FERC.

- **MPD OATT 2018 Annual Informational Filing (ER15-1429-010)**

As previously reported, the FERC granted, in part, on April 30, 2019, the formal challenge filed on December 31, 2018 by the Maine Customer Group[46] (the "2018 Challenge") to Emera Maine's May 15, 2018 annual informational filing[47]and set the remaining issues for hearing and settlement judge procedures.[48] As previously reported, the 2018 Challenge sought certain cost reductions/ exclusions[49] to be effective June 1, 2018 following unsuccessful efforts to obtain the relief sought directly from Emera Maine MPD through informal resolution procedures in accordance with the Protocols. In granting in part the 2018 Challenge, the FERC found that Emera Maine's formula rate should be corrected for the current rate year and Emera Maine must submit a compliance filing on or before May 30 that revises its 2018-2019 formula rate charges to correct certain acknowledged errors, exclusion of certain costs for land associated with a project not in service, the exclusion of certain costs for distribution equipment from transmission rates, and the flowback of excess accumulated deferred income tax ("ADIT"). As to the remaining issues, addressing Administrative and General ("A&G") expenses, merger-related prior losses, exclusion of costs attributed to Line 6901, and exclusion of land rights cost, the FERC found that the 2018 Annual Update raises issues of material fact that cannot be resolved based on the record and set those issues for hearing and settlement judge procedures. Hearings will be held in abeyance to provide time for settlement judge procedures.

Settlement Judge Procedures. Chief Judge Cintron designated John P. Dring as the Settlement Judge for these proceedings. Judge Dring held two settlement conferences, one on July 18, 2019 and the second on September 11, 2019. A third settlement conference occurred on October 7, 2019, and the parties reached an agreement in principle at that time. As reported in ER15-1429-012 immediately above, the parties filed a settlement on March 12, 2020, and Judge Dring certified and recommended approval of the Settlement on April 14, 2020. On April 22, Chief Judge Cintron terminated settlement judge procedures, subject to final action by the Commission.

Further reporting on this matter will continue in ER15-1429-012. If there are questions, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **TOs' *Opinion 531-A* Compliance Filing Undo (ER15-414)**

Rehearing remains pending of the FERC's October 6, 2017 order rejecting the TOs' June 5, 2017 filing in this proceeding.[50] As previously reported, the June 5 filing was designed to reinstate TOs' transmission rates to those in place prior to the FERC's orders later vacated by the DC Circuit's *Emera Maine*[51] decision. In

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[45] *Emera Maine*, 171 FERC ¶ 63,008 (Apr. 14, 2020) ("*MPD OATT 2018 Annual Info Filing Settlement Agreement Certification*").

[46] For purposes of this proceeding, "Maine Customer Group" or "MCG" is the MPUC, MOPA, Houlton Water Co., and Van Buren Light & Power District, and Eastern Maine Electric Cooperative.

[47] The May 15 filing, submitted in accordance with the Protocols for Implementing and Reviewing Charges Established by the MPD OATT Attachment J Rate Formulas ("Protocols"), set forth for the June 1, 2018 to May 31, 2019 rate year, the charges for transmission service under the MPD OATT ("MPD Charges"). *See* May 31, 2018 Litigation Report.

[48] *2018 Challenge Order*.

[49] The formal challenge sought (i) exclusion of certain regulatory expenses allocated or directly assigned to the MPD transmission customers; (ii) exclusion of costs that would otherwise constitute a double-recovery for amortization of losses incurred as a result of a merger; (iii) correction of MPD-acknowledged errors in its Annual Update Filing; (iv) exclusion of certain costs for land associated with a project not in service; (v) exclusion from transmission rates certain costs for distribution equipment; (vi) exclude of costs improperly attributed to line 6901; and (vii) a flowback of excess ADIT resulting from the corporate tax reduction, and a requirement for Emera MPD to include a worksheet in its tariff to track excess/deficient ADIT.

[50] *ISO New England Inc.*, 161 FERC ¶ 61,031 (Oct. 6, 2017) ("*Order Rejecting Filing*"), *reh'g requested*.

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

its *Order Rejecting Filing*, the FERC required the TOs to continue collecting their ROEs currently on file, subject to a future FERC order.[52] The FERC explained that it will "order such refunds or surcharges as necessary to replace the rates set in the now-vacated order with the rates that the Commission ultimately determines to be just and reasonable in its order on remand" so as to "put the parties in the position that they would have been in but for [its] error." For the time being, so as not to "significantly complicate the process of putting into effect whatever ROEs the Commission establishes on remand" or create "unnecessary and detrimental variability in rates," the FERC has temporarily left in place the ROEs set in *Opinion 531-A*, pending an order on remand.[53] On November 6, the TOs requested rehearing of the *Order Rejecting Filing*. On December 4, 2017, the FERC issued a tolling order providing it additional time to consider the TOs' request for rehearing of the *Order Rejecting Filing*, which remains pending. If you have any questions concerning this matter, please contact Joe Fagan (202-218-3901; jfagan@daypitney.com) or Eric Runge (617-345-4735; ekrunge@daypitney.com).

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

- **Waiver Request: Settlement Only Resources Definition -- GMP's Searsburg facility (ER20-1755)**

On May 4, Green Mountain Power ("GMP") requested a limited waiver from the revised definition of Settlement Only Resources[54] as applied to GMP's Searsburg wind power facility[55] because the vintage and unique physical characteristics of the Searsburg facility's wind turbines will make compliance with the revised definition of a Settlement Only Resource infeasible.[56] Comments on GMP's waiver request are due on or before May 22, 2020. Thus far, NEPOOL filed a doc-less intervention. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Extension of Implementation Date: SOG Dispatchability Changes (ER20-1582)**

On April 16, ISO-NE filed requested, due to COVID-19 related impacts, a deferral of the effective date of previously-accepted revisions to Tariff § I.2 that require Settlement Only Resources (SOGs) above 5 MW to register as dispatchable generators and meet offer telemetry requirements, from Jun 1, 2020 to Jan 1, 2021.[57] ISO-NE reported that a total of 23 generators (with an aggregate capacity of approximately 90 MW) are required to either convert from SOG status to dispatchable status under the Tariff change or otherwise demonstrate that their maximum net output is not 5 MW or greater, with approximately 24 percent of this capacity indicating that they will retire rather than make the conversion. On April 22, 2020, the Reliability Committee unanimously supported companion changes to OP-14. Comments on this filing were due on or before April 27, 2020; none were filed. Doc-less interventions were filed by NEPOOL and National Grid. This matter is pending before the FERC. If you

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[52] *Order Rejecting Filing* at P 1.

[53] *Id.* at P 36.

[54] *See* ER20-1582 below.

[55] The Searsburg facility is comprised of eleven Zond Z-40 turbines, each of which is rated at 550 kW; the overall project has a nameplate rating of 6MW. However, due to the age and physical characteristics of the turbines (the facility went online in July 1997, and reached its projected design lifetime of 20 years in July 2017), the Searsburg facility has a 20-25 percent capacity factor and produces on average 1.2 to 1.5 MW annually.

[56] Searsburg's SCADA system does not have the ability to set an active power limit for the wind facility, and the GMP control room does not have any turbine-level control capability. In addition, because the facility's Zond Z-40 turbines are among the last turbines of this model still in operation in the country, updated or modified control systems or spare parts for Searsburg's legacy Zond turbines are not available, and GMP states that it is unable to acquire turbine software capable of allowing Searsburg to set up an active power limit. The power output of the facility can only be limited by manually taking individual turbines offline, if a technician is available, or alternatively, shutting down the entire plant remotely by tripping the substation breaker, potentially damaging the wind turbines. Over the coming years, as each of Searsburg's turbines becomes inoperable, GMP will decommission the turbine.

[57] *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER20-1094 (Apr. 20, 2020).

have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **ESI Alternatives (ER20-1567)**

This proceeding was initiated by ISO-NE's April 15, 2020 filing of Tariff revisions to incorporate comprehensive, long-term market enhancements to address the fuel security challenges facing the New England region ("Energy Security Improvements" or "ESI"). The revisions included NEPOOL-supported alternatives to certain aspects of the enhancements proposed by ISO-NE, which ISO-NE and NEPOOL agreed would be considered on equal legal footing with ISO-NE's favored alternative. ISO-NE asked that the FERC issue an order and accept the changes effective no later than November 1, 2020, conditioned on ISO-NE's filing of an appropriate market power mitigation proposal supported by a Market Power Assessment by the fourth quarter of 2021. The ESI Proposals were considered at the April 2 Participants Committee meeting. ISO-NE's ESI proposal with three amendments proposed by NESCOE was approved by NEPOOL and is the NEPOOL Alternative. ISO-NE's ESI proposal without the amendments (the "ISO-NE Proposal") was not supported. Comments on this filing are due on or before May 15, 2020. On April 24, NEPOOL submitted comments to provide NEPOOL's support for the NEPOOL Alternative. Doc-less interventions have thus far been filed by Avangrid, Brookfield RTM, Calpine, CT DEEP, CT OCC, Dominion, ENE, Eversource, Exelon, MA AG, National Grid, NEPGA, NESCOE, NRG, PSEG, MPUC, VT PUC, AWEA, EPSA, Helix Maine, and Public Citizen. 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).

- **eTariff § III.13.6 Conforming Changes (ER20-1497)**

On April 3, 2020, ISO-NE filed updates to its eTariff to ensure that Section III.13.6 consolidates, as of June 1, 2020, previously-accepted changes made with the October 18, 2019 PRD Revisions,[58] April 2, 2018 FCM Revisions,[59] and October 12, 2016 Resource Dispatchability Changes.[60] Comments on this filing were due on or before April 24; none were filed. NEPOOL intervened doc-lessly. 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).

- **NCPC Audit Eligibility Clean-Up (ER20-1094)**

On April 20, 2020, the FERC accepted changes to the Net Commitment Period Compensation ("NCPC") eligibility rules that add Real-Time Dispatch Lost Opportunity Cost NCPC Credits and Rapid Response Pricing Opportunity Cost NCPC Credits.[61] The changes were accepted effective May 1, 2020, as requested. Unless the April 20 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).

- **Fuel Security Retention Limit Revision (ER20-89)**

On March 6, 2020, the ***FERC rejected*** the revision to Market Rule 1 Section III.13.2.5.2.5A(j), jointly filed by ISO-NE and NEPOOL, that would have provided that a resource retained for fuel security reasons would not be retained for a longer period for some other reason beyond the two-year fuel-security retention period ("Fuel

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[58] *See* Price Responsive Demand Clean-Up Changes, *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER20-140 (filed Oct. 18, 2019) ("PRD Revisions"); accepted in *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER20-140 (Dec. 10, 2019) (unpublished letter order).

[59] *See* Forward Capacity Market Revisions, *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER18- 1287-000 (filed Apr. 2, 2018) ("FCM Revisions"). Accepted in *ISO New England Inc. and New England Power Pool Participants Comm.,* Docket No. ER18-1287 (May 8, 2018) (unpublished letter order).

[60] *See* Revisions to Increase Resource Dispatchability , *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER17-68 (filed Oct. 12, 2016) ("Resource Dispatchability Changes"). Accepted in *ISO New England Inc. and New England Power Pool Participants Comm.*, 157 FERC ¶ 61,189 (Dec. 9, 2016).

[61] *ISO New England Inc. and New England Power Pool Participants Comm.*, Docket No. ER20-1094 (Apr. 20, 2020) (unpublished letter order).

Security Retention Limit Revision").[62] Effectively agreeing with Exelon,[63] the FERC did not find the Fuel Security Retention Limit Revision just and reasonable.[64] The FERC explained that, "while we favor limiting the scope and length of out-of-market actions, we seek to balance that objective against the ability to address reliability concerns. The proposal here would remove ISO-NE's ability to retain a fuel security resource to address potential future transmission reliability issues that may arise simply because the resource in question had been retained previously for fuel security."[65] The FERC noted that "the long-term fuel security solution and the competitive transmission solution RFP in response to the Boston Area Needs Assessment … have not yet resolved the reliability concerns identified in the Boston Area Needs Assessment" and added that "we remain open to Filing Parties proposing to revise the relevant reliability review timeline to ensure that resources are not unnecessarily retained when transmission solutions will be in place in time to address identified reliability needs."[66] The March 6 order was not challenged and is final and unappealable. 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).

- **Waiver Request: Vineyard Wind FCA13 Participation (ER19-570)**

Still pending FERC action is Vineyard Wind's December 14, 2018 petition for a waiver of the ISO-NE Tariff provisions necessary to allow Vineyard Wind to participate in FCA13 as an RTR. As previously reported, Vineyard Wind's request for RTR designation was earlier rejected by ISO-NE on the basis that the resource is to be located in federal waters. Under the CASPR Conforming Changes, Vineyard Wind would not have been precluded from utilizing the RTR exemption. Consistent with the discussion in the CASPR Conforming Changes filing, Vineyard Wind asked that the proration requirement that would be triggered by Vineyard Wind's participation in FCA13 as an RTR be limited for FCA13 to it and any other similarly-situated entities (i.e. new offshore wind resources located in federal waters seeking RTR treatment); Vineyard Wind claimed that there would have been no impact on resources qualified to use the RTR exemption in FCA13. ISO-NE filed comments not opposing the Waiver Request, but requested FERC action by January 29, 2019 if the waiver was to be effective for FCA13. NEPGA protested the Waiver Request. Answers to NEPGA's protest were filed by Vineyard Wind and NESCOE. On January 15, the Massachusetts Department of Energy Resources ("MA DOER") intervened out-of-time and submitted comments supporting the Waiver Request. Doc-less interventions were filed by NEPOOL, Avangrid, Dominion, ENE, National Grid, and NextEra. Despite several last minute requests to do so, including a Vineyard Wind emergency motion for immediate stay of FCA13 or, in the alternative, a requirement that FCA13 be re-run following FERC action, the FERC took no action ahead of FCA13 and FCA13 was run without Vineyard Wind receiving RTR treatment. As noted, this matter remains pending before the FERC, with no activity since the last Report. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- ***Order 841* Compliance Filings (Electric Storage in RTO/ISO Markets) (ER19-470)**

As previously reported, the FERC conditionally accepted on November 22, 2019, subject to an additional compliance filing, New England's *Order 841*[67] compliance filing.[68] For the majority of the revisions,

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[62] *ISO New England Inc. and New England Power Pool Participants Comm.*, 157 FERC ¶ 61,189 (Dec. 9, 2016).

[63] As previously reported, Exelon protested the Revision, asserting that the Revision (i) unduly discriminates against fuel security resources in general, and Mystic specifically; (ii) is premature and unreasonably ignores the likelihood that neither the transmission upgrades nor the comprehensive fuel security market mechanism will be completed or implemented prior to the proposed sunset; and (ii) has not been shown to be just and reasonable.

[64] *Id.* at P 29.

[65] *Id*.

[66] *Id.* at P 30.

[67] *See Elec. Storage Participation in Mkts. Operated by Regional Transmission Orgs. and Indep. Sys. Operators*, Order No. 841, 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*").

[68] *ISO New England Inc.*, 169 FEC ¶ 61,140 (Nov. 22, 2019) ("*Order 841 Initial Compliance Filing Order*").

the effective date was December 3, 2019; the effective date for the revisions to Section II.21, Schedule 9 (Regional Network Service), and Schedule 21 (Local Service) of the OATT was December 1, 2019; the effective date for the remainder of the changes will be January 1, 2024.[69]

ISO-NE Request for Rehearing (ER19-470-003). On April 16, 2020, the FERC rejected ISO-NE's request for rehearing of the FERC's finding that the initial compliance filing did not comply with *Order 841*'s requirement to allow electric storage resources to account for their state of charge and duration in the Day-Ahead Energy Market.[70] Confirming its finding that ISO-NE's proposal "failed to account for these State of Charge and Duration Characteristics in the day-ahead market [at the start of each market interval]", the FERC went on to clarify of a number of issues, including (i) that it not prescribe a particular method by which ISO-NE must account for State of Charge and Duration Characteristics of electric storage resources in its day-ahead market, and suggested that ISO-NE might use something akin to the Available Energy and Available Storage parameters used for real-time market purposes;[71] (ii) that it agreed with ISO-NE's argument that "Maximum Run Time and Maximum Charge Time parameters are unnecessary if the duration of an electric storage resource's commitment is otherwise constrained based on its energy schedule and its State of Charge", and suggested that were ISO-NE "to revise its day-ahead market to constrain Binary Storage Facilities' commitment durations based on their approximated Available Energy and Available Storage at the start of each market interval, ISO-NE would sufficiently account for both Maximum Charge Time and Maximum Run Time" ;[72] (iii) that the order did not preclude or prohibit consideration of optimization in day-ahead accounting, nor is accounting for State of Charge and Duration Characteristics of electric storage resources mutually exclusive with optimization;[73] (iv) and it was the fact that "electric storage resources would be in the position of either risking an infeasible day-ahead schedule or offering less energy to the market than they are technically capable of providing" that contravened *Order 841*'s requirements.[74] Having denied rehearing, the FERC stated that it would address the issue of the effective date for the required software upgrades in the Compliance Filing II sub-docket (-004).

Order 841 Compliance Filing II (ER19-470-004). On February 10, 2020, ISO-NE and NEPOOL jointly filed Tariff revisions in response to the *Order 841 Initial Compliance Filing Order*. The revisions included: (i) a provision that addresses the state of charge and duration characteristics of an energy storage facility in the Day-Ahead Energy Market;[75] (ii) metering and accounting practices for electric storage resources, including direct metering requirements and certainty that electric storage resources will not pay twice for the same charging energy; and (ii) a provision which provides that an electric storage facility will "not be precluded from providing retail services so long as it is able to fulfill its wholesale Energy Market and [FCM] obligations". The filing explained why no additional Tariff language was needed to apply transmission charges to an electric storage resource when it is charging for later resale in the wholesale markets and not providing a service. The Tariff Revisions were unanimously supported by the Participants Committee at its February 6 meeting (Agenda

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[69] The Order 841 revisions that became effective on Dec. 3, 2019 were filed in ER19-470-000; the revisions to § II.21, Schedule 9 and Schedule 21 became effective on Dec. 1, 2019 as requested in ER19-470-002; the remainder of the changes will become effective on Jan. 1, 2024 as requested in ER19-470-001.

[70] *ISO New England Inc.*, 171 FERC ¶ 61,043 (Apr. 16, 2020) ("*Order 841 Initial Compliance Filing Rehearing Order*").

[71] *Id.* at P 18.

[72] *Id.* at P 19.

[73] *Id.* at P 21.

[74] *Id.* at P 26.

[75] *See* proposed § III.1.10.6(d) -- "In clearing the Day-Ahead Energy Market, the ISO will account for maximum run time, maximum charge time, state of charge, maximum state of charge, and minimum state of charge through bidding parameters or other means, as required by the Commission in Order No. 841." This language reflects ISO-NE's pending challenge to the *Order 841 Initial Compliance Filing Order* on this point and will be subject to additional revision following disposition of that challenge.

Item #5). Comments on this filing were due on or before March 2, 2020; none were filed. This filing is now pending before the FERC.

If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Fuel Security Retention Proposal (ER18-2364)**

Requests for rehearing and/or clarification of the *Fuel Security Retention Proposal Order*[76] remain pending before the FERC. As previously reported, the *Fuel Security Retention Proposal Order* accepted ISO-NE's Proposal[77] in all respects, despite the various protests and alternative proposals filed. There was a concurring decision from Commissioner Glick, and a partial dissent from Chairman Chatterjee on the FCA price treatment issue. Challenges to the *Fuel Security Retention Proposal Order* were filed by NEPGA, NRG, Verso, Vistra/Dynegy Marketing & Trade, MPUC, and PIOs.[78] On February 1, 2019, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending. If you have further questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **Economic Life Determination Compliance Revisions (ER18-1770-003)**

On April 9, 2020, ISO-NE and NEPOOL jointly filed Tariff changes to reflect the FERC's rejection on rehearing[79] of the previously-accepted[80] Economic Life Revisions to Section III.13.1.2.3.2.1.2.C of the Tariff, and the prospective implementation of the Economic Life Revisions beginning with FCA16. Specifically, the Section was revised in relevant part to read: "The economic life is the maximum evaluation period in which a resource's net present value is non-negative. However, effective April 9, 2020, beginning with the sixteenth Forward

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[76] *ISO New England Inc.*, 165 FERC ¶ 61,202 (Dec. 3, 2018), *reh'g requested* ("*Fuel Security Retention Proposal Order*"). In accepting the ISO-NE Proposal, the FERC, among other things: (i) found ISO-NE's trigger and assumptions for the fuel security reliability review for retention of resources be reasonable, but required ISO-NE at the end of each winter to "to submit an informational filing comparing the study assumptions and triggers from the modeling analysis to actual conditions experienced in the winter of 2018/19; (ii) found cost allocation on a regional basis to Real-Time Load Obligation just and reasonable and consistent with precedent regarding the past Winter Reliability Programs; (iii) found that entering retained resources into the FCAs as price takers would be just and reasonable to ensure that they clear and are counted towards resource adequacy so that customers do not pay twice for the resource; and (Iv) found that it was appropriate to include FCAs 13, 14 and 15 in the term. The FERC agreed that it is necessary to implement a longer-term market solution as soon as possible, and required ISO-NE to file its longer-term market solution no later than June 1, 2019. The FERC declined to provide guidance on what the long-term solution(s) should be.

[77] As previously reported, ISO-NE filed, in response to the *Mystic Waiver Order*, "interim Tariff revisions that provide for the filing of a short-term, cost-of-service agreement to address demonstrated fuel security concerns". ISO-NE proposed three sets of provisions to expand its authority on a short-term basis to enter into out-of-market arrangements in order to provide greater assurance of fuel security during winter months in New England (collectively, the "Fuel Security Retention Proposal"). ISO-NE stated that the interim provisions would sunset after FCA15, with a longer-term market solution to be filed by July 1, 2019, as directed in the *Mystic Waiver Order*. In addition, the ISO-NE transmittal letter described (i) the generally-applicable fuel security reliability review standard that will be used to determine whether a retiring generating resource is needed for fuel security reliability reasons; (ii) the proposed cost allocation methodology (Real-Time Load Obligation, though ISO-NE indicated an ability to implement NEPOOL's alternative allocation methodology if determined appropriate by the FERC); and (iii) the proposed treatment in the FCA of a retiring generator needed for fuel security reasons that elects to remain in service. The ISO-NE Fuel Security Changes were considered but not supported by the Participants Committee at its August 24, 2018 meeting. There was, however, super-majority support for (1) the Appendix L Proposal with some important adjustments to make that proposal more responsive to the FERC's guidance in the Mystic Waiver Order and other FERC precedent, and (2) the PP-10 Revisions, also with important adjustments (together, the "NEPOOL Alternative").

[78] "PIOs" for purposes of this proceeding are Sierra Club, NRDC, Sustainable FERC Project, and Acadia Center.

[79] *ISO New England Inc. and New England Power Pool Participants Comm.*, 170 FERC ¶ 61,187 (Mar. 10, 2020) ("*Economic Life Revisions Rehearing Order*") (rejecting the Economic Life Revisions, effective Aug. 10, 2018, without prejudice to ISO-NE filing proposed Tariff revisions similar to the Economic Life Revisions, to be effective prospectively. Notwithstanding the fact that the Economic Life Revisions were rejected with an effective date prior to FCA13 and FCA14, the FERC did not require ISO-NE to re-run FCA13 or FCA14 without applying the Economic Life Revisions).

[80] *ISO New England Inc. and New England Power Pool Participants Comm.*, 165 FERC ¶ 61,088 (Nov. 9, 2018) ("*Economic Life Determination Revisions Order*"), *reh'g granted*, 170 FERC ¶ 61,187 (Mar. 10, 2020).

Capacity Auction, the economic life is the evaluation period in which a resource's net present value is maximized." These changes were unanimously supported by the Participants Committee at the April 2, 2020 meeting (Agenda Item #5). Comments on the compliance filing were due on or before April 30, 2020. NEPGA filed comments asking the FERC to "accept the Tariff changes that eliminate the Economic Life Revisions." National Grid filed a doc-less intervention. 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).

- **ISO-NE Waiver Filing: Mystic 8 & 9 (ER18-1509; EL18-182)**

On July 2, 2018, the FERC issued an order[81] that (i) denied ISO-NE's request for waiver of certain Tariff provisions that would have permitted ISO-NE to retain Mystic 8 & 9 for fuel security purposes (ER18-1509); and (ii) instituted an FPA Section 206 proceeding (EL18-182) (having preliminarily found that the ISO-NE Tariff may be unjust and unreasonable in that it fails to address specific regional fuel security concerns identified in the record that could result in reliability violations as soon as year 2022). The *Mystic Waiver Order* required ISO-NE, on or before August 31, 2018 to either: (a) submit interim Tariff revisions that provide for the filing of a short-term, cost-of-service agreement (COS Agreement) to address demonstrated fuel security concerns (and to submit by July 1, 2019 permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns "Chapter 3 Proposal"); or (b) show cause as to why the Tariff remains just and reasonable in the short- and long-term such that one or both of Tariff revisions filings is not necessary.

Addressing the waiver element, the FERC found the waiver request "an inappropriate vehicle for allowing Mystic 8 and 9 to submit a [COS Agreement] in response to the identified fuel security need" and further that the request "would not only suspend tariff provisions but also alter the existing conditions upon which a market participant could enter into a [COS Agreement] (for a transmission constraint that impacts reliability) and allow for an entirely new basis (for fuel security concerns that impact reliability) to enter into such an agreement." The FERC concluded that "[s]uch new processes may not be effectuated by a waiver of the ISO-NE Tariff; they must be filed as proposed tariff provisions under FPA section 205(d)."[82] Even if it were inclined to apply its waiver criteria, the FERC stated that it would still have denied the waiver request as "not sufficiently limited in scope."[83]

Although it denied the waiver request, the FERC was persuaded that the record supported "the conclusion that, due largely to fuel security concerns, the retirement of Mystic 8 and 9 may cause ISO-NE to violate NERC reliability criteria." Finding ISO-NE's methodology and assumptions in the Operational Fuel-Security Analysis ("OFSA") and Mystic Retirement Studies reasonable, the FERC directed the filing of both interim and permanent Tariff revisions to address fuel security concerns (or a filing showing why such revisions are not necessary).[84] The FERC directed ISO-NE to consider the possibility that a resource owner may need to decide, prior to receiving approval of a COS Agreement, whether to unconditionally retire, and provided examples of how to address that possibility.[85] The FERC also directed ISO-NE include with any proposed Tariff revisions a mechanism that addresses how cost-of-service-retained resources would be treated in the FCM[86] and an *ex ante* cost allocation proposal that appropriately identifies beneficiaries and adheres to FERC cost causation precedent.[87]

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[81] *ISO New England Inc.*, 164 FERC ¶ 61,003 (July 2, 2018), *reh'g requested* ("*Mystic Waiver Order*").

[82] *Id.* at P 47.

[83] *Id.* at P 48.

[84] *Id.* at P 55.

[85] *Id.* at PP 56-57.

[86] *Id.* at P 57.

[87] *Id.* at P 58.

Requests for Rehearing and/or Clarification. The following requests for rehearing and or clarification of the *Mystic Waiver Order* remain pending before the FERC:

- ***NEPGA*** (requesting that the FERC grant clarification that it directed, or on rehearing direct, ISO-NE to adopt a mechanism that prohibits the re-pricing of Fuel Security Resources in the FCA at $0/kW-mo. or at any other uncompetitive offer price);
- ***Connecticut Parties***[88] (requesting that the FERC clarify that (i) the discussion in the *Mystic Waiver Order* of pricing treatment in the FCM for fuel security reliability resources is not a final determination nor is it intended to establish FERC policy; (ii) the FERC did not intend to prejudge whether entering those resources in the FCM as price takers would be just and reasonable; and (iii) that ISO-NE may confirm its submitted position that price taking treatment for these resources would, in fact, be a just and reasonable outcome. Failing such clarification, Connecticut Parties request rehearing, asserting that the record fails to support a determination that resources retained for reliability to address fuel security concerns must be entered into the FCM at a price greater than zero);
- ***ENECOS*** (asserting that the *Mystic Waiver Order* (i) misplaces reliance on ISO-NE "assertions concerning 'fuel security,' which do not in fact establish a basis in evidence or logic for initiating" a Section 206(a) proceeding; (ii) impermissibly relies on extra-record material that the FERC did not actually review and that intervenors were afforded no meaningful opportunity to challenge; and (iii) speculation concerning potential future modifications to the FCM bidding rules as to retiring generation retained for fuel security misunderstands the problem it seeks to address, and prejudices the already truncated opportunities for stakeholder input in this proceeding), ENECOS suggest that the FERC should grant rehearing, vacate its show cause directive, strike its dictum concerning potential treatment of FCM bidding for retiring generation retained for "fuel security," and direct ISO-NE to proceed either in accordance with its Tariff or under FPA Section 205 to address, with appropriate evidentiary support, whatever concerns it believes to exist concerning "fuel security");
- ***MA AG*** (asserting that the decision to institute a Section 206 proceeding was insufficiently supported by sole reliance on highly contested OFSA and Mystic Retirement Studies; and the FERC should reconsider the timeline for the permanent tariff solution and set the deadline for implementation no later than February 2020);
- ***MPUC*** (challenging the Order's (i) adoption of ISO-NE's methodology and assumptions in the OFSA and Mystic Retirement Studies without undertaking any independent analysis; (ii) failure to address arguments and analysis challenging assumptions in the OFSA and Mystic Retirement Studies; (iii) failure to address the MPUC argument that the Mystic Retirement Studies adopted a completely new standard for determining a reliability problem three years in advance; (iv) unreasonably discounting of the ability of Pay-for-Performance to provide sufficient incentives to Market Participants to ensure their performance under stressed system conditions; and (v) failure to direct ISO-NE to undertake a Transmission Security Analysis consistent with the provisions in the Tariff);
- ***New England EDCs***[89] (requesting clarification that (i) the central purpose of ISO-NE's July 1, 2019 filing is to assure that New England adds needed new infrastructure to address the fuel supply shortfalls and associated threats to electric reliability that ISO-NE identified in its OFSA and (ii) that, in developing the July 1, 2019 filing, ISO-NE is to evaluate Tariff revisions (such as those the EDCs described in their request), through which ISO-NE customers would pay for the costs of natural gas pipeline capacity additions via rates under the ISO-NE Tariff);
- ***PIOs***[90] (asserting that (i) the FERC failed to respond to or provide a reasoned explanation for rejecting the arguments submitted by numerous parties that key assumptions underlying and the results of the

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[88] "Connecticut Parties" are CT PURA and CT DEEP.

[89] The "EDCs" are the National Grid companies (Mass. Elec. Co., Nantucket Elec. Co., and Narragansett Elec. Co.) and Eversource Energy Service Co. (on behalf of its electric distribution companies – CL&P, NSTAR and PSNH).

[90] "PIOs" are the Sierra Club, Natural Resources Defense Council ("NRDC"), and Sustainable FERC Project.

ISO-NE analyses were flawed; and (ii) the FERC's determination that ISO-NE's analyses were reasonable is not supported by substantial evidence in the record); and

- ♦ ***AWEA/NGSA*** (asserting that the FERC erred (i) in finding that ISO-NE's OFSA and subsequent impact analysis of fuel security was reasonable without further examination and (ii) in its preliminary finding that a short-term out-of-market solution to keep Mystic 8 & 9 in operation is needed to address fuel security issues).

On August 13, 2018, CT Parties opposed the NEPGA motion for clarification. On August 14, NEPOOL filed a limited response to Indicated New England EDCs, requesting that the FERC "reject the relief sought in [their motion] to the extent that relief would bypass or predetermine the outcome of the stakeholder process, without prejudice to [them] refiling their proposal, if appropriate, following its full consideration in the stakeholder process." Answers to the Indicated New England EDCs were also filed by the MA AG, NEPGA, NextEra, and CLF/NRDC/Sierra Club/Sustainable FERC Project. On August 29, the Indicated New England EDCs answered the August 14/16 answers. On August 27, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending.

If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **CASPR (ER18-619)**

Rehearing of the FERC's order accepting ISO-NE's Competitive Auctions with Sponsored Policy Resources ("CASPR") revisions,[91] summarized in more detail in prior Reports, remains pending. Those requests were filed by (i) ***NextEra/NRG*** *(which* challenged the RTR Exemption Phase Out); (ii) ***ENECOS***[92] (challenging the FERC's findings with respect to the definition of Sponsored Policy Resource and the allocation of CASPR side payment costs to municipal utilities); (iii) ***Clean Energy Advocates***[93] (which challenged the CASPR construct in its entirety, asserting that state-sponsored resources should not be subject to the MOPR); and (iv) ***Public Citizen*** (which also challenged the CASPR construct in its entirety and the *CASPR Order*'s failure to define "investor confidence"). On April 24, ISO-NE answered Clean Energy Advocates' answer. On May 7, 2018, the FERC issued a tolling order affording it additional time to consider the requests for rehearing, which remain pending. If you have any questions concerning this proceeding, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com) or Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **2013/14 Winter Reliability Program Remand Proceeding (ER13-2266)**

On April 1, 2020, the FERC issued its long-awaited order on compliance and remand, accepting ISO-NE's January 23, 2017 compliance filing and finding that the bid results from the 2013/14 Winter Reliability Program were just and reasonable.[94] The FERC also provided the further reasoning requested by the DC Circuit for this finding.[95] As has been reported for some time, the FERC directed ISO-NE in its August 8, 2016

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[91] *ISO New England Inc.*, 162 FERC ¶ 61,205 (Mar. 9, 2018) ("*CASPR Order*"), *reh'g requested*.

[92] The Eastern New England Consumer-Owned Systems ("ENECOS") are: Braintree Electric Light Department, Georgetown Municipal Light Department, Groveland Electric Light Department, Littleton Electric Light & Water Department, Middleton Electric Light Department, Middleborough Gas & Electric Department, Norwood Light & Broadband Department, Pascoag (Rhode Island) Utility District, Rowley Municipal Lighting Plant, Taunton Municipal Lighting Plant, and Wallingford (Connecticut) Department of Public Utilities. Wellesley Municipal Light Plant, which intervened in this proceeding as one of the ENECOS, did not join in the ENECOS' request for rehearing.

[93] For purposes of this proceeding, "Clean Energy Advocates" are, collectively, the NRDC, Sierra Club, Sustainable FERC Project, CLF, and RENEW Northeast, Inc.

[94] *ISO New England Inc.*, 171 FERC ¶ 61,003 (Apr. 1, 2020) ("*2013/14 Winter Reliability Program Order on Compliance and Remand*"), *reh'g requested*.

[95] *See Id.* at PP 54-96.

remand order[96] to request from Program participants the basis for their bids, including the process used to formulate the bids, and to file with the FERC a compilation of that information, an IMM analysis of that information, and ISO-NE's recommendation as to the reasonableness of the bids, so that the FERC could further consider the question of whether the Bid Results were just and reasonable.[97] ISO-NE submitted its compliance filing on January 23, 2017, reporting the IMM's conclusion that "the auction was not structurally competitive and a 'small proportion' of the total cost of the program may be the result of the exercise of market power" but that the "vast majority of supply was offered at prices that appear reasonable and that, for a number of reasons, it is difficult to assess the impact of market power on cost." Based on the IMM and additional analysis, ISO-NE recommended that "there is insufficient demonstration of market power to warrant modification of program." Both TransCanada and the MA AG protested ISO-NE's conclusion and recommendation that modification of the program was unwarranted, but the FERC did not find convincing either challenge.

Request for Rehearing (ER13-2266-005). On May 1, TransCanada requested rehearing of the *2013/14 Winter Reliability Program Order on Compliance and Remand*. In its request for rehearing, TransCanada argued that the Order (i) erred when it found the bid results just and reasonable; (ii) violated FPA Section 205, the rule against retroactive ratemaking and the filed rate doctrine by approving the bid results under a market-based rate paradigm; and (iii) was arbitrary and capricious, not based on reasoned decision-making and contrary to, and without foundation in, substantial evidence in the record. This matter is again before the FERC.

If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

IV.OATT Amendments / TOAs / Coordination Agreements

- **CIP IROL Cost Recovery Rules (ER20-739)**

On January 6, 2020, ISO-NE filed revisions to incorporate into the Tariff as a new Schedule 17 a mechanism to facilitate the recovery of critical infrastructure protection ("CIP") costs by facilities that ISO-NE identifies as critical to the derivation of Interconnection Reliability Operating Limits ("IROL") (the "CIP IROL Cost Recovery Rules"). ISO-NE requested a March 6, 2020 effective date for the CIP IROL Cost Recovery Rules. The CIP IROL Cost Recovery Rules were considered but not supported by the Participants Committee at its November 1, 2019 meeting (Agenda Item #8). Comments on this filing were due on or before January 27, 2020. On January 22, NEPOOL filed comments to provide the FERC with further information explaining NEPOOL's consideration of the Rules and reasons provided by members for supporting or not supporting the Rules. Calpine, Cross-Sound Cable, and the IROL-Critical Facility Owners[98] filed comments supporting the Rules. NESCOE conditionally supported the Rules, subject to the FERC providing its requested guidance and clarifications.[99] Doc-less interventions only were filed by: Brookfield, Dominion, Eversource, Exelon, MA AG, National Grid, NextEra (out-of-time), PSEG, UI, MA

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[96] *ISO New England Inc.*, 156 FERC ¶ 61,097 (Aug. 8, 2016) ("*2013/14 Winter Reliability Program Remand Order*"). As previously reported, the DC Circuit remanded the FERC's decision in ER13-2266, agreeing with TransCanada that the record upon which the FERC relied is devoid of any evidence regarding how much of the 2013/14 Winter Reliability Program cost was attributable to profit and risk mark-up (without which the FERC could not properly assess whether the Program's rates were just and reasonable), and directing the FERC to either offer a reasoned justification for the order in ER13-2266 or revise its disposition to ensure that the Program rates are just and reasonable. *TransCanada Power Mktg. Ltd. v. FERC,* 2015 U.S. App. LEXIS 22304 (D.C. Cir. 2015).

[97] *2013/14 Winter Reliability Program Remand Order* at P 17.

[98] The "IROL-Critical Facility Owners" are: Cogentrix, CSC, FirstLight, NextEra, NRG, and Vistra.

[99] NESCOE requested that the FERC (i) clarify that any order approving Schedule 17 is limited in scope and does not set broad precedent, (ii) confirm that under no circumstances may IROL-critical facilities recover costs subject to recovery under another provision of the Tariff or under any other mechanism; (iii) clarify that costs eligible for recovery under Schedule 17 must be solely and directly related to ISO-NE's designation; and (iv) clarify that only going-forward costs are eligible for recovery under Schedule 17.

DPU, MPUC, Public Citizen, and RESA. On February 11, ISO-NE and NESCOE answered the IROL-Critical Facility Owners' comments and the IROL-Critical Facility Owners answered NESCOE's comments.

Deficiency Letter; ISO-NE Response. On February 26, 2020, the FERC issued a deficiency letter directing ISO-NE (a) to explain if it intends to allow the recovery of costs incurred prior to the March 6, 2020 requested effective date and if so (b) to explain how that cost recovery would be consistent with the filed rate doctrine and the rule against retroactive ratemaking. ISO-NE responded to the deficiency letter on March 27, 2020. Comments on ISO-NE's response were due on or before April 17, 2020 and were filed by the IROL-Critical Facility Owners, who requested that the FERC clarify that ISO-NE's proposed cost recovery mechanism authorizes recovery of historic compliance costs, and such historic cost recovery does not implicate, or alternatively is consistent with, the filed rate doctrine and rule against retroactive ratemaking. On April 24, NESCOE answered the IROL-Critical Facility Owners' comments, challenging their view on the scope of cost recovery, but agreeing that the a "generic finding on this threshold legal issue [would be] administratively efficient."

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

- **ISO-NE *Order 845* Compliance Filing (ER19-1951)**

On March 19, 2020, the FERC conditionally accepted, subject to further compliance filings, the proposed revisions to the Large Generator Interconnection Procedures ("LGIP") and Agreement ("LGIA") in Schedule 22 of the ISO-NE OATT jointly filed on May 22, 2019 by ISO-NE and the PTO AC ("Filing Parties") in response to the requirements of *Order 845* ("*Order 845* Compliance Filing").[100] While the Order largely accepted the *Order 845* Compliance Filing, the FERC identified a number of ways in which the *Order 845* Compliance Filing only partially complied or did not comply with *Order 845*, directing changes to the following (Paragraph citations to the *Order 845 Compliance Filing Order* in brackets):

- ♦ ***Stand-Alone Network Upgrades definition***. Finding that the Filing Parties did not sufficiently justify their proposal to revise the definition of "Stand Alone Network Upgrades" to specify that the 15-day period for the system operator to provide a written explanation for why an upgrade is not considered a stand-alone network upgrade is 15 business days instead of 15 calendar days, the FERC directed the Filing Parties either to provide sufficient justification or to submit proposed Tariff revisions that make no modification to the 15 calendar day period. [P 32]
- ♦ ***Interconnection Customer's ability to exercise the option to build***. Finding the Filing Parties independent entity variation justification insufficient, the FERC directed the Filing Parties to "submit a further compliance filing within [120][101] days of the date of this order with proposed Tariff revisions that remove this variation from ISO-NE *pro forma* LGIA article 5.1.3." [P 35]
- ♦ ***Option to Build Cost Recovery***. The FERC rejected the PTO-sponsored proposed variation for transmission owners to recover the actual costs for their oversight responsibilities pursuant to ISO-NE *pro* forma LGIA article 5.2 as "not consistent with or superior to the oversight cost requirements in the [FERC's] pro forma LGIA". [P 36]
- ♦ ***Determination of Contingent Facilities***. Finding the proposed Tariff revisions "lack the requisite transparency required by *Orders 845* and *845-A* because the proposed Tariff revisions do not detail the specific technical screens or analyses and the specific thresholds or criteria that ISO-NE will use as part of its method to identify contingent facilities," the FERC directed the Filing Parties to add "in section 3.8 of the ISO-NE LGIP (1) the method ISO-NE will use to determine contingent facilities, including technical screens or analyses Filing Parties propose to use to identify these facilities and (2)

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[100] *ISO New England Inc. and Participating Transmission Owners Admin. Comm.*, 170 FERC ¶ 61,209 (Mar. 19, 2020) ("*Order 845 Compliance Filing Order*").

[101] The FERC issued an errata notice on Apr. 22, 2020 correcting the deadline from "60 days to the intended 120 days".

the specific thresholds or criteria ISO-NE will use in its technical screens or analysis to achieve the level of transparency required by *Order 845*." [PP 45-46]

- ***Requesting interconnection service below generating facility capacity***. Filing Parties were directed to incorporate required language into LGIP sections 3.1 and 8.2. [PP 78, 76]
- ***Provisional Interconnection Service***. Rejecting the proposal to require interconnection customers to request provisional interconnection service before the system impact study, the FERC directed the Filing Parties to remove the following sentence from *pro forma* ISO-NE LGIA article 5.9.2: "Prior to the commencement of the Interconnection System Impact Study associated with a Large Generating Facility, an Interconnection Customer may request Provisional Interconnection Service." [PP 85-86]
- ***Surplus Interconnection Service – Definition***. Agreeing with NEPOOL's and other parties' protests, the FERC directed the Filing Parties "to provide sufficient justification for their independent entity variation that limits the availability of surplus interconnection service for customers with NRIS, or to propose Tariff revisions that adopt the *pro forma* definition of 'Surplus Interconnection Service' for NRIS customers." [PP 111-112]
- ***Surplus Interconnection Service – Process***. Again agreeing with NEPOOL's and other parties' protests, the FERC directed the Filing Parties to revise revises section 3.3.1 of the LGIP to make clear that ISO-NE will not limit studies for surplus interconnection service to 10 business days, and will continue to study a surplus interconnection service request, without requiring a new interconnection request, until it determines whether any additional interconnection facilities and/or network upgrades necessary for surplus interconnection service. [PP 128-129]

A memo describing the in more detail the *Order 845 Compliance Order* was posted with the materials for, and discussed at, the March 25, 2020 Transmission Committee meeting. The *Order 845* Compliance Filing changes were conditionally accepted effective May 19, 2020. A compliance filing with the directed changes will be due on or before July 17, 2020 (subject to the further clarification described immediately below).

ISO-NE Request for Clarification. On April 20, 2020, ISO-NE sought expedited clarification of two aspects of the *Order 845 Compliance Filing Order*. First, ISO-NE sought clarification that, with respect to its obligation to remove the variation related to an Interconnection Customer's ability to exercise the option to build from ISO-NE *pro forma* LGIA article 5.1.3, it may submit the proposed changes with the rest of its compliance changes due July 17 (rather than May 18). As noted above, on April 22, 2020, the FERC issued an errata notice correcting the deadline for the submission of this change "to the intended 120 days."

Second, ISO-NE requested clarification of certain aspects of the *Order 845 Compliance Filing Order* related to the availability of Surplus Interconnection Service for Network Resource Interconnection Service ("NR Interconnection Service" or "NRIS") customers. Specifically, ISO-NE sought clarification (i) that surplus interconnection service is limited to the same service available to the Original Interconnection Customer and (ii) that ISO-NE is only required to identify whether upgrades are required and that, if the ISO's analysis confirms that upgrades are required to accommodate a request for surplus interconnection service, then its analysis under the expedited process ceases (or additional guidance if the FERC did in fact intend to require ISO-NE to identify the specific upgrades that would be required to accommodate the proposed surplus interconnection request). On May 4, NEPOOL objected to both of these requested clarifications, asserting that, if granted, the clarifications would tend to unnecessarily limit the use of surplus interconnection service and should be viewed critically as generally contrary to the FERC's purposes for surplus interconnection service. ISO-NE's request for clarification on this point is pending before the FERC.

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

V.Financial Assurance/Billing Policy Amendments

No Activity to Report

VI.Schedule 20/21/22/23 Changes

- **Schedule 21-NEP: NSTAR LSA (ER20-1692)**

On April 29, 2020, National Grid filed a Local Service Agreement ("LSA") between NEP and NSTAR that provides for the provision of Local Network Service and Firm Local Point-To-Point Service over NEP's Local Service transmission facilities to NSTAR Electric after the existing Service Agreement for Network Integration Transmission Service Agreement expired on March 30, 2020. National Grid states that the LSA sets forth the same provisions as the *pro forma* LSA contained in Attachment A to Schedule 21-Common, but was filed as a non-conforming agreement because, as a two-party agreement, it omits references to ISO-NE as a party. Comments on this filing are due on or before May 20. Thus far, Eversource, on behalf of NSTAR , intervened doc-lessly. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 20A-NEP: NEP-Brookfield RTM Phase I/II HVDC-TF Service Agreement (ER20-1626)**

On April 21, 2020, New England Power Company ("NEP") submitted a new Phase I/II HVDC-TF Service Agreement between NEP and Brookfield Renewable Trading and Marketing LP ("Brookfield RTM"). The Service Agreement will allow the continuation without interruption of firm point-to-point transmission service that is currently being provided under Schedule 20A. NEP stated that the Agreement conforms generally to the *pro forma* Schedule 20A service agreement, but contains provisions related to NEP's contractual rights allowing it to sell service over the Phase I/II HVDC transmission facilities ("Phase I/II HVDC-TF") through October 31, 2020, and that permit Brookfield to exercise its transmission customer rollover service rights through August 31, 2025 as specified in the NEP-Brookfield Service Agreement. NEP requested a September 1, 2020 effective date for the changes. Comments on this filing are due on or before May 12. Thus far, on April 29, 2020, Brookfield RTM submitted comments urging the FERC to accept the Agreement and clarifying that, by executing the Agreement, Brookfield RTM has not waived its rights to continue taking service from another IRH or IRHs in the event that NEP does not renew its Use Rights by extending participation as an IRH under the Phase I/II agreements. If there are questions on this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Schedule 21-NEP National Grid/Winchendon Hydro SGIA (ER20-1413)**

On March 27, 2020, National Grid filed a non-conforming Small Generation Interconnection Agreement ("SGIA") with Winchendon Hydroelectric LLC ("Winchendon Hydro") to cover the continued interconnection between National Grid and Winchendon Hydro with respect to Winchendon Hydro's 100 kW run-of-river hydro facility located in Winchendon, Massachusetts. The SGIA replaces an existing interconnection agreement. Since the SGIA covers an existing, interconnected facility, a new three-party interconnection agreement (that would include ISO-NE) was not required. A February 26, 2020 effective was requested. Comments on this filing were due on or before April 17, 2020; none were filed. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-NEP: Deepwater Block Island Wind Indemnification Agreement Cancellation (ER20-962)**

On April 3, 2020, the FERC accepted Narragansett's notice of cancellation of its Indemnification Agreement with the Deepwater Companies.[102] As previously reported, the Indemnification Agreement, which went into effect May 10, 2016, provided for the Deepwater Companies to indemnify Narragansett for costs directly incurred in connection with the delivery of switchgear at certain Rhode Island substations related to

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[102] *The Narragansett Electric Co.*, Docket No. ER20-962 (Apr. 3, 2020) (unpublished letter order).

the Deepwater Companies' construction of the Block Island Wind Farm. The Indemnification Agreement was cancelled because the Block Island Wind Farm is completed and in commercial operation and the Agreement is no longer needed. The FERC accepted the notice of cancellation effective April 7, 2020, as requested. The April 3 order was not challenged and is final and unappealable. Reporting on this proceeding has concluded. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

On March 19, 2020, Emera Maine submitted a joint offer of settlement between itself and the MPUC to resolve all issues raised by the MPUC in response to Emera Maine's 2019 annual charges update filed, as previously reported, on June 10, 2019 (the "Emera 2019 Annual Update Settlement Agreement"). Under Part V of Attachment P-EM, "Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the [Attachment P-EM] Rate Formula. . . ." and follow a dispute resolution procedure set forth there. In accordance with those provisions, the MPUC identified certain disputes with the 2019 Annual Update, all of which are resolved by the Emera 2019 Annual Update Settlement Agreement. Comments on the Emera 2019 Annual Update Settlement Agreement were due on or before April 9, 2020; none were filed. This matter is pending before the FERC. If you have any questions concerning this proceeding, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

- **Schedule 21-EM: 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,*[103]and certified by Settlement Judge Dring[104] to the Commission,[105] 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-EM of the BHD OATT and $260,000 under the MPD OATT. If you have any questions concerning these matters, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

On April 30, 2020, VEC submitted its 17th annual update to the formula rates contained in Schedules 21-VEC and 20-VEC covering the July 1, 2020 – June 30, 2021 period. VEC indicated that it was not proposing any changes to the underlying formulas. In addition, VEC noted that, as a not-for-profit entity, it does not have ADIT, and no change would be necessary to address ADIT if VEC were a public utility subject to an Order 864 compliance obligation. The FERC will not notice this filing for public comment, and absent further activity,

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[103] *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.

[104] 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.

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

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).

- ***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*[106] *and 531-B*[107] also remains pending. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

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

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

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

- **Capital Projects Report - 2019 Q4 (ER20-973)**

On April 3, 2020, the FERC accepted ISO-NE's Capital Projects Report and Unamortized Cost Schedule covering the fourth quarter ("Q4") of calendar year 2019 (the "Report").[108] ISO-NE filed the Report as required by Section IV.B.6.2 of the Tariff. As previously reported, highlights included the following new projects: (i) nGEM software development part I ($3.2 million); (ii) markets database refresh ($1.7 million); (iii) enterprise application integration replacement ($1.4 million); (iv) application server upgrade ($894,100); (v) 2020 issue resolution project phase I ($680,000); (vi) streamline asset registration user interface enhancements ($631,300); and (vii) e-mail infrastructure upgrade ($84,500). Projects with a significant changes were (i) change request system replacement ($687,600 budget increase); (ii) energy market offer caps (*Order 831*) (2019 and overall budget decrease of $543,100); and (iii) energy storage device phase II ($141,300 budget increase). The Report was accepted effective January 1, 2020, as requested. The April 3 order was not challenged, and is final and unappealable. Reporting on this proceeding has concluded. If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

- **LFTR Implementation: 46th Quarterly Status Report (ER07-476; RM06-08)**

ISO-NE filed the 46th of its quarterly status reports regarding LFTR implementation on April 15, 2020. 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

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

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

[108] *ISO New England Inc.*, Docket No. ER20-973 (Apr. 3, 2020) (unpublished letter order).

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.

- **Reserve Market Compliance (28th) Semi-Annual Report (ER06-613)**

As directed by the original ASM II Order,[109] as modified,[110] ISO-NE submitted its 28th semi-annual reserve market compliance report on April 2, 2020. In the 28th report, ISO-NE explained, as in its prior compliance reports, that work on the forward TMSR market issues continues to be on hold due to its efforts on other priority projects. The report was not noticed for public comment. If there are questions on this matter, please contact Dave Doot (860-275-0102; dtdoot@daypitney.com).

- **IMM Quarterly Markets Reports – Winter 2020 (ZZ20-4)**

On May 4, 2020, the IMM filed with the FERC its Winter 2020 report of "market data regularly collected by [the IMM] in the course of carrying out its functions under … Appendix A and analysis of such market data," as required pursuant to Section 12.2.2 of Appendix A to Market Rule 1. These filings are not noticed for public comment by the FERC. The Winter 2020 Report will be discussed with the Markets Committee at its May 12 meeting.

- **ISO-NE FERC Form 1 (not docketed)**

On April 15, 2020, ISO-NE submitted its 2019 FERC Form 1 (Annual Report of Major Electric Utilities, Licensees and Others). On April 16, ISO-NE filed the CPA Certification Statement for that Form. FERC Form 1 filings are not noticed for comment.

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

On April 27, 2020, ISO-NE submitted a report of its total MWh of transmission service during 2019. ISO-NE reported that 126,676,919 MWh of transmission service in interstate commerce was provided during 2019 (roughly 4.6 MWh less than 2018 (131,249,024 MWh). These filings are not noticed for comment.

IX.Membership Filings

- **May 2020 Membership Filing (ER20-1694)**

On April 30, 2020 NEPOOL requested that the FERC accept the membership of RPA Energy Inc. d/b/a/ Green Choice Energy (Supplier Sector) and termination of the Participant status of Empire Generating Co, LLC [Related Person of Kleen Energy Systems (Generation Sector)]. Comments on this filing are due on or before May 21, 2020.

- **April 2020 Membership Filing (ER20-1454)**

On March 31, 2020 NEPOOL requested that the FERC accept (i) the memberships of Axon Energy, LLC (Supplier Sector); Energy Harbor LLC (Supplier Sector); and Nexus Energy Inc. (Supplier Sector); and (ii) the termination of the Participant status of ADG Group Inc. (Supplier Sector); Beacon Falls Energy Park, LLC (Related Person of Kleen Energy Systems (Generation Sector)); Clear River Energy (Related Person of Invenergy Energy Management (Generation Sector); Entergy Nuclear Power Marketing (Supplier Sector); and Rinar Power (Data-Only Participant). Comments on this filing were due on or before April 21, 2020; none were filed. This matter is pending before the FERC.

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

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

- **March 2020 Membership Filing (ER20-1130)**

On April 3, the FERC accepted (i) the membership of SP Transmission, LLC (Provisional Member); (ii) the termination of the Participant status of QPH Capital, LLC (Supplier Sector); and (iii) the name change of Pixelle Energy Services LLC (f/k/a Verso Energy Services LLC). The April 3 order was not challenged and is final and unappealable. Reporting on this proceeding is concluded.

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

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

- **Joint Staff White Paper on Notices of Penalty for Violations of CIP Standards (AD19-18)**

Still pending is the FERC's White Paper, prepared jointly with NERC staff and issued on August 27, 2019, that sets out a proposed new format for NERC Notices of Penalty ("NOP") involving violations of CIP Reliability Standards. The FERC explained that the revised format is intended to improve the balance between security and transparency in the filing of NOPs. Specifically, NERC CIP NOP submissions would consist of a proposed public cover letter that discloses the name of the violator, the Reliability Standard(s) violated (but not the Requirement), and the penalty amount. NERC would submit the remainder of the CIP NOP filing containing details on the nature of the violation, mitigation activity, and potential vulnerabilities to cyber systems as a nonpublic attachment, along with a request for the designation of such information as CEII.

Public comment on the proposal was sought with respect to the following: (i) the potential security benefits from the new proposed format; (ii) potential security concerns that could arise from the new format; (iii) any other implementation difficulties or concerns that should be considered; and (iv) whether the proposed format provides sufficient transparency to the public. Other suggested approaches to CIP NOP submissions were welcomed. No changes to the CIP NOP filing format will be made prior to consideration of public comment on the White Paper. Comments were filed by over 80 parties. This matter is pending before the FERC.

- **Complaint re: CIP-014-2 (Physical Security) (EL20-21)**

On January 30, 2020, Michael Mabee, a private citizen ("Complainant"), filed a formal complaint alleging that Critical Infrastructure Protection ("CIP") Reliability Standard (CIP-014-2) (Physical Security) is inadequate and asked the FERC to issue an order directing NERC to correct the deficiencies. Specifically, Complainant alleges that (1) CIP-014-2 is inadequate in that there is no requirement that an entity's risk assessment or physical security plan be reviewed by anyone with any physical security expertise and no regulator determination as to the effectiveness of any entity's physical security plan and (2) enforcement of CIP-014-2 seems nonexistent (asserting that in the past seven years, there's only been four citations (for administrative violations) for violations of CIP-014-2. Complainant supplement his complaint on February 19 with further background and detail on the allegations and further recommendations. Responses and comments to this complaint, as supplemented, were due on or before March 10, 2020, and were filed by NERC (requesting that the FERC dismiss the Complaint), APPA/LPPC/TAPS, EEI/NRECA, the Foundation for Resilient Societies, Task Force on National and Homeland Security, and by individuals supporting the Complaint, including R. James Woolsey, an honorary co-chairman of the Secure the Grid Coalition (a project of the Center for Security Policy) (encouraging the FERC to "deeply analyze the effectiveness and the enforcement of the physical security standard you previously approved against the current threat environment and the reality that our modern civilization depends entirely upon the bulk power system"). AEP, Georgia System Operations Corp., LA PSC, Public Citizen and Dayton Power & Light intervened doc-lessly. This matter is pending before the FERC.

- **Revised Reliability Standard: PRC-024-3 (RD20-7)**

On March 20, 2020, NERC filed for approval proposed changes to Reliability Standards PRC-024-3 (Frequency and Voltage Protection Settings for Generating Resources) ("Revised PRC-024"). The changes clarify voltage and frequency protection settings requirements. Specifically, the changes clarify the types of protection subject to the requirements and incorporates language used by inverter manufacturers and solar development owners in order to ensure inverter-based resources respond to grid disturbances in a manner that contributes to the reliable operation of the Bulk-Power System. 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. Comments on Revised PRC-024 were due on or before April 20, 2020 and were filed by CAISO (supporting approval of Revised PRC-024). This matter is pending before the FERC.

- **Revised Reliability Standards: FAC-002-3; IRO-010-3; MOD-031-3; MOD-033-2; NUC-001-4; PRC-006-4; TOP-003-4 (RD20-4)**

Still pending before the FERC are the proposed changes to the following Reliability Standards filed on February 21, 2020: FAC-002-3 (Facility Interconnection Studies); IRO-010-3 (Reliability Coordinator Data Specification and Collection); MOD-031-3 (Demand and Energy Data); MOD-033-2 (Steady-State and Dynamic System Model Validation); NUC-001-4 (Nuclear Plant Interface Coordination); PRC-006-4 (Automatic Underfrequency Load Shedding); and TOP-003-4 (Operational Reliability Data) (“Revised Standards”). The changes remove references to Load Serving Entity (which is no longer an applicable entity), add Underfrequency Load Shedding (“UFLS”)-Only Distribution Provider to PRC-006-3 as an applicable entity, and make consistent across the Standards the use of the term “Planning Coordinator”. 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 three months following FERC approval. Comments on the Revised Standards were due on or before March 23, 2020; none were filed. American Municipal Power (“AMP”) submitted a doc-less intervention. This matter remains pending before the FERC.

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

On February 20, 2020, the FERC directed NERC to submit, on or before March 23, 2020, an informational filing describing the activity of two NERC CIP standard drafting projects pertaining to virtualization and cloud computing services.[111] Specifically, NERC was directed to submit a schedule for Project 2016-02 (Modifications to CIP Standards) and Project 2019-02 (BES Cyber System Information Access Management) (collectively, the “NERC Projects”), that would include the current status of the project, interim target dates, and the anticipated filing date for new or modified Reliability Standards. NERC submitted that filing on March 19, 2020. Comments were submitted by a private citizen (Barry Jones) and VMware, Inc. on April 21 and 27, respectively. In addition, the FERC directed NERC to file on an information basis quarterly status updates, until such time as new or modified Reliability Standards are filed with the FERC.

- **Reliability Standard Implementation Deferral (RD18-4; RM17-13; RM16-22; RM15-4)**

On April 6, 2020, NERC requested, and on April 17, 2020, the FERC issued an order granting,[112] deferred the implementation of the following FERC-approved Reliability Standards that have effective dates or phased-in implementation dates in the second half of 2020:

- ♦ CIP-005-6 (Cyber Security – Electronic Security Perimeter(s)), by three months;
- ♦ CIP-010-3 (Cyber Security – Configuration Change Management and Vulnerability Assessments), by three months;
- ♦ CIP-013-1 (Cyber Security – Supply Chain Risk Management), by three months;
- ♦ PER-006-1 (Specific Training for Personnel), by six months;
- ♦ PRC-002-2 (Disturbance Monitoring and Reporting Requirements) (phased-in implementation for Requirements R2-R4 and R6-R11), by six months;

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[111] *N. Am. Elec. Rel. Corp.*, 170 FERC ¶ 61,109 (Feb. 20, 2020).

[112] *N. Am. Elec. Rel. Corp. et al.*, 171 FERC ¶ 61,052 (Apr. 17, 2020).

- PRC-025-2 (Generator Relay Loadability) (phased-in implementation for Requirement R1, Attachment 1, Table 1 Relay Loadability Evaluation Criteria Options 5b, 14b, 15b, 16b), by six months; and
- PRC-027-1 (Coordination of Protection Systems for Performance During Faults), by six months.

NERC stated that its request was intended as a measure to help ensure grid reliability amid the impacts posed by COVID-19. NERC committed to continue to evaluate the circumstances to determine whether additional implementation delays may be warranted and to submit further filings with the FERC if and as appropriate. In addition, NERC indicated that it is taking other steps that will allow registered entities to continue focusing their resources in the coming months on keeping people safe and the lights on, e.g. exercising its enforcement discretion with respect to certain currently effective Reliability Standards and considering the COVID-19 outbreak an extenuating circumstance under its Sanction Guidelines for all noncompliance where the impacts COVID-19, uch as on workforce availability or supply chain resources, were a cause or contributing factor to the noncompliance.

NERC's request was supported by the ISO/RTO Council ("IRC"), including ISO-NE, and Joint Associations.[113] Protect Our Power and Michael Mabee protested the full deferral request, particularly with respect to the Cyber Security Standards. On April 17, the granted the requested deferral. Challenges, if any, to the April 17 order will be due on or before May 18.

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

On February 20, 2020, the FERC issued a notice of inquiry 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 ("NOI").[114] On March 25, 2020, Joint Associations[115] 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. Notwithstanding that deadline extension, since the last Report, comments were filed by the Bureau of Reclamation, Barry Jones, Siemens Energy Management, VMware, Inc., American Association for Laboratory Accreditation ("A2LA"), and Waterfall Security Solutions.

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

On January 23, 2020, the FERC issued a NOPR[116] proposing to approve the retirement of 74 of the 77 Reliability Standard requirements requested to be retired by NERC in these two dockets[117] in connection with the

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[113] "Joint Associations" were Edison Electric Institute ("EEI"), the American Public Power Association ("APPA"), the National Rural Electric Cooperative Association ("NRECA"), and the Large Public Power Council ("LPPC").

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

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

[116] *Electric Reliability Organization Proposal to Retire Requirements in Rel. Standards Under the NERC Standards Efficiency Review*, 170 FERC ¶ 61,032 (Jan. 23, 2020).

[117] As previously reported, NERC filed in ***RM19-17*** for approval (i) the retirement of individual requirements in the following four Reliability Standards: FAC-008-4 (Facility Ratings); INT-006-5 (Evaluation of Interchange Transactions); INT-009-3 (Implementation of Interchange); and PRC-004-6 (Protection System Misoperation Identification and Correction); and (ii) the retirement, in their entirety, of the following 10 Reliability Standards: 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-001-1a (Available Transmission System Capability); MOD-004-1 (Capacity Benefit Margin); MOD-008-1 (Transmission Readability Margin Calculation Methodology); MOD-020-0 (Providing Interruptible Demands and Direct Control Load Management Data to System Operators and Reliability Coordinators); MOD-028-2 (Area Interchange Methodology); MOD-029-2a (Rated System Path Methodology); and MOD-030-3 (Flowgate Methodology). NERC filed in ***RM19-16*** for approval of the retirement of individual requirements in the following three Reliability Standards: IRO-002-7 (Reliability Coordination – Monitoring and Analysis); TOP-001-5 (Transmission Operations); and VAR-001-6 (Voltage and Reactive Control).

first phase of work under NERC's Standards Efficiency Review[118] ("*Retirements NOPR*"). The FERC explained in the *Retirements NOPR* that the requirements to be retired "(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."[119] The FERC also proposes to approve the associated VRFs, VSLs, implementation plan, and effective dates proposed by NERC. With respect to the remaining three requirements that NERC seeks to retire, the FERC seeks more information on two -- the retirement of FCA-008-3, Requirements R7 and R8 (with the FERC's final determination to be based on the comments received) – and proposes to remand one – VAR-001-6 – in order to retain R2, which it found neither redundant nor unnecessary for reliability. Comments on the *Retirements NOPR* were due on or before April 6, 2020.[120] Comments were filed by J. Applebaum, Bonneville Power Administration ("BPA"), NERC, and the Western Area Power Administration ("WAPA").

XI. Misc. - of Regional Interest

- **203 Application: CMP/NECEC (EC20-24)**

On March 13, 2020, the FERC authorized CMP to transfer to NECEC Transmission LLC 7 TSAs, executed on June 13, 2018, that provide the rates, terms, and conditions under which transmission service will be provided over the New England Clean Energy Connect ("NECEC") Transmission Line to the participants that are funding construction of the Line.[121] Pursuant to the March 13 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.

- **PJM MOPR-Related Proceedings (EL18-178; EL16-49)**

Since the last Report, the FERC, on April 16, issued an order granting, in part, and denying, in part, the requests for rehearing and clarification of the *Dec 2019 PJM MOPR Order*, and directed PJM to submit a further compliance filing within 45 days.[122] Subsequently, several petitions for federal court review of the FERC's April *2020 PJM MOPR Rehearing Order* have been filed, including appeals by APPA/AMP, Energy Harbor, Illinois Commerce Commission, New Jersey Division of Rate Counsel/Office of the People's Counsel for the District of Columbia/ Maryland Office of People's Counsel/Delaware Division of the Public Advocate, and the North Carolina Electric Membership Corporation. This appeals are pending before the US Court of Appeals for the DC Circuit ("DC Circuit").

As previously reported, on December 19, 2019, in a long-awaited order (approved 2-1),[123] the FERC ***found*** that "any resource, new *or existing*, that receives, or is entitled to receive, a State Subsidy, and does not qualify for [an exemption], should be subject to the [Minimum Offer Price Rule ("MOPR")]"[124] and ***directed*** PJM to submit a replacement rate that "extends the MOPR to include both new and existing resources, internal and external, that receive, or are entitled to receive, certain out-of-market payments, with certain

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[118] The Standards Efficiency Review initiative, which began in 2017, 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.

[119] *Id.* at P 1.

[120] The *Retirements NOPR* was published in the *Fed. Reg.* on Feb. 6, 2020 (Vol. 85, No. 25) pp. 6,831-6,838.

[121] *Central Maine Power Co.*, 170 FERC 62,145 (Mar. 13, 2020).

[122] *PJM Interconnection, L.L.C.* and *Calpine Corp. et al. v. PJM*, 171 FERC ¶ 61,035 (Apr. 16, 2020) ("*April 2020 PJM MOPR Rehearing Order*").

[123] *PJM Interconnection, L.L.C.* and *Calpine Corp. et al.*, 169 FERC ¶ 61,239 (Dec. 19, 2019) ("*Dec 2019 PJM MOPR Order*"), *reh'g and clarification granted, in part, and denied, in part*, 171 FERC ¶ 61,035 (Apr. 16, 2020).

[124] *Id.* at P 9 (emphasis added).

exemptions."[125] The FERC directed PJM to include five exemptions: (1) a Self-Supply Exemption [PP 12; 202-204]; (2) a Demand Response, Energy Efficiency, and Capacity Storage Resources Exemption [PP 13; 208-209]; (3) a RPS Exemption [PP 14; 173-174]; (4) a Competitive Exemption [PP 15; 161]; and (5) a Unit-Specific Exemption [PP 16; 214-216].[126] The FERC established the replacement rate under section 206 of the FPA, but declined to order refunds (which it otherwise had the discretion to do).[127] The FERC directed PJM to submit a compliance filing consistent with its guidance on or before March 18, 2020 (90 days from the date of the *Dec 2019 PJM MOPR Order*). In the compliance filing, PJM was directed to also provide revised dates and timelines for the 2019 Base Residual Auction ("BRA") and related incremental auctions, along with revised dates and timelines for the May 2020 BRA and related incremental auctions.[128]

The *Dec 2019 PJM MOPR Order* was the latest milestone in the FERC's consideration of out-of-market support affecting the PJM capacity market.[129] The FERC found in a *June 2018 PJM MOPR Order*[130] that "the integrity and effectiveness of the capacity market administered by [PJM] have become untenably threatened by out-of-market payments provided or required by certain states for the purpose of supporting the entry or continued operation of preferred generation resources," determined that the PJM Tariff was unjust and unreasonable, rejected the PJM MOPR Filing, granted in part Calpine's Complaint, and *sua sponte* initiated a new FPA section 206 proceeding (EL18-178) in which it conducted a paper hearing to resolve proposed alternatives, whether put forth in the *June 2018 PJM MOPR Order* or otherwise,[131] addressing "price-suppressive" effects of out-of-market support for certain resources.

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[125] *Id.* at P 2 ("[g]oing forward, the default offer price floor for applicable new resources will be the Net Cost of New Entry ("Net CONE") for their resource class; the default offer price floor for applicable existing resources will be the Net Avoidable Cost Rate ("Net ACR") for their resource class").

[126] *Id.* ("The replacement rate will include three categorical exemptions to reflect reliance on prior Commission decisions: (1) existing self-supply resources, (2) existing demand response, energy efficiency, and storage resources, and (3) existing renewable resources participating in RPS programs. The replacement rate will also include a fourth exemption, the Competitive Exemption, for new and existing resources that are not subsidized and thus do not generally require review to protect 'the integrity and effectiveness of the capacity market.' To preserve flexibility, PJM will also permit new and existing suppliers that do not qualify for a categorical exemption to justify a competitive offer below the applicable default offer price floor through a Unit-Specific Exemption.")

[127] *Id.* at P 3. The FERC had previously established a refund effective date of March 21, 2016, the date of the original Calpine Complaint in EL16-49.

[128] *Id.* at P 4. As previously reported, the FERC directed PJM not to run the BRA in August 2019 as it had proposed to do (*see Calpine et al. v. PJM*, 168 FERC ¶ 61,051 (July 25, 2019)).

[129] The *PJM 2019 MOPR Order* addressed a paper hearing that arose from two separate, but related proceedings. The first, EL16-49, was initiated by a complaint originally filed by Calpine, joined by additional generation entities ("Calpine Complaint") on March 21, 2016, and later amended on January 9, 2017. The Calpine Complaint argued that PJM's MOPR was unjust and unreasonable because it did not address the impact of existing resources receiving out-of-market payments on the capacity market, and proposed interim tariff revisions that would extend the MOPR to a limited set of existing resources. The Calpine Complaint also requested the FERC to direct PJM to conduct a stakeholder process to develop and submit a long-term solution. The second proceeding was PJM's filing of its proposed revisions to its Tariff, pursuant to section 205 of the FPA in ER18-1314 ("PJM MOPR Filing"). The PJM MOPR Filing consisted of two alternate proposals designed to address the price impacts of state out-of-market support for certain resources. The first approach, preferred by PJM but not supported by its stakeholders, consisted of a two-stage annual auction, with capacity commitments first determined in stage one of the auction and the clearing price set separately in stage two ("Capacity Repricing"). The second alternative approach, proposed in the event that the FERC determined that Capacity Repricing was unjust and unreasonable, would have revised PJM's MOPR to mitigate capacity offers from both new and existing resources, subject to certain proposed exemptions ("MOPR-Ex"). A summary of the development and FERC consideration of PJM's capacity market is set out in the Order.

[130] *Calpine Corp. et al.*, 163 FERC ¶ 61,236 (June 29, 2018) ("*June 2018 PJM MOPR Order*"), *clarif. and/or reh'g dismissed,* 171 FERC ¶ 61,036 (Apr. 21, 2020).

[131] The proposed alternative approach would have (i) modified PJM's MOPR such that it would apply to new and existing resources that receive out-of-market payments, regardless of resource type, but would include few to no exemptions; and (ii) in order to accommodate state policy decisions and allow resources that receive out-of-market support to remain online, established an option in PJM's Tariff that would allow, on a resource-specific basis, resources receiving out-of-market support to choose to be removed from the PJM capacity market, along with a commensurate amount of load, for some period of time. That option, which is similar in concept to the

The *Dec 2019 PJM MOPR Order* affirmed the FERC's prior finding that "[a]n expanded MOPR with few or no exceptions, should protect PJM's capacity market from the price-suppressive effects of resources receiving out-of-market support by ensuring that such resources are not able to offer below a competitive price."[132] The expanded MOPR[133] only applies to "State-Subsidized Resources" (Resources that receive, or are entitled to receive, State Subsidies).[134] The FERC considers a "State Subsidy" to be:

> a direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is (1) a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law, and that (2) is derived from or connected to the procurement of (a) electricity or electric generation capacity sold at wholesale in interstate commerce, or (b) an attribute of the generation process for electricity or electric generation capacity sold at wholesale in interstate commerce, or (3) will support the construction, development, or operation of a new or existing capacity resource, or (4) could have the effect of allowing a resource to clear in any PJM capacity auction.[135]

The FERC declined to adopt a materiality threshold for the level of State Subsidies or the size of State-Subsidized Resources. State-Subsidized Resources "that intend to offer below the default offer price floor for a given resource type, and do not qualify for [one of the four] categorical exemption[s], must support their offers through a Unit-Specific Exemption."[136] While the FERC acknowledged that the extension of the MOPR may prevent certain existing resources that states have recently chosen to subsidize from clearing PJM's capacity auctions, it noted that states may continue to support their preferred resource types in pursuit of state policy goals and make decisions about preferred generation resources, with "resources that states choose to support, and whose offers may fail to clear the capacity market under the revised MOPR directed in this order, … still … permitted to sell energy and ancillary services in the relevant PJM markets."[137] The *Order*, the FERC highlighted, "addresses the growing impact of State-Subsidized Resources because those subsidies reject the premise of the capacity market and circumvent competitive outcomes."[138]

The *Dec 2019 PJM MOPR Order* was accompanied by a 28-page dissent of Commissioner Glick ("Glick Dissent"), who explained why he believes the Order to be "illegal, illogical, and truly bad public policy."[139] Commissioner Glick further suggested that it "may well be that a mandatory capacity market is no longer a sensible approach to resource adequacy at a time when states are increasingly exercising their authority under the FPA to shape the generation mix. Indeed, the conclusion that I draw from the record in front of us is not

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Fixed Resource Requirement ("FRR") that currently exists in PJM's Tariff, is referred to as the "FRR Alternative." Unlike the existing FRR construct, the FRR Alternative would apply only to resources receiving out-of-market support.

[132] *Dec 2019 PJM MOPR Order* at P 5.

[133] The FERC adopted an expanded MOPR rather than PJM's Resource Carve-Out ("RCO") and Extended RCO proposals. The FERC determined that those proposals would unacceptably distort the markets, inhibiting incentives for competitive investment in the PJM market over the long term. PJM's longstanding FRR Alternative remains unchanged in the PJM tariff. *See Id.* at P 6.

[134] Resources with federal subsidies will not be subject to the MOPR. *See Id.* at P 10.

[135] *Id.* at P 9. Renewable Energy Credits ("RECs") procured as part of a state-mandated or state-sponsored procurement process are State Subsidies. *Id.* at P 176. Demand response, energy efficiency, and capacity storage resources that participate in the PJM capacity market are considered to be capacity resources for purposes of this definition. *Id.* at P 9.

[136] *Id.* ("A threshold based on resource size will not prevent a collection of smaller resources from having a significant cumulative impact on competitive outcomes. In addition, if a State Subsidy is small enough for a capacity resource to perform economically without it, then the State-Subsidized Resource should be able to secure a Unit-Specific Exemption.")

[137] *Id.* at P 7.

[138] *Id.* at P 17.

[139] Glick Dissent at P 1.

that there is an urgent need to mitigate the effects of state public policies, but rather that we should be taking a hard look at whether a mandatory capacity market remains a just and reasonable resource adequacy construct in today's rapidly evolving electricity sector."[140]

Requests for Rehearing and Clarification Denied, In Part, and Granted In Part. As reported above, on April 16, 2020, the FERC issued an order granting, in part, and denying, in part, the requests for rehearing and clarification[141] of the *Dec 2019 PJM MOPR Order*, and directed PJM to submit a further compliance filing within 45 days.

Also, as previously reported, the New Jersey Division of Rate Counsel ("NJ Rate Counsel") and NRECA, each out of an abundance of caution, have appealed the *Dec 2019 PJM MOPR Order*. They each explained that they seek judicial review now in case the DC Circuit's action in *Allegheny Defense Project v. FERC*[142] should work to advance the time period for those wishing to seek judicial review of the *Dec 2019 PJM MOPR Order.* Until a decision on *Allegheny Defense Project v. FERC* is issued and its import known, each asked the DC Circuit to hold its appeal in abeyance. For further information on these proceedings, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **PJM Clean MOPR Complaint (EL18-169)**

On April 16, 2020, the FERC denied as moot[143] the May 31, 2018 complaint filed by CPV Power Holdings, L.P. ("CPV"), Calpine Corporation ("Calpine"), and Eastern Generation, LLC ("Eastern Generation") (collectively, "PJM MOPR Complainants") that requested that the FERC protect PJM's Reliability Pricing Model ("RPM") market from below-cost offers for resources receiving out-of-market subsidies by requiring PJM to adopt a "Clean MOPR" (i.e. a MOPR applicable to all subsidized resources and without categorical exemptions like those in PJM's MOPR-Ex proposal). In denying the Complaint, the FERC stated that it "addressed the very issue raised in this Complaint in the [*June 2018 PJM MOPR Order*] and exercised its discretion to not order refunds in that proceeding (which covers the refund period from the May 2018 Complaint here)."[144] If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com).

- **VTransco/VEC ShPA and O&M Agreements (ER20-1679)**

On April 29, Vermont Transco LLC ("VTransco") submitted a Shared Structure Participation Agreement ("ShPA") and an Operating and Maintenance Agreement ("O&M Agreement") between VTransco and Vermont

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[140] Id. at P 62.

[141] Requests for rehearing and/or clarification ("Requests") of the Dec 2019 PJM MOPR Order were filed by over 50 parties, including: PJM IMM, AEP/Duke, AES, Buckeye Power, Calpine, Clean Energy Advocates, CPower, Dominion, EDF Renewables, Exelon, FirstEnergy Utility Companies, First Energy Solutions, Hershey Co., J-POWER, Longroad Development, PSEG, Vistra, Allegheny Electric Coop., East Kentucky Power Coop. ("EKPC"), IL Municipal Electric Agency, North Carolina Electric Membership Corp., Old Dominion Elec. Coop., the S. MD Elec. Coop, the Organization of PJM States ("OPSI"), DC PSC, IL ICC, MD PSC, NJ BPU, OH PUC, PA PUC, VA State Corporation Commission, WV PSC, DE Public Advocate, DC AG, IL AG, MD AG, NJ Div. of Rate Counsel/People's Counsel for DC/MD People's Counsel, OH Consumers' Counsel, PJM Consumer Representatives, Advanced Energy Buyers Group, Advanced Energy Economy ("AEE"), APPA/AMP/Public Power Assoc. of NJ, AWEA, ELCON, EPSA and the PJM Power Providers Group, NEI, NRECA/EKPC, and Public Citizen. An answer to PJM IMM's request for clarification was filed by the Talen PJM Companies. Answers were also filed by the PJM IMM, Longroad Development and Old Dominion Electric Cooperative. EEI filed a motion for reconsideration. On February 18, 2020, the PJM IMM filed a second request for clarification and The National Association of State Energy Officials filed a letter to the Commissioners. On February 25, Old Dominion answered EEI's request for reconsideration. On February 28, the MD PSC answered the IMM's second request for clarification.

[142] *Allegheny Def. Project v. FERC*, Case No. 17-1098 (D.C. Cir. Dec. 5, 2019).

[143] *CPV Power Holdings, L.P., Calpine Corp., and Eastern Generation, LLC v. PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,036 (Apr. 21, 2020).

[144] *Id.* at P 10.

Electric Cooperative, Inc. ("VEC"). VTransco reported that the ShPA and O&M Agreement are part of a transaction between VTransco and VEC that involves the cancellation of a Bill-Back Agreement and an Operating and Maintenance Agreement,[145] and the entering into of a Purchase and Sale Agreement ("PSA"), dated as of April 30, 2020. The ShPA establishes the allocation of costs associated with the design, construction, repair, replacement, general maintenance, operation, and preventative maintenance of facilities on VTransco's structures shared with VEC, where those facilities are used either exclusively by VEC or in common with VTransco. The purpose of the ShPA is to calculate and allocate those costs that are not recovered through a regional transmission tariff on file with the FERC. The O&M Agreement establishes VTransco's and VEC's operational control of the facilities on the shared structures. Comments on the Agreements are due on or before May 20, 2020. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **Phase II VT DMNRC Support Agreement Order 864-Related Filing (ER20-1480)**

On April 1, Vermont Electric Power Company ("VELCO"), as an agent of the Joint Owners, submitted a filing (following consultation with FERC staff) that described why no changes were required to the Phase II Vermont Dedicated Metallic Neutral Return Conductor ("DMNRC") Support Agreement[146] as a result of *Order 864*. Comments on this filing were due April 22 and were filed by GMP, which supported the filing and agreed with VELCO that no *Order 864* compliance filing is necessary. The IRH Management Committee, Eversource and National Grid intervened doc-lessly. 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).

- **Emera Maine/Houlton Water Company NITSA (ER20-1445)**

On March 31, Emera Maine filed a non-conforming Network Integration Transmission Service Agreement ("NITSA") with Houlton Water Company. The NITSA provides for continued provision of network integration transmission service by Emera Maine to Houlton until Houlton's electric system is successfully interconnected with New Brunswick Power, which is now expected to happen sometime in mid-2020. An April 1, 2020 effective date was requested. Comments on this filing were due on or before April 21, 2020; 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).

- **IA Amendment: CMP/Sappi (ER20-1434)**

On March 30, 2020, CMP filed a first amendment to its interconnection agreement ("IA") with Sappi North America, Inc. ("Sappi"). The Amendment extends the term of the Agreement, which expired by its own terms on February 29, 2020, for an additional 20 years, to February 29, 2040. Comments on this filing were due on or before April 20, 2020; 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).

- **IA Cancellations: NGrid/GRS and NGrid/Mini-Watt (ER20-1405/1406/1407)**

On April 28, 2020 [and April , 2020], the FERC accepted the notices of cancellation filed by Massachusetts Electric Company ("NGrid") of three Interconnection Agreements superseded by previously-accepted Small Generator Interconnection Agreements ("SGIA") -- one with Gas Recovery Systems ("GRS") for

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[145] Both the Bill-Back Agreement and the original Operating and Maintenance Agreement were entered into between VTransco's predecessor, VELCO, and VEC's predecessor, Citizens Communication Company. VTransco submitted a separate Notice of Cancellation of the Bill-Back Agreement and the original Operating and Maintenance Agreement, effective April 30, 2020, in ER20-1685.

[146] The DMNRC was installed on VETCO's Phase I facilities to provide a neutral return for Phase I and Phase II at a total construction cost of approximately $2.6 million. Pursuant to the Agreement, the Joint Owners recover their total cost of service by making the DMNRC available to NHH who in turn makes the DMNRC available to the Participants pursuant to, and for the term of, the Phase II New Hampshire Transmission Facilities Support Agreement.

its Fall River facility (ER20-1405),[147] and two with Mini-Watt Hydroelectric, LCC ("Mini-Watt") covering Mini-Watt Unit No 1. (ER20-1406) and Units 2 and 3 (ER20-1407).[148] Thus far, the FERC has accepted the notice of cancellation of the Mini-Watt Unit No. 1 SGIA; the other two notices remain pending before the FERC. If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement Cancellation: CL&P/CPV Towantic (ER20-1221)**

On March 10, 2020, CL&P filed a notice of cancellation of the Design and Engineering Agreement ("D&E Agreement") with CPV Towantic (designated as service agreement IA-ESCLP-005). The D&E Agreement set forth the terms and conditions under which CL&P undertook preliminary engineering and design activities on the mitigation of violations (including reconductoring a 115kV 1029-2 line from Bunker Hill to Baldwin Tap) identified in ISO-NE studies, prior to execution of an LGIA. The D&E Agreement terminated by its terms when an LGIA was executed on February 26, 2020. A February 26, 2020 effective date was requested. Comments on this filing were due on or before March 31; 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).

- **IA / TSA Cancellations: Emera Maine/ReEnergy Ashland (ER20-1173/1172)**

On April 22, 2020, the FERC accepted the notices of cancellation filed by Emera Maine of its IA (ER20-1173) and Transmission Service Agreement ("TSA") (ER20-1172) with ReEnergy Ashland LLC ("Ashland").[149] The Agreements were cancelled in light of the termination of operations at the 40 MW Ashland biomass facility. The notices of cancellation were each accepted effective February 28, 2020, as requested. Unless either of the April 22 orders are challenged, these proceedings will be concluded. If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **IA / TSA Cancellations: Emera Maine/ReEnergy Fort Fairfield (ER20-1076/1077)**

On April 8, 2020, the FERC accepted Emera Maine's notices of cancellation of both the IA (ER20-1076) and TSA (ER20-1077) between itself and ReEnergy Fort Fairfield LLC ("Fort Fairfield").[150] The Agreements were cancelled in light of the termination of operations at the 37 MW Fort Fairfield biomass facility, and the notice accepted as of February 24, 2020, as requested. Unless the April 8 orders are cancelled, these proceeding will be concluded. If you have any questions concerning these matters, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Northern Pass: TSA Cancellation / Cost Reimbursement (ER20-1030/1031)**

On April 14, the FERC accepted Northern Pass Transmission LLC's ("Northern Pass") (i) notice of termination of its bilateral, cost-based Transmission Service Agreement ("TSA") with Hydro Renewable Energy Inc. ("HRE") for transmission service over the Northern Pass Transmission Project (ER20-1030); and (ii) its December 16, 2019 agreement with Hydro-Québec Production ("HQP") under which HQP has agreed to reimburse Northern Pass for certain Project costs (ER20-1031).[151] As previously reported, Northern Pass is no

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[147] The currently effective SGIA with GRS was accepted in *Mass. Elec. Co.*, Docket No. ER19-2352 (Aug. 13, 2019) (unpublished letter order).

[148] The currently effective SGIAs with Mini-Watt were accepted in *Mass. Elec. Co.*, Docket No. ER19-2464 (Sep. 16, 2019) (unpublished letter order) (Unit No. 1) and *Mass. Elec. Co.*, Docket No. ER19-2465 (Sep. 16, 2019) (unpublished letter order) (Unit Nos. 2-3).

[149] *Emera Maine*, Docket No. ER20-1173 (Apr. 22, 2020) (unpublished letter order); *Emera Maine*, Docket No. ER20-1172 (Apr. 22, 2020) (unpublished letter order).

[150] *Emera Maine*, Docket No. ER20-1076 (Apr. 8, 2020) (unpublished letter order); *Emera Maine*, Docket No. ER20-1077 (Apr. 8, 2020) (unpublished letter order).

[151] *Northern Pass Transmission LLC*, Docket Nos. ER20-1030 and ER20-1031-000 (not consolidated) (Apr. 14, 2020) (unpublished letter order).

longer moving forward with the Project as a result of the New Hampshire Site Evaluation Committee's decision to deny a Certificate of Site and Facility for the Project, a decision that was affirmed by the New Hampshire Supreme Court on July 19, 2019. The notice and letter were accepted effective September 6, 2019 and April 19, 2020, respectively. Unless the April 14 order is challenged, these proceedings will be concluded. If there are questions on these proceedings, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Amended and Restated CONVEX Services Agreement: CL&P/MMWEC (ER20-996)**

On April 6, 2020, the FERC accepted an Amended and Restated Agreement for CONVEX Services between CL&P and MMWEC.[152] Under the Agreement, CL&P provides certain scheduling and dispatching services to MMWEC through the Connecticut Valley Exchange ("CONVEX") dispatch center. The amendments reflect the fact that MMWEC has elected not to take certain services previously provided by CONVEX (services related to switching and tagging, and training and coordination on switching and tagging plans). The amended and restated Agreement was accepted effective February 14, 2020, as requested. Unless the April 6 order is challenged, this proceeding will be concluded. If there are questions on this proceeding, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Emera Maine *Order 845* Compliance Filing (ER19-1887)**

On March 19, 2020, the FERC conditionally accepted, effective May 20, 2019, Emera Maine's *Order 845* compliance filing revising the Maine Public District Open Access Transmission Tariff ("MPD OATT"), subject to a further compliance filing due on or before July 17, 2020.[153] The further compliance filing must (i) address an apparent incongruity between the deadlines for submission of a non-disputing party's position statement and a disputing party's response (which could become due before the position statement itself); (ii) add to section 3.8 of Emera Maine's LGIP (a) the method Emera Maine will use to determine contingent facilities, including technical screens or analyses it proposes to use to identify these facilities; and (b) the specific thresholds or criteria it will use in its technical screens or analysis to achieve the level of transparency required by *Order 845*; (iii) incorporate all, not just some of, the *pro forma* revisions to LGIP section 3.1; (iv) provide explanations for the term "technical specifications" and the phrase "materially change" used in the definition of "permissible technological advancement"; (v) revise LGIP section 4.4.6 to clarify how it will assess changes to a generating facility's technical specifications to determine whether the technological advancement request will result in a material modification; (vi) permit the acceptance of technological changes until execution of facilities study agreement rather than up to the conclusion of the system impact study; (vii) revise the technological change procedure to state that an interconnection customer should submit a technological advancement request if it seeks to incorporate the technological advancements into its proposed generating facility; (viii) propose a deposit amount for a technological change request; (ix) revise the LGIP to specify that Emera Maine will complete its assessment and determination of whether a proposed technological change is a material modification within 30 days of an interconnection customer submitting a technological change request; and (x) correct the reference to LGIP 4.4.6 in the definition of "permissible technological advancement". The *MPD OATT Order 845 Compliance Order* was not challenged and is final and unappealable. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **FERC Enforcement Action: Order Assessing Civil Penalties – Vitol & F. Corteggiano (IN14-4)**

On October 25, 2019, the FERC issued an order[154] finding Vitol Inc. ("Vitol") and its co-head of FTR trading operations, Frederico Corteggiano, violated from October 28-November 1, 2013, the FERC's Anti-Manipulation Rule by selling physical power at a loss in CAISO's market in order to eliminate congestion that they expected to

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[152] *The Connecticut Light and Power Co.*, Docket No. ER20-996 (Apr. 6, 2020) (unpublished letter order).

[153] *Emera Maine*, 170 FERC ¶ 61,206 (Mar. 19, 2020) ("*MPD OATT Order 845 Compliance Order*").

[154] *Vitol Inc. and Federico Corteggiano*, 169 FERC ¶ 61,070 (Oct. 25, 2019) ("*Vitol Penalties Order*").

cause losses on Vitol's congestion revenue rights ("CRRs").[155] The FERC assessed civil penalties of $1,515,738 against Vitol and $1 million against Corteggiano. In addition, the FERC directed Vitol to disgorge unjust profits, plus applicable interest of $1,227,143.

Because Respondents' previously elected the FPA's *de novo* review procedures, which permits a reviewing federal court "to review *de novo* the law and the facts involved" and "jurisdiction to enter a judgment . . . modifying . . . or setting aside [the assessment] in whole or in Part", the *Vitol Penalties Order* was not subject to rehearing. On January 6, 2020, the FERC instituted an action in federal district court (Eastern District of California) for an order affirming the penalties assessed against Respondents and ordering Vitol to disgorge its unjust profits, plus interest.[156] Reporting on this case will be continued in future Reports, when and as appropriate, in Section XV.

XII. Misc. - Administrative & Rulemaking Proceedings

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

On April 14, 2020, Interest Parties[157] requested that the FERC convene a technical conference or workshop to discuss integrating state, regional, and national carbon pricing in FERC-jurisdictional organized regional wholesale electric energy markets. They suggested that the scope of the conference/workshop could include examination of a variety of mechanisms through which carbon could be priced on a state, regional, or national level and how wholesale market pricing and dispatch could (or already do) account for the costs arising from compliance with such programs. A technical conference or workshop, they believe, "would be helpful to the Commission and stakeholders in the electric energy industry in deciding how best to move forward at the state and regional levels on these issues and in the relevant organized markets. This dialogue would complement state, regional, and national discussions currently taking place." Comments on the request are due on or before May 21, 2020. Thus far, the request has been supported by the PJM IMM, MA AG, Institute for Policy Integrity, and the Western Power Trading Forum.

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

On April 7, 2020, the FERC issued a notice that staff will convene a technical conference on July 23, 2020 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"). For purposes of this inquiry, the focus will be on a generation resource and an electric storage resource paired together as a hybrid resource. Commissioners may participate in the technical conference. Individuals interested in participating as panelists should submit a self-nomination form by May 15, 2020 at: https://www.ferc.gov/whatsnew/registration/07-23-20-speaker-

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[155] Enforcement Staff alleges that Vitol and Corteggiano ("Respondents") sold physical power at a loss at the Cragview node in CAISO's day-ahead market from Oct. 28 through Nov. 1, 2013, in order to eliminate congestion costs that they expected would negatively affect Vitol's CRRs. On Vitol's behalf, Corteggiano purchased CRRs sourcing at Cragview in CAISO's annual CRR auction for 2013. In mid-October 2013, CAISO derated the Cascade intertie to "0" in only the export direction, while still allowing imports. During the derate, an unusually high LMP appeared at Cragview due to congestion costs. The congestion costs caused Respondents' CRRs to lose money. CAISO announced that identical derates would occur during the week of October 28 through November 1 and on additional dates later in November and in December. Respondents were able to protect against losses on their CRR positions for November and December by buying counter-flow CRRs in the CRR auctions for those months (i.e., "flattening" the CRR position). However, because the monthly CRR auction for October had closed, it was too late for Respondents to flatten their CRR position for the last week of October. Facing over $1.2 million in potential losses on their CRRs during that week's scheduled partial derate, Respondents imported physical power in the day-ahead market at an offering price of $1/MWh, which prevented a recurrence of the congestion costs that Respondents had observed during the October 18-19 derate. Staff alleges Respondents undertook the import transactions in disregard of market fundamentals and were indifferent to whether they made a profit on them. In fact, Respondents lost money on the imports, but avoided a far larger loss on their CRRs. *Id.* at P 3.

[156] FERC v. Vitol Inc. and Federico Corteggiano, Case No. 2:20-cv-00040-KJM-AC (E. D. CA) (filed Jan. 6, 2020).

[157] "Interested Parties" are AEE, the American Council on Renewable Energy, the American Wind Energy Association, Brookfield Renewable, Calpine, CPV, EPSA, the Independent Power Producers of New York ("IPPNY"), LS Power Associates ("LS Power"), the Natural Gas Supply Association ("NGSA"), NextEra, PJM Power Providers Group, R Street Institute, and Vistra Energy Corp.

form.asp. Individuals who are interested in registering for the conference can do so at https://www.ferc.gov/whats-new/registration/07-23-20-form.asp.

- **Credit Reforms in Organized Wholesale Markets (AD20-6)**

On December 16, 2019, the Energy Trading Institute[158] requested that the FERC hold a technical conference and conduct a rulemaking to update the requirements adopted in *Order 741*[159] and Section 35.47 of the FERC's regulations addressing credit and risk management in the markets operated by RTO/ISOs. ETI, citing a recent filing by NYISO (which it protested),[160] and stating that several expedited initiatives related to RTO/ISO credit policies are underway, suggested that it would be helpful for the FERC to consolidate any "filings with this proceeding and hold the technical conference ETI is requesting by March 30, 2020 so the ISOs, RTOs and their stakeholders consider those discussions in any initiatives they have underway." ETI suggested in its request that RTO/ISO credit support requirements be standardized, and that the requested technical conference and rulemaking explore various ways to identify and mitigate counterparty risk (including know-you-customer ("KYC") tools and participant suspensions or bans) and enhance risk management infrastructure/processes within the organized markets. Doc-less interventions have been filed by, among others, PJM, the PJM IMM, SPP, CAISO, Tenaska, Avangrid, and Roscommon Analytics. On January 24, the ISO/RTO Council ("IRC"), including ISO-NE, submitted comments and proposed, as an alternative approach to the one suggested by ETI, that the FERC not commence a rulemaking or schedule a technical conference at this time and instead allow individual RTO/ISOs to address their respective credit and risk management issues, permit sufficient time for experience with the evolving rules to be gained, and then consider the best path forward to facilitate a dialogue on best practices and potential points of alignment among the RTO/ISO. ETI responded to those comments on February 10, 2020.

The FERC issued a notice of ETI's request for technical conference and petition for rulemaking on February 11, 2020, setting March 12, 2020 as the deadline for comments thereon. Comments were submitted by a number of parties, including APPA, CAISO, the Committee of Chief Risk Officers ("CCRO"), DC Energy, EEI, EPSA, Indicated PJM Transmission Owners,[161] and an independent consultant.[162] This matter is pending before the FERC.

- **Grid Resilience in RTO/ISOs; DOE NOPR (AD18-7; RM18-1)**

On January 8, 2018, the FERC initiated a Grid Resilience in RTO/ISOs proceeding (AD18-7)[163] and terminated the DOE NOPR rulemaking proceeding (RM18-1).[164] In terminating the DOE NOPR proceeding, the

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[158] In its request, The Energy Trading Institute ("ETI") describes itself generally as "represent[ing] a diverse group of energy market participants, all with substantial interests in wholesale electricity transactions in Commission-jurisdictional markets. ETI members provide important services to a wide variety of wholesale energy market participants. They act as intermediaries between producers and consumers of electric energy that have mismatched quantity, timing, and contract type needs. In addition, they provide liquidity by engaging in energy related commercial transactions with a variety of market entities including, but not limited to, generation owners, project developers, load-serving entities, and investors. ETI members advocate for markets that are open, transparent, competitive and fair - all necessary attributes for markets ultimately to benefit electricity consumers."

[159] *Credit Reforms in Organized Wholesale Elec. Mkts.*, 75 Fed. Reg. 65942 (2010), FERC Stats. & Regs. ¶ 31,317 (2010) ("*Order 741*"); *order on reh'g*, 76 Fed. Reg. 10492 (2011), FERC Stats. & Regs. ¶ 31,320 (2011) ("*Order 741-A*"); *order on reh'g*, 135 FERC ¶ 61,242 (2011) (*"Order 741-B*"); 18 C.F.R. § 35.47.

[160] *See* Proposed Tariff Amendments to Enhance Credit Reporting Requirements and Remedies, *New York Indep. Sys. Operator*, Inc., Docket No. ER20-483 (filed Nov. 26, 2019).

[161] "Indicated PJM Transmission Owners" are Exelon Corp. ("Exelon"), American Electric Power Service Corp. ("AEP"), Dominion Energy Services, Inc. ("Dominion"), PPL Electric Utilities Corp. ("PPL"), the FirstEnergy Utility Companies. ("FirstEnergy"), East Kentucky Power Coop. ("EKPC"), Duke Energy Corp. ("Duke"), Duquesne Light Co. ("Duquesne"), and the PSEG Companies ("PSEG").

[162] W. Scott Miller, III, Whitehall Bay Energy Services, LLC.

[163] *Grid Rel. and Resilience Pricing*, 162 FERC ¶ 61,012 (Jan. 8, 2018), *reh'g requested*.

[164] As previously reported, the FERC opened the DOE NOPR proceeding in response to a September 28, 2017 proposal by Energy Secretary Rick Perry, issued under a rarely-used authority under §403(a) of the Department of Energy ("DOE") Organization Act, that would have required RTO/ISOs to develop and implement market rules for the full recovery of costs and a fair rate of return for "eligible units" that (i) are able to provide essential energy and ancillary reliability services, (ii) have a 90-day fuel supply on site in the event of supply

FERC concluded that the Proposed Rule and comments received did not support FERC action under Section 206 of the FPA, but did suggest the need for further examination by the FERC and market participants of the risks that the bulk power system faces and possible ways to address those risks in the changing electric markets. On February 7, Foundation for Resilient Societies ("FRS") requested rehearing of the January 8 order terminating the DOE NOPR proceeding. The FERC issued a tolling order on March 8, 2018 affording it additional time to consider the FRS request for rehearing, which remains pending.

Grid Resilience Administrative Proceeding (AD18-7). AD18-7 was initiated to evaluate the resilience of the bulk power system in RTO/ISO regions. The FERC directed each RTO/ISO to submit information on certain resilience issues and concerns, and committed to use the information submitted to evaluate whether additional FERC action regarding resilience is appropriate. RTO submissions were due on or before March 9, 2018.

ISO-NE Response. In its response, ISO-NE identified fuel security[165] as the most significant resilience challenge facing the New England region. ISO-NE reported that it has established a process to discuss market-based solutions to address this risk, and indicated that it believed it will need through the second quarter of 2019 to develop a solution and test its robustness through the stakeholder process. In the meantime, ISO-NE indicated that it would continue to independently assess the level of fuel-security risk to reliable system operation and, if circumstances dictate, would take, with FERC approval when required, actions it determines to be necessary to address near-term reliability risks. ISO-NE's response was broken into three parts: (i) an introduction to fuel-security risk; (ii) background on how ISO-NE's work in transmission planning, markets, and operations support the New England bulk power system's resilience; and (iii) answers to the specific questions posed in the January 8 order.

Industry Comments. Following a 30-day extension issued on March 20, 2018, reply comments were due on or before May 9, 2018. NEPOOL's comments, which were approved at the May 4 meeting, were filed May 7, and were among over 100 sets of initial comments filed. A summary of the comments that seemed most relevant to New England and NEPOOL was circulated to the Participants Committee on May 15 and is posted on the NEPOOL website. On May 23, NEPOOL submitted a limited response to four sets of comments, opposing the suggestions made in those pleadings to the extent that the suggestions would not permit full use of the Participant Processes. Supplemental comments and answers were also filed by FirstEnergy, MISO South Regulators, NEI, and EDF. Exelon and American Petroleum Institute filed reply comments. FirstEnergy included in this proceeding its motion for emergency action also filed in ER18-1509 (ISO-NE Waiver Filing: Mystic 8 & 9), which Eversource answered (in both proceedings). Reply comments were filed by APPA and AMP and the Nuclear Energy Institute ("NEI") moved to lodge presentations by the National Infrastructure Advisory Council. On December 6, the Harvard Electricity Law Initiative filed a comment suggesting that, as a matter of law, "Commission McNamee cannot be an impartial adjudicator in these proceedings" and "any proceeding about rates for 'fuel-secure' generators" and should recuse himself. Similarly, on December 18, "Clean Energy Advocates"[166] requested Commissioner McNamee recuse himself from these proceedings. These matters remain pending before the FERC.

FirstEnergy DOE Application for Section 202(c) Order. In a related but separate matter, FirstEnergy Solutions ("FirstEnergy") asked the Department of Energy ("DOE") in late March to issue an emergency order to

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disruptions caused by emergencies, extreme weather, or natural or man-made disasters, (iii) are compliant with all applicable environmental regulations, and (iv) are not subject to cost-of-service rate regulation by any State or local authority. More than 450 comments were submitted in response to the DOE NOPR, raising and discussing an exceptionally broad spectrum of process, legal, and substantive arguments. A summary of those initial comments was circulated under separate cover and can be found with the posted materials for the November 3, 2017 Participants Committee meeting. Reply comments and answers to those comments were filed by over 100 parties.

[165] ISO-NE defined fuel security as "the assurance that power plants will have or be able to obtain the fuel they need to run, particularly in winter – especially against the backdrop of coal, oil, and nuclear unit retirements, constrained fuel infrastructure, and the difficulty in permitting and operating dual-fuel generating capability."

[166] For purposes of these proceedings, "Clean Energy Advocates" are NRDC, Sierra Club and UCS.

provide cost recovery to coal and nuclear plants in PJM, saying market conditions there are a "threat to energy security and reliability". FirstEnergy made the appeal under Section 202(c) of the FPA, which allows the DOE to issue emergency orders to keep plants operating, but has previously been exercised only in response to natural disasters. Action on that 2018 request is pending.

- **Increasing Market and Planning Efficiency Through Improved Software (AD10-12)**

The FERC will hold a technical conference by WebEx addressing increasing Real-Time and Day-Ahead market efficiency through improved software June 23-25, 2020. This is the eleventh consecutive year that the FERC has held a summer conference on this topic. FERC Staff will be facilitating a discussion to explore research and operational advances with respect to market modeling that appear to have significant promise for potential efficiency improvements. A supplemental notice of the technical conference was posted on April 7. Those planning to participate in the WebEx must register through the FERC's website by June 12, 2020. WebEx connections may not be available to those who do not register. Staff anticipates facilitating participant questions and discussions of materials presented through WebEx. Details will be released prior to the conference on how such discussions will take place. The FERC will accept comments following the conference, with a deadline of July 31, 2020.

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

On March 20, 2020, the FERC issued a NOPR[167] proposing to revise its existing transmission incentives policy and corresponding regulations.[168] The proposed revisions include 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***.
- ***RTO-Participation Inventive***. A 100-basis-point increase for transmitting utilities that turn over their wholesale facilities to an RTO, ISO, or Transmission Organization, and available regardless of whether participation 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.

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[167] *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, 170 FERC ¶ 61,204 (Mar. 20, 2020) ("*Electric Transmission Incentives NOPR*").

[168] 18 CFR 35.35 (2020).

A more detailed summary of the NOPR was distributed to the Transmission Committee and discussed at its March 25, 2020 meeting. Comments on the proposed revisions are due on or before July 1, 2020.[169] Thus far, one set of comments has been submitted (by Schulte Associates). On April 29, American Manufacturers[170] requested a 90-day extension of time to comment. Their request was supported by APPA/TAPS, but opposed by WIRES and EEI (each advocating for no more than a few weeks' extension). The FERC has not yet acted on American Manufacturers' request. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **NOPR: QF Rates and Requirements; Implementation Issues under PURPA (RM19-15)**

In an action that could have significant impacts on the development and financing of renewable resources, the FERC, on September 19, 2019, proposed rules to reform its long-standing regulations implementing sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA").[171] Those regulations address the obligation of electric utilities to purchase power produced by "qualifying facilities" or "QFs" at rates that must be "just and reasonable to the electric consumers of the electric utility and in the public interest, and not discriminate against" those QFs.[172]

The *QF NOPR* seeks public comment on draft rule changes "to rebalance the benefits and obligations of the [FERC's] PURPA Regulations in light of the changes in circumstances since the PURPA Regulations were promulgated."[173] The *QF NOPR* proposes the following changes that would revise how and when prices for QF power may be established and would reduce the circumstances under which a utility's mandatory purchase obligation would be triggered:

- Provide states the flexibility to establish QF energy rates at the purchasing utility's avoided costs at the time of energy *delivery*, rather than allowing the QFs to elect to *fix* the energy rate for an extended term at the time the utility becomes compelled to purchase the QF's energy.
- Specify that an avoided cost rate for QF energy can be based on *market factors* (including locational market prices, indices, trading hubs, or competitive solicitation processes) or, at the state's discretion, can continue to be set as they are under current PURPA Regulations.
- Reduce in states with a retail choice program an electric utility's obligation to purchase from QFs to the extent that the utility's provider of last resort ("POLR") supply obligation has been reduced by the state's

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[169] The *Electric Transmission* Incentives NOPR was published in the *Fed. Reg.* on Apr. 2, 2020 (Vol. 85, No. 64) pp. 18,784-18,810.

[170] "American Manufacturers" are: the Indus. Energy Consumers of America ("IECA"), Aluminum Assoc., American Chemistry Council, American Forest & Paper Assoc. ("AF&PA"), American Foundry Society, American Fuel & Petrochemical Manufacturers, American Iron and Steel Institute, Associated Industries of Arkansas, Assoc. of Businesses Advocating Tariff Equity ("ABATE"), California Large Energy Consumers Assoc., California Manufacturers & Technology Assoc., CalPortland Co., Carolina Indus. Group for Fair Utility Rates I, II & III, Carolina Utility Customers Assoc., Carpenter Technology Corp., Chemistry Council of New Jersey, Clearwater Paper Corp., Coalition of MISO Transmission Customers, Conn. Indus. Energy Consumers, Domtar Corp., ELCON, Ellwood Quality Steels, Evonik Corp., Fertilizer Institute, Flex-N-Gate, Florida Indus. Power Users Group, Ford Motor Co., Gerdau, Glass Packaging Institute, Illinois Indus. Energy Consumers, Indiana Indus. Energy Consumers, Indus. Energy Consumers of Penn., Indus. Energy Users-Ohio, Indus. Minerals Assoc. – North America, Ingevity Corp., Iowa Indus. Energy Group, Kimberly-Clark, Kentucky Indus. Utility Customers, Lafarge-Holcim, Louisiana Chemical Assoc., Maine Indus. Energy Consumer Group ("IECG"), Messer Americas, Michigan Chemistry Council, Michigan Indus. Energy Assoc., Midwest Food Products Assoc., National Council of Textile Orgs., National Stone, Sand & Gravel Assoc., Ohio Energy Group (OEG), Ohio Manufacturers' Assoc. Energy Group, Oklahoma Indus. Energy Consumers, Olin Corp., Penn. Energy Consumers Assoc., PJM Indus. Customer Coalition, Portland Cement Assoc., South Carolina Energy Users Comm., Steel Manufacturers Assoc., TimkenSteel Corp., Tyson Foods, US Silica Co., Utah Assoc. of Energy Users, WestRock Co., West Virginia Energy Users Group, Western Kansas Indus. Energy Consumers, and Wisc. Indus. Energy Group.

[171] 16 U.S.C. § 2601 et seq. (2018). PURPA was enacted to help lessen the dependence on fossil fuels and promote the development of power generation from non-utility power producers.

[172] 16 U.S.C. § 824a–3; PURPA, Sec. 210(a)-(b).

[173] *Qualifying Facility Rates and Requirements; Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Notice of Proposed Rulemaking, 168 FERC ¶ 61,184 (2019) ("*QF NOPR*").

program. If POLR supplies are obtained through solicitations having a specific contract term, the term of any PURPA purchase contract should match the term of the POLR supply contract.

- Decrease from 20 MW to 1 MW the maximum size of QFs that would be entitled to require utilities located in areas with demonstrably competitive markets (RTO/ISOs) to purchase their power. If QF facilities qualify as cogeneration, the 20 MW cap would not change.
- Replace the "one-mile rule" for determining whether generation facilities under common ownership should be considered to be part of a single facility (to be eligible for favorable QF treatment, a small power production facility must be 80 MW or less). Some have argued that the current one-mile rule has been gamed to permit QF certification of projects that if combined would otherwise exceed the 80 MW cap. The impact of this change, if made, would primarily affect projects in non-RTO/ISO markets (e.g., the bilateral markets of the southern and western United States).
- Clarify that a utility's mandatory purchase obligation under PURPA does not arise until the QF can demonstrate commercial viability and financial commitment pursuant to objective and reasonable state-defined criteria.
- Allow for interested stakeholders to protest the self-certification of a QF.

Comments on the proposed rule changes were due on or before December 3, 2019.[174] More than 130 sets of comments were submitted, including comments from Bloom Energy, Borrego Solar, ConEd, Covanta, CT PURA, MA AG, MA DPU, and AEE. Since the last Report, several Congressman have sent comments supporting comments submitted by others. Chairman Chatterjee acknowledged each of the comments received from Congressmen. Late filed comments were submitted by the American Dams, California PUC, TerraForm and the Arizona Corporation Commission. Since the last Report, US Representative Sean Casten (D-IL) submitted comments opposing FERC action. SEIA submitted supplemental comments. This matter remains pending before the FERC.

- ***Orders 864/864-A*: Public Util. Trans. ADIT Rate Changes (RM19-5)**

On November 21, 2019, the FERC issued its final rule a NOPR ("*Order 864*")[175] requiring 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. The FERC did not adopt its proposals in the ADIT NOPR[176] that were applicable to public utilities with stated rates. *Order 864* will become effective January 27, 2020. Requests for rehearing were filed by APPA and Exelon.

Order 864-A. On April 16, the FERC denied the requests for rehearing and granted APP's request for clarification in part.[177] Specifically, the FERC clarified that public utilities with transmission stated rates that have a FERC-approved ratemaking method for addressing excess and deficient ADIT return the appropriate amount of excess ADIT resulting from the Tax Cuts and Jobs Act to customers through their transmission stated rates. For public utilities with transmission stated rates that lack a FERC-approved ratemaking method, the ratemaking

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[174] The *QF NOPR* was published in the *Fed. Reg.* on Oct. 4, 2019 (Vol. 84, No. 193) pp. 53,246-53,275.

[175] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, Order No. 869, 169 FERC ¶ 61,139 (Nov. 21, 2019), *reh'g denied and clarification granted in part,* 171 FERC ¶ 61,033 (Apr. 16, 2020).

[176] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, 165 FERC ¶ 61,117 (Nov. 15, 2018) ("*ADIT NOPR*").

[177] *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*").

method used to make provision for excess and deficient ADIT will be subject to case-by-case determination in a later rate proceeding.[178]

New England TO Compliance Filings - Extensions of Time to File. VTransco (Feb 3), National Grid (Feb 10), Eversource (Feb 18), UI (Feb 20), VT Electric Transmission Co. ("VETCO") (Feb 25), and New Hampshire Transmission ("NHT") (Feb 26) each requested that their deadline for submitting a compliance filing be extended until July 31, 2020—the date of the TOs' next annual informational filing for regional formula rates. Each of those requests has been granted.

New England Compliance Filings - New England Electric Transmission Corporation (ER20-1089), New England Hydro Transmission Electric Company (ER20-1088), and New England Hydro Transmission Corporation (ER20-1087) each submitted their compliance filings on February 26, 2020, with comments, if any, on those filings due on or before March 18, 2020; none were filed. VELCO, the IRH Management Committee, and GMP (just in ER20-1089) each intervened. These compliance filings are pending before the FERC.

- **DER Participation in RTO/ISOs (RM18-9)**

In *Order 841*[179] (*see* RM16-23 below), the FERC initiated a new proceeding in order to continue to explore the proposed distributed energy resource ("DER") aggregation reforms it was considering in the *Storage NOPR*.[180] All comments filed in response to the *Storage NOPR* will be incorporated by reference into Docket No. RM18-9 and further comments regarding the proposed distributed energy resource aggregation reforms, including comments regarding the April 10-11 technical conference in AD18-10,[181] were also to be filed in RM18-9. On June 26, 2018, over 50 parties submitted post-technical conference comments in this proceeding, including comments from ISO-NE, Calpine, Direct, Eversource, Icetec, NRG, Utility Services, EEI, EPRI, EPSA, NARUC, NRECA, and SEI. On February 11, 2019, a group of 18 US Senators submitted a letter urging the FERC to adopt a final rule that enable all DERs the opportunity to participate in the RTO/ISO markets and requesting an update no later than March 1, 2019. Reply comments and answers were submitted by the Arkansas PUC, AEE, AEMA, and the Missouri PUC. APPA/NRECA submitted supplemental comments.

On September 5, the FERC requested that each of the RTO/ISOs provide responses to data requests seeking information on their policies and procedures that affect DER interconnections. The RTO/ISO responses were due and were filed on October 7, 2019. Comments on the responses were filed by 8 parties, including comments addressing ISO-NE's responses by MA DPU, MA DOER and MA AG (collectively, "Massachusetts"), MMWEC, AEE, EEI and NRECA. This matter is pending before the FERC.

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[178] *Order 864-A* at PP 18-19

[179] *Elec. Storage Participation in Mkts. Operated by Regional Trans. Orgs. and Indep. Sys. Operators*, Order No. 841, 162 FERC ¶ 61,127 (Feb. 15, 2018), reh'g and/or *clarif. requested* ("*Order 841*").

[180] *Elec. Storage Participation in Mkts. Operated by Regional Trans. Orgs. and Indep. Sys. Operators*, 157 FERC ¶ 61,121 (Nov. 17, 2016) ("*Storage NOPR*").

[181] On April 10-11, 2018, the FERC held a technical conference to gather additional information to help the FERC determine what action to take on DER aggregation reforms proposed in the *Storage NOPR* and to explore issues related to the potential effects of DERs on the bulk power system. Technical conference materials are posted on the FERC's eLibrary. Interested persons were invited to file post-technical conference comments on the topics concerning the Commission's DER aggregation proposal discussed during the technical conference, including on follow-up questions from FERC Staff related to the panels. Comments related to DER aggregation were to be filed in RM18-9; comments on the potential effects of DERs on the bulk power system, in AD18-10.

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

On July 18, 2019, the FERC issued *Order 860*.[182] *Order 860*, issued three years after the FERC's *Data Collection NOPR,*[183] (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 will post 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. While *Order 860* will become effective October 1, 2020, submitters will have until close of business on February 1, 2021 to make their initial baseline submissions. In the fall of 2020, 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,[184] 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 submitted by EEI, Fund Management Parties ("FMP"), Joint Consumer Advocates, NRG/Vistra, Starwood Energy Group, and TAPS.

Order 860-A. On February 20, 2020, the FERC denied rehearing of *Order 860*.[185] The FERC denied all the requests for clarification of *Order 860*, 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.

Feb 27, 2020 Technical Conference. On February 27, 2020, FERC staff held a technical workshop on the relational database being built in accordance with *Order 860* ("MBR Database").

- ***Order 676-I*: NAESB WEQ Standards v. 003.2 - Incorporation by Reference into FERC Regs (RM05-5-027)**

On February 4, 2020, the FERC issued Order *676-I*,[186] which incorporates by reference into its regulations, with certain enumerated exceptions, the latest version (Version 003.2) of certain Standards for Business Practices and Communication Protocols for Public Utilities adopted by the Wholesale Electric

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[182] *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).

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

[184] 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.

[185] *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*").

[186] *Standards for Business Practices and Communication Protocols for Public Utilities*, Order No. 676-I, 170 FERC ¶ 61,062 (Feb. 4, 2020) ("*Order 676-I*"), *reh'g and/or clarif. pending*.

Quadrant ("WEQ") of the North American Energy Standards Board ("NAESB").[187] The Version 003.2 Standards included NAESB's Version 003.1 revisions, which were the subject of an earlier NOPR.[188] The FERC declined to adopt the proposal to remove the incorporation by reference of the WEQ-006 Manual Time Error Correction Business Practice Standards as adopted by NAESB. *Order 676-I* will become effective April 27, 2020.[189] Requests for clarification and/or rehearing of *Order 676-I* were filed by EEI and Southern Companies. On April 6, the FERC issued a tolling order affording it additional time to consider those requests, which remain pending before the FERC.

Compliance dates: Public utilities must make a compliance filing to comply with the requirements of *Order 676-I* through eTariff no later than July 27, 2020. The FERC will set an effective date for the proposed tariff changes in the order(s) on the compliance filings, but no earlier than October 27, 2020.

- **NOI: FERC's ROE Policy (PL19-4)**

On March 21, 2019, the FERC issued a notice of inquiry seeking information and views to help the Commission explore whether, and if so how, it should modify its policies concerning the determination of the return on equity ("ROE") to be used in designing jurisdictional rates charged by public utilities.[190] The Commission also seeks comment on whether any changes to its policies concerning public utility ROEs should be applied to interstate natural gas and oil pipelines. This NOI follows *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). Initial comments were due June 26, 2019; reply comments, July 26, 2019.[191] Initial comments were been submitted by more than 60 organizations; nearly 15,000 initial comments were received from individuals. Reply comments were received from nearly 30 organizations. Further reply comments (also submitted in PL19-3, were submitted by a large group of state public utility commissions, public power utilities, electric cooperatives, consumer advocates, industrial users of electricity, and associations, TEC-RI and the RI Manufacturers Association. SPP transmission owners submitted comments in light of *Opinion 569*[192] and statements made by the FERC concurrent with the issuance of *Opinion 569*. This matter, and its voluminous record, are pending before the FERC.

- **NOI: Electric Transmission Incentives Policy (PL19-3)**

As reported above, the FERC issued its *Electric Transmission Incentives NOPR* on March 20, 2020, based in part on the record developed earlier in this proceeding. Reporting on developments with respect to the FERC's Electric Transmission Incentives Policy will be addressed in future Reports in RM20-10.

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

On April 19, 2018, the FERC announced its intention to revisit its approach under its 1999 Certificate Policy Statement to determine whether a proposed jurisdictional natural gas project is or will be required by the present or future public convenience and necessity, as that standard is established in NGA Section 7. Specifically, the NOI[193] seeks comments from interested parties on four broad issue categories: (1) project

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[187] *Standards for Business Practices and Communication Protocols for Public Utilities*, 167 FERC ¶ 61,127 (May 16, 2019) ("*NAESB WEQ v. 003.2 Standards NOPR*").

[188] *Standards for Business Practices and Communication Protocols for Public Utilities*, 156 FERC ¶ 61,055 (July 21, 2016), ("*WEQ v. 003.1 NOPR*").

[189] *Order 676-I* was published *Fed. Reg.* on Feb. 25, 2020 (Vol. 85, No. 37) pp. 10,571-10,586.

[190] *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 166 FERC ¶ 61,207 (Mar. 21, 2019) ("*ROE Policy NOI*").

[191] The *ROE Policy NOI* was published in the *Fed. Reg.* on Mar. 28, 2019 (Vol. 84, No. 61) pp. 11,769-11,777.

[192] *Ass'n of Bus. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569, 169 FERC ¶ 61,129 (2019) ("*Opinion 569*").

[193] The NOI was published in the *Fed. Reg.* on Apr. 26, 2018 (Vol. 83, No. 80) pp. 18,020-18,032.

need, including whether precedent agreements are still the best demonstration of need; (2) exercise of eminent domain; (3) environmental impact evaluation (including climate change and upstream and downstream greenhouse gas emissions); and (4) the efficiency and effectiveness of the FERC certificate process. Pursuant to a May 23 order extending the comment deadline by 30 days,[194] comments were due on or before July 25, 2018. Literally thousands of individual and mass-mailed comments were filed. This matter remains pending before the FERC.

XIII.Natural Gas Proceedings

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

- **Natural Gas-Related Enforcement Actions**

The FERC continues to closely monitor and enforce compliance with regulations governing open access transportation on interstate natural gas pipelines:

BP (IN13-15). On July 11, 2016, the FERC issued *Opinion 549*[195] affirming Judge Cintron's August 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 Commission's regulations ("Anti-Manipulation Rule") and NGA Section 4A.[196] Specifically, after extensive discovery and hearing procedures, Judge Cintron found that BP's Texas team engaged in market manipulation by changing their trading patterns, between September 18, 2008 through the end of November 2008, in order to suppress next-day natural gas prices at the Houston Ship Channel ("HSC") trading point in order to benefit correspondingly long position at the Henry Hub trading point. The FERC agreed, finding that the "record shows that BP's trading practices during the Investigative Period were fraudulent or deceptive, undertaken with the requisite scienter, and carried out in connection with Commission-jurisdictional transactions."[197] Accordingly, the FERC assessed a ***$20.16 million civil penalty*** and required BP to ***disgorge $207,169*** in "unjust profits it received as a result of its manipulation of the Houston Ship Channel Gas Daily index." The $20.16 million civil penalty was at the top of the FERC's Penalty Guidelines range, reflecting increases for having had a prior adjudication within 5 years of the violation, and for BP's violation of a FERC order within 5 years of the scheme. BP's penalty was mitigated because it cooperated during the investigation, but BP received no deduction for its compliance program, or for self-reporting. The *BP Penalties Order* also denied BP's request for rehearing of the order establishing a hearing in this proceeding.[198] BP was directed to pay the civil penalty and disgorgement amount within 60 days of the *BP Penalties Order*. On August 10, 2016 BP requested rehearing of the *BP Penalties Order*. On September 8, 2018, the FERC issued a tolling order, affording it additional time to consider BP's request for rehearing of the *BP Penalties Order*, which remains pending.

On September 7, 2016, BP submitted a motion for modification of the *BP Penalties Order's* disgorgement directive because it cannot comply with the disgorgement directive as ordered. BP explained that the entity to which disgorgement was to be directed, the Texas Low Income Home Energy Assistance Program ("LIHEAP"), is not set up to receive or disburse amounts received from any person other than the Texas Legislature. In response, on September 12, 2016, the FERC stayed the disgorgement directive (until an order on BP's pending request for

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[194] *Certification of New Interstate Natural Gas Facilities*, 163 FERC ¶ 61,138 (May 23, 2018).

[195] *BP America Inc.*, Opinion No. 549, 156 FERC ¶ 61,031 (July 11, 2016) ("*BP Penalties Order*").

[196] *BP America Inc.,* 152 FERC ¶ 63,016 (Aug. 13, 2015) ("*BP Initial Decision*").

[197] *BP Penalties Order* at P 3.

[198] *BP America Inc.*, 147 FERC ¶ 61,130 (May 15, 2014) ("*BP Hearing Order*"), *reh'g denied,* 156 FERC ¶ 61,031 (July 11, 2016).

rehearing is issued), but indicated that interest will continue to accrue on unpaid monies during the pendency of the stay.[199]

BP moved, on December 11, 2017, to lodge, to reopen the proceeding, and to dismiss, or in the alternative, for reconsideration based on changes in the law it asserted are dispositive and that have occurred since BP filed its request for rehearing of the *BP Penalties Order*. FERC Staff asked for, and was granted, additional time, to January 25, 2018, to file its Answer to BP's December 11 motion. FERC Staff filed its answer on January 25, 2018, and revised that answer on January 31. On February 9, BP replied to FERC Staff's revised answer. This matter remains pending before the FERC.

Total Gas & Power North America, Inc. et al. (IN12-17). On April 28, 2016, the FERC issued a show cause order[200] 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.[201]

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

- **New England Pipeline Proceedings**
  The following New England pipeline projects are currently under construction or before the FERC:
  - ***Constitution Pipeline (CP13-499) and Wright Interconnection Project (CP13-502)***
    - Constitution Pipeline Company and Iroquois Gas Transmission (Wright Interconnection) concurrently filed for Section 7(c) certificates on June 13, 2013.
    - 650,000 Dth/d of firm capacity from Susquehanna County, PA (Marcellus Shale) through NY to Iroquois/Tennessee interconnection (Wright Interconnection).
    - New 122-mile interstate pipeline.
    - Two firm shippers: Cabot Oil & Gas and Southwestern Energy Services.
    - Final EIS completed on Oct 24, 2014.
    - Certificates of public convenience and necessity granted Dec 2, 2014.

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[199] *BP America Inc.*, 156 FERC ¶ 61,174 (Sep. 12, 2016) ("*Order Staying BP Disgorgement*").

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

[201] 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 section 4A of the Natural Gas Act 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.

    - By letter order issued July 26, 2016, the Director of the Division of Pipeline Certificates (Director) granted Constitution's requested two-year extension of time to construct the project.
    - Construction was expected to begin Spring 2016 (after final Federal Authorizations), but has been plagued by delays (see below).
- On April 22, 2016, New York State Department of Environmental Conservation (NY DEC) denied Constitution's application for a Section 401 permit under the Clean Water Act.
    - On August 18, 2017, the 2nd Circuit denied Constitution's petition for review of the NY DEC decision, concluding that (1) the court lacked jurisdiction over the Constitution's claims to the extent that they challenged the timeliness of the decision; and (2) the NY DEC acted within its statutory authority in denying the certification, and its denial was not arbitrary or capricious.
    - Constitution filed a petition for a writ of certiorari of the 2nd Circuit's decision at the United States Supreme Court in January 2018 alleging, among other things, that the State's denial of the Clean Water Act permit exceeded the state's authority, and interfered with FERC's exclusive jurisdiction. On April 30, 2018, the Supreme Court denied Constitution's petition, thereby letting stand the 2nd Circuit's ruling.
- On October 11, 2017, Constitution filed with the FERC a petition for declaratory order ("Petition") requesting that the FERC find that NY DEC waived its authority under section 401 of the Clean Water Act by failing to act within a "reasonable period of time." (CP18-5)
    - On January 11, 2018, the FERC denied Constitution's Petition.[202] Although noting that states and project sponsors that engage in repeated withdrawal and refiling of applications for water quality certifications are acting, in many cases, contrary to the public interest and to the spirit of the Clean Water Act by failing to provide reasonably expeditious state decisions, the FERC did not conclude that the practice violates the letter of the statute, found factually that Constitution gave the NY DEC new deadlines, and found that the record did not show that the NY DEC in any instance failed to act on Constitution's application for more than the outer time limit of one year.[203]
    - On February 12, 2018, Constitution Pipeline requested rehearing of the January 11, 2018 order. FERC denied Constitution's request for rehearing of the January 2018 order.[204] On September 14, 2018, Constitution filed a petition for review in the U.S. Court of Appeals for the D.C. Circuit.[205]
- On May 16, 2016, the New York Attorney General filed a complaint against Constitution at the FERC (CP13-499) seeking a stay of the December 2014 order granting the original certificates, as well as alleging violations of the order, the Natural Gas Act, and the Commission's own regulations due to acts and omissions associated with clear-cutting and other construction-related activities on the pipeline right of way in New York.
    - In July 2016, the FERC rejected the NY AG's filing as procedurally deficient, and declined to stay of the Certificate Order. The NY AG sought rehearing, and the Commission denied rehearing on November 22, 2016, noting again that the NY AG's complaint was still procedurally deficient.

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[202] *Constitution Pipeline Co.*, 162 FERC ¶ 61,014 (Jan. 11, 2018), *reh'g requested*.

[203] *Id.* at P 23.

[204] *Constitution Pipeline Co., LLC*, 164 FERC ¶ 61,029 (2018) (September 2018 Waiver Rehearing Order).

[205] *Constitution*, Petition for Review in U.S. Court of Appeals for the D.C. Circuit, Docket No. CP18-5-000 (filed Sep. 14, 2018).

    - Tree felling and site preparation continues, but the long-term status of the pipeline is currently unknown.
    - On June 25, 2018, Constitution requested a further 2-year extension of the deadline to complete construction of its project, given the delays caused by the on-going fight over the water quality certification from the NYSDEC. Iroquois made a similar request on August 1, 2018. Constitution's request was opposed by several parties and Constitution answered some of the opposition pleadings. The FERC granted the requested two-year extension of time on November 5, 2018.[206]
    - Rehearing of the November 5, 2018 order was requested by Halleran Landowners and a group of intervenors comprised of Catskill Mountainkeeper; Clean Air Council; Delaware-Otsego Audubon Society; Delaware Riverkeeper Network; Riverkeeper, Inc.; and Sierra Club ("Intervenors"). On November 8, 2019, the FERC dismissed or denied the requests for rehearing.[207]
    - On March 31, 2020, Iroquois notified the FERC that (i) Constitution terminated its precedent agreement with Iroquois for the lease of the incremental capacity created by the Wright Interconnection Project; and, accordingly, (ii) Iroquois will not be moving forward with the Wright Interconnection Project. Reporting on his proceeding has now concluded.

- **Non-New England Pipeline Proceedings**
  The following pipeline projects could affect ongoing pipeline proceedings in New England and elsewhere:
  - **Northern Access Project (CP15-115)**
    - The New York State Department of Environmental Conservation ("NY DEC") and the Sierra Club requested rehearing of the *Northern Access Certificate Rehearing Order* on August 14 and September 5, 2018, respectively. On August 29, National Fuel Gas Supply Corporation and Empire Pipeline ("Applicants") answered the NY DEC's August 14 rehearing request and request for stay. On April 2, 2019, the FERC denied the NY DEC and Sierra Club requests for rehearing.[208] 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*.[209] 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,[210] 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.

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[206] *Constitution Pipeline Co.*, 165 FERC ¶ 61,081 (Nov. 5, 2018), *reh'g denied*, 169 FERC ¶ 61,102 (Nov. 8, 2019).

[207] *Constitution Pipeline Co.*, 169 FERC ¶ 61,102 (Nov. 8, 2019) (order on rehearing).

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

[209] *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).

[210] 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).

- 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.[211] 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.[212] On February 2, 2019, the 2nd Circuit vacated the decision of the NY DEC and remanded the case with instructions for the NY DEC to more clearly articulate its basis for the denial and how that basis is connected to information in the existing administrative record. The matter is again before the NY DEC.
- On November 26, 2018, the Applicants filed a request at FERC for a 3-year extension of time, until February 3, 2022, to complete construction and to place the certificated facilities into service. The Applicants cited the fact that they "do not anticipate commencement of Project construction until early 2021 due to New York's continued legal actions and to time lines required for procurement of necessary pipe and compressor facility materials." The extension request was granted on January 31, 2019.
- On August 8, 2019, the NY DEC again denied Applicants request for a Water Quality Certification, and as directed by the Second Circuit,[213] provided a "more clearly articulate[d] basis for denial."
- On August 27, 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.[214]

XIV.State Proceedings & Federal Legislative Proceedings

- **Executive Order on Securing the United States Bulk-Power System**

On May 1, 2020, President Trump signed an Executive Order that authorizes U.S. Secretary of Energy Dan Brouillette to work with the Cabinet and energy industry to secure America's Bulk-Power System ("BPS"). The Executive Order prohibits Federal agencies and U.S. persons from "acquiring, transferring, or installing BPS equipment in which any foreign country or foreign national has any interest and the transaction poses an unacceptable risk to national security or the security and safety of American citizens. Evolving threats facing our critical infrastructure have only served to highlight the supply chain risks faced by all sectors, including energy, and the need to ensure the availability of secure components from American companies and other trusted sources." The Secretary of Energy is accordingly authorized to (i) establish and publish criteria for

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[211] *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*").

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

[213] 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).

[214] *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).

recognizing particular equipment and vendors as "pre-qualified" (pre-qualified vendor list); (ii) identify any now-prohibited equipment already in use, allowing the government to develop strategies and work with asset owners to identify, isolate, monitor, and replace this equipment as appropriate; and (iii) work closely with the Departments of Commerce, Defense, Homeland Security, Interior; the Director of National Intelligence; and other appropriate Federal agencies to carry out the authorities and responsibilities outlined in the Executive Order. A Task Force led by Secretary Brouillette will develop energy infrastructure procurement policies to ensure national security considerations are fully integrated into government energy security and cybersecurity policymaking. The Task Force will consult with the energy industry through the Electricity and Oil and Natural Gas Subsector Coordinating Councils to further its efforts on securing the BPS. A copy of the Executive Order may be accessed here.

XV.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's Inventoried Energy Program (Chapter 2B) Proposal (19-1224***; 19-1247; 19-1252; 19-1253)(consolidated)**
  Underlying FERC Proceeding: ER19-1428[215]
  Petitioners: ENECOS (Belmont et al.) (19-1224); MA AG (19-1247); NH PUC/NH OCA (19-1252); SIERRA CLUB/UCS (19-1253)

On October 24, 2019, ENECOS[216] petitioned the DC Circuit Court of Appeals for review of the FERC's August 6, 2019 Chapter 2B Notice that ISO-NE's Chapter 2B Proposal took effect by operation of law. MA AG (November 25), the NH PUC and NH OCA (December 3) (together, the "State Petitioners"), and RENEW Northeast, Sierra Club and UCS (December 3) ("Nonprofit Petitioners")[217] similarly filed separate appeals. All of the cases were ultimately consolidated on December 30, 2019 (with 19-1224 to serve as the lead docket). Petitioners' initial submissions, procedural and dispositive motions were filed on January 6, 2020. On January 6, 2020, the FERC submitted a motion asking for 60 days between the filing of Petitioners' opening brief and the FERC's brief in response, and filed the Certified Index to the Record. On January 21, the Court granted the motions to intervene of NEPOOL, ISO-NE, NEPGA, Calpine, and the MPUC. On March 5, 2020 Petitioners proposed a briefing format and schedule for this case, which included separate briefing for Petitioners (three opening and reply briefs, one each for ENECOS, State Petitioners and Nonprofit Petitioners), and the extra time requested by the FERC.

Since the last Report, the Court adopted the proposed briefing schedule, but at the unopposed request of the FERC, issued an order suspending the briefing schedule and remanded the record back to the FERC. In the request to suspend the briefing schedule and remand the record back to the FERC, the FERC stated that it "now has a quorum of Commissioners who can participate in the review of the ISO New England tariff filing," that remand "could obviate the need for a subsequent appeal by Petitioners", and it "anticipates issuing an order on remand within 90 days of this Court's order remanding the agency record and an order addressing the merits of any subsequent requests for rehearing within 180 days of the close of the 30-day period for applying for

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[215] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

[216] "ENECOS" are Belmont; Block Island Utility District; Braintree; Energy New England ("ENE"); Georgetown Municipal Light Department; Groveland; Hingham; Littleton; Merrimac; Middleborough; Middleton; North Attleborough; Norwood; Pascoag; Reading; Rowley; Stowe; Taunton; and Wellesley.

[217] RENEW has since moved, and the court granted that motion, to withdraw its appeal.

rehearing". The Court directed the FERC to file status reports at 90-day intervals beginning July 20, 2022 and the parties to file motions to govern further proceedings in these consolidated cases within 30 days of the completion of the remand proceedings.

- ***Order 841* (19-1142, 19-1147) (consol.)**
  Underlying FERC Proceeding: RM16-23; AD16-[218]
  Petitioners: NARUC, APPA et al.

NARUC and APPA et al.[219] petitioned the DC Circuit Court of Appeals for review of *Orders 841* and *841-A* (Electric Storage Participation in RTO/ISO Markets). The cases were consolidated, with 19-1142 as the lead docket. Since the last Report, briefing was completed.[220] On March 11, oral argument was set for May 5, 2020. In light of the Court's March 17 order suspending all in-person onsite oral arguments (in response to the COVID-19 (coronavirus) pandemic), the Court-assigned panel (Judges Rodgers, Garland and Wilkins) proceeded by teleconference and augments by counsel for NARUC, APPA and FERC were heard. This matter is now pending before the panel.

- **FCM Pricing Rules Complaints (15-1071**, 16-1042) (consol.)**
  Underlying FERC Proceeding: EL14-7,[221] **EL15-23**[222]
  Petitioners: NEPGA, Exelon

On February 2, 2018, DC Circuit granted NEPGA's and Exelon's petitions for review of orders accepting the FCM's 7-year price lock-in (EL14-7) and capacity-carry-forward rules (EL15-23).[223] Finding that "the FERC failed to adequately explain why its rationale [for rejecting price lock-in and capacity carry forward rules] in PJM – which seems to foreclose signing off on a Tariff scheme like ISO-NE's – does not apply even more forcefully to the scheme it accepted in the Orders [appealed from]," the DC Circuit granted the Petitions and remanded the case to the FERC for further proceedings in which the FERC, in order to accept the changes filed, must provide some analysis and explanation why it changed course. The remand is now pending before the FERC.

Other Federal Court Activity of Interest

- **PG&E Bankruptcy (19-71615) (9th Cir.)**
  Underlying FERC Proceeding: EL19-35, EL19-36[224]
  Petitioner: PG&E

On June 26, PG&E appealed the FERC's orders finding that it has concurrent jurisdiction with the bankruptcy courts to review and address the disposition of wholesale power contracts sought to be rejected through its bankruptcy. On July 11, PG&E moved to suspend the briefing schedule pending the Court's decision on whether to authorize direct appeal of a decision by the Bankruptcy Court in the Northern District of California. In a declaratory judgment, the Bankruptcy Court came to a completely different conclusion than the FERC and held that it has "original and exclusive jurisdiction over . . . [PG&E's] rights to assume or reject executory contracts under 11 U.S.C. § 365" and that the FERC "does not have concurrent jurisdiction, or any jurisdiction, over the

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[218] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

[219] "APPA et al." are APPA, NRECA, EEI, and AMP.

[220] Final Briefs were filed by: Respondent (FERC) (Mar 13); Petitioner (NARUC) (Mar 13); Petitioner (APPA/NRECA/EEI/AMP) (Mar 12); Joint Intervenor for Respondent (AEE/ESA/SEIA) (Mar 16); Joint Intervenor for Respondent (EDF/NRDC/Vote Solar) (Mar 16); Intervenor for Petitioner (TAPS); and Amicus for Respondent (Sunrun/Tesla/Vivint Solar/Engie Storage Services) (Mar 11).

[221] 150 FERC ¶ 61,064 (Jan. 30, 2015); 146 FERC ¶ 61,039 (Jan. 24, 2014).

[222] 154 FERC ¶ 61,005 (Jan. 7, 2016); 150 FERC ¶ 61,067 (Jan. 30, 2015).

[223] *New England Power Generators Assoc. v FERC*, 881 F.3d 202 (DC Cir. 2018).

[224] *NextEra Energy, Inc. v. PG&E*, 166 FERC ¶ 61,049 (Jan. 25, 2019); *Exelon Corp. v. PG&E*, 166 FERC ¶ 61,053 (Jan. 28, 2019); *Order Denying Rehearing*, 167 FERC ¶ 61,096 (May 1, 2019).

determination of whether any rejections of power purchase contracts by [PG&E] should be authorized."[225] Because of the opposite conclusions, PG&E suggested that, should the Ninth Circuit allow the direct appeal of the Bankruptcy Court decision, the two appeals should proceed together. The PG&E motion was granted on August 1. On February 24, 2020, PG&E submitted a motion to further expedite oral argument in this case so that the case can be resolved by June 30, 2020, if possible. In response to that motion, the Court issued an order directing the case be calendared on a priority basis and assigned to the next available panel, but not by June 30, 2020. Since the last Report, the Court issued an order that this "case will be calendared on August 12 or 14, 2020 in Pasadena. The Court is planning on in person oral arguments, but is monitoring the ongoing health emergency and CDC guidelines and will update the parties closer to the argument date if the panel intends on holding arguments remotely."

- **PennEast Project (18-1128)**
  Underlying FERC Proceeding: CP15-558[226]
  Petitioners: NJ DEP, DE and Raritan Canal Commission, NJ Div. of Rate Counsel

Pending before the DC Circuit is an appeal of the FERC's orders granting certificates of public convenience and necessity to PennEast Pipeline Company, LLC ("PennEast")[227] 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"). All briefing is complete and oral argument was scheduled for October 4, 2019. However, on October 1, the court removed the cases from the oral argument calendar and will hold the cases in abeyance "pending final disposition of any post-dispositional proceedings in the Third Circuit or 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, the DC Circuit will not take up this case.

Since the last Report, the parties filed status reports indicating that the Third Circuit case remains unresolved, with some requesting that the Court continue to hold this case in abeyance, and with Delaware Riverkeeper Network and the Delaware Riverkeeper ("DRN") reiterating its request that the PennEast Certificate Order also be stayed.

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[225] Declaratory Judgment at 1-2, *PG&E v. FERC*, (Bankr. N.D. Cal. June 7, 2019).

[226] *PennEa*st *Pipeline Co., LLC*, 162 FERC ¶ 61,053 (Jan. 19, 2018), *reh'g denied*, 163 FERC ¶ 61,159 (May 30, 2018).

[227] 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.

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