NEW ENGLAND POWER POOL

David T. Doot
Secretary

July 30, 2020

VIA ELECTRONIC MAIL

TO: MEMBERS AND ALTERNATES OF THE NEPOOL PARTICIPANTS COMMITTEE

RE: Supplemental Notice of August 6, 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 August meeting of the Participants Committee will be held **via teleconference on *Thursday*, August 6, 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 August 6 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**.

We hope all of you are staying safe and healthy.

Respectfully yours,

/s/
David T. Doot, Secretary

NEPOOL PARTICIPANTS COMMITTEE
AUG 6, 2020 MEETING

FINAL AGENDA

1. To approve the draft minutes of the Participants Committee meeting held June 23-24, 2020, which have been marked t show changes since the draft circulated with the initial notice.

2. To adopt and approve the actions recommended by the Technical Committees 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 the Tariff to update the Gross Load Forecast Reconstitution Methodology. Background materials and a draft resolution are included and posted with this supplemental notice.

6. 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.

7. 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

8. Presentation and discussion of potential future market frameworks in light of expected changes to New England's grid.

9. Administrative matters.

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

Electronic Participation Guidelines
August 6, 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 MEETING
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>. Video will be disabled.

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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, the 2020 Summer Meeting of the NEPOOL Participants Committee was held via teleconference and WebEx meeting on Tuesday, June 23, and via WebEx event on Wednesday, June 24, pursuant to notice duly given. There also were WebEx meetings between modified Sector groups and ISO Board Members on Thursday, June 25 and Friday June 26. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the session on Tuesday, June 23. All motions acted on during the Summer Meeting were voted on Tuesday, June 23. Attachment 1 identifies the members, alternates and temporary alternates attending the meeting and voting that day.

Ms. Nancy Chafetz, Chair, presided and Mr. David Doot, Secretary, recorded for the Summer Meeting.

JUNE 23, 2020 SESSION

The June 23, 2020 session began at 9:00 a.m., with Ms. Chafetz offering ~~welcome~~welcoming remarks and reporting that this would be the last meeting for Mr. Cal Bowie, who was retiring (again). On behalf of NEPOOL, she thanked Mr. Bowie for his contributions to NEPOOL and offered well wishes for a long, happy and healthy retirement.

APPROVAL OF JUNE 4, 2020 MINUTES

Ms. Chafetz referred the Committee to the preliminary minutes of the June 4, 2020 meeting, as circulated and posted in advance of the meeting. Mr. Doot identified a correction to be made to the measurement units for the Regional Network Service rate. Following motion duly made and seconded, the preliminary minutes of the June 4, 2020 meeting were unanimously approved with the correction identified and with an abstention by Mr. Michael Kuser noted.

CLEAN-UP REVISIONS TO THE FAP AND AN ISO TARIFF DEFINITION

Ms. Michelle Gardner, Chair of the Budget and Finance Subcommittee (Subcommittee), referred the Committee to revisions to the ISO New England Financial Assurance Policy (FAP) and the definition of Credit Coverage in the ISO New England Transmission, Markets and Services Tariff (Tariff) (the Clean-Up Revisions).

The following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports clean-up revisions to the ISO New England Financial Assurance Policy and the ISO New England Transmission, Markets and Services Tariff, as proposed by the ISO and as circulated to this Committee with the June 16, 2020 supplemental notice, together with such non-substantive changes as may be approved by the Chair of the Budget and Finance Subcommittee.

In response to schedule-related questions, Ms. Cheryl Arnold, ISO Director, Finance & Accounting, indicated that the Clean-Up Revisions, if supported, would be filed with the FERC within a few days after the meeting, and that filing would request a September 10, 2020 effective date for the Revisions. As for the “Know Your Customer” changes that had been separated from the Clean-Up Revisions, additional questions and concerns not already addressed in the process completed to date were scheduled for further consideration by the Subcommittee at its August 21 meeting. Without further discussion, the motion was then voted and approved unanimously, with abstentions noted by Cross-Sound Cable and Mr. Kuser.

ISO EMM REPORT

Dr. David Patton, Ph.D., President of Potomac Economics, the ISO’s External Market Monitor (EMM), presented highlights from the EMM’s 2019 Markets Report (EMM Annual Report), which had been circulated and posted in advance of the meeting.

Referring to his presentation, Dr. Patton summarized the market outcomes for 2019. He stated that energy prices fell 30 percent as natural gas prices decreased by 34 percent. Dr. Patton noted that average load fell 4 percent in part because of mild conditions in the winter and summer and also a continuation of the downward trend in recent years because of increased energy efficiency (EE) and behind-the-meter (BTM) solar generation. He recommended that the region further analyze the role of EE in the market. Elaborating on this point in response to a question, Dr. Patton opined that customers have sufficient incentive to invest in EE without the need for capacity market payments, which he characterized as inefficient market design. He explained that there were complexities in calculating EE to adjust the load forecast. He noted that the Midcontinent Independent System Operator (MISO) and ISO-NE were different in how they treated EE in the wholesale market, particularly where ISO-NE tries to reconstitute the load to reflect the impact of EE.

Continuing, he reported that, because of the low load levels and mild weather during 2019, the market was never short of operating reserves. There were also no Pay-For-Performance (PFP) settlements.

He identified the high capacity prices in effect in 2019, which he attributed in part to peak load forecasts for the Forward Capacity Auction (FCA) that were higher than the actual peak load. He reminded the Committee that capacity prices would fall through 2024, which he attributed in part to lower load forecasts and the retention of the Mystic units. He opined that a prompt capacity market would perform better than the region’s current three-year forward market.

Dr. Patton then discussed the all-in price comparisons among ISO-NE, MISO, PJM, NYISO and ERCOT. He explained that ISO-NE generally had the highest costs, driven largely by high capacity costs and higher natural gas prices. He stated that the Eastern RTOs rely more heavily on capacity markets because of ~~the~~their comparatively high minimum capacity requirements~~ in the region compared~~, comparing them to the energy-only market in ~~the~~ ERCOT ~~region~~.

Discussing load forecasting in response to a question, Dr. Patton urged diligence in forecasting as accurately as possible. He acknowledged the challenges of producing accurate forecasts for capacity markets given the requirement that ISO-NE perform the load forecasts well in advance of the auction, which itself ~~is~~was three years in advance of the commitment period. He noted this challenge ~~is~~was even greater given the uncertainty over how the coronavirus and related recession ~~will~~would impact load years from now.

Focusing next on congestion costs, Dr. Patton noted that New England had much lower congestion costs, only 5-15% of the relative congestion costs, than other RTOs. He explained that less congestion impacts market performance and reduces market power concerns. He attributed the results to the large transmission investments made in New England~~, which~~. Those transmission investments, however, were producing transmission charges of approximately $17/MWh of load, which was much higher than in other markets. He noted, in response to a question, the reduction in Reliability Must-Run (RMR) payments, which he ascribed in part to New England's implementation of local reserves and locational capacity requirements.

Discussing Coordinated Transaction Scheduling (CTS), Dr. Patton highlighted the benefits achieved by adjusting the interchange between New York and New England through CTS. He noted reliability improvements and price reductions through optimizing imports. He stated that there were more CTS transactions in 2019 than in prior years, but lower cost savings because of lower energy prices. He said both ISO-NE and NYISO were more accurate in their load forecasts, which allowed Participants to offer at lower prices. He noted that forecasting error had been reduced from 25% error in 2017 to 20% error in 2019.

Dr. Patton also attributed the relative success of CTS to the agreement of ISO-NE and NYISO to waive transaction fees and transmission fees. In other regions where such fees were not waived, the benefits of interregional trading were much reduced. He noted that MISO was considering CTS with a 5-minute transaction window. He encouraged New England to consider that change if the MISO implementation, which would take some time, proved successful.

Transitioning to discussion of market competitiveness, Dr. Patton opined that the New England Market had been performing competitively. He said market competitiveness had improved because of 1.5 GW of new Combined Cycle units (CCs) in the import-constrained areas, transmission upgrades in Boston, and lower market concentrations because of portfolio changes of several large suppliers. Dr. Patton explained that competitiveness was further confirmed through very little economic and physical withholding or other forms of exercise of market power. He referred the members to a chart showing the relatively infrequent mitigation in the area, noting ~~that the~~mitigation was most frequent ~~mitigation was~~ for local reliability.

Discussing uplift costs, Dr. Patton reported that those costs fell significantly in 2019. He attributed ~~this~~the decrease to lower gas prices, milder weather, and reduced congestion. He showed that New England uplift costs still were comparatively higher than other RTOs. He opined that the Energy Security Improvements (ESI) would further reduce uplift costs.

He then talked about experiences with commitments for local second-contingency issues. He showed that Maine was seeing more frequent commitments and higher costs to address local transmission constraints. In contrast, transmission expansion in ~~NEMA-Boston~~Northeast Massachusetts (NEMA)/Boston had reduced local uplift. Previously, the implied value of having reserves in Boston was $14.64 and in 2019 it dropped to $0.35. He used this comparison to demonstrate that the local value of reserves in different areas can change very significantly over time, and can be significantly different from one location to another. He recommended that ISO-NE implement local operating requirements in both its Day-Ahead and Real-Time Energy Markets. Dr. Patton opined that the impact of this improvement would be modest since local requirements are relatively low, but that could change significantly year-to-year.

He indicated in response to a question that Connecticut appeared to have virtually no Day-Ahead reliability commitments, but he would double check to ensure there was not a reporting oversight.

Dr. Patton noted that ISO-NE needed to commit resources in Real-Time during 3,700 hours in 2019 in order to satisfy the system-level Ten-Minute Spinning Reserve (TMSR) requirement. He explained this produced uplift payments to units that were committed, but were not economic at the Day-Ahead energy price. The uplift rate of $2-$3/MWh produced millions of dollars in uplift payments during the year, which undermined energy prices. Dr. Patton opined that ESI would significantly reduce this uplift.

He recommended that ISO-NE eliminate the Forward Reserve Market, particularly with the introduction of Day-Ahead reserve markets. He explained that forward reserve providers were required to offer inefficiently, which distorted energy and reserve prices. Further, obligations were satisfied outside the centralized clearing of the Day-Ahead Energy Market, which raised the cost of participation for non-peak resources. Finally, the forward procurements did not ensure that sufficient reserves would be available when needed.

Dr. Patton then repeated his recommendation from past years that virtual trading not be subject to Real-Time Net Commitment Period Compensation (NCPC) allocation. He explained that these charges were over-allocated to virtual trades in New England~~ were over-allocated these charges, which~~, and were typically higher than in most RTOs. This inhibited virtual trading that could have otherwise helped to reduce NCPC. He compared the liquidity of virtual trades across the organized markets and noted that ISO-NE had far less virtual trading activity than other markets. He stated that some of these issues may resolve themselves with the implementation of ESI.

Dr. Patton then recommended that ISO-NE utilize the lowest-cost fuel and/or configuration model for multi-unit generators ~~when~~ committed for local reliability. He explained that ISO-NE often committed two- or three-turbine configurations, which increased NCPC payments and committed more capacity than needed to resolve local issues. In response to a question, Dr. Patton clarified that allowing a Participant to run at a higher-capacity configuration (such as two turbines) in order to get more NCPC was akin to having a dual-fuel unit opt to burn more expensive oil in order to increase its payout.

Reviewing long-term investment signals from the New England Markets, Dr. Patton noted that net revenues had been at or above levelized entry costs for combustion turbines and wind turbines. Accordingly, there had been recent new entry of both of these types of resources. He predicted that net revenues for these resources would fall as capacity payments fall in upcoming years.

Comparing the various RTO markets, Dr. Patton noted that, in New York, recent entry of combustion turbines had been more limited, while wind turbines continued to enter more steadily. Energy revenues dropped in most markets between 2018 and 2019 because of mild weather and lower gas prices. In New England, combustion turbines had been close to breaking even because of higher capacity payments, and wind resources came close to covering costs because of production tax credits. In the coming years, with falling capacity payments, the gap for these resources to break even was predicted to grow.

Transitioning to predicted returns on new and existing units in coming years, Dr. Patton presented a table showing the internal rate of return (IRR) for different technologies at different locations over the next 20 years. That data showed that, after taxes, Maine-based onshore wind had the highest IRR, followed by New England hub onshore wind, offshore wind, utility-grade solar, battery storage and combustion turbines. Dr. Patton noted in particular that the battery investment, which was evaluated at the New England hub, looked more attractive than a combustion turbine. He noted that the IRR for Maine-based onshore wind may actually be lower than calculated in light of congestion and transmission limitations.

Members questioned the EMM conclusion that onshore wind was economically attractive given the very few projects without long-term contracts. Members argued that, if onshore wind was actually economically viable in the market, it could enter without long-term contracts. In response to a question about renewable energy credit (REC) pricing, Dr. Patton agreed that REC pricing was extremely volatile based on decisions of individual states and it was difficult for investors to rely on RECs for long-term investment decisions.

In discussions that followed, Dr. Patton noted that merchant resources had a higher cost of debt than resources with cost-of-service rates. He recommended that the demand curve for the Forward Capacity Market (FCM) be based on what it would take for a merchant to build a new resource, taking into account the higher cost of debt. He confirmed that the EMM was monitoring ISO-NE’s plans to use gas-fired combustion turbines as Cost of New Entry (CONE) reference technology. He defended the continued use of CCs as the reference technology, noting that the only resource that might be better as a reference technology than combustion turbines was battery, but battery could not run as indefinitely as a combustion turbine.

Showing the economic viability, net revenues, and going-forward costs of an existing unit, he noted that dual-fuel steam turbines, combined cycle turbines and gas turbines would all be challenged in their ability to cover their going-forward costs. Unless unit owners ~~predict~~predicted capacity prices to turn around, the EMM predicted significant retirement of these units, particularly if there were more PFP events because PFP significantly penalizes these units. He said that retirements were necessary to allow for the entry of state-sponsored renewable resources but higher capacity prices provide a disincentive for unit owners to retire. He predicted the resources next to exit the markets would be those that are not called on because of their higher operating costs. He was challenged by some members on whether PFP would have any impact on retirement decisions given the size of the penalties and the fact that there had not been PFP events even during the three recent disturbances with a very substantial loss of supply.

Discussing why retirements had not been happening, Dr. Patton suggested that resources were making decisions based on potential opportunity costs associated with expectations that the market would turn around. Talking about the method for retiring, Dr. Patton noted that the units had to first acquire a Capacity Supply Obligation (CSO) in the first auction in order to sell in the substitute CASPR auction. He said that units might choose not to retire because of how they valued their going-forward options. For example, a resource might accept a price below its going-forward cost in the near term because of an expectation that it would recover such costs later through a future substitution auction through CASPR. Members challenged this observation, questioning whether falling capacity prices would lead to lower severance payments, encouraging resources to wait for higher prices before retiring. Dr. Patton said the EMM did consider the unintended consequences of CASPR, and concluded that units would likely consider a potentially higher severance payment preferable to losing money for 3-4 years while waiting for capacity prices to rebound. Related to this discussion, Dr. Patton recommended that the Minimum Offer-Price Rule (MOPR) be improved ~~through~~by (a) eliminating the performance payment eligibility for units subject to the MOPR; (b) capping the minimum offer price at net CONE; and (c) exempting from the MOPR resources that are funded by competitive private investment. Dr. Patton stated that, to the extent the market sees a wave of retirements in the first auction, fixing these elements of the MOPR would still allow retirements to facilitate the entry of renewables and reduce unintended consequences of buyer-side mitigation.

Dr. Patton then discussed the evaluation of ~~Pay-for-Performance (~~PFP~~)~~. He compared reserve prices to the Expected Value of Lost Load during PFP events and explained how the EMM performed that comparison. He explained that the impact of PFP events should be considered as energy settlements, so ~~the~~that energy prices during the scarcity events become critical. When the PFP rate increases to $5,500/MWh, the challenge of compensating units far above the value of lost load during small shortage events would be exacerbated. With more renewables on the system, the value of energy at low shortages increases and decreases with high shortages. With substantial intermittent resources on the system there ~~are~~were more scenarios threatening potential load shedding events.

Members raised a variety of concerns with the PFP penalty and its potential impact on operations. Following discussion of those concerns, Dr. Patton suggested that the EMM might further discuss going forward costs with Market Participants, but that retirements of some units was inevitable and helpful to the markets.

Dr. Patton then referred to a review of potential revenues for a 2-hour battery resource to illustrate one of the ways in which PFP could overcompensate resources. He explained that, because PFP events were short and transitory, a 2-hour battery could receive substantial PFP revenues that do not fairly reflect its overall value to the system. The EMM calculated that a 2-hour battery at a modest level of penetration ~~gives~~produced about 66% of the value of a conventional resource because it ~~can~~could only be dispatched for a short time. This reliability difference would become more pronounced as investments in batteries ~~accelerate~~accelerated and potentially ~~replace~~replaced conventional resources. Dr. Patton stated that this concern could be mitigated with sloped PFP values and improved assignment of capacity values for batteries. He clarified in response to a question, that his observations were based on calculated PFP revenues for a 2-hour battery during the 2018 PFP events. As a point of reference, he noted that combined cycle generators do not have the same accreditation problem as batteries, but like batteries are over-compensated in the PFP process.

Members challenged Dr. Patton’s conclusions about 2-hour batteries, noting that PFP, as designed, would properly reward those resources given their contribution to performance during times of need. Dr. Patton responded that the goal of the EMM was to ensure that the market was giving accurate signals. That does not prevent policy makers from incentivizing particular resources. He stated that setting up a PFP regime that results in energy settlements that diverge from the true value of the energy distorts the incentive for some technologies over others.

Dr. Patton finished by taking questions on the overall recommendations. He was critical of the seven-year price lock in the FCM, particularly during times of surplus, because it discriminated in favor of new resources and led to unfavorable market conditions. He repeated the EMM's preference for a prompt market rather than a three-year forward market. In response, he was encouraged by members to reflect that recommendation in future EMM reports.

He discussed the EMM recommendation to eliminate performance payment eligibility for units subject to the MOPR. He explained this recommendation was to reduce incentives for units subject to the MOPR to make uneconomic decisions in order to get performance payments. He also explained that the recommendation to exempt competitive private investment from the MOPR ~~seeks~~sought to remove the MOPR as a force in the market in order to motivate private investment. He did not agree with capping the MOPR at net CONE, urging instead that MOPR fluctuate around net CONE to motivate investors to build resources when needed.

Finally, in response to a question, Dr. Patton highlighted that, while the EMM recommended throughout the report that ISO-NE could benefit from a transition to a more prompt capacity market rather than its current forward market, it would be a massive change in both market design and in the expectations of ~~participants~~Participants who have put capital at risk based on the current market design. Therefore, the EMM ~~has not included that in their~~did not include the transition to a more prompt capacity market in its list of recommendations.

LITIGATION REPORT

Mr. Doot reported that the next Litigation Report would be circulated in the beginning of July. He noted the following items that had occurred since the June 4 Report was circulated:

(1) the ISO's nearly 150-page June 16 answer to the protests and comments filed in response to the April 15 ESI filing.

(2) a June 10 complaint by Constellation Mystic Power, LLC (Exelon) requesting that the FERC prohibit the ISO from implementing changes to Planning Procedure No. 10 (PP-10) (supported at the prior Participants Committee meeting).

(3) The FERC's June 17 notice granting the request to hold a technical conference on carbon pricing, which was scheduled for September 30, 2020.

COMMITTEE REPORTS

Ms. Chafetz reported that the next joint Markets Committee/Reliability Committee meeting to discuss the future grid study would be held on July 1. The July 8 Transmission Committee meeting had been cancelled. The Markets Committee summer meeting would be held July 14-15 by teleconference; the third day of that meeting had been cancelled. At ~~the~~its July 21 ~~Reliability Committee~~ meeting, the Reliability Committee was scheduled to vote on a new treatment for passive demand resources in the gross load forecast (the forecast of demand absent reductions from passive demand resources that participate as supply in the FCM).

OTHER BUSINESS

Mr. Doot noted there would be a session to explore the challenges and opportunities with New England's transition to a future grid the next day and virtual modified Sector meetings with ISO Board panels would be on Thursday, June 25 and Friday June 26. Sector meetings with state officials and representatives were scheduled in July for those Sectors interested. The next regularly-scheduled meeting of the Participants Committee would be held August 6, 2020.

There being no other business, the June 23 session ended at 12:35 p.m., with the Summer Meeting to reconvene the following day, on Wednesday, June 24 at 8:30 a.m.

JUNE 24, 2020 SESSION

The Summer Meeting reconvened by WebEx event at 8:30 a.m. on June 24, 2020.

NEW ENGLAND'S TRANSITION TO A FUTURE GRID: CHALLENGES & OPPORTUNITIES

ASSESSMENT OF CHALLENGES ASSOCIATED WITH EVOLVING GRID SYSTEMS

Setting the Stage – Melanie Kenderdine

Ms. Chafetz introduced Ms. Melanie Kenderdine, Managing Principal, Energy Futures Initiative (EFI), to provide her thoughts and observations regarding the evolving electric grid and the challenges associated with deep decarbonization. Ms. Kenderdine referred the Committee to a presentation that members were advised would be posted following the meeting. She began her presentation summarizing statistics on the contribution of the energy sector to the economy. She observed that energy jobs were created at twice the rate of overall jobs in the US. She showed EFI research that ranked one or more of the New England States in the top ten (10) of states across the country for ~~percent~~percentage of employees in energy jobs. She observed that, as states transition to clean energy, energy jobs would need to transition as well.

Before discussing EFI's California study, she compared overall emission sources by economic sector in the United States with those of New England and California (CA). Ms. Kenderdine noted that emissions in New England as a percent of overall emissions were significantly higher than the national average in the transportation and commercial and residential building sectors. Emissions in New England were lower than national averages from electricity generation and industrial sources. Comparing CA with New England, while emissions from the electricity sector were similar, New England generated a higher percentage of emissions in the transportation, commercial and residential sectors than CA; CA generated industrial emissions that were 17 percent higher than the percentage of emissions from that sector in New England.

Ms. Kenderdine then discussed the May 2019 EFI report entitled *Optionality, Flexibility & Innovation: Pathways for Deep Decarbonization in California* (the CA Study) and the relevance of its findings and conclusions for New England. She highlighted CA's policies for Greenhouse Gas (GHG) reductions targets economy-wide of 40 percent below 1990 levels by 2030, carbon neutrality by 2045, and 80 percent reduction of GHG emissions below 1990 levels by 2050. Further CA goals were to generate 60 percent of its electricity from renewable sources by 2030, to have 5 million zero-emission electric vehicles on the road by 2030 and to generate 100 percent of its electricity from zero carbon sources by 2045. EFI noted that, in order for CA to meet its goals, the state needed to achieve the largest reductions in metric tons of carbon dioxide equivalent from the transportation and industrial sectors, followed by the electricity and building sectors.

Regarding challenges with integrating large-scale intermittent renewables in CA, Ms. Kenderdine noted the following based on the CA Study:

- With increased dependence on solar and wind, there were times of the year when back-up options were critical to reliability. The CA Study identified over 90 days a year in 2017 when there was little to no wind, in some cases for multiple days in a row.
- There were considerable seasonal variations in solar and wind in CA, with significantly less solar and wind generation in January than in June. That variation between January and June statistics in 2016 amounted to 3.1 terawatt-hours.
- Droughts in the West in 2007-2009 reduced hydro generation to about 13 percent of CA's total generation from a peak of 18 percent. During the drought from 2011 to 2016, hydro generation decreased to about 7 percent of total generation for CA.
- With increased intermittent renewables in CA, the region needs increased electric storage capacity. She showed a chart comparing deployments of 4-hour storage in CA versus storage deployment in PJM and ISO-NE.

Ms. Kenderdine then summarized pathways for meeting CA's 2030 GHG targets, which she explained required different options across the different economic sectors. She summarized that there were sufficient commercially available pathways to meet 2030 targets, including carbon capture technologies in the electricity and industrial sectors, corporate average fuel standards in the transportation sector, energy efficiency in the building sector, and biogas capture in the agricultural sector. Beyond 2030, she said that innovations and technology breakthroughs would be needed to meet CA's decarbonization goals.

Because of differences between CA and New England, New England would need to consider different technology options to meet its decarbonization goals. By way of example, there ~~are~~were no sequestration opportunities in New England due to a lack of saline aquifers for storage. She showed a ~~calculation~~reference frame of how much land would be needed to replace existing conventional resources entirely with solar and wind. She noted that the very large acreage needed for renewable resources underscored the land use and infrastructure issues facing New England and demonstrated the need for energy storage as reliance on dispatchable generation lessens over time. She opined that there needed to be increased focus in New England on demand response.

Discussing New England's future options, she presented data showing the considerable spread in the levelized cost of energy across generation technologies, noting the ~~leveled~~levelized cost of storage for utility-scale solar becomes much higher when the battery storage was factored into the overall cost. With the integration of more variable energy resources, the system required more automation and improved analytics to ensure system reliability. She cautioned that the increasing complexity of the grid now and into the future only ~~serves~~served to accentuate the importance of grid security.

She then talked about the availability of metals, including nickel, cobalt and lithium, to support the growing demand for low carbon technologies. She noted the increased US dependence ~~by US~~ on foreign sources of such metals. She noted the need for further study and attention given finite global resources and the lifespan of the technologies being deployed.

Concluding her presentation, she noted EFI's efforts to identify critical breakthrough technologies that have the potential to aid in the deep carbonization of the energy sector. Those technologies included storage and long duration batteries, advanced nuclear reactors, technology applications for the industry and building sectors, electric grid modernization and deep carbonization technologies and large-scale carbon management. She noted the important role New England was playing in clean energy innovation, research and development.

In response to questions following ~~Ms. Kenderdine's~~her presentation, ~~she~~Ms. Kenderdine noted the need to study more closely the impact on efficiency of combined cycle and gas turbine units due to increased start and stop events. She acknowledged that comparing levelized cost of energy for various resources was an imperfect measure in determining the true cost of such technologies for use by investors. She clarified that New England was less likely to have the same large scale hydro generation issues as CA, noting that CA was heavily reliant on water from disappearing glaciers in the Northwest. On the topic of dependency on various metals for future energy generation, Ms. Kenderdine noted that EFI had not yet studied the potential for recycling necessary metals.

Reliability Challenges – James Robb

Ms. Chafetz introduced Mr. James R. Robb, NERC's President and Chief Executive Officer. He emphasized that NERC was an independent reliability and security agency, not an economic regulator. Mr. Robb referred the Committee to his presentation, which had been circulated and posted in advance of the meeting, addressing potential future reliability challenges facing the industry, which he described as a "3-D Transformation" – a transformation to a more distributed, decarbonized and digitized system.

Mr. Robb identified the following physics-based characteristics that the future system would need to be reliable: (i) the ability to maintain frequency and voltage within narrow parameters, (ii) adequate flexibility to follow loads and minimize system disturbances, and (iii) adequate capacity and fuel to serve load. He noted that batteries (both grid and consumer scale), fuel cells, small modular nuclear reactors, and off-shore wind were likely to be key technologies needed for a highly decarbonized, but reliable, future. He explored the importance of improvements in inverter-based resources (particularly solar panels and batteries) for system reliability. He said that, with proper programming and deployment, those resources could support grid stability and, in aggregate, could achieve reliability benefits comparable to those provided by conventional generation. Although many inverter-based resources were not covered by NERC reliability standards or guidelines given their position below the Bulk Power System (BPS), NERC continued to share information and address their integration given their critical importance to a clean energy future.

Mr. Robb addressed the role of the BPS in a clean energy future, referring to a National Renewable Energy Laboratory (NREL) model of the BPS as an electric super highway. He discussed some of the technical, economic and reliability complexities that challenged the BPS to meet the challenges associated with the changing resource mix, especially the dramatic reduction in traditional solid fuel resources like coal and nuclear and rapid expansion of variable generation resources such as wind and solar.

Until the clean energy vision was achieved, Mr. Robb emphasized the important role that natural gas would need to play. He noted the need for flexibly dispatch gas resources to balance variable generation production. With increasingly pronounced "duck curves" resulting in steep power plant ramp rates and other changes to the BPS that were intensifying wear and tear on natural gas resources, as well as increasing fluctuations in gas system pressure, there was a near term need for gas-fired peaking assets. Since that need may only be for a shorter duration than the engineering life of those assets, pricing and cost recovery challenges would have to be resolved.

He identified key issues for bridging the gap between where the systems around the country are now and where policy makers are seeking to take them. He noted considerable uncertainty on how long that bridge needed to be in place, which would depend in part on the timing of technology development and deployment. Other issues he noted included the pace of electrification of other economic sectors and how to price, get cost recovery for, and incent electric industry to pay for the gas infrastructure that would be required along the way. Getting to the end state, he said, would require substantial investment in technology, new planning and operational tools (with particular focus on fuel and energy adequacy and not simply capacity/resource adequacy), much improved and broader situational awareness and visibility to support integrated coordination, and integrated cyber defenses that secure the system against ever-expanding attack surfaces and ever-emerging attack vectors.

In response to questions, Mr. Robb stressed the need to think of the distribution network and the BPS as increasingly interdependent rather than simply as integrated, and to reflect that thinking in the design of markets and reliability standards supporting the grid. He reiterated that inverter-based resources are fully capable of providing many of the essential system reliability services, but must be incented to do so. In addition, he reiterated that system operators would need more visibility into the system than they have now, and achieving such visibility would require both federal and state support.

POTENTIAL FUTURE PATHWAYS AND THEIR IMPLICATIONS

What Pathways Have Others Chosen Or Are They Considering – Frank Felder

Ms. Chafetz introduced Mr. Frank Felder, PhD, Director of the Center for Energy, Economic and Environmental Policy at Rutgers University and Director of the Rutgers Energy Institute. Dr. Felder proceeded to review his presentation that had been circulated to the Committee in advance of the meeting. He introduced his discussion by noting that he had been requested generally to discuss what other regions of the country and world were doing to address the desire to decarbonize the power sector.

Beginning, he explained that the challenges to be addressed with decarbonization covered three discrete problems and timelines: political/economy; economic/regulatory; and engineering/operational. All these problems would have to be addressed in a coordinated way or difficulties would occur with increased costs to consumers. There were tradeoffs among those three sets of challenges that would need to be addressed and would be addressed by different decision makers depending on the circumstances. The decision makers would all look at different design variables, which he described for the members, as well as different objectives~~,~~. He discussed how those objectives were developed, and various policy options that could be exercised to achieve the desired objectives. He summarized various options used by other systems, flagging pros and cons of each of those options, each with both benefits and risks or burdens, specifically referencing options such as banning carbon technologies, adopting feed-in tariffs, greenhouse gas pricing, and using RECs. He noted that out-of-market payment structures lower wholesale energy prices, which has other impacts on the system and markets.

He then discussed transmission business challenges. He reinforced as had Mr. Robb that transmission and distribution must be thought of in a highly integrated and coordinated way, with careful thought given to timing of upgrades and impact on planning and contingencies. He noted the various objectives to be addressed, and the means for addressing those objectives through political negotiations during legislation and transmission planning. He identified the options of integrated resource planning, the various types of transmission (e.g., reliability, public policy, and economic) and the importance of assessing how best to address uncertainties and to allocate costs.

Dr. Felder went on to highlight examples of tradeoffs that must be taken into account. Long-term power purchase agreements (PPAs) lower cost of capital but shift risks to ratepayers. Market solutions might advance some immediate goals but may increase future costs (noting transmission planning as one example). Long-term PPAs might address political desires but add to future operational challenges.

Breaking from his presentation for questions and comments, Dr. Felder agreed in response to a question that there were potentially conflicting objectives between the goals of maximizing efficiency and economy through markets and the goals of policy makers for reducing greenhouse gasses. He observed that this conflict could fairly be attributed to the ~~s’~~ failure to price explicitly the externalities associated with carbon emissions. He summarized that any movement through administrative means to decarbonize effectively did price this externality, at least implicitly if not explicitly. He suggested transparency as to what was actually being paid for may assist in reconciling the potentially conflicting objectives.

Returning to his presentation, he then explored more the challenges of balancing supply and demand in a deeply decarbonized system. He referenced an NREL 2016 study for the Eastern Interconnection~~ and summarized~~. Summarizing the scenarios studied~~. Summarizing,~~, he noted high penetration of renewable resources would cause cycling of gas-fired generation and ~~decrease~~decreased coal production. Operations would be increasingly dependent on careful load balancing and anticipating and addressing challenging contingencies. He emphasized that there were many options to be considered to address objectives when one worked in a planning time horizon but when there was considerable uncertainty over what the future holds. As the system gets closer to Real-Time, certainty would increase, but options to address the needs would decrease. With different phases of increasing penetration of variable resources, the operational challenges with short-term control and the need for additional ancillary services both increase. Overall, he projected volatile and increasing ancillary services costs. He noted that there were no common definitions for ancillary services. The importance of ancillary services would increase as variable resources ~~increase~~increased. With increased need for ancillary services, the need to co-optimize those services with each other and with energy would become even greater, as would the need to ensure appropriate opportunity cost pricing. He emphasized that some variable resources could be equipped to provide various ancillary services as needed and priced accordingly.

Dr. Felder described various options to ensure supply and demand balance, including incentivizing flexible resources, imposing operational requirements on renewable resources, increasing demand response (with supporting metering), and improving scheduling and dispatching by providing transparency to distributed resources. ~~Describing tradeoffs, he noted that adding ancillary services raises prices and also challenges those resources with long-term~~

~~agreements.~~ He explained that using mechanisms outside of the markets to accomplish resource adequacy and increase renewables on the system may achieve political objectives in a way that might be inconsistent or incompatible with operational needs. Higher energy prices may help balance supply and demand but would increase political, operational and pricing challenges.

In response to Dr. Felder's presentation, Massachusetts (MA) Department of Public Utilities (DPU) Chairman Nelson noted that the Commonwealth wanted to achieve its political/economy objectives through the markets. MA supported carbon pricing but would not surrender jurisdiction to FERC. MA needed assurance that prices would be set in a way that would permit states with different objectives and goals each to achieve their objectives without paying for those of other states. He said MA was interested in exploring the use of a forward clean energy market (FCEM) to help drive capital into the markets. He noted that there were many more details to work out but MA was interested in helping to make a market solution happen.

~~The NPC Chair~~Ms. Chafetz discussed context for future discussions of pathways and tradeoffs. She noted that his session was the kick-off for broader discussion, which she indicated would continue at the Participants Committee meeting in August.

Dr. Felder indicated in response to questions that ancillary services could be designed with very high granularity to help achieve the objectives of the system, but that ancillary services market design would only be a piece of the overall solution. He was not aware of any country that had fully identified the needed ancillary services. He commended those interested to a close read of reference materials he identified in his presentation that explored various engineering options available.

Investing in the Future – Scott Kushner

For the final presentation and discussion, Ms. Chafetz introduced Mr. Scott Kushner, Managing Director, John Hancock Infrastructure Investments. Mr. Kushner explored the considerations that influence decisions to invest, either in debt or equity, given the various market structures identified and discussed and the impacts of changing public policy.

After a brief overview of John Hancock's investment activities, both on its own and on behalf of others, Mr. Kushner focused on the trade-offs to be made by both consumers and investors in ~~de-carbonization~~decarbonization efforts and how those interests might be better aligned to help both groups achieve their goals as efficiently as possible. He explained how lowering the cost of capital could help facilitate ~~de-carbonization~~decarbonization, consistent with consumer economic and policy interests. He noted, by way of example, experiences in Massachusetts where, in connection with state solar programs, the cost of capital had continued to decrease and renewable penetration continued to increase.

In response to questions, he noted that the cost of capital for renewable generation had generally decreased, and identified a variety of factors that could have played a role. While there was no denying that longer-term contracts, with their associated price certainty, were most likely to lower the cost of capital, other mechanisms, that provided liquidity and some degree of price certainty (e.g. liquid merchant markets) could similarly achieve comparable results.

Addressing the role of government-created incentives (tax credits, renewable energy credits, carbon pricing) on past and future decarbonization, Mr. Kushner acknowledged their impact to date, driven in large part by their effect on project risk profiles and costs of capital. He suggested that the effectiveness of incentives going forward would hinge on the kinds of incentives that are offered developers and investors. For example, the distribution of incentive payments would play a role in how penetration of renewables would be achieved and whether that penetration would also result in a lower overall cost of electricity.

In response to questions regarding how lessons learned from conventional generation experience might be applied to a transformation of the grid, Mr. Kushner noted first that the growth in participants and transactions would continue to be driven by a shift in contracts (from conventional power production to renewables). From a debt perspective, longer-term contracts were likely to minimize unknowns and keep risk and cost of capital at levels acceptable to institutional investors. From an equity perspective, comfort levels with how a market functions and price certainty would be equally as important.

Mr. Kushner concluded his remarks by addressing how the competitive market construct influences the type of investor interested in that market. He reiterated that liquid, competitive markets would incent investment, but not necessarily for every type of investor, and not necessarily at the lowest possible cost of capital. In general terms, institutional investors offer more competitive pricing in longer-term markets; banks, in shorter-term markets.

There being no further business, the meeting adjourned at 12:40 p.m.

Respectfully submitted,

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David Doot, Secretary

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN JUNE 23-24, 2020 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User		Deborah Donovan	
Actual Energy, Inc.	Supplier		John Driscoll	
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			Roger Borghesani
AVANGRID: CMP/UI	Transmission		Alan Trotta	
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Borrego Solar Systems Inc.	AR-DG	Liz Delaney		
Boylston Municipal Light Department	Publicly Owned Entity		Brian Thomson	
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity			Dave Cavanaugh
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Calpine Energy Services, LP	Supplier	Brett Kruse		Bill Fowler
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Central Rivers Power	AR-RG		Dan Allegretti	
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw		
Connecticut Office of Consumer Counsel	End User		Dave Thompson	
Conservation Law Foundation (CLF)	End User	Phelps Turner		
Consolidated Edison Energy, Inc.	Supplier	Norman Mah		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Direct Energy Business, LLC	Supplier	Nancy Chafetz		
Dominion Energy Generation Marketing, Inc.	Generation	Mike Purdie		
DTE Energy Trading, Inc.	Supplier			José Rotger
Dynegy Marketing and Trade, LLC	Supplier			Bill Fowler
Emera Energy Services Companies	Supplier		Bill Fowler	
Enel X North America, Inc.	AR-LR		Herb Healy	
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission	James Daly	Cal Bowie	Dave Burnham
Excelerate Energy LP	Fuels Industry Part.			Gary Ritter
Exelon Generation Company	Supplier		Bill Fowler	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger		
Generation Group Member	Generation	Dennis Duffy	Abby Krich	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Great River Hydro	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned Entity		Brian Thomson	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	Louis Guibault	Bob Stein	
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	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN JUNE 23-24, 2020 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Ipswich Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Jericho Power LLC (Jericho)	AR-RG	Mark Spencer		
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Long Island Power Authority (LIPA)	Supplier		Bill Killgoar	
Maine Power LLC	Supplier	Jeff Jones		
Maine Public Advocate's Office	End User	Drew Landry		Erin Camp
Mansfield Municipal Electric Department	Publicly Owned Entity		Brian Thomson	
Maple Energy LLC	AR-LR		Luke Fishback	Doug Hurley
Marblehead Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Mass. Attorney General's Office (MA AG)	End User	Tina Belew	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			José 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	
National Grid	Transmission	Tim Brennan	Tim Martin	
Natural Resources Defense Council (NRDC)	End User	Bruce Ho		
Nautilus Power, LLC	Generation		Bill Fowler	
New Brunswick Energy Marketing Corp.	Supplier		Kim McKinley	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski		Brian. Forshaw; Dave. Cavanaugh; Brian Thomson
New Hampshire Office of Consumer Advocate (NHOCA)	End User	Pradip Chattopadhya	Erin Camp	
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Novatus Energy (Blue Sky West, LLC)	AR-RG		Katie Bellezza	
NRG Power Marketing LLC	Generation	Neal Fitch	Pete Fuller	
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Peabody Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PowerOptions, Inc.	End User			Erin Camp
Priogen Power LLC	Supplier	Michel Soucy		
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	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Brian Thomson	
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Brian Thomson	
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
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			Brian Forshaw
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Brian Thomson	

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN JUNE 23-24, 2020 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
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	

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CONSENT AGENDA

Markets Committee (MC)

From the previously-circulated notice of actions of the ***MC's July 14-15, 2020 Summer Meeting***, dated July 16, 2020:[1]

1. NEPOOL GIS – Amended and Restated Services Agreement with ISO-NE

Approve the Amended and Restated Services Agreement between NEPOOL and ISO New England Inc. (ISO-NE) (related to the NEPOOL Generation Information System (GIS)), as recommended by the MC at its July 14-15, 2020 meeting, with such non-material changes thereto as the Vice Chair of the MC and an appropriate ISO-NE officer may approve.

The motion to recommend PC approval was approved unanimously.

2. Manuals M-28 and M-RPA Revisions (Metering Requirements for DC-Coupled Assets)

Support revisions to Manual M-28 (Market Rule 1 Accounting) and Manual M-RPA (Registration and Performance Auditing) relating to the Metering Requirements for DC-Coupled Assets, as recommended by the MC at its July 14-15, 2020 meeting, with such further non-material changes as the Chair and Vice-Chair of the MC may approve.

The motion to recommend PC support was approved unanimously.

Reliability Committee (RC)

From the previously-circulated notice of actions of the ***RC's June 16, 2020 meeting***, dated June 16, 2020:

3. OP-18 Revisions (Metering Requirements for DC-Coupled Assets)

Support revisions to OP-18 (Metering and Telemetering Criteria), which adds requirements for DC-Coupled Assets, as recommended by the RC at its June 16, 2020 meeting, with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend PC support was approved, with two oppositions in the Publicly Owned Entity Sector and one abstention in the Transmission Sector noted.

4. Revisions to PP-5-1, including Attachments 1 and 3 (Process Enhancements)

Support revisions to ISO-NE Planning Procedure No. 5-1 (Procedure for Review of Market Participant's or Transmission Owner's Proposed Plans (Section I.3.9 Applications: Requirements, Procedures, and Forms)), including changes to timing of PPA and Generator Notification Forms submissions (at least 10 Business Days prior to consideration by RC), and changes to Attachments 1 and 3 (enabling bulk review and summarization, including summarization of storage component information of co-located facilities), as recommended by the RC at its June 16, 2020 meeting, with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend PC support was approved unanimously.

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

Summary of ISO New England Board and Committee Meetings

August 6, 2020 Participants Committee Meeting

Since the last update, the Compensation and Human Resources Committee, and the System Planning and Reliability Committee met on June 24. In addition, the Board of Directors met on June 25, and the Nominating and Governance Committee met on June 26. Given the pandemic, all meetings were held by videoconference.

The Compensation and Human Resources Committee conducted its biennial consideration of the Committee charter to confirm compliance, and discussed several modifications to consider at its next meeting. Next, the Committee met in executive session to review the Company's organizational structure and succession plans for management. The Committee also conducted its annual assessment of the risks within the Committee's purview, and agreed that the primary risks relate to succession planning, recruitment and retention of employees. The Committee proposed to clarify its responsibility for the oversight of the Company's diversity and inclusion efforts, and agreed to consider specific language at its next meeting.

The System Planning and Reliability Committee received an update on the review of Phase One proposals for the Boston 2028 Request for Proposals, the first phase of the two-phase competitive transmission process. The Committee also received updates on the system operations outlook for Summer 2020, key observations from the economic study results, and Order 1000 implementation efforts. Next, the Committee conducted its biennial consideration of the Committee charter to confirm compliance, and determined no changes to the charter were necessary. Finally, the Committee received an update on the Company's phased workforce re-entry plan.

The Board of Directors considered topics raised in advance by participants for discussion at the sector meetings to be held the next day, and continued its strategic planning discussions. The Board also reviewed the Company's Form 990 for 2019 to be filed with the Internal Revenue Service and received reports from the standing committees.

The Nominating and Governance Committee discussed board leadership, committee membership and state liaison assignments, and agreed to finalize its recommendations in time for Board consideration at the Board's annual meeting in September. The Committee also discussed the current Board orientation process and contemplated recommendations for enhancements. Finally, the Committee considered topics for its upcoming annual corporate governance review.

NEPOOL Participants Committee Report

August 2020

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

Table of Contents

Regular Operations Report - Highlights

ISO Operations During COVID-19 Outbreak

- Effective March 14, ~95% of ISO workforce has been working remotely
- All reliability, market and planning functions are being operated in accordance with all applicable standards
- ISO initiated its re-entry plan on June
  - ~90 employees are on-site (all volunteers)
  - Given the current situation nationally, and continued uncertainty, the ISO re-entry will stay open for volunteers only through Labor Day
  - By the end of August, the ISO will assess and determine its plan for the rest of this year
- The ISO re-entry plan conforms to national, state, and local guidelines, is phased over a minimum period of four months, and will adapt to changing circumstances as necessary
- The ISO will continue to monitor the situation and take all necessary steps to reliably operate the bulk power system

Highlights

- Day-Ahead (DA), Real-Time (RT) Prices and Transactions
  - July Energy market value was $302M, up $87M from June 2020 and down $113M from July 2019
    - July natural gas prices over the period were 6.6% higher than June average values
    - Average RT Hub Locational Marginal Prices ($22.37/MWh) over the period were 5.7% higher than June averages
      - DA Hub: $23.55/MWh
    - Average July 2020 natural gas prices and RT Hub LMPs over the period were down 29% and down 23%, respectively, from July 2019 averages
  - Average DA cleared physical energy during the peak hours as percent of forecasted load was 100.6% during July, up from 98.9% during June*
  - The minimum value for the month was 94.9% on Saturday, July 11th

Data through July 29th, except where otherwise noted.

Underlying natural gas data furnished by:

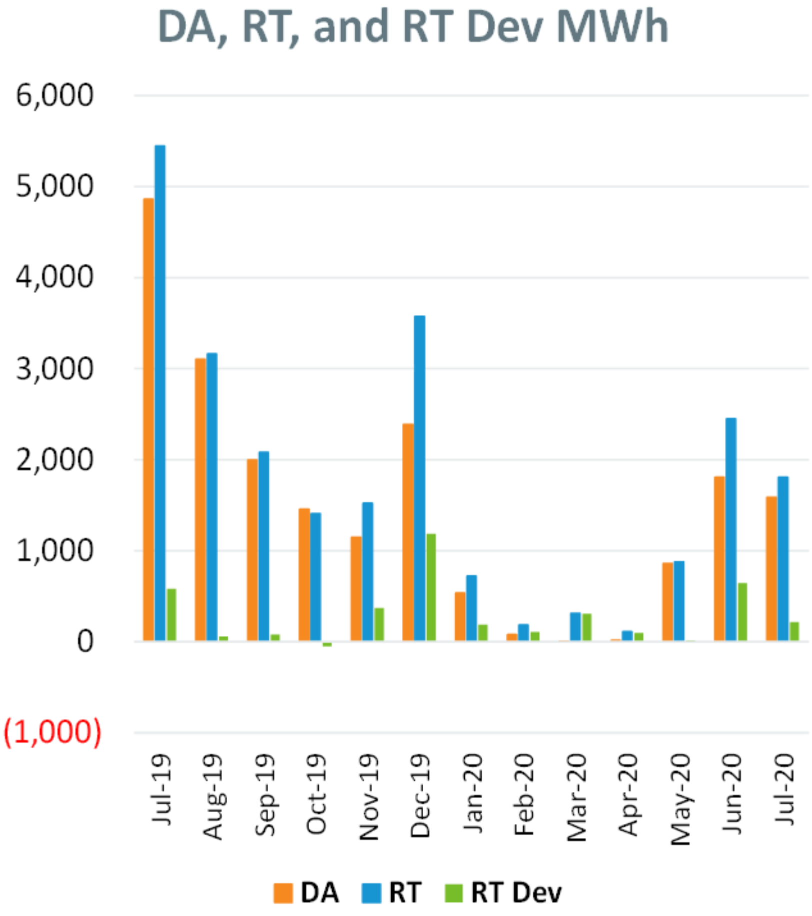
*DA Cleared Physical Energy is the sum of Generation and Net Imports cleared in the DA Energy Market

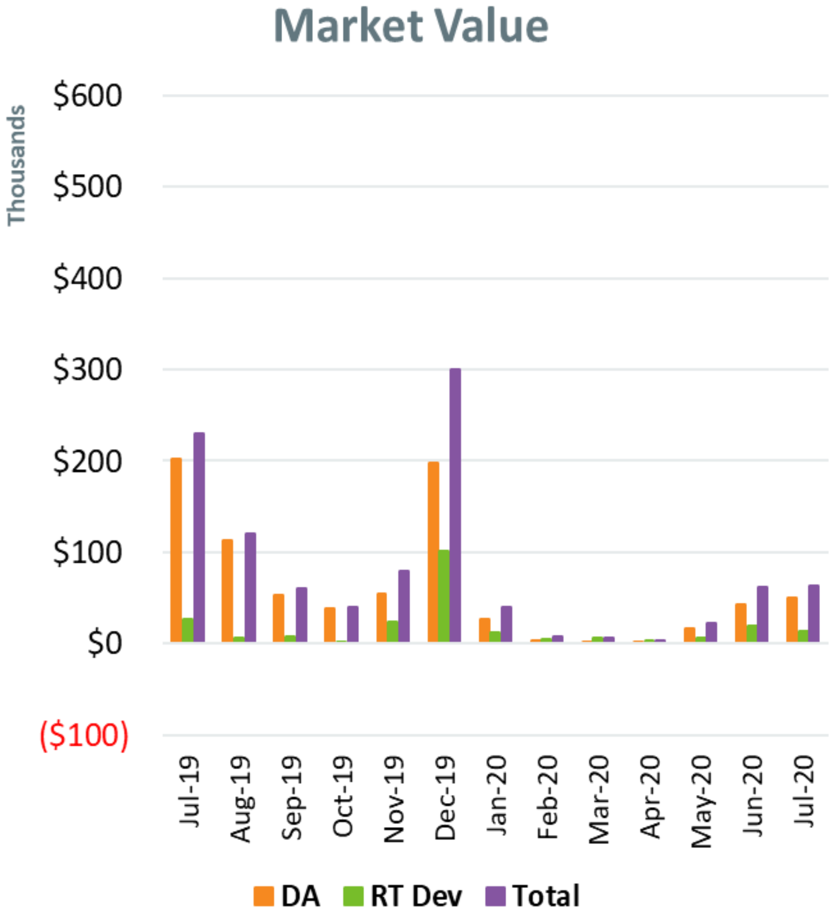
Highlights, cont.

- Daily Net Commitment Period Compensation (NCPC)
  - July 2020 NCPC payments totaled $1.6M over the period, down $0.2M from June 2020 and down $0.3M from July 2019
    - First Contingency* payments totaled $1.5M, down $0.3M from June
      - $1.4M paid to internal resources, down $0.2M from June
        - » $191K charged to DALO, $807K to RT Deviations, $430K to RTLO
      - $38K paid to resources at external locations, down $146K from June
        - » Charged to RT Deviations
    - Second Contingency payments were zero
    - Voltage and Distribution payments totaled $22K and $127K, respectively
  - NCPC payments over the period as percent of Energy Market value were 0.5%

* NCPC types reflected in the First Contingency Amount: Dispatch Lost Opportunity Cost (DLOC) - $157K; Rapid Response Pricing (RRP) Opportunity Cost - $269K; Demand Response Performance Audit (DRPA) - $4K;

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.

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
  - ICR and related values development for ARA3 to commence in August, with assumption discussions being held at the PSPC

CCP – Capacity Commitment Period

Forward Capacity Market (FCM) Highlights

- CCP 13 (2022-2023)
  - First reconfiguration auction (ARA1) was held June 1-3, and results were posted on June 25
  - ICR and related values development for ARA2 to commence in August, with assumption discussions being held at the PSPC
- CCP 14 (2023-2024)
  - Auction results were filed with FERC on February 18 and FERC accepted the filing on April 10
  - ICR and related values development for ARA1 to commence in August, with assumption discussions being held at the PSPC

FCM Highlights, cont.

- CCP 15 (2024-2025)
  - It was confirmed at the May 28 PSPC meeting that FCA 15 will model the same zones as FCA 14
    - Export-constrained zones: Maine nested inside Northern New England
    - Import-constrained zone: Southeast New England
  - Existing capacity values were posted on March 6
  - Summary of retirement and permanent delist bids was posted on March 18 and summary of substitution auction demand bids was posted on May 1
  - New Capacity Resource Qualification is ongoing
  - ICR and related values development continues, with assumption discussions being held at the PSPC through the September timeframe

FCA – Forward Capacity Auction
ICR – Installed Capacity Requirement

Highlights

- ISO released the final list of qualifying Phase One proposals on July 17 and has initiated the Solutions Study process
- ICR and related values development continues, with assumption discussions being held at the PSPC through the September timeframe
- Impacts of COVID19 to the load forecast are being pursued and will be discussed at the August 27 PAC meeting
- Anbaric and RENEW 2019 economic study reports to be completed in August

Load Forecast

- 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
- Impacts of COVID19 to the load forecast are being pursued and will be discussed at the August 27 PAC meeting
- EE Reconstitution project
  - RC was introduced to the issue at their April 22 meeting
  - Changes will impact the 2021 forecast used for FCA 16 ICR development

FERC Order 1000

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

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 discussed the draft list of qualifying Phase One Proposals at the 6/17/2020 PAC meeting
  - On 7/17/2020, the ISO released:
    - Final Boston 2028 RFP Review of Phase One Proposals report, which documents the final list of qualifying Phase One proposals
    - Stakeholder comments and the ISO's responses
    - Memo announcing posting of the report and notice initiating the Solutions Study process
    - Lessons-learned announcement
  - The Boston 2028 RFP process has been completed and the ISO has started the Solutions Study process

Highlights

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

- The lowest 50/50 and 90/10 Preliminary Fall Operable Capacity Margins are projected for week beginning October 17, 2020.

JULY 31, 2020

July Peak Load

COVID-19 Impact on System Load

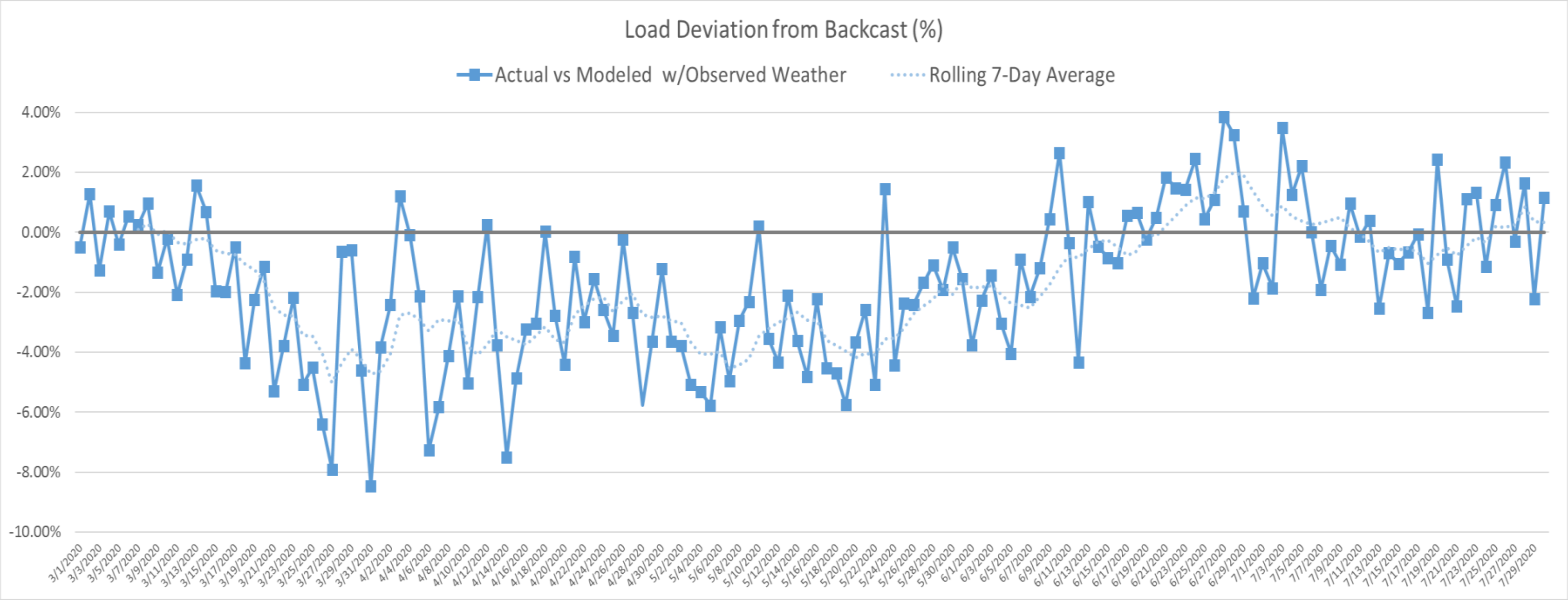
- March through May 2020 demand was approximately **3% to 5% lower than normal**
- June demand approximately **1% to 3% lower** than normal
  - Air conditioning added some demand
  - States' limited re-opening restored some demand
- July demand **returned to normal**, responding to higher temperatures when air conditioning demand increased in the residential space, supplemented by expanded re-opening
- Load curves have changed shape with the pandemic outbreak
- ISO is continuously evaluating trends in the load curve, paying mind to the expected differences from historical data

COVID-19 Impact on System Load

- A backcast model was built to calculate what load would have been without the pandemic
  - The 'backcast' model is a load model where weather *forecast* inputs are replaced with *actual* weather, removing weather forecast variability from the calculation
  - The model has **not** been retrained since the onset of the pandemic
- 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

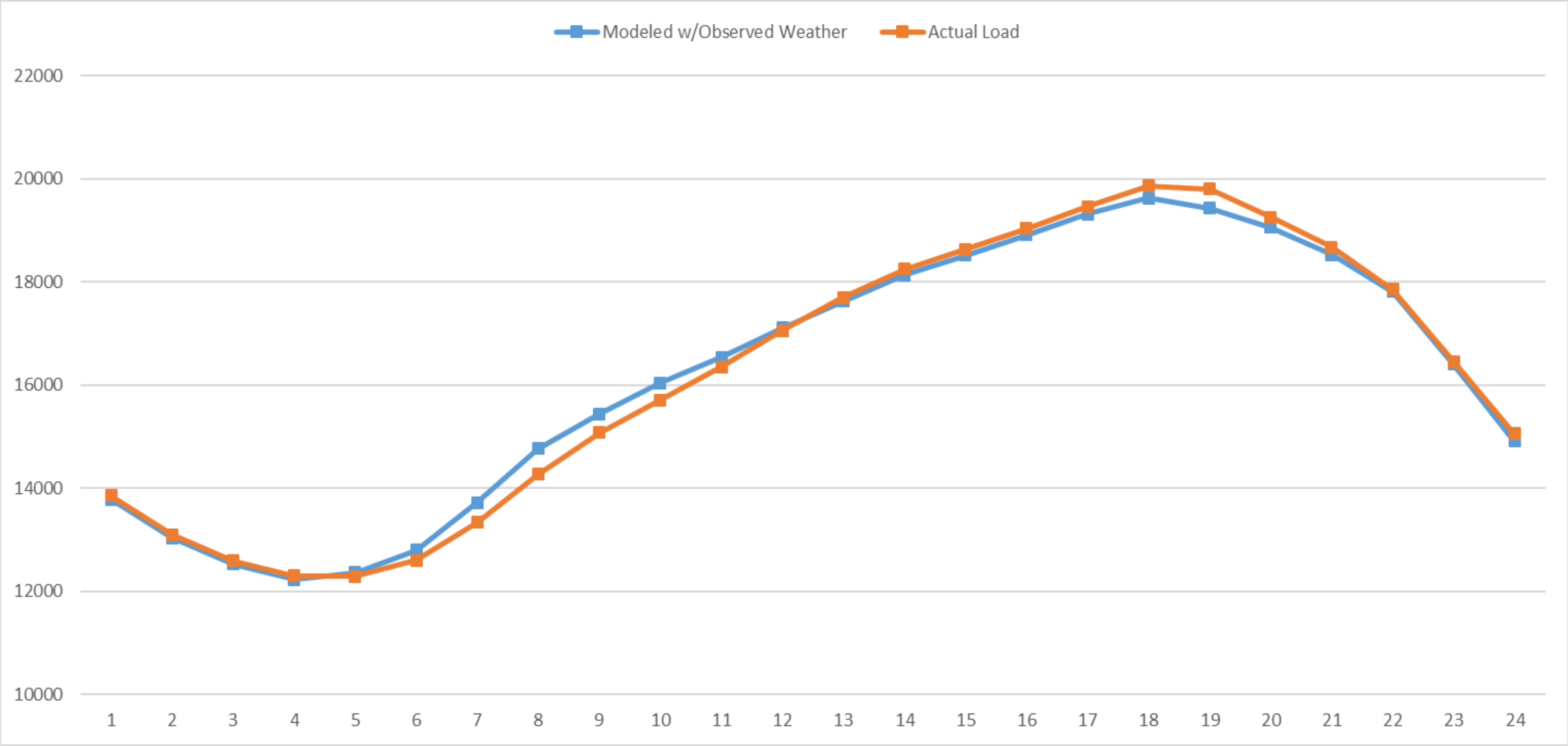
Average Hourly Actual Load Deviations from Backcast Model

- Values less than 0 % indicate lower loads than non-COVID19 expectations
- High and low points are generally caused by weather
  - Air conditioning sustainably contributing to higher-than-normal loads



Comparison of Average Hourly Actual Loads to Backcast Loads

- 'Average' Load Curve created by averaging the hourly loads for July 2020.

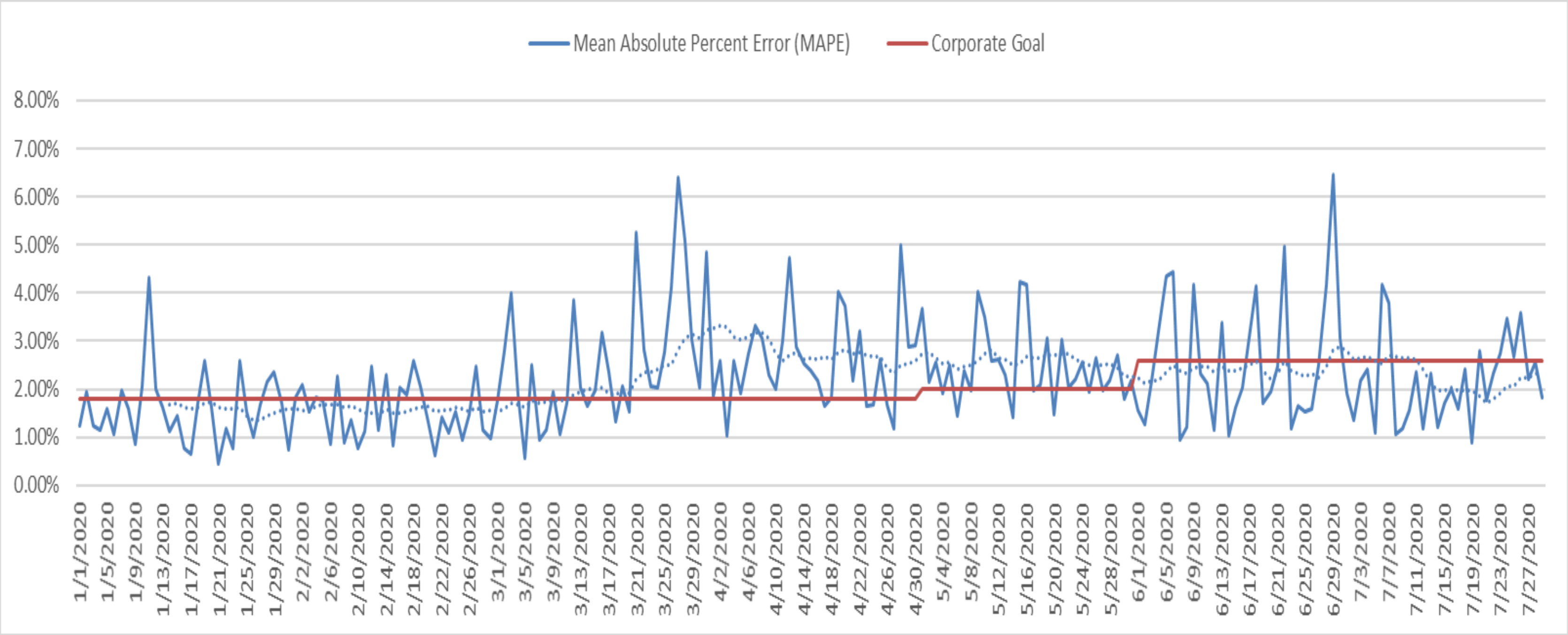


General ‘Average’ Load Curve Observations for July 2020

- Slower morning ramp, likely due to staggering schedules
- Evening peaks are slightly higher, likely due to air conditioning systems cycling on more frequently
- Overnight actual loads are similar to what would be expected using the actual weather
- With lower morning ramps and higher peaks, total energy is very close to the expected values

Load Forecast Accuracy

- Forecast challenges had reduced the overall accuracy of the load forecast through May
  - Forecasters and Modelers are retraining models frequently

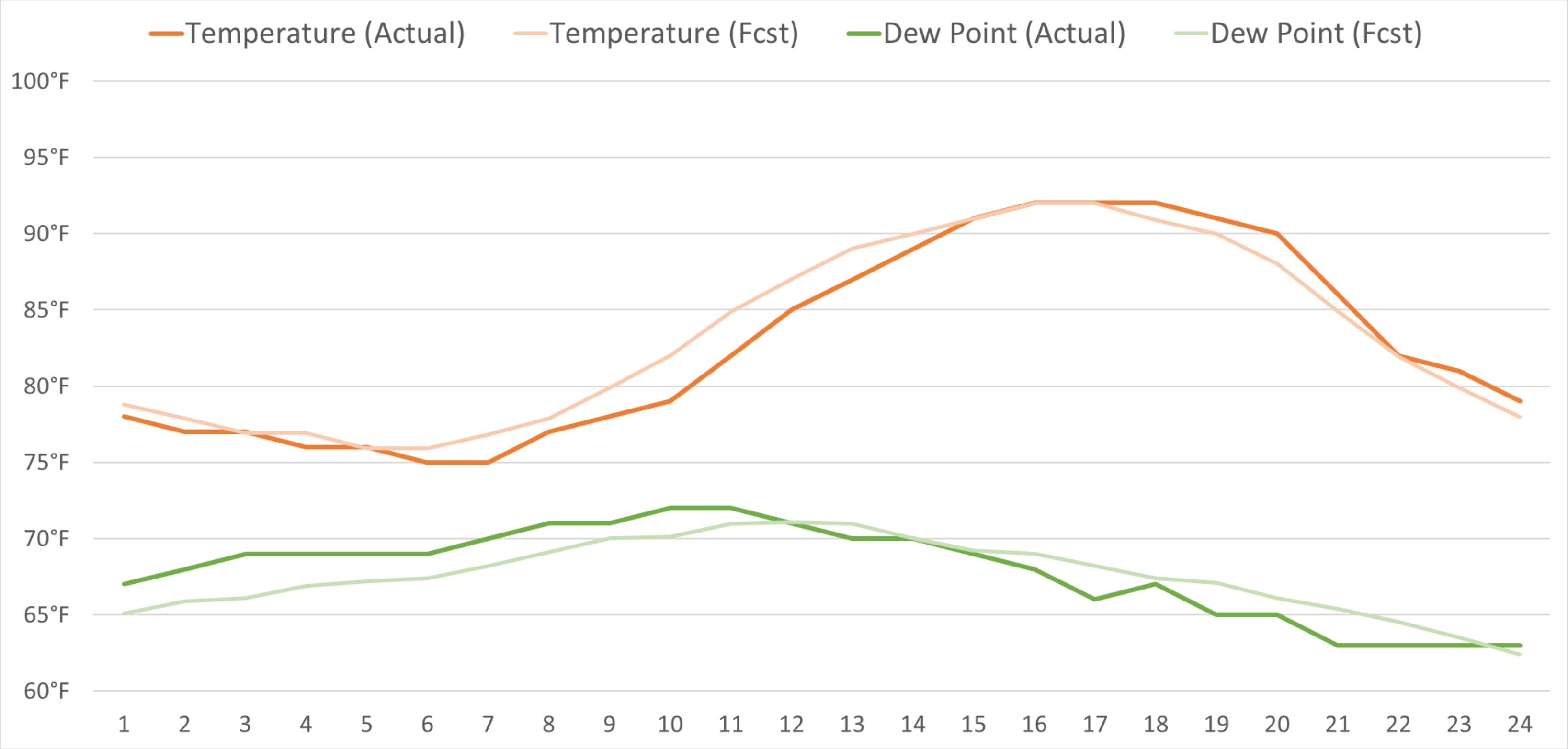


Late July Heat

- Two heat waves in New England, one week apart, with peak days on 7/20 and 7/27, forecasted to peak at 24,500 MW and 25,500 MW respectively
- Actual peak loads on both days were lower than forecast at 23,862 MW and 24,736 MW (the current summer peak)
  - Weather forecasts on both days were for higher temperatures
- The power system operated normally during these periods with good operational performance of transmission, generation and load assets as well as control centers throughout New England and the broader interconnection
- The weekend peak load for July was 22,359, on Sunday 7/19
  - The all time weekend peak load was 24,668 on July 20, 2013

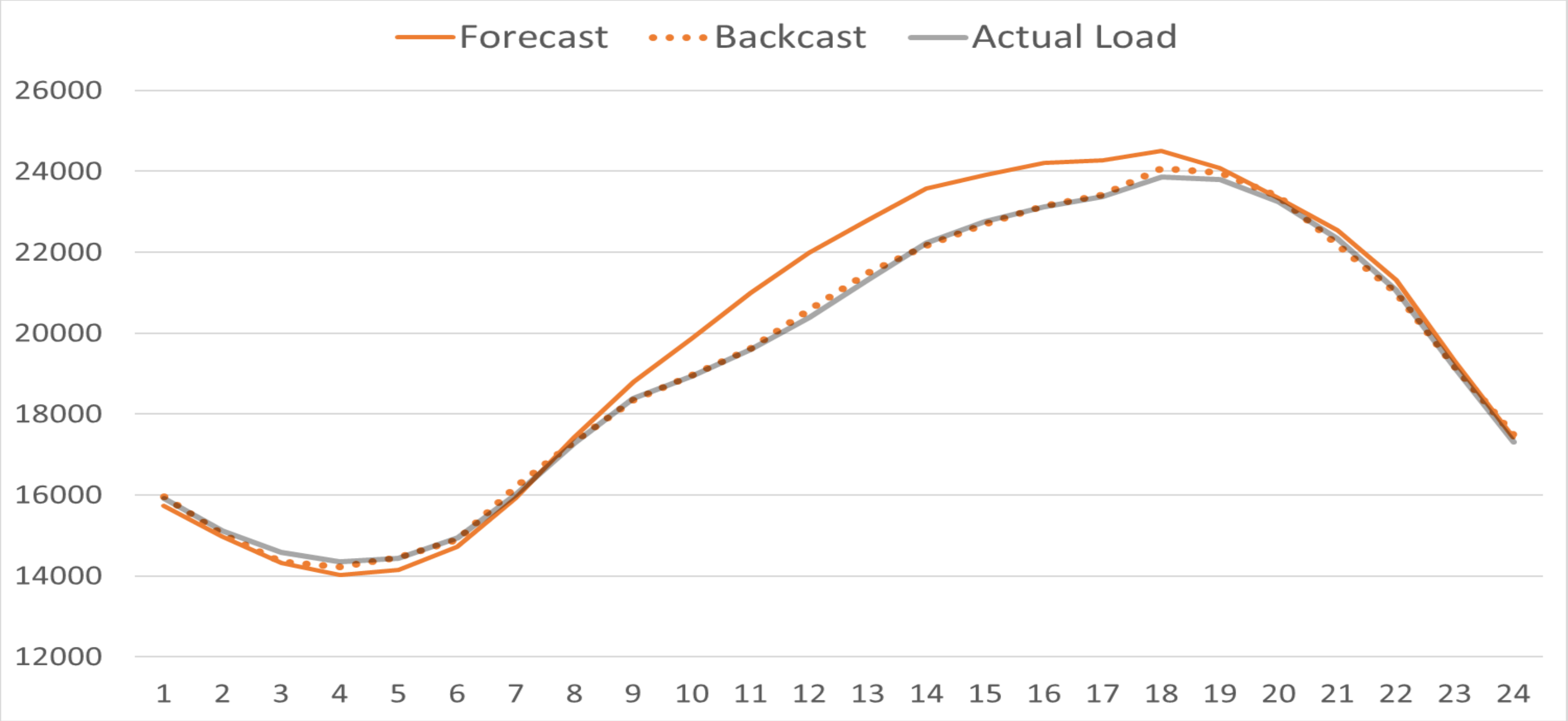
July 20 – Actual vs Forecast Weather

- Lower temperature(s) through the afternoon hours; Once temperature caught up to the forecast, dew points fell below forecast



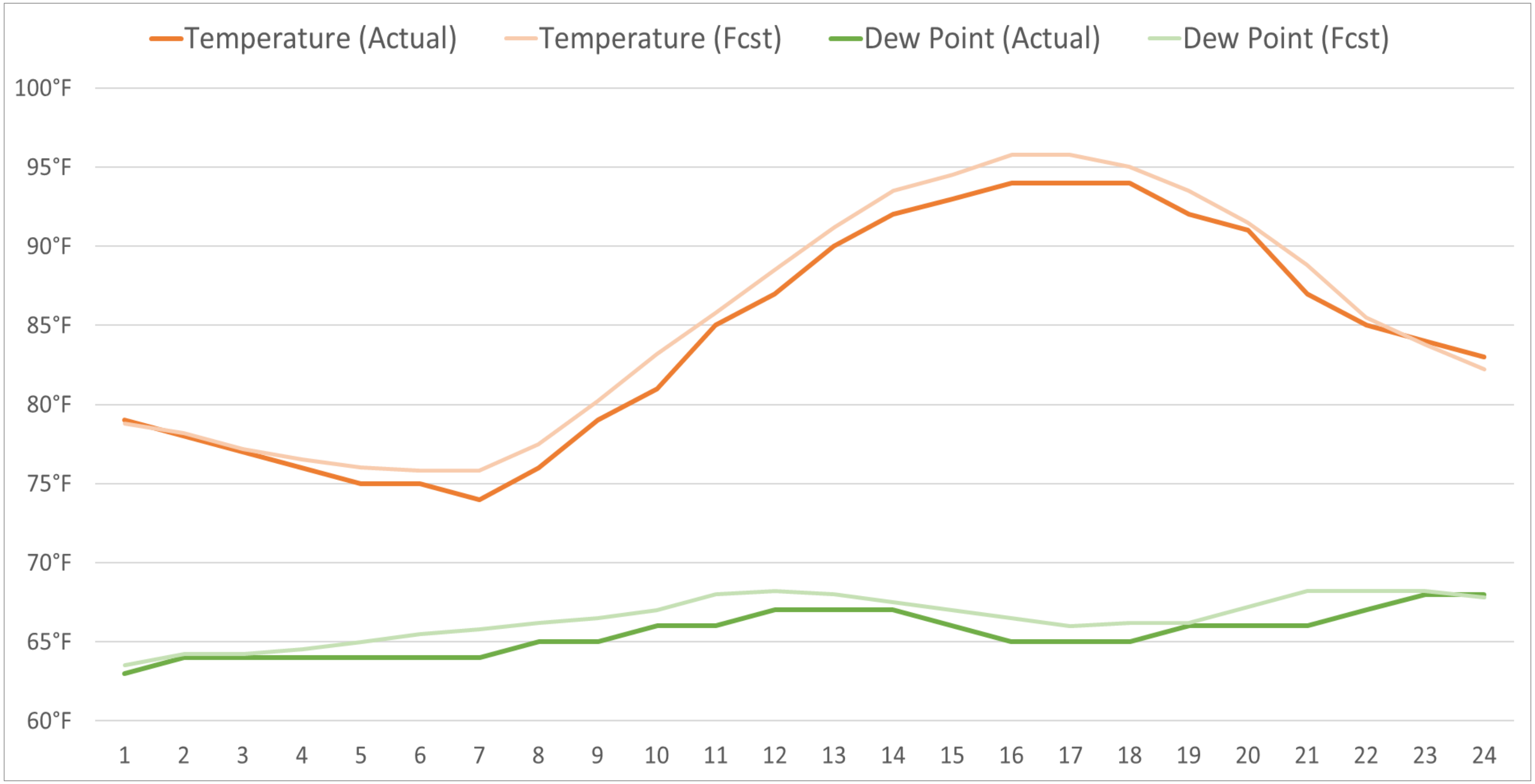
July 20 – Actual vs Forecast vs Backcast Load

- While the forecasted load was higher than the actual, a backcast showed a predictable load curve



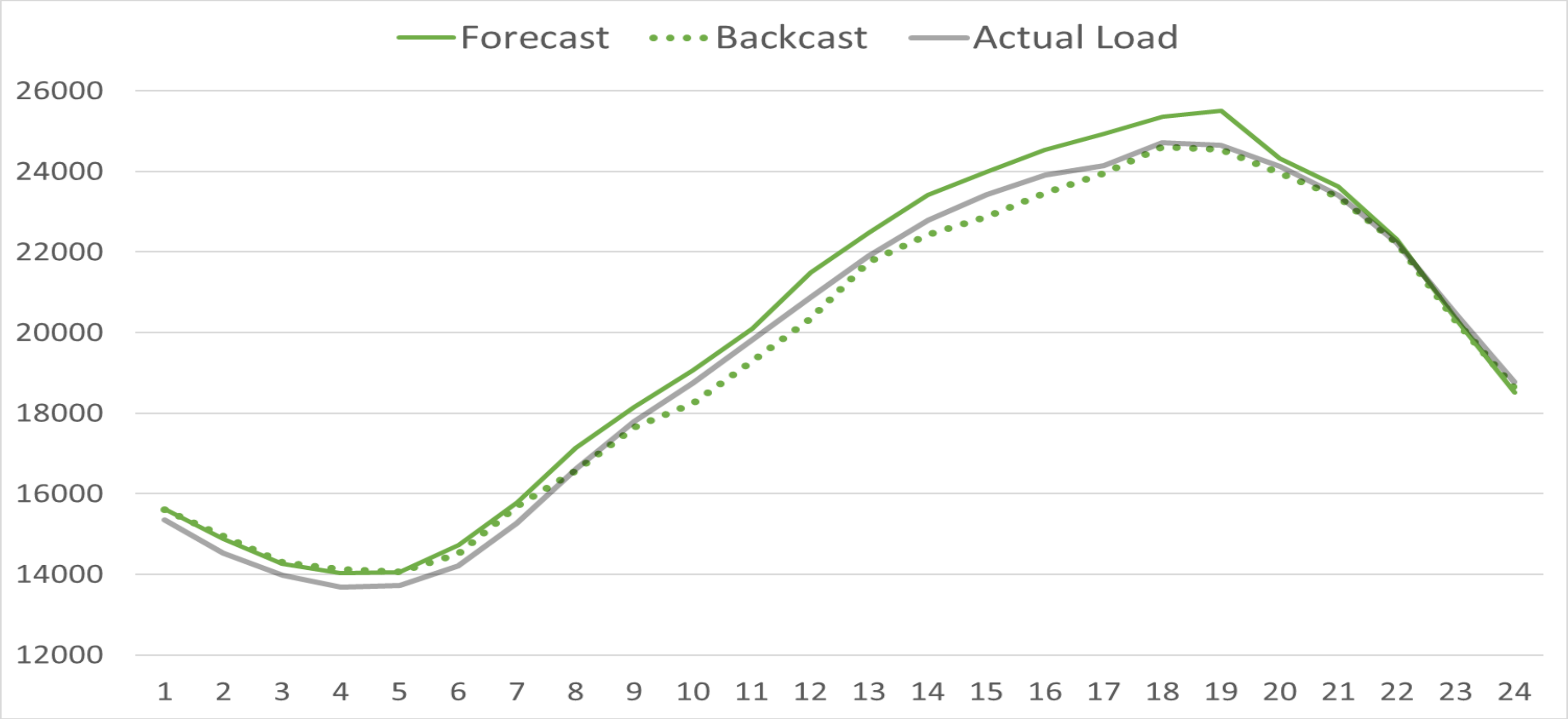
July 27 – Actual vs Forecast Weather

- Both temperature and dew point lower than forecast for most of the day



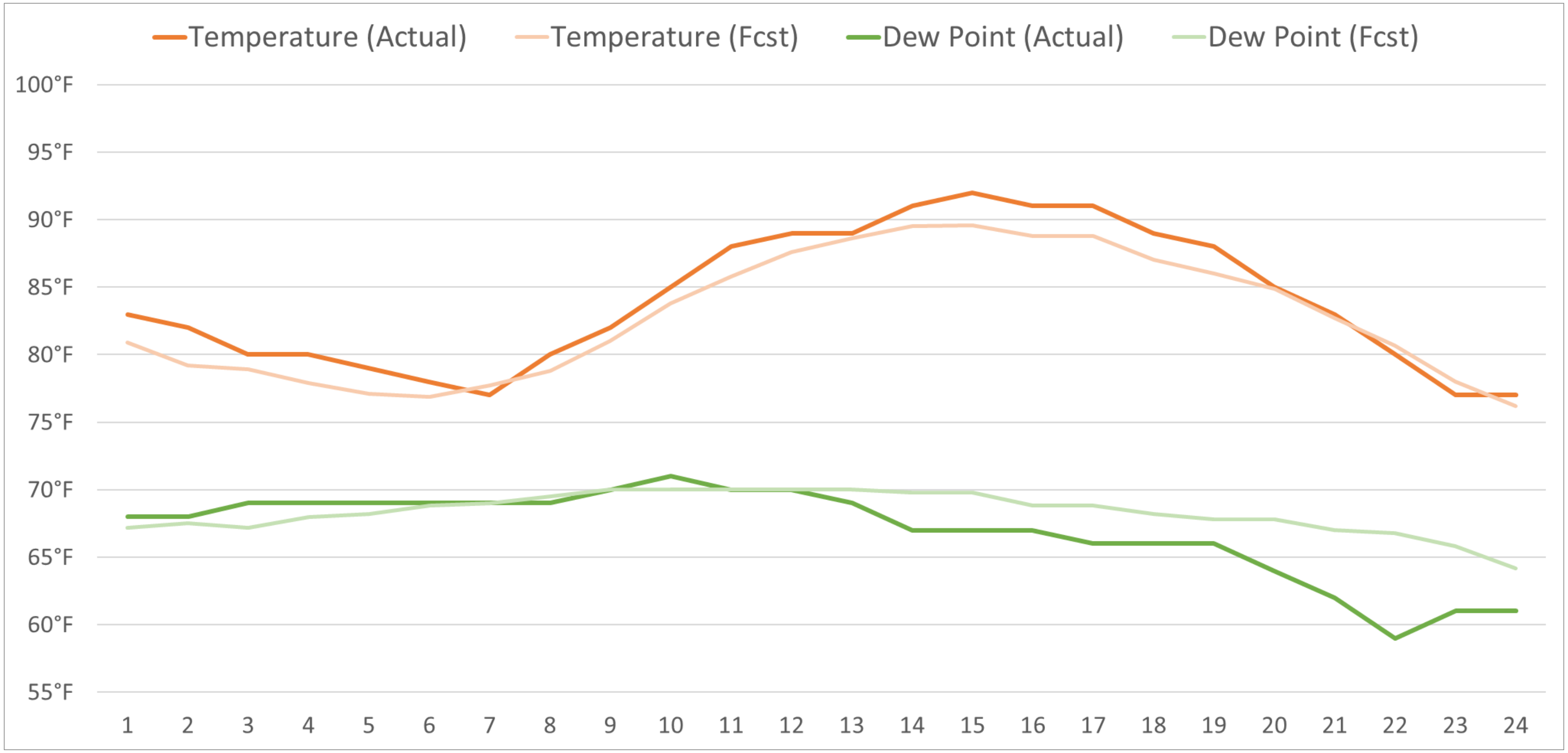
July 27 – Actual vs Forecast vs Backcast Load

- Again, the load was predictable for a known set of weather conditions using the backcast model



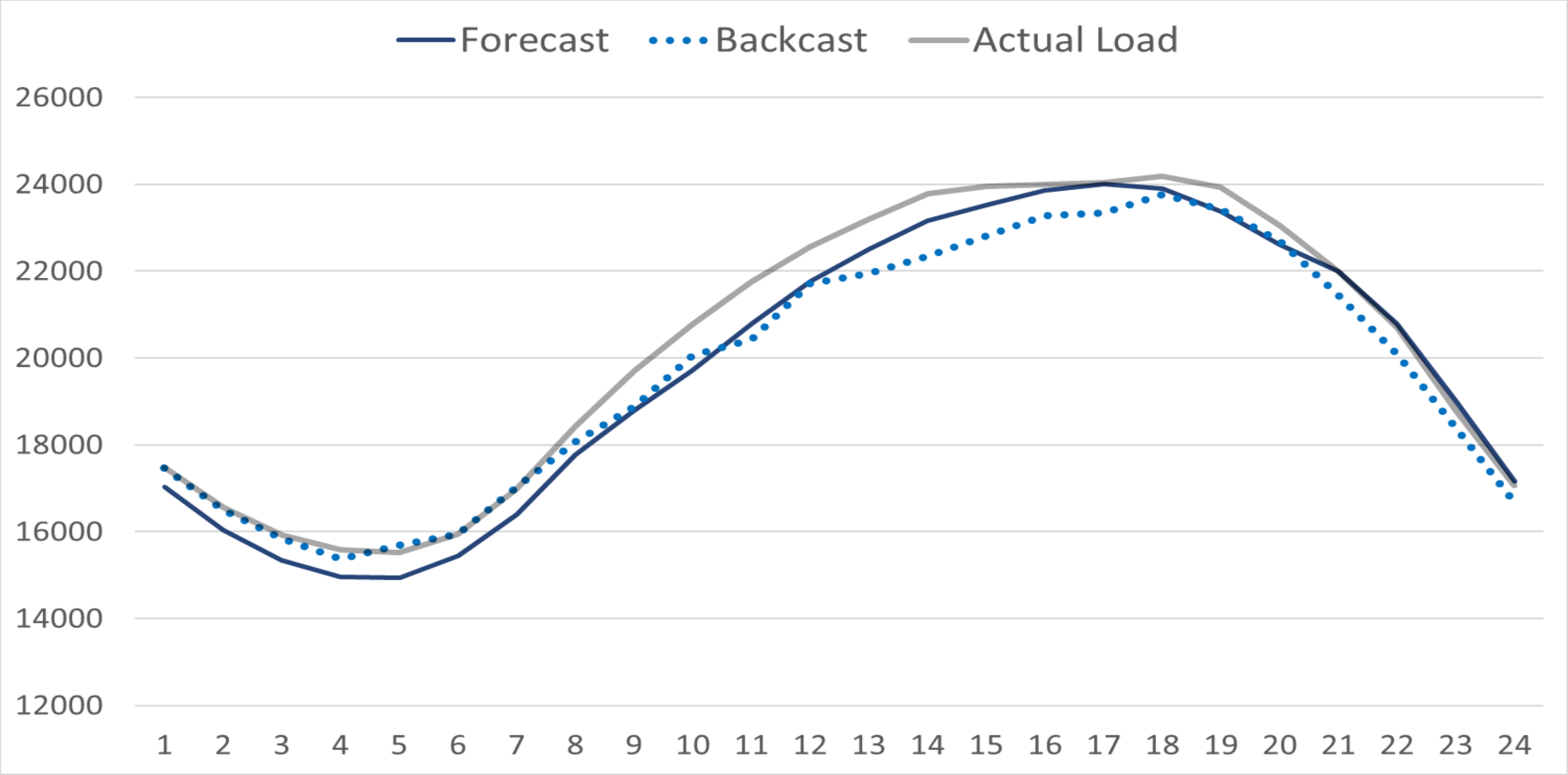
July 28 – Actual vs Forecast Weather

- Higher temperature overnight and throughout most of the day, with an accurate dew point forecast through the morning



July 28 – Actual vs Forecast vs Backcast Load

- Actual load higher than the backcast model on the 4th consecutive 90+ degree day



Peak Load Observations

- Load stalled at specific points on 7/20 and 7/27
  - Stalls occurred at 16:00 on both days: ~23,250 MW on 7/20 and ~24,000 MW on 7/27
- ISO believes the ‘stalls’ are demand side management programs and is working to obtain more detailed information
- Reductions were in the range of ~150 MW during the peak hours

SYSTEM OPERATIONS

System Operations

Weather Patterns	Boston	Temperature: Above Normal (1.9°F) Max: 95°F, Min: 59°F Precipitation: 1.74" – Below Normal Normal: 3.43"	Hartford	Temperature: Above Normal (4.4°F) Max: 99°F, Min: 58°F Precipitation: 0.98 - Below Normal Normal: 4.18"

Peak Load:	24,736 MW	July 27, 2020	18:00 (ending)

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

Procedure	Declared	Cancelled	Note
None for July 2020			

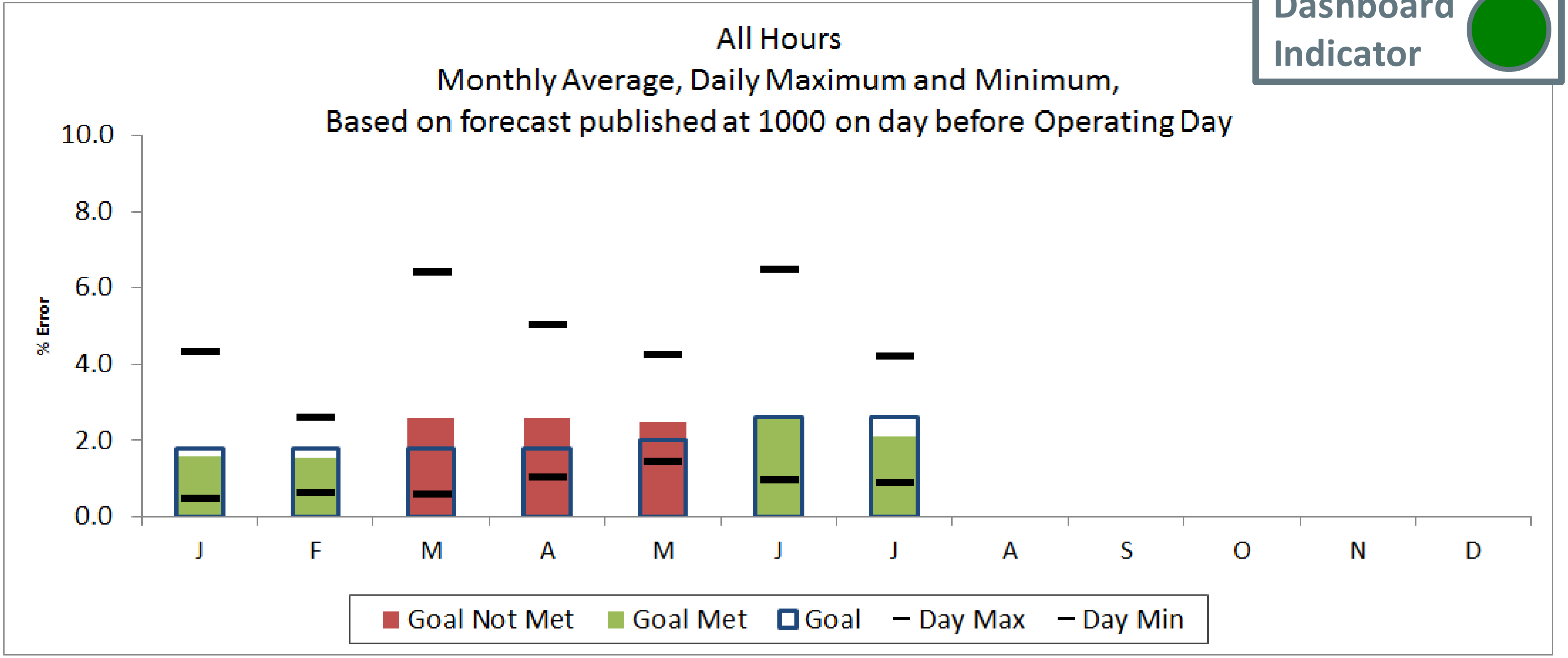
System Operations

NPCC Simultaneous Activation of Reserve Events

Date	Area	MW Lost
7/6/2020	PJM	750
7/9/2020	IESO	850
7/13/2020	NBPSO	700
7/21/2020	NBPSO	710
7/23/2020	PJM	850
7/29/2020	NYISO	520
7/31/2020	NYISO	500

2020 System Operations - Load Forecast Accuracy

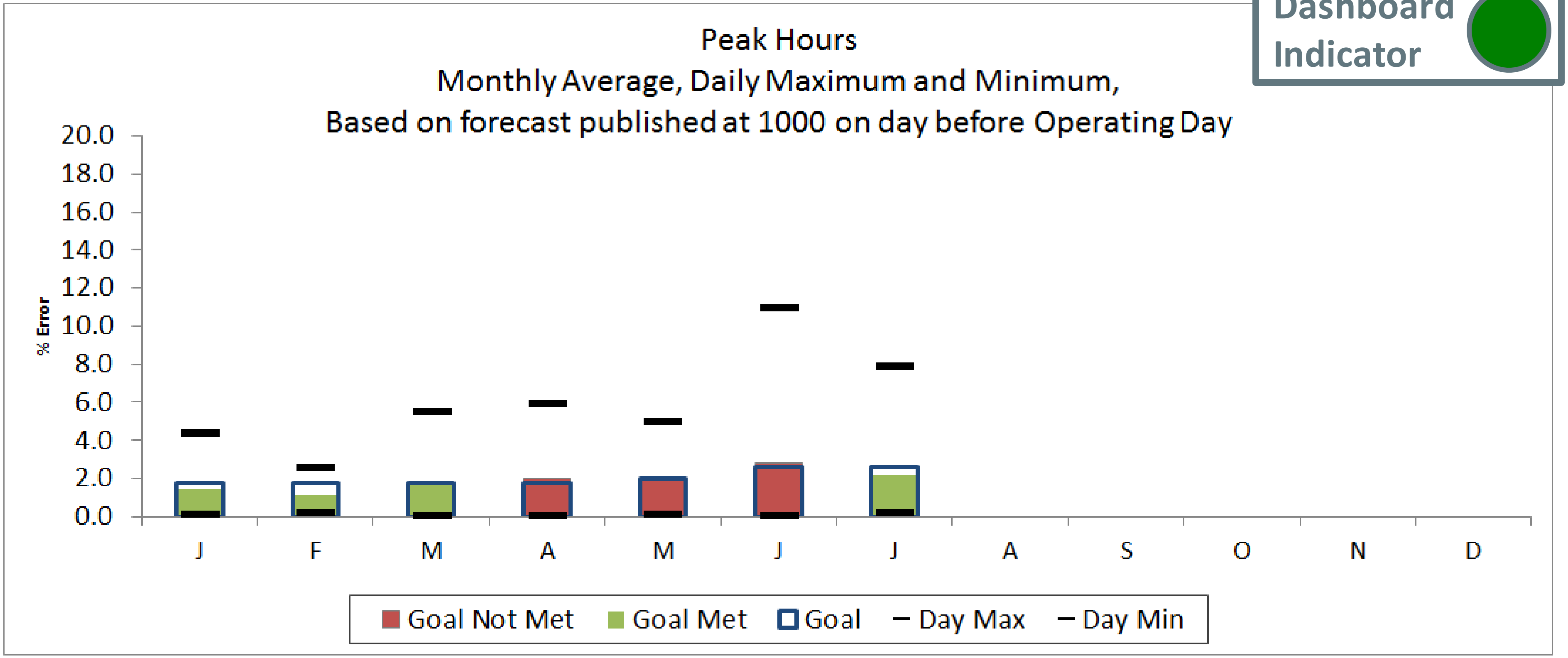
Dashboard Indicator ●


All Hours
Monthly Average, Daily Maximum and Minimum,
Based on forecast published at 1000 on day before Operating Day

Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.31	2.59	6.40	5.00	4.22	6.47	4.18						6.47
Day Min	0.46	0.61	0.58	1.03	1.42	0.96	0.88						0.46
MAPE	1.57	1.54	2.60	2.58	2.49	2.58	2.10						2.21
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60						

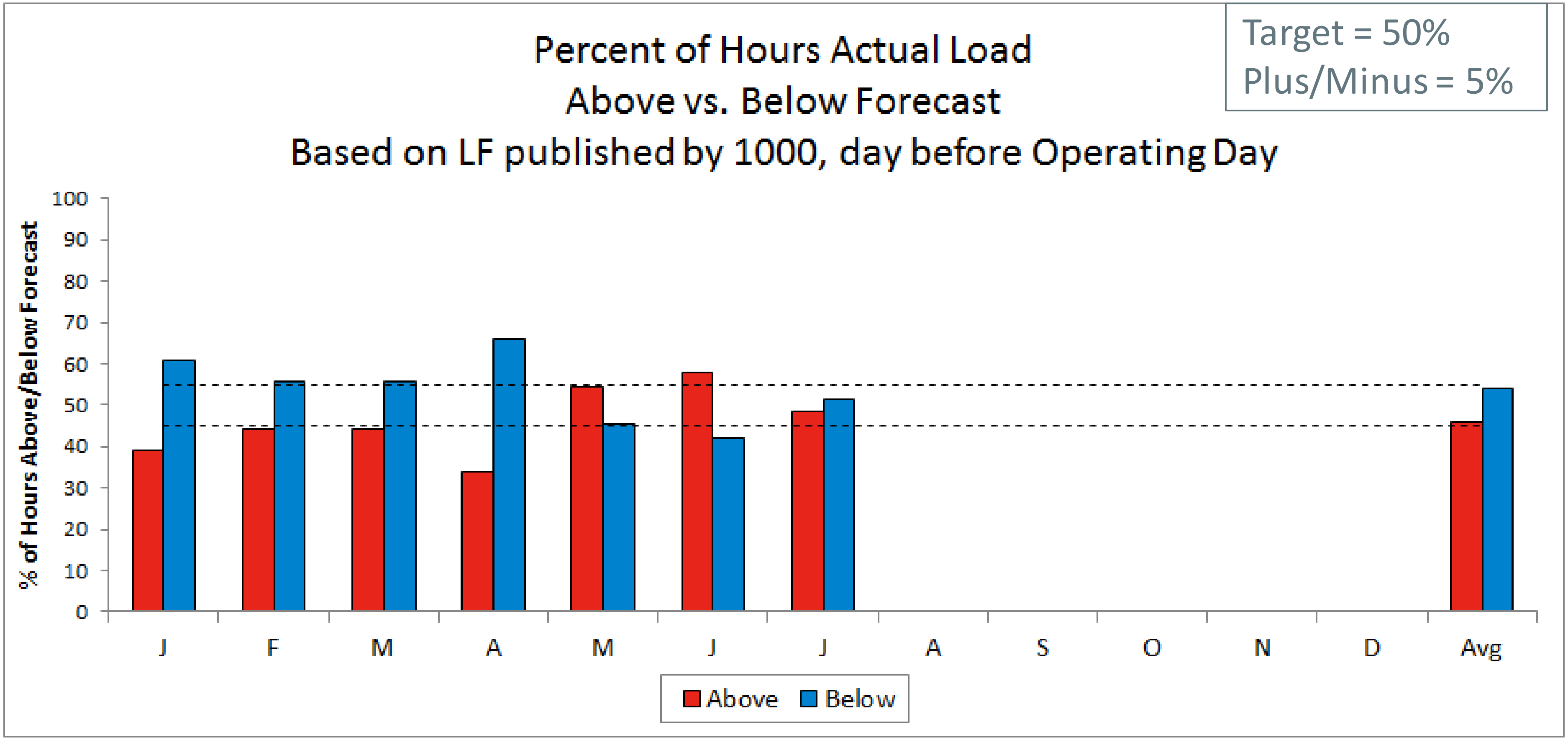
2020 System Operations - Load Forecast Accuracy cont.

Dashboard Indicator ●



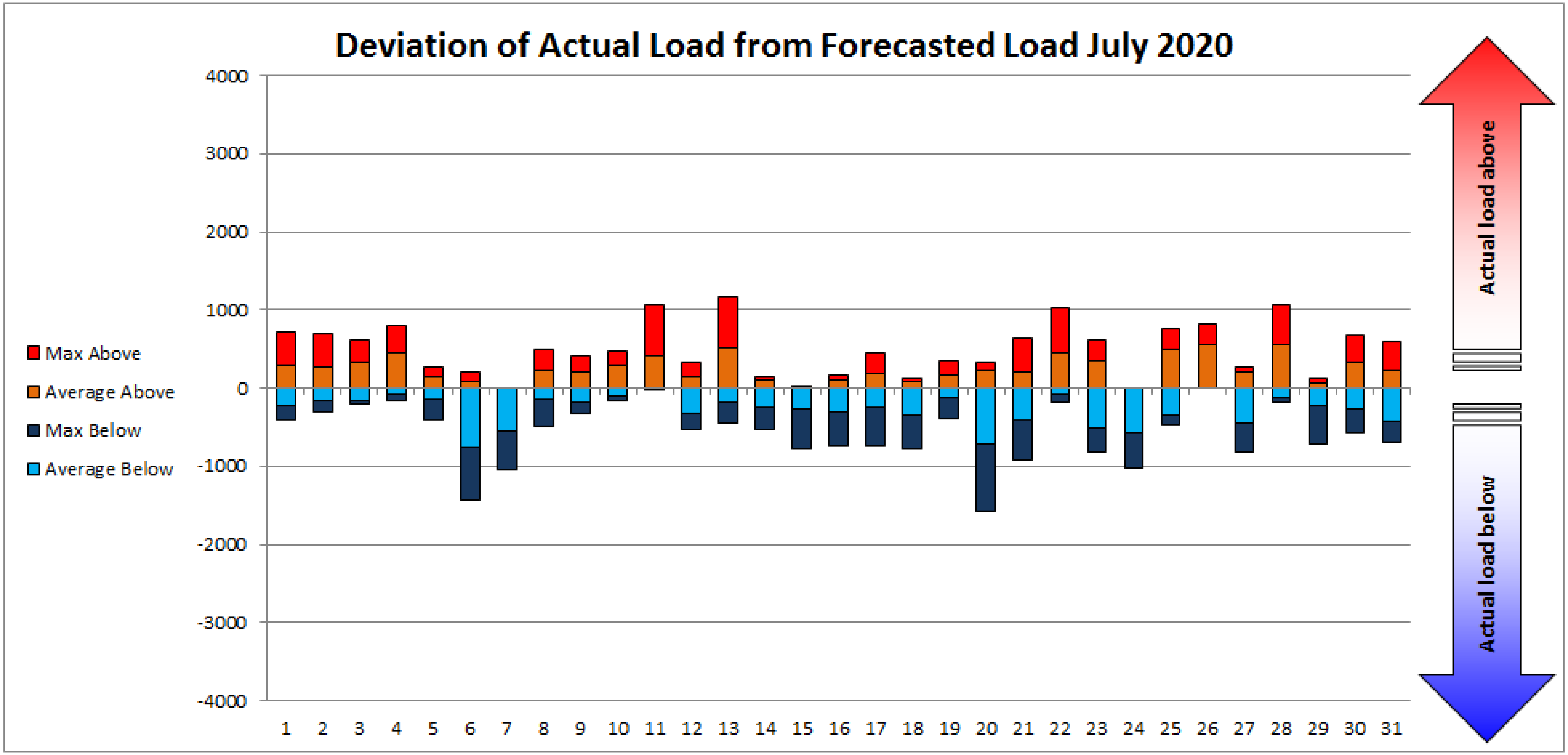
Month	J	F	M	A	M	J	J	A	S	O	N	D	
Day Max	4.33	2.59	5.48	5.93	4.94	10.93	7.84						10.93
Day Min	0.07	0.19	0.01	0.00	0.13	0.05	0.14						0.00
MAPE	1.41	1.12	1.72	1.97	2.11	2.83	2.18						1.91
Goal	1.80	1.80	1.80	1.80	2.00	2.60	2.60						

2020 System Operations - Load Forecast Accuracy cont.

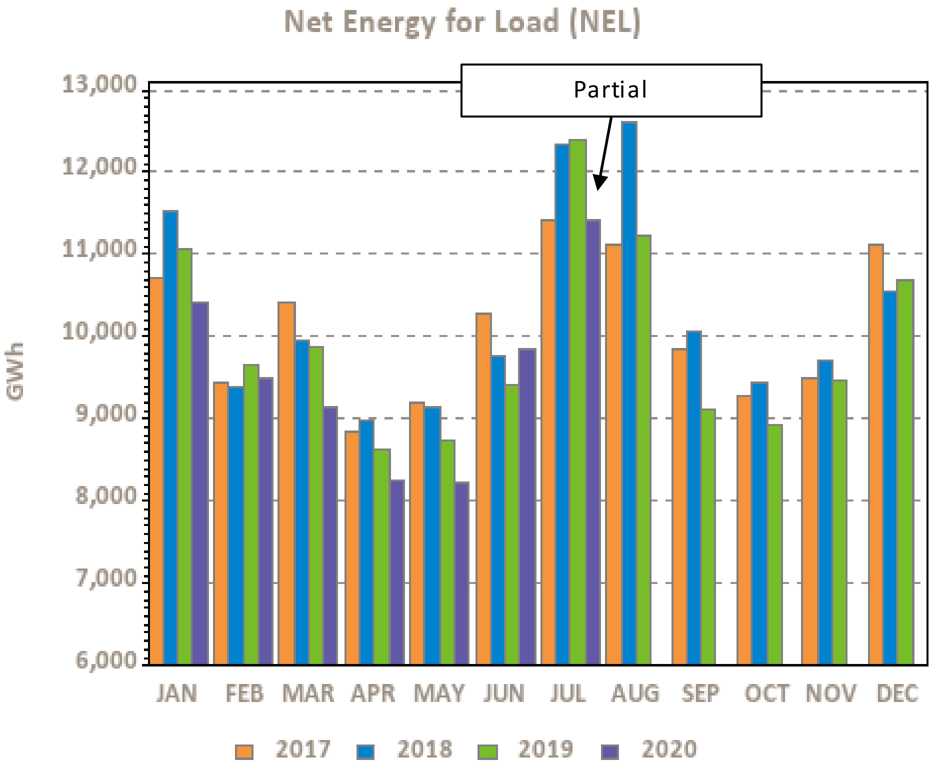


	J	F	M	A	M	J	J	A	S	O	N	D	Avg
Above %	39	44.3	44.4	33.9	54.4	57.9	48.4						46
Below %	61	55.7	55.6	66.1	45.6	42.1	51.6						54
Avg Above	136.2	169.9	207	178.9	231.9	257.5	248.3						258
Avg Below	-192.4	-157.6	-263.9	-265.3	-196.3	-243.5	-281.7						-282
Avg All	-65	-13	-56	-106	38	22	-26						-29

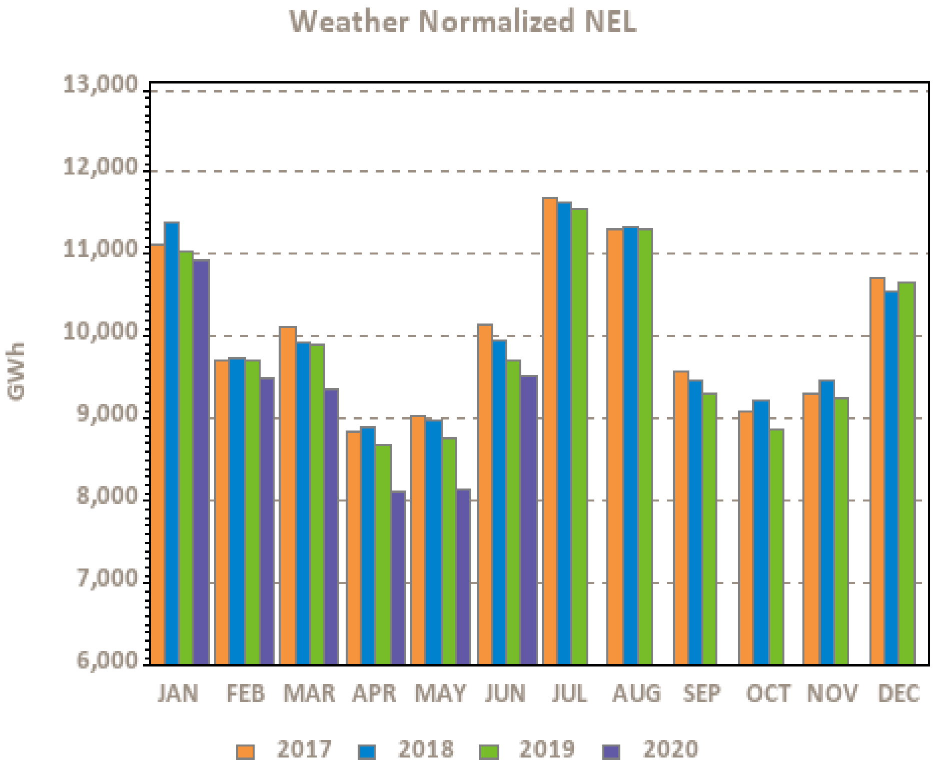
2020 System Operations - Load Forecast Accuracy cont.



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



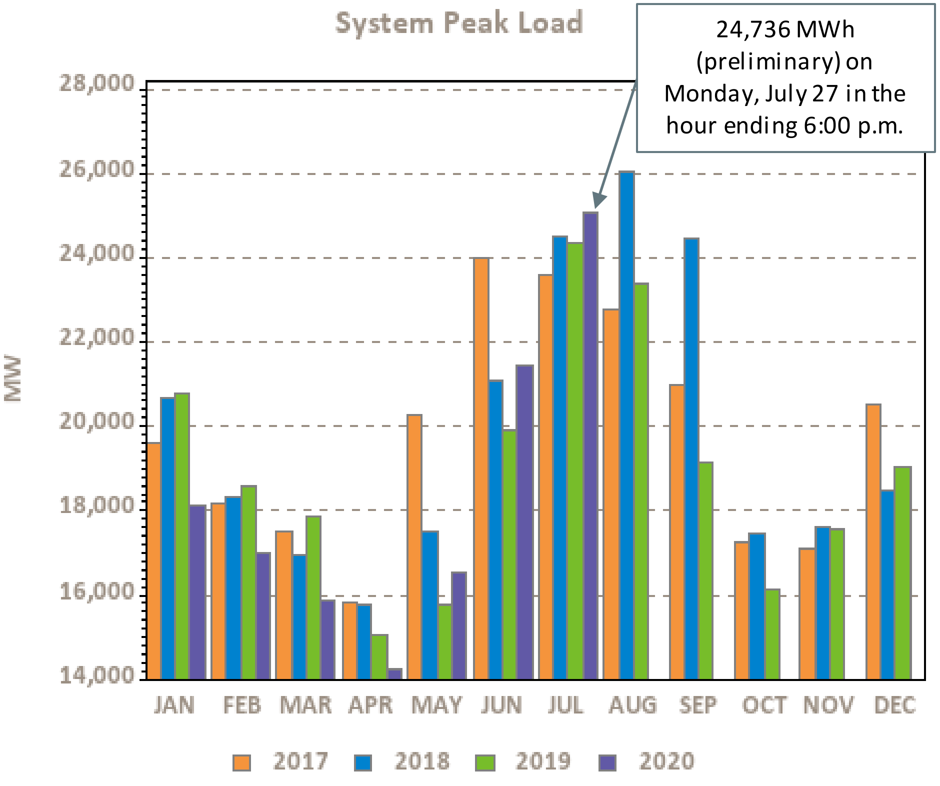
Ann Tot (TWh): 121.2 123.5 119.2 66.8



Ann Tot (TWh): 120.7 120.6 118.7 55.6

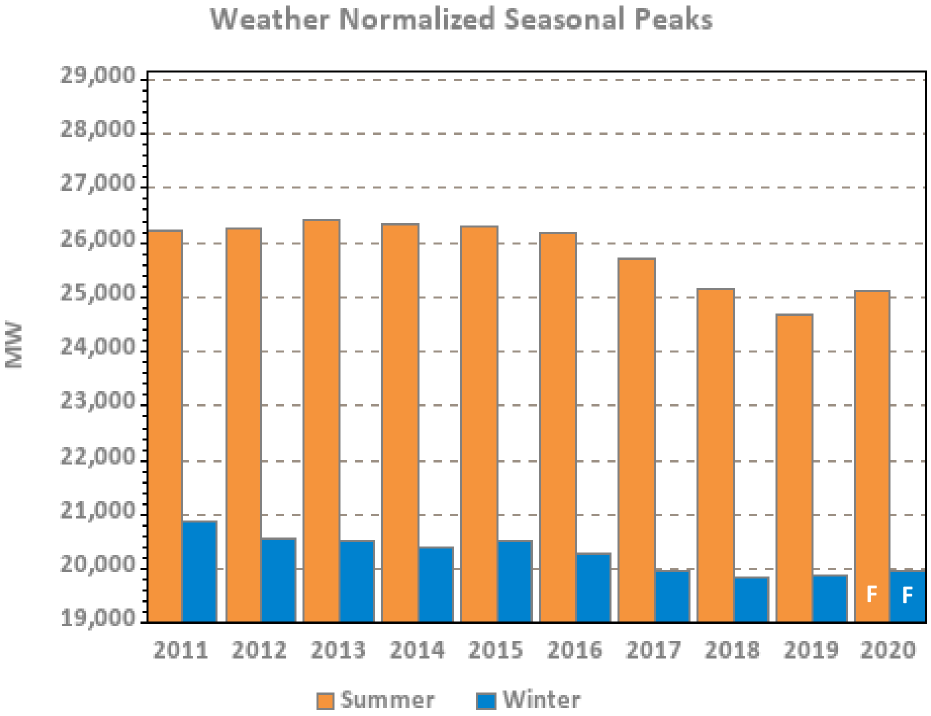
NEPOOL NEL is the total net revenue quality metered energy required to serve load and is analogous to 'RT system load.' NEL is calculated as: Generation – pumping load + net interchange where imports are positively signed. Current month's data may be preliminary. Weather normalized NEL may be reported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

Monthly Peak Loads and Weather Normalized Seasonal Peak History



24,736 MWh (preliminary) on Monday, July 27 in the hour ending 6:00 p.m.

Revenue quality metered value

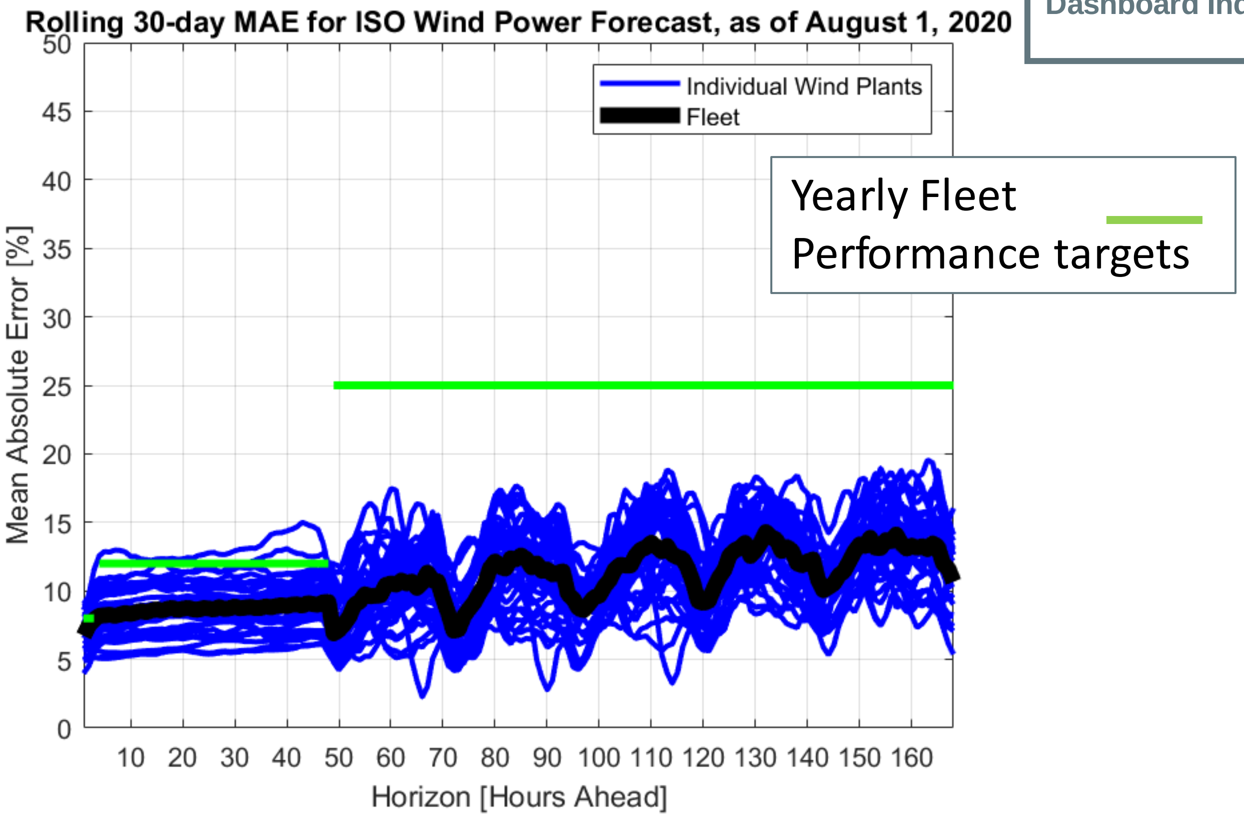


Winter beginning in year displayed

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

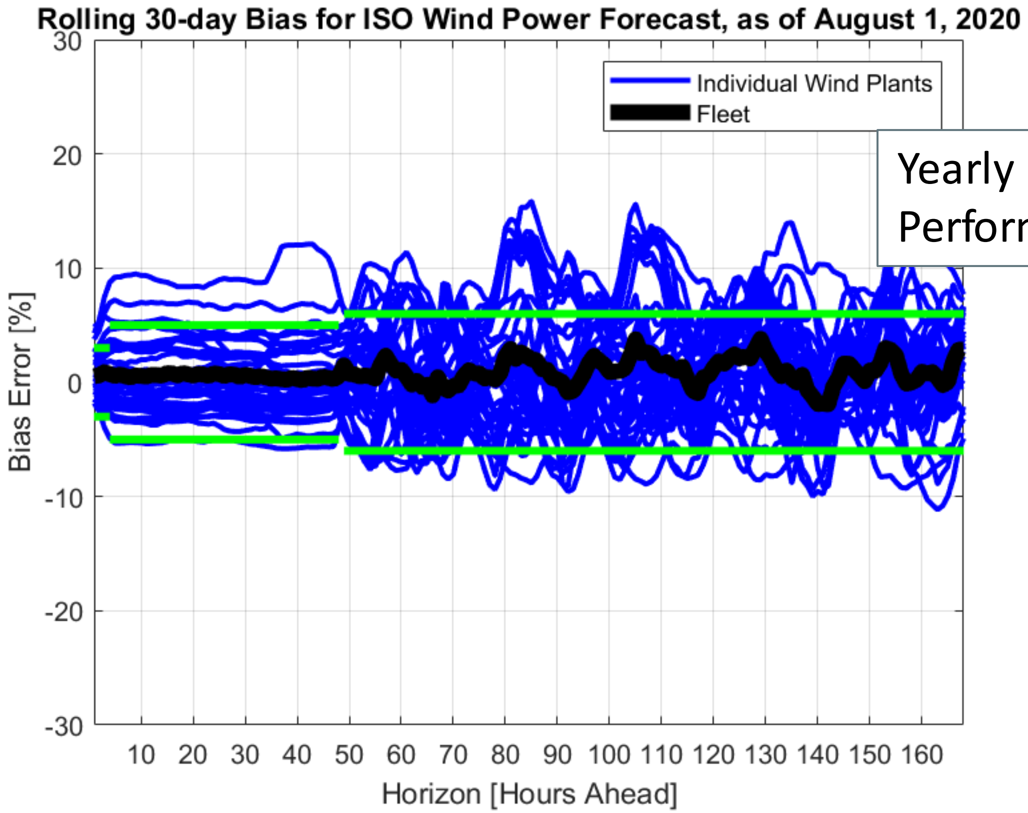
Dashboard Indicator ●



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 ●

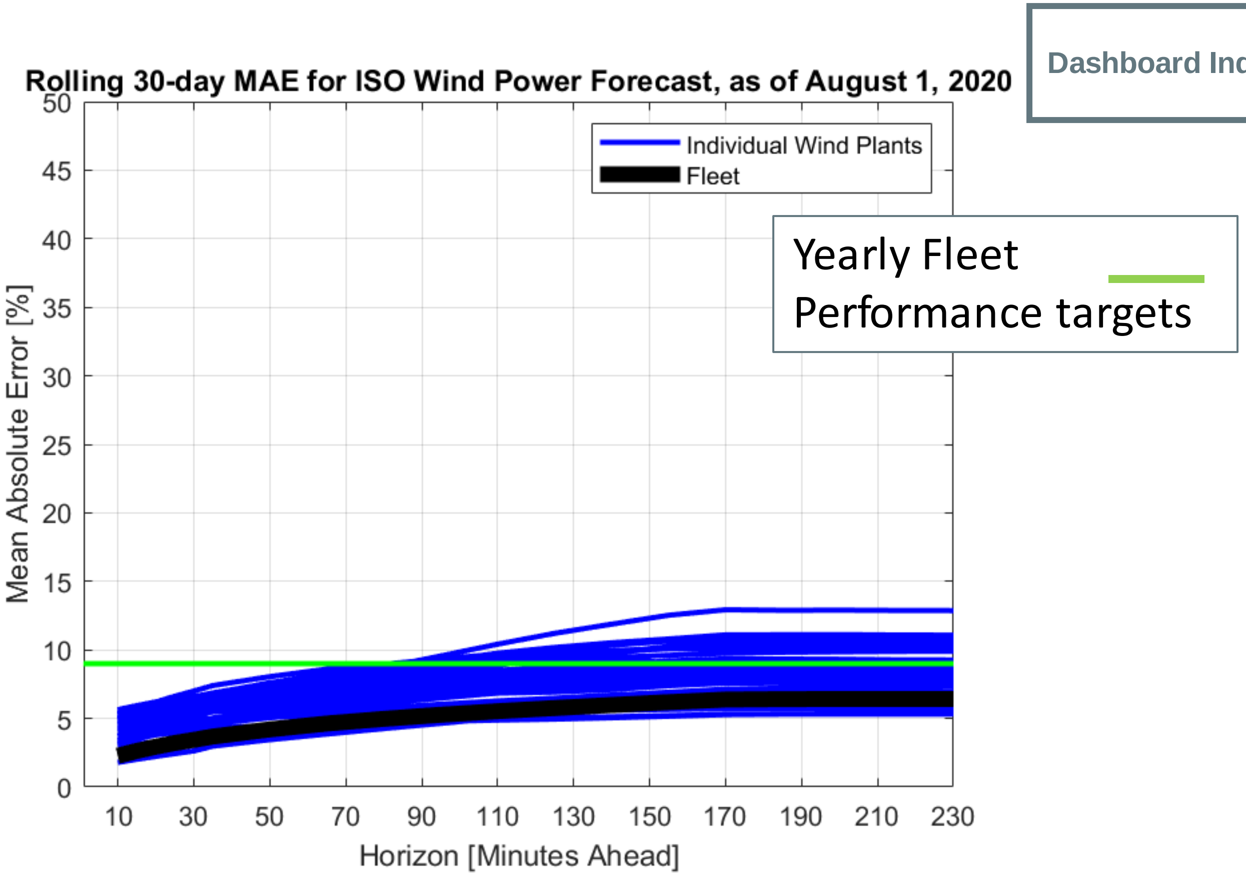


Yearly Fleet Performance targets 🟩

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 ●



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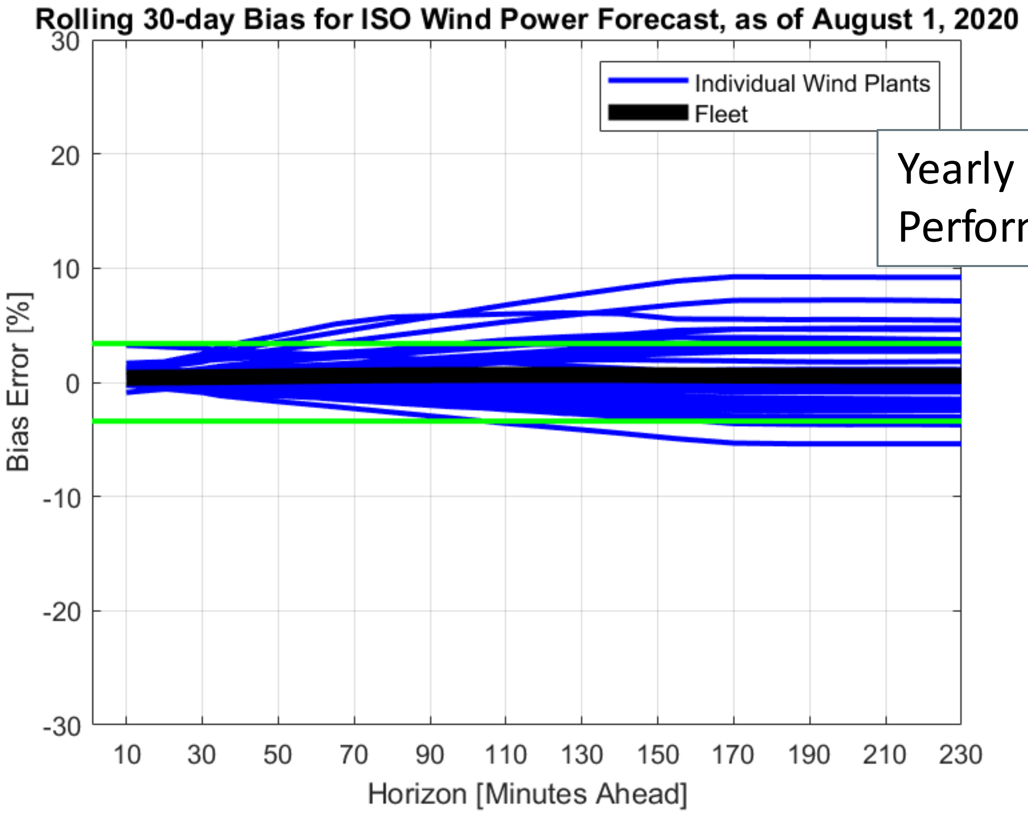
Wind Power Forecast Error Statistics: Short Term Forecast Bias

Dashboard Indicator ●

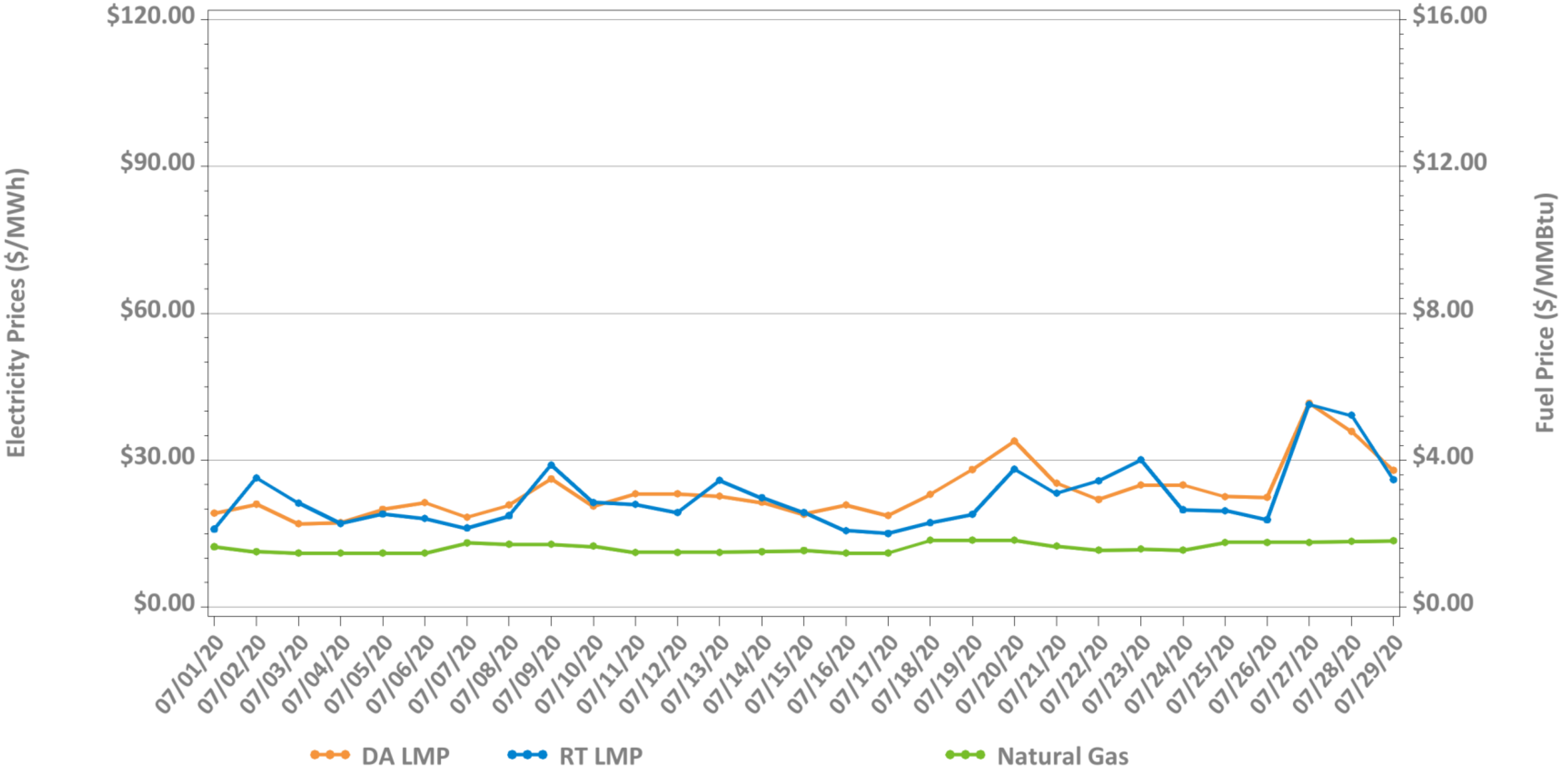


Yearly Fleet Performance targets

Ideally, MAE and Bias would be both equal to zero. Positive bias means less windpower was actually available compared to forecast. Negative bias means more windpower was actually available compared to forecast. Across all time frames, the ISO-NE/DNV-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: July 1-29, 2020

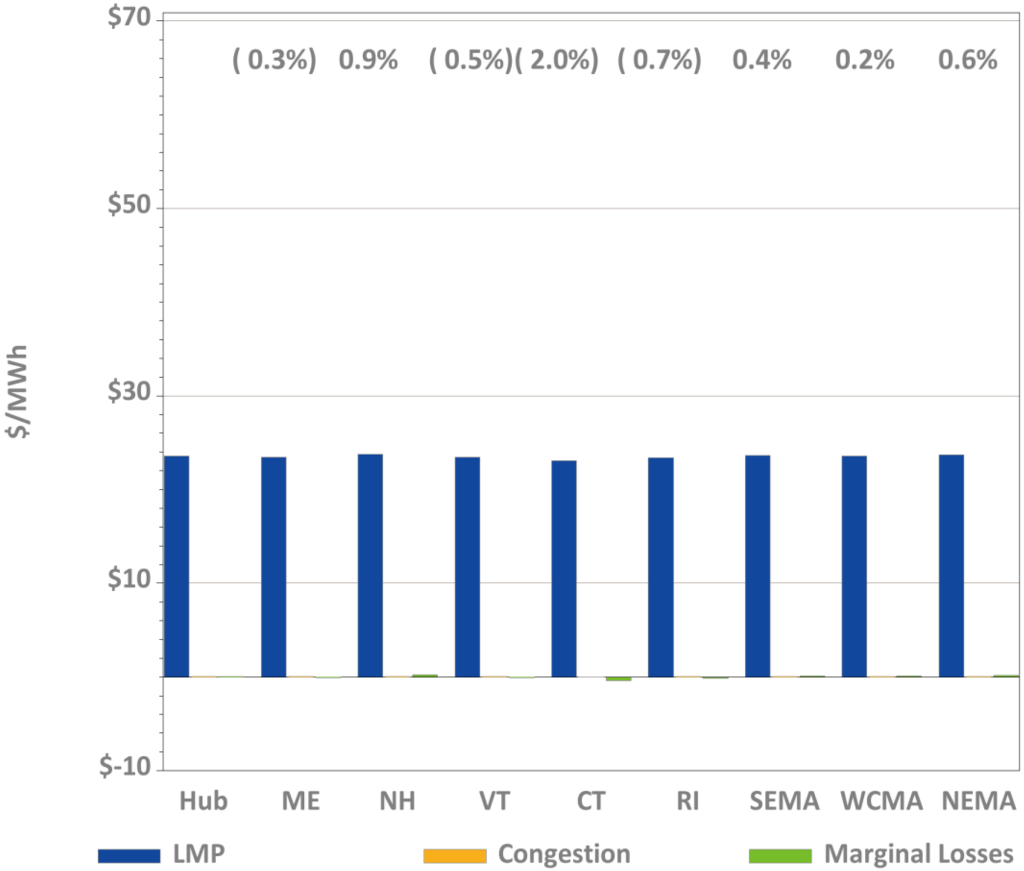


Underlying natural gas data furnished by:

ICE Global markets in clear view

Average price difference over this period (DA-RT): $1.18
Average price difference over this period ABS(DA-RT): $3.25
Average percentage difference over this period ABS(DA-RT)/RT Average LMP: 15%
Gas price is average of Massachusetts delivery points

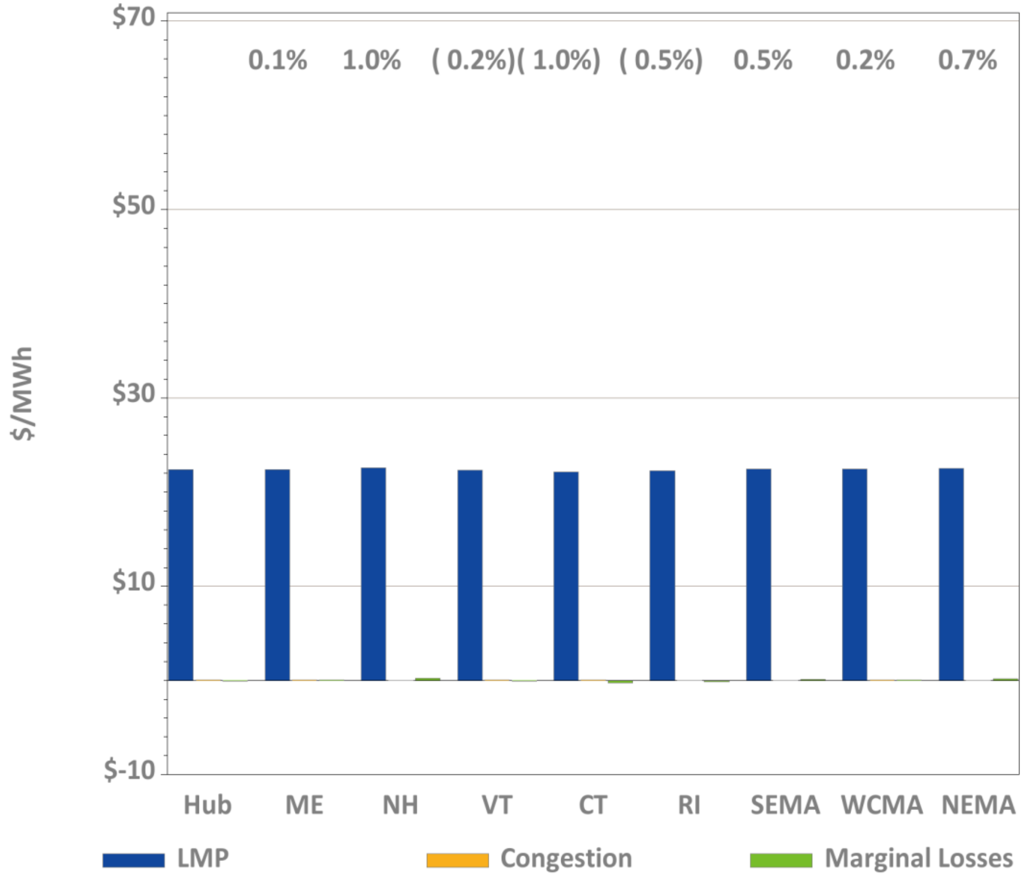
DA LMPs Average by Zone & Hub, July 2020



ME - Maine
NH – New Hampshire
VT – Vermont
CT – Connecticut

RI – Rhode Island
SEMA – Southeastern Massachusetts
WCMA – Western/Central Massachusetts
NEMA – Northeastern Massachusetts

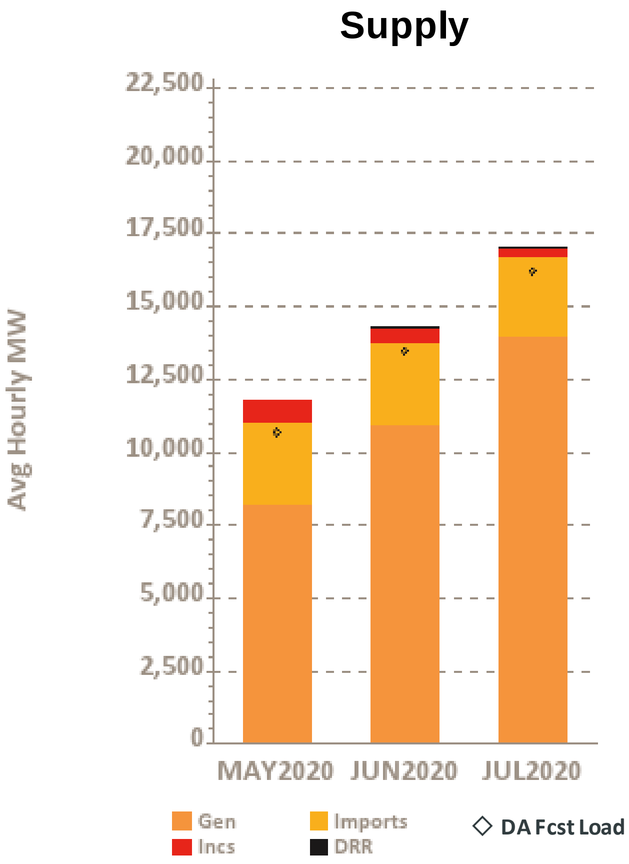
RT LMPs Average by Zone & Hub, July 2020

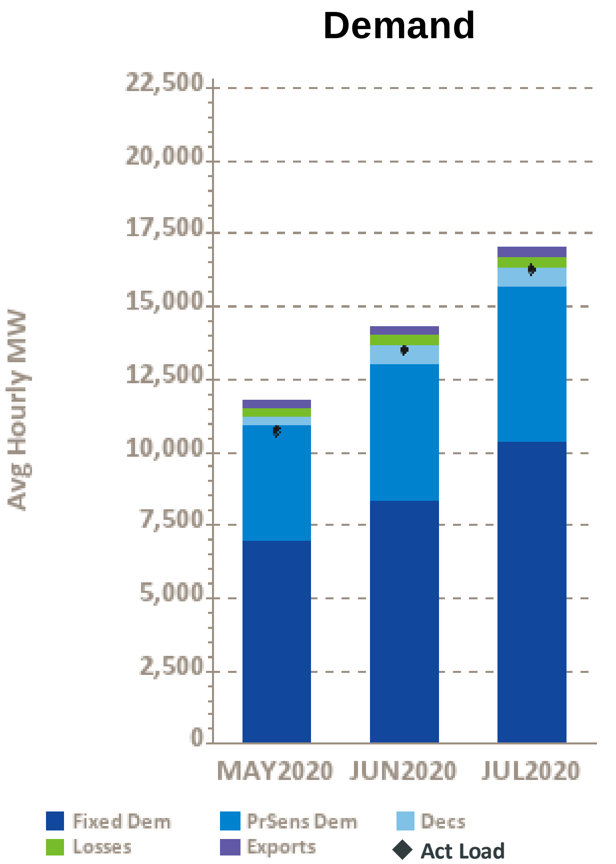


Definitions

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

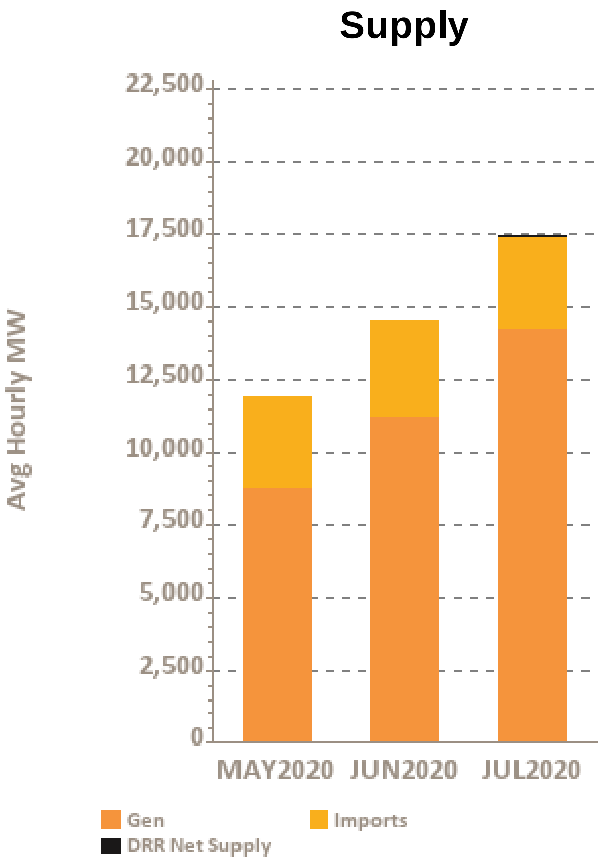


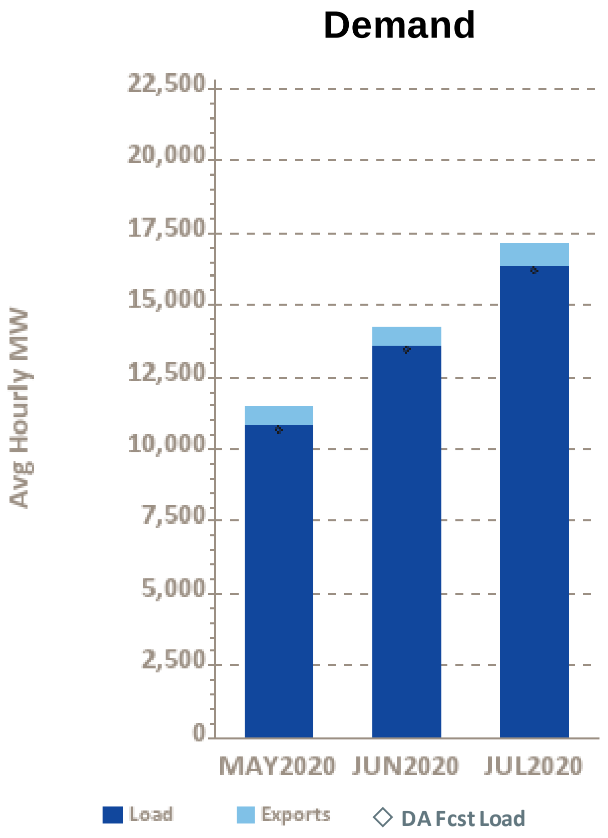


Gen – Generation
Incs – Increment Offers
DA Fcst Load – Day-Ahead Forecast Load

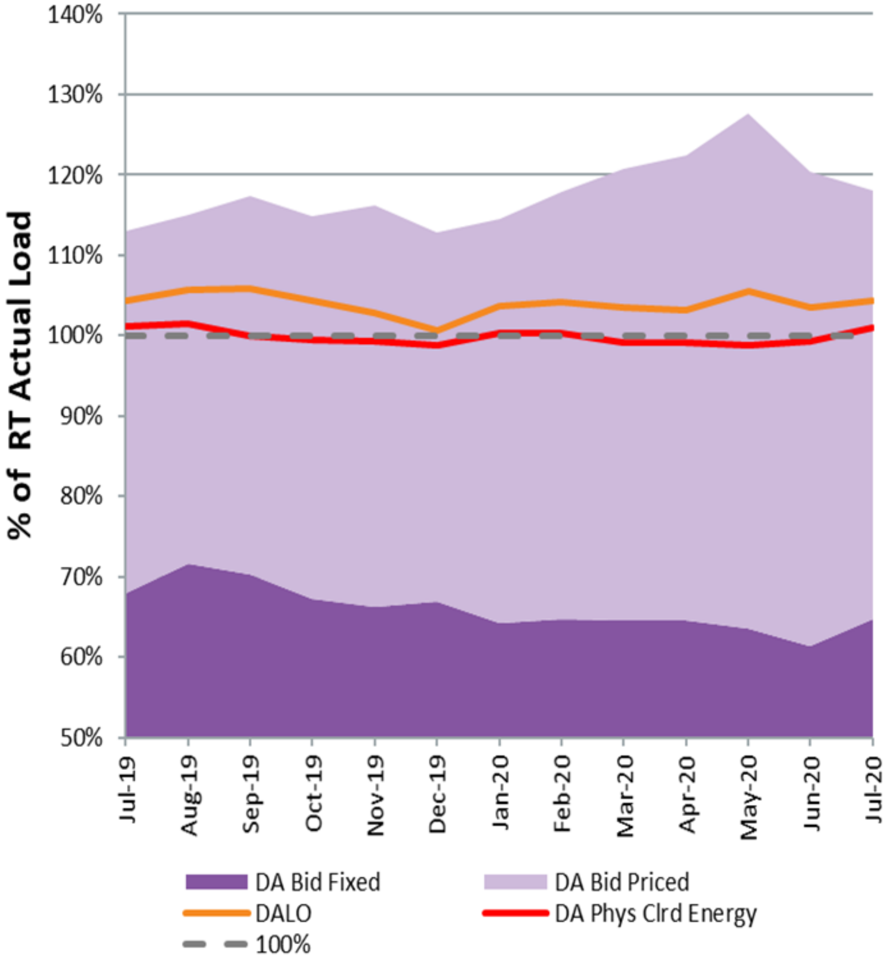
Fixed Dem – Fixed Demand
PrSens Dem – Price Sensitive Demand
Decs – Decrement Bids
Act Load – Actual Load

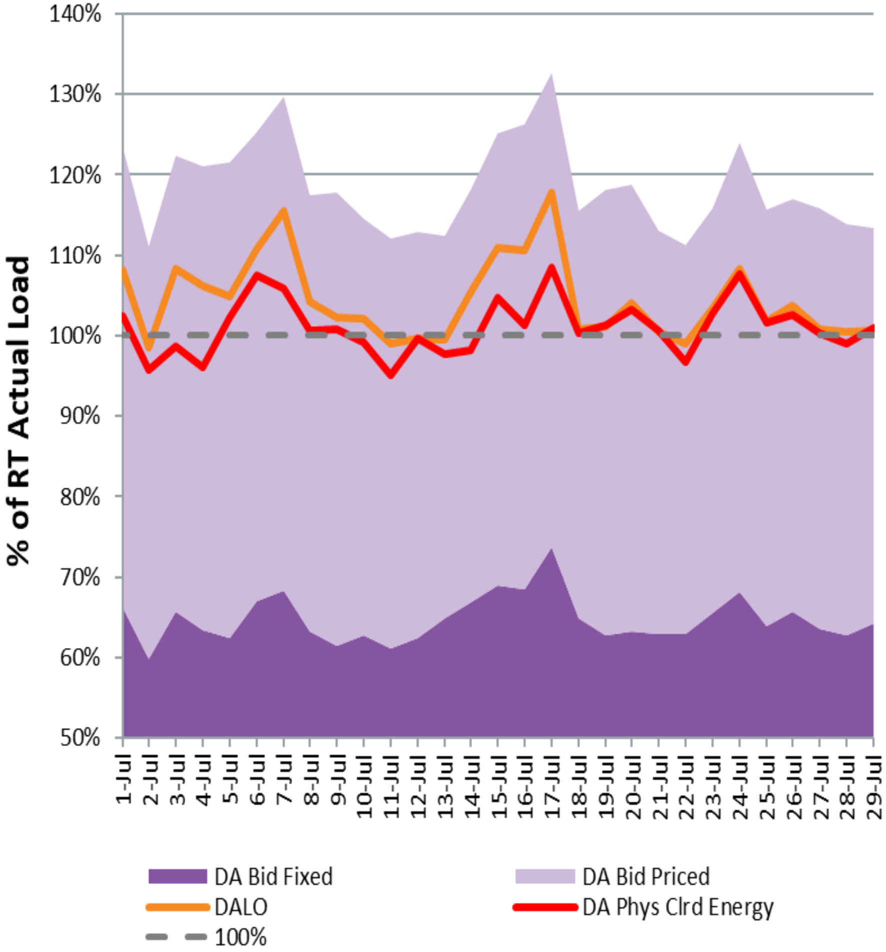
Components of RT Supply and Demand – Last Three Months





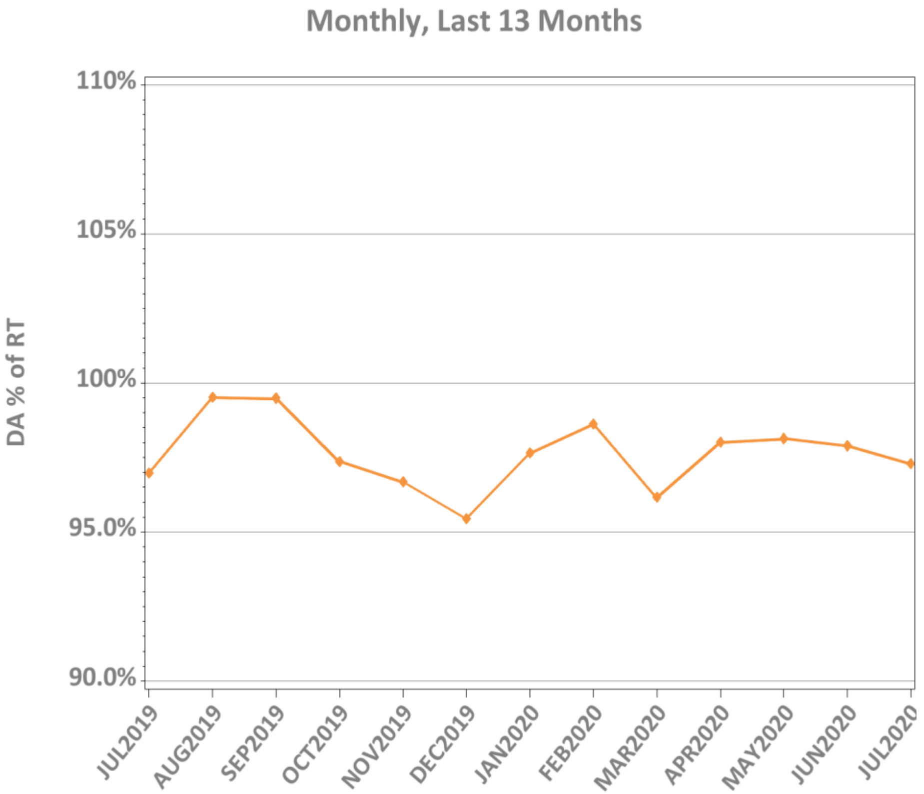
DAM Volumes as % of RT Actual Load (Forecasted Peak Hour)

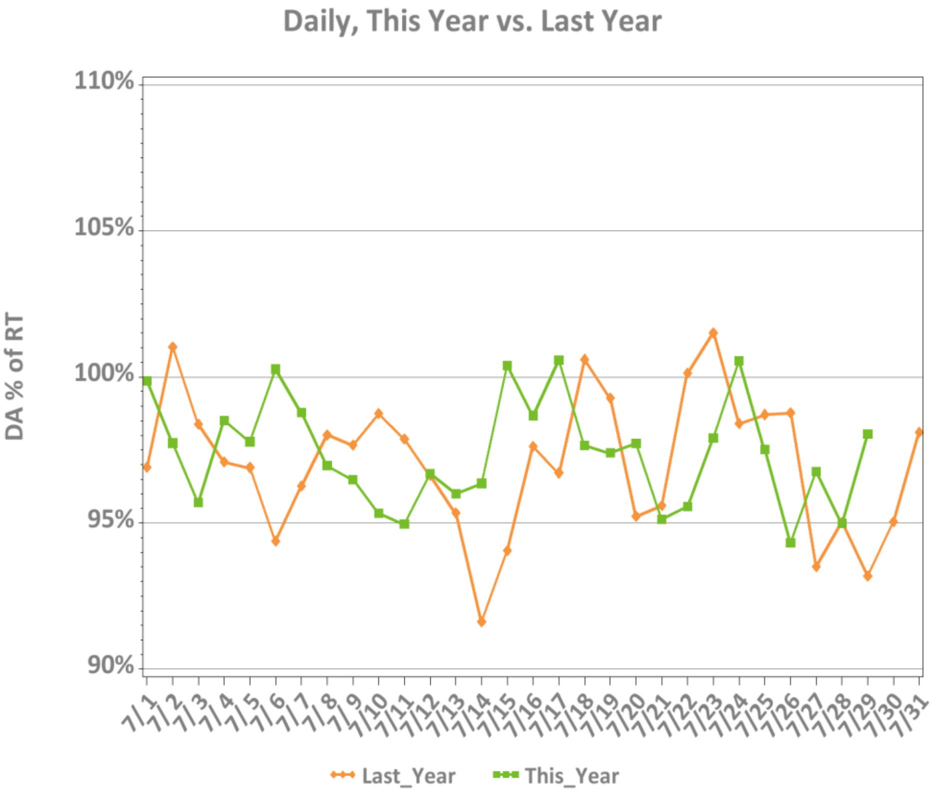




Note: Forecasted peak hour for each day is reflected in the above values. Shown for each day (chart on right) and then averaged for each month (chart on left). 'DA Bid' categories reflect load assets only (Virtual and export bids not reflected.)

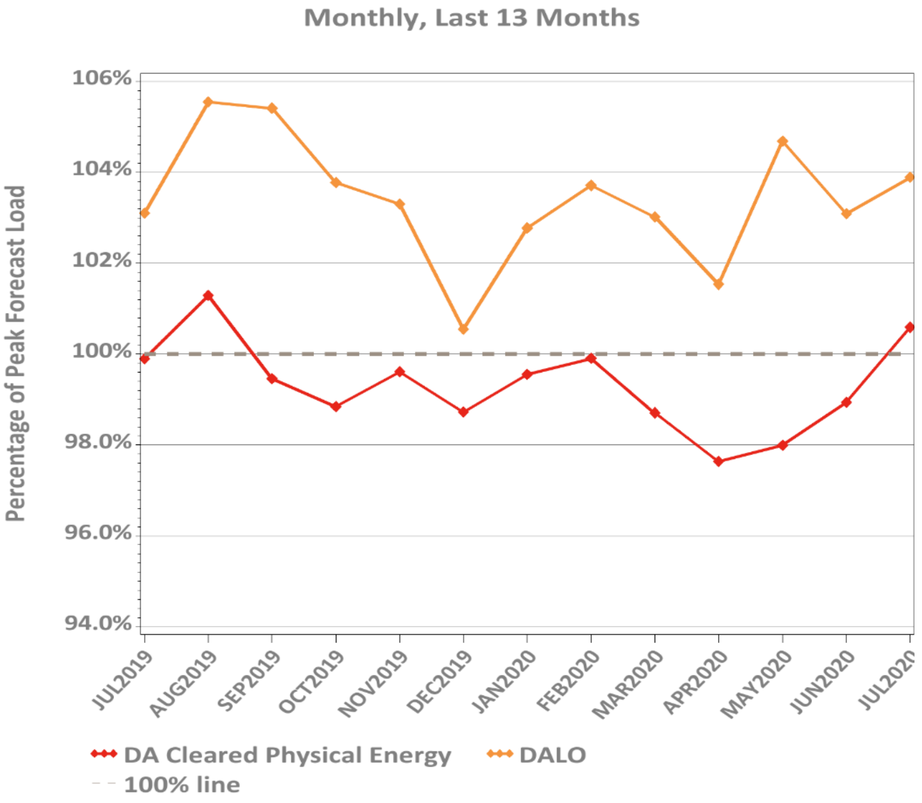
DA vs. RT Load Obligation: July, This Year vs. Last Year

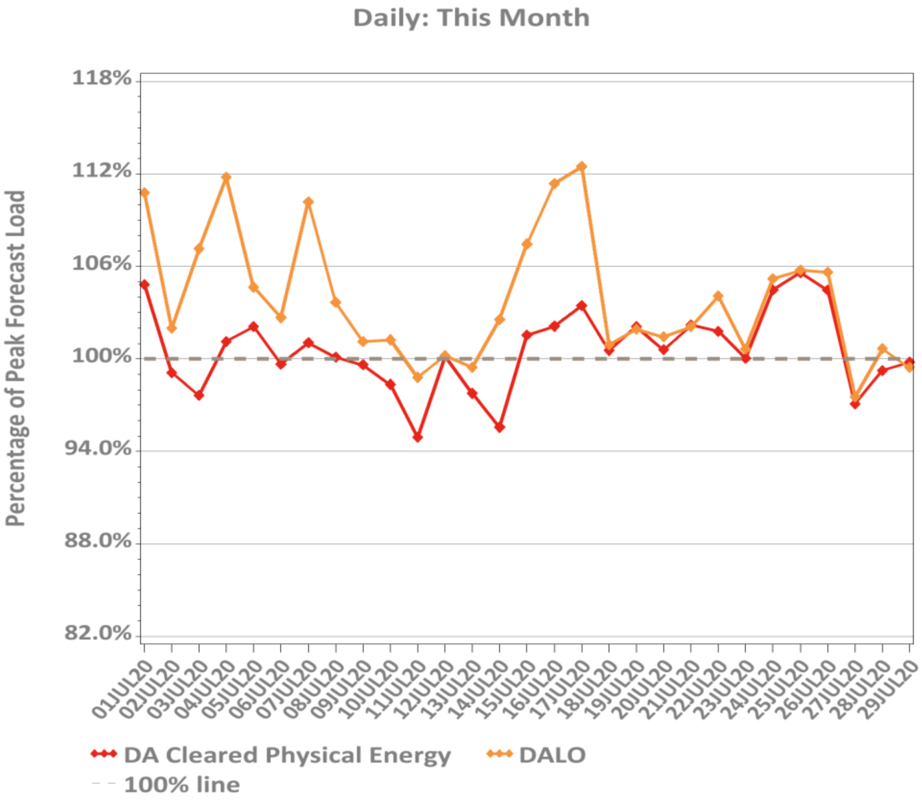




*Hourly average values

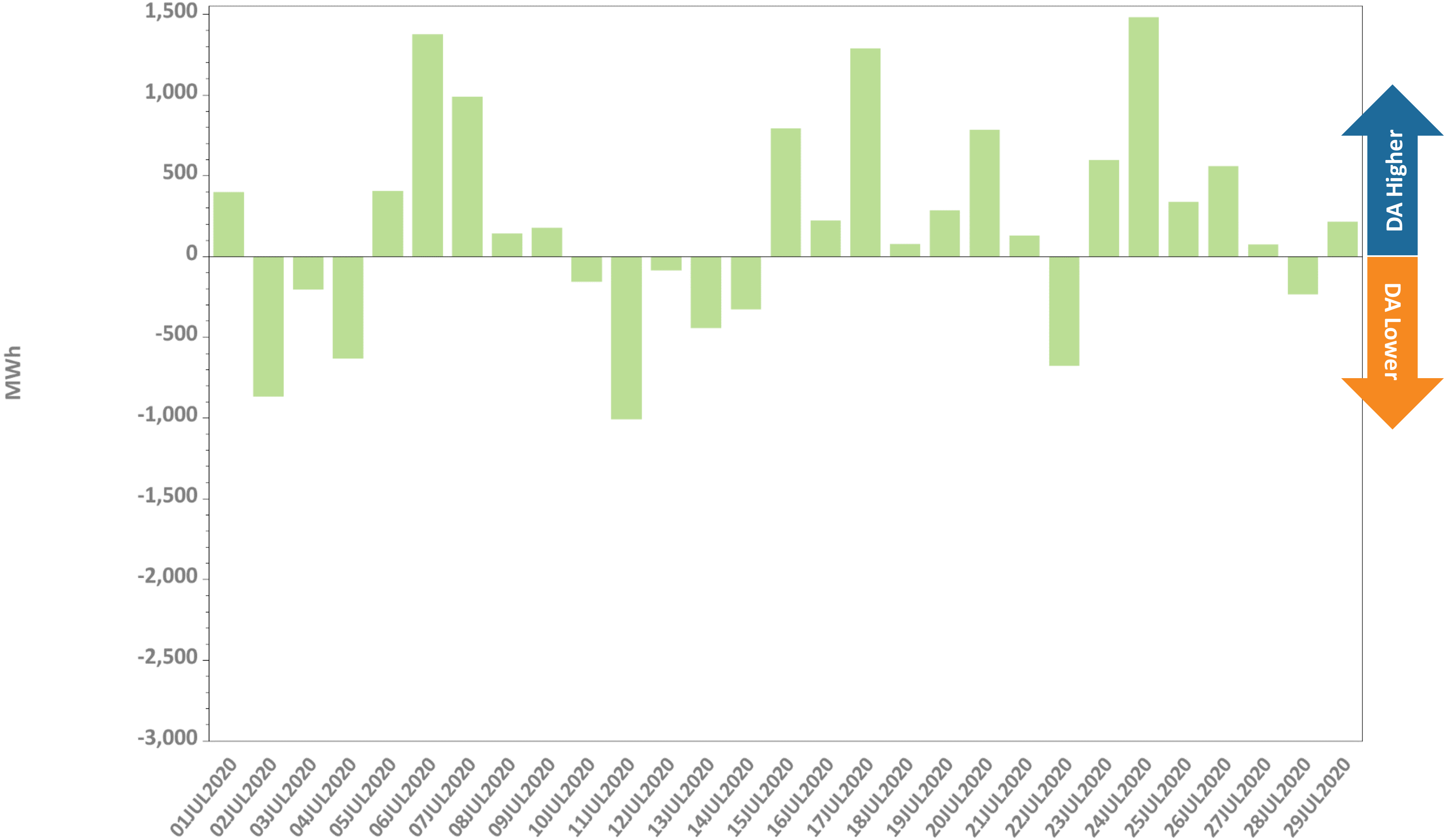
DA Volumes as % of Forecast in Peak Hour





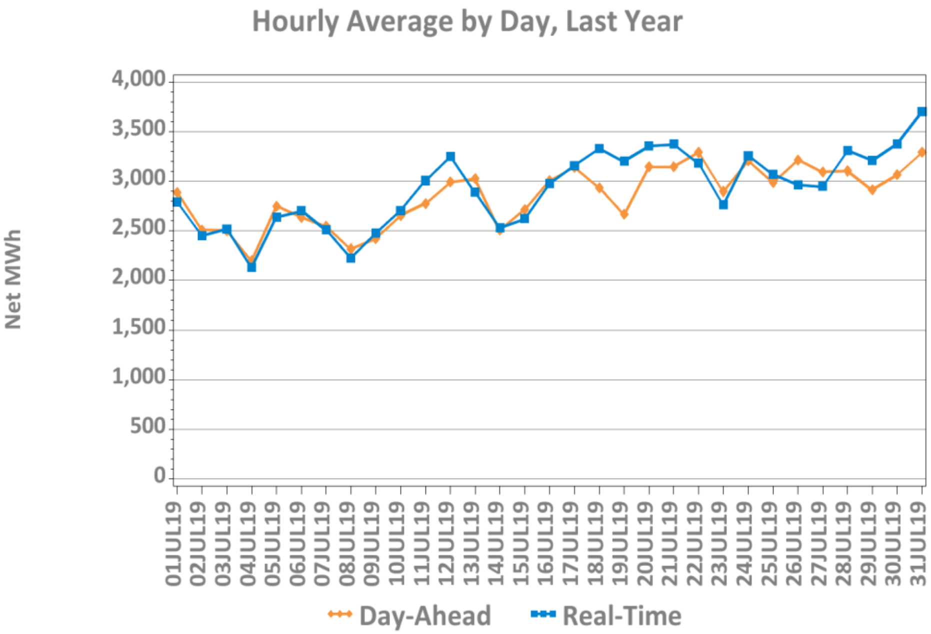
* There were *no* system-level supplemental commitments for capacity required during the Reserve Adequacy Assessment (RAA) during July.

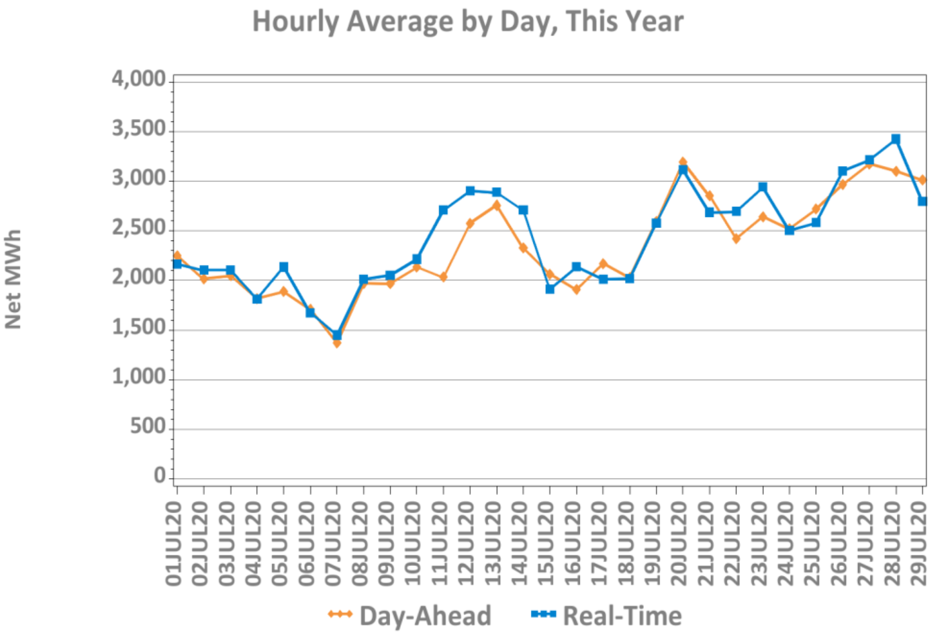
DA Cleared Physical Energy Difference from RT System Load at Peak Hour*



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

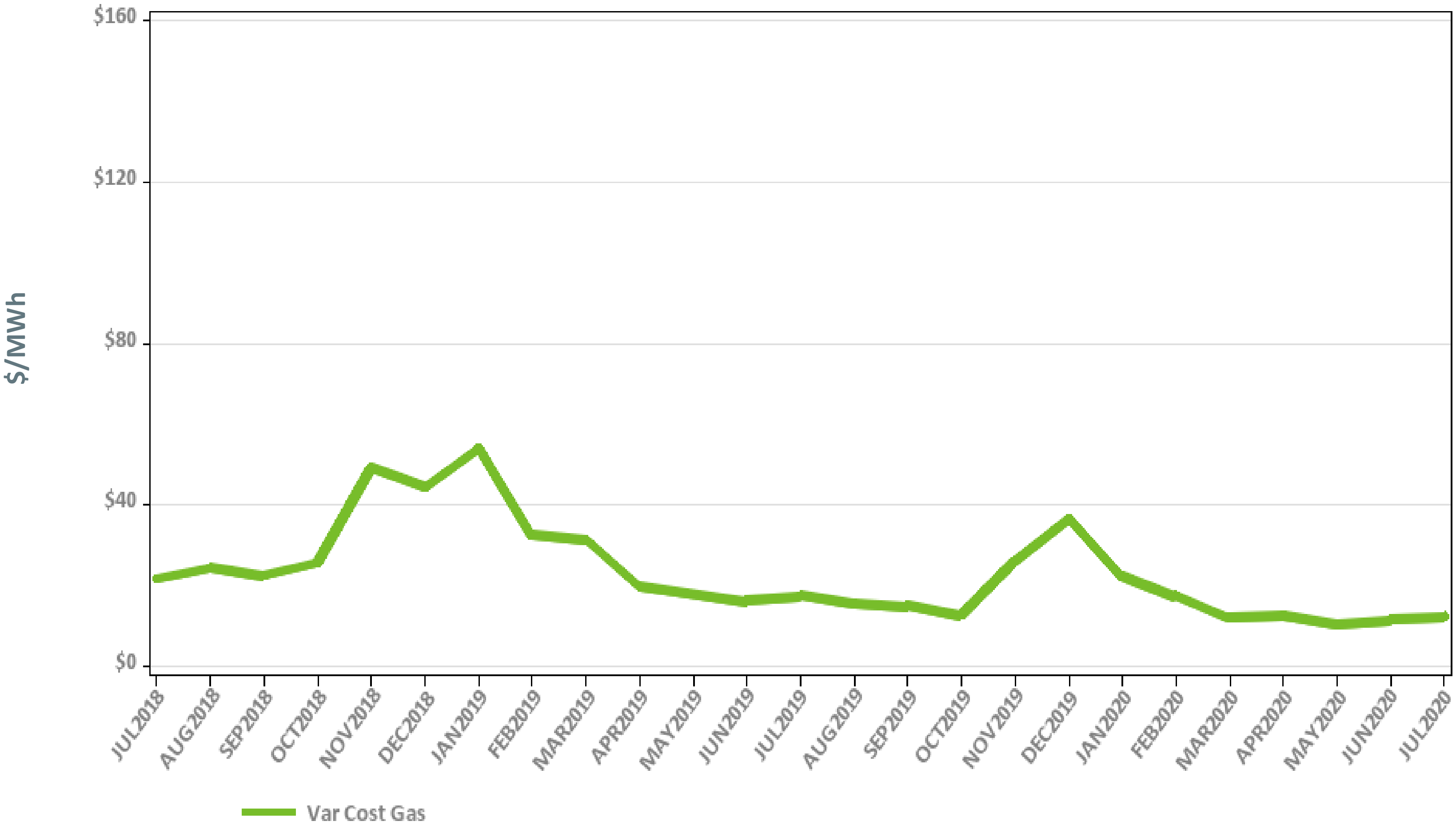
DA vs. RT Net Interchange July 2019 vs. July 2020





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

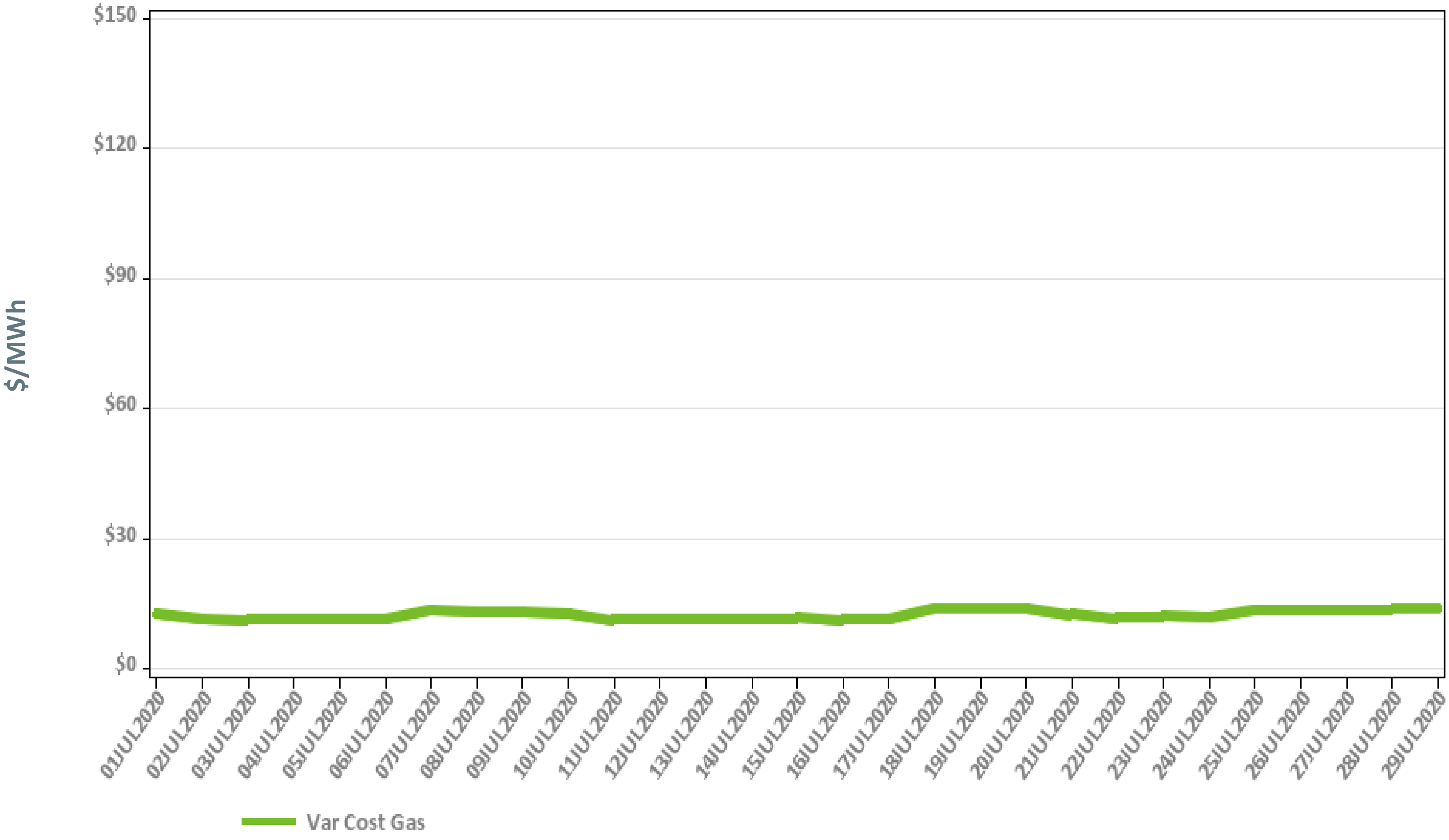


Underlying natural gas data furnished by:

ICE Global markets in clear view

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

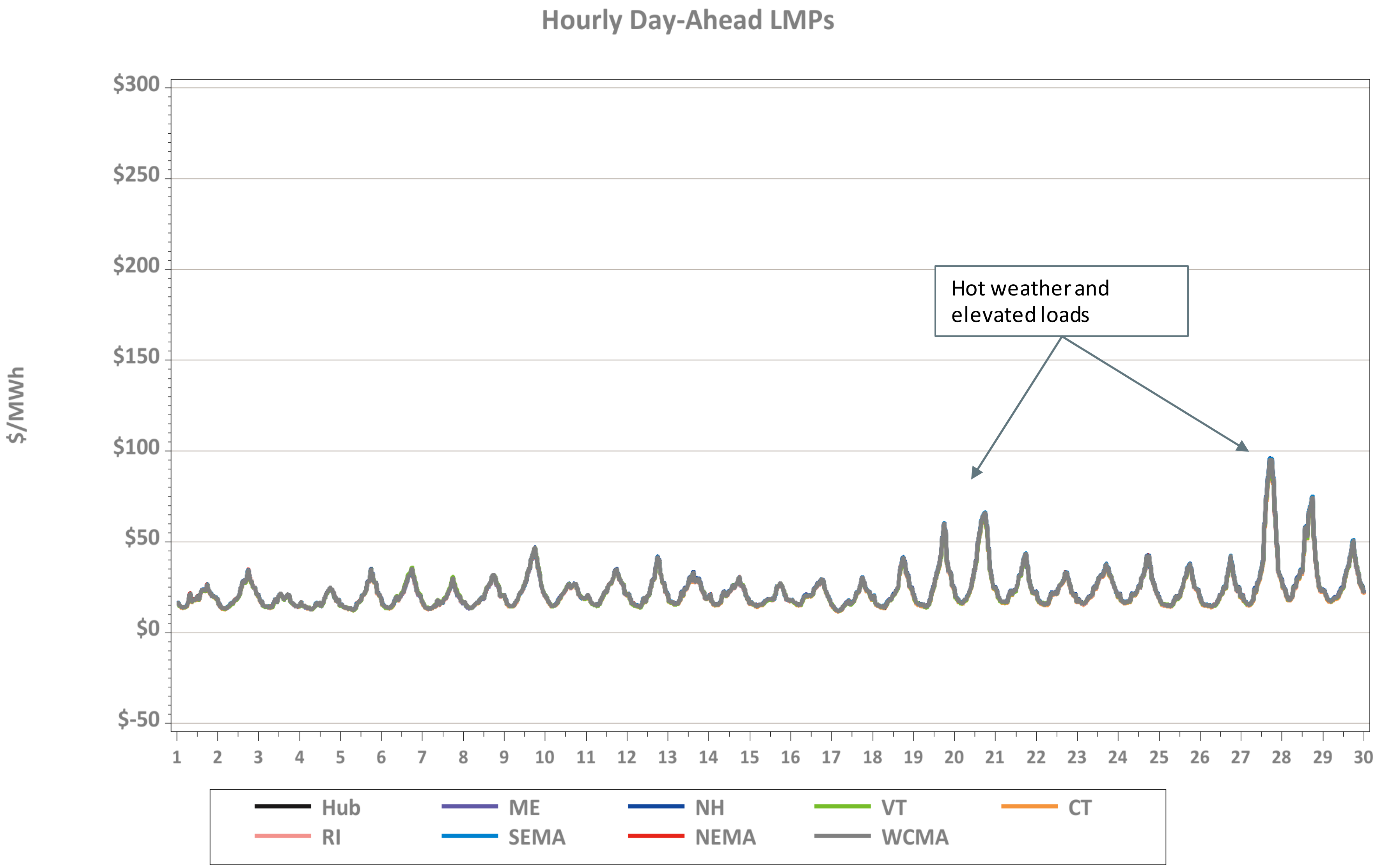
Variable Production Cost of Natural Gas: Daily



Underlying natural gas data furnished by:

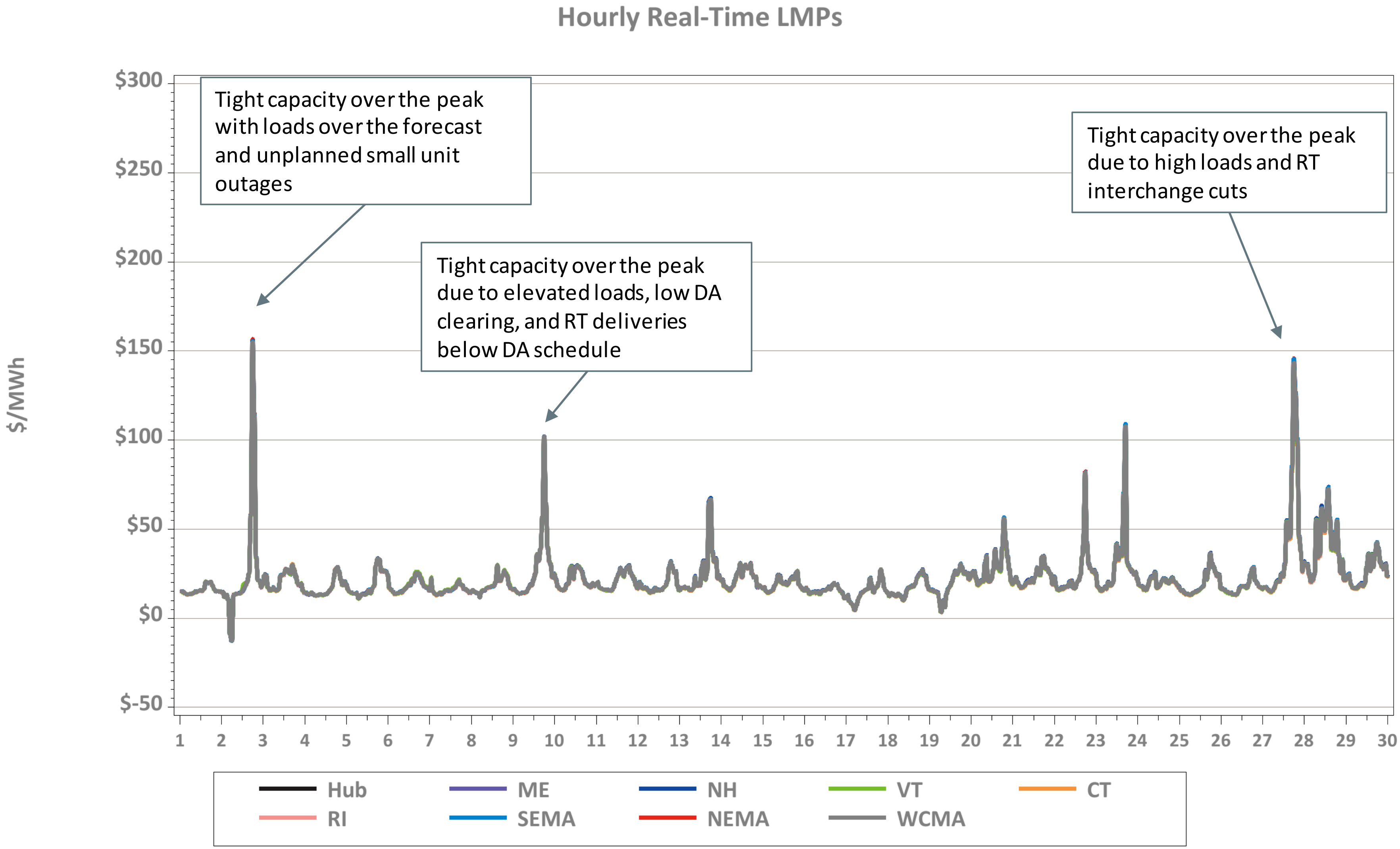
Note: Assumes proxy heat rate of 7,800,000 Btu/MWh for natural gas units.

Hourly DA LMPs, July 1-29, 2020



Hot weather and elevated loads

Hourly RT LMPs, July 1-29, 2020



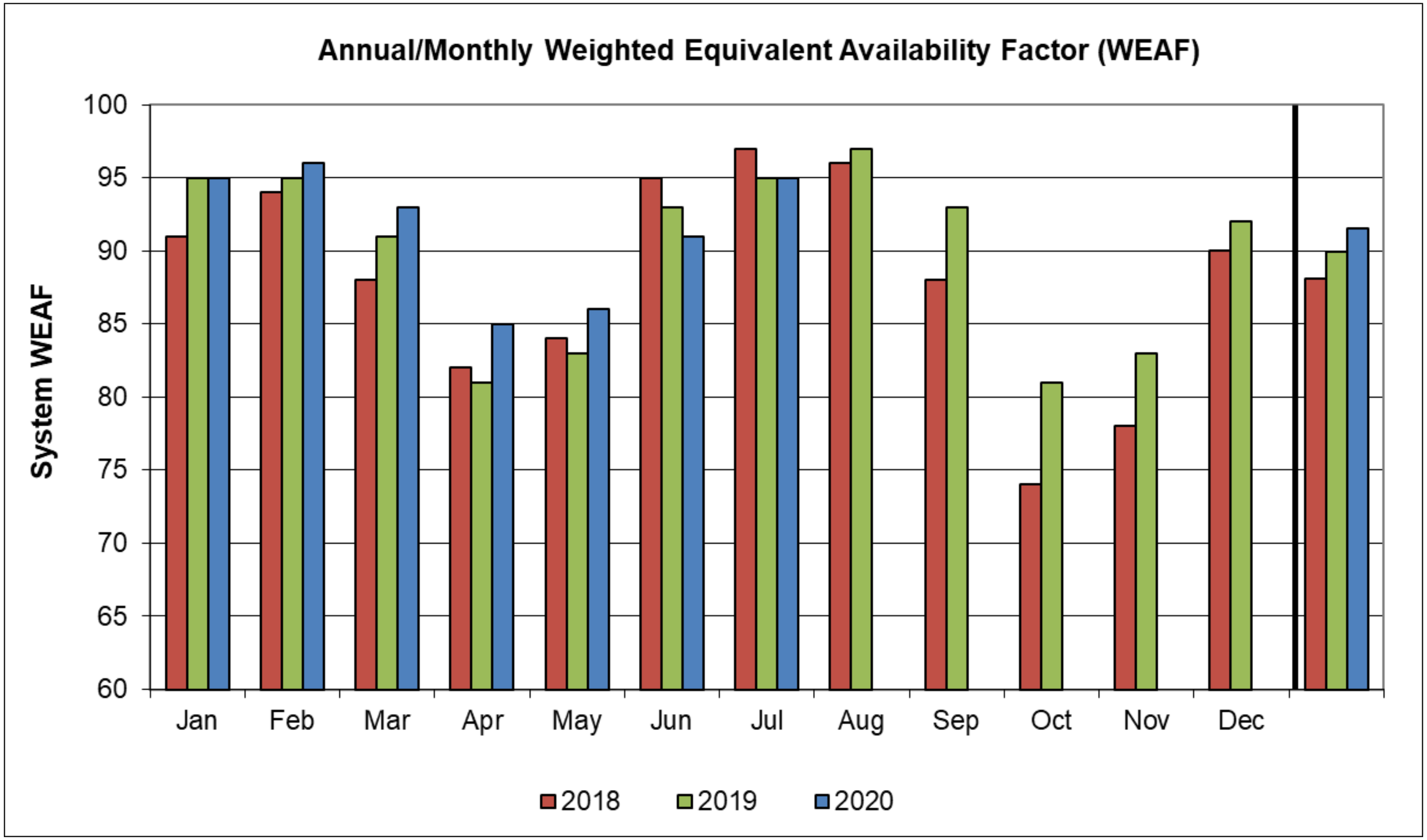
Tight capacity over the peak with loads over the forecast and unplanned small unit outages

Tight capacity over the peak due to elevated loads, low DA clearing, and RT deliveries below DA schedule

Tight capacity over the peak due to high loads and RT interchange cuts

- No Minimum Generation Emergencies were declared during July.

System Unit Availability



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YTD
2020	95	96	93	85	86	91	95						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 7/28/2020

BACK-UP DETAIL

DEMAND RESPONSE

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

Load Zone	ADCR*	On Peak	Seasonal Peak	Total
ME	71.2	184.1	0.0	255.3
NH	28.4	148.4	0.0	176.8
VT	29.3	100.7	0.0	130.0
CT	100.7	163.9	549.2	813.8
RI	34.7	270.0	0.0	304.8
SEMA	45.5	443.0	0.0	488.6
WCMA	70.5	464.7	45.3	580.4
NEMA	51.9	811.4	0.0	863.3
Total	**432.3**	**2,586.2**	**594.5**	**3,612.9**

*** Active Demand Capacity Resources**

NOTE: CSO values include T&D loss factor (8%).

NEW GENERATION

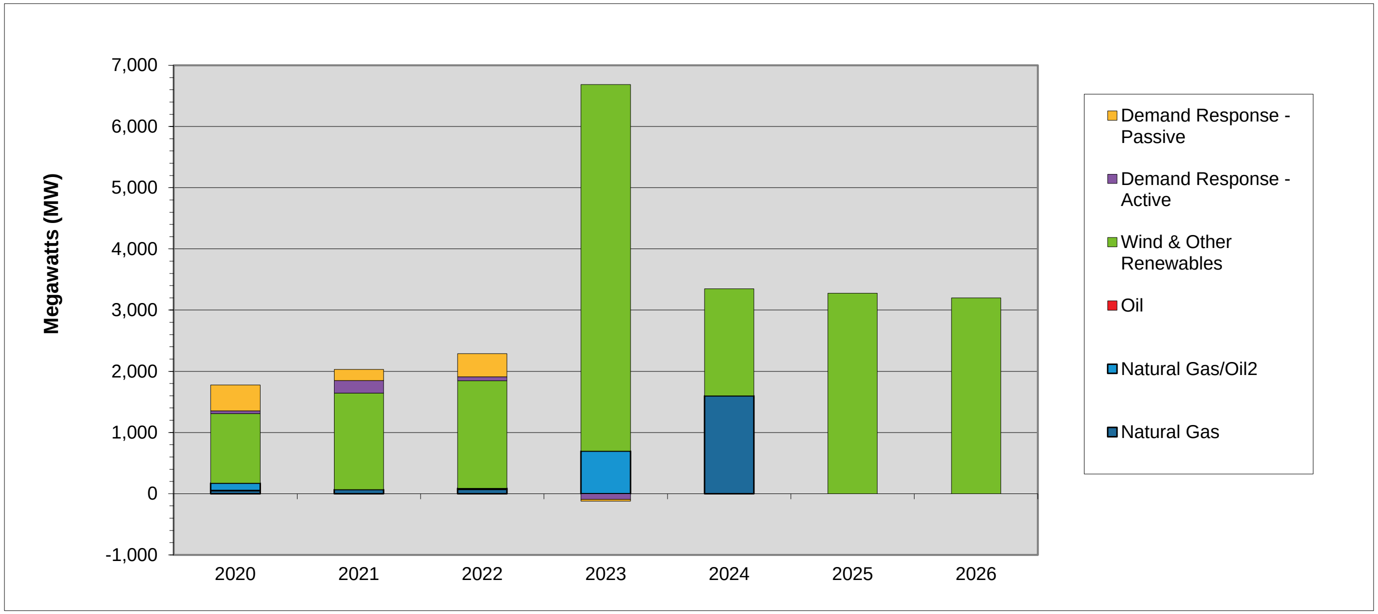
New Generation Update

Based on Queue as of 7/31/20

- One 85 MW project applied for interconnection study since the last update
- One project went commercial, resulting in a net increase in new generation projects of 66 MW
- In total, 237 generation projects are currently being tracked by the ISO, totaling approximately 21,230 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	1,147	1,623	1,758	5,991	1,749	3,276	3,200	18,744	83.4
Oil	0	0	0	0	0	0	0	0	0.0
Natural Gas/Oil[2]	121	0	16	695	0	0	0	832	3.7
Natural Gas	43	21	73	0	1,600	0	0	1,737	7.7
Totals	**1,776**	**2,032**	**2,289**	**6,564**	**3,349**	**3,276**	**3,200**	**22,486**	**100.0**

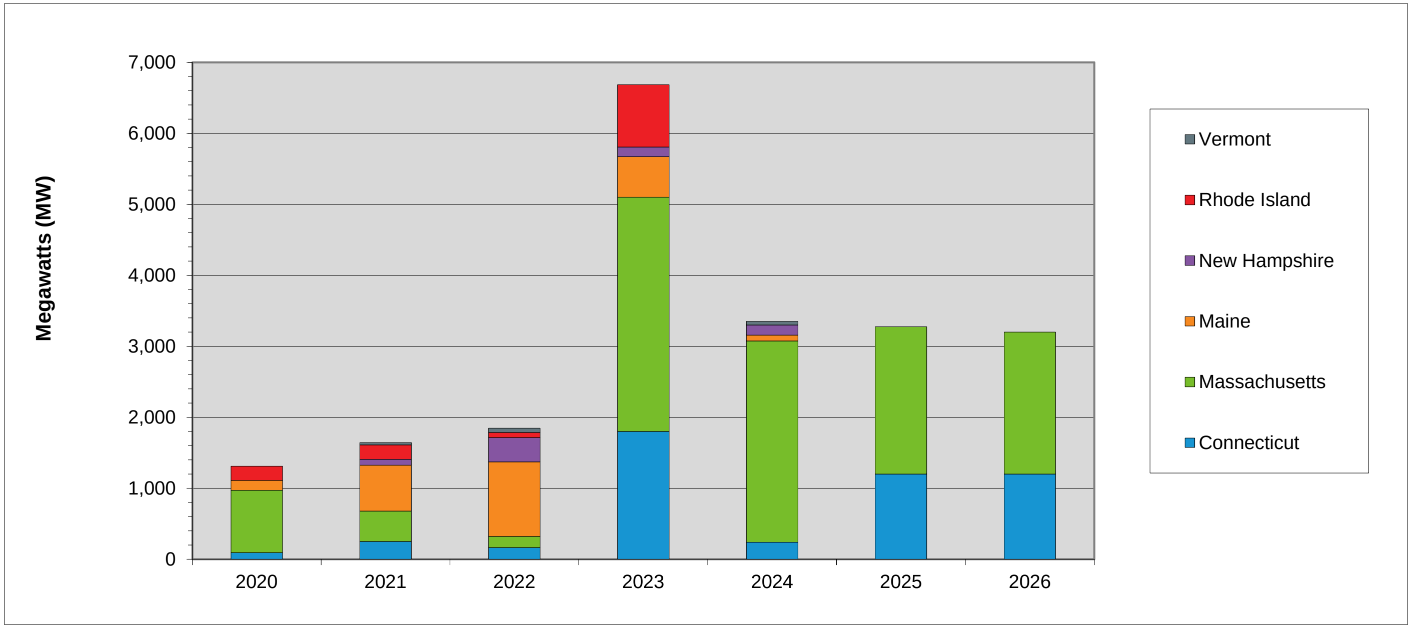
[1] Sum may not equal 100% due to rounding

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

- 2020 values include the 83 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	200	202	73	880	0	0	0	1,355	6.4
New Hampshire	0	83	342	135	142	0	0	702	3.3
Maine	141	644	1,050	571	81	0	0	2,487	11.7
Massachusetts	878	430	159	3,300	2,836	2,076	2,000	11,679	54.8
Connecticut	92	250	163	1,800	240	1,200	1,200	4,945	23.2
Totals	**1,311**	**1,644**	**1,847**	**6,686**	**3,349**	**3,276**	**3,200**	**21,313**	**100.0**

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

- 2020 values include the 83 MW of generation that has gone commercial in 2020

New Generation Projection

By Fuel Type

	Total		Green		Yellow	
Unit 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	2,079	0	0	15	2,079
Fuel Cell	4	55	1	10	3	45
Hydro	3	99	1	66	2	33
Natural Gas	9	1,737	0	0	9	1,737
Natural Gas/Oil	5	787	1	14	4	773
Nuclear	1	37	0	0	1	37
Solar	177	4,028	8	173	169	3,855
Wind	22	12,400	2	88	20	12,312
Total	237	21,230	13	351	224	20,879

- 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	1	10	7	123
Intermediate	11	2,433	1	14	10	2,419
Peaker	196	6,264	9	239	187	6,025
Wind Turbine	22	12,400	2	88	20	12,312
Total	237	21,230	13	351	224	20,879

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

New Generation Projection

By Operating Type and Fuel Type

	Total		Baseload		Intermediate		Peaker		Wind Turbine	
Unit Type	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**	**No. of Projects**	**Capacity (MW)**
Biomass/Wood Waste	1	8	1	8	0	0	0	0	0	0
Battery Storage	15	2,079	0	0	0	0	15	2,079	0	0
Fuel Cell	4	55	4	55	0	0	0	0	0	0
Hydro	3	99	2	33	0	0	1	66	0	0
Natural Gas	9	1,737	0	0	8	1,731	1	6	0	0
Natural Gas/Oil	5	787	0	0	3	702	2	85	0	0
Nuclear	1	37	1	37	0	0	0	0	0	0
Solar	177	4,028	0	0	0	0	177	4,028	0	0
Wind	22	12,400	0	0	0	0	0	0	22	12,400
Total	237	21,230	8	133	11	2,433	196	6,264	22	12,400

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

* 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

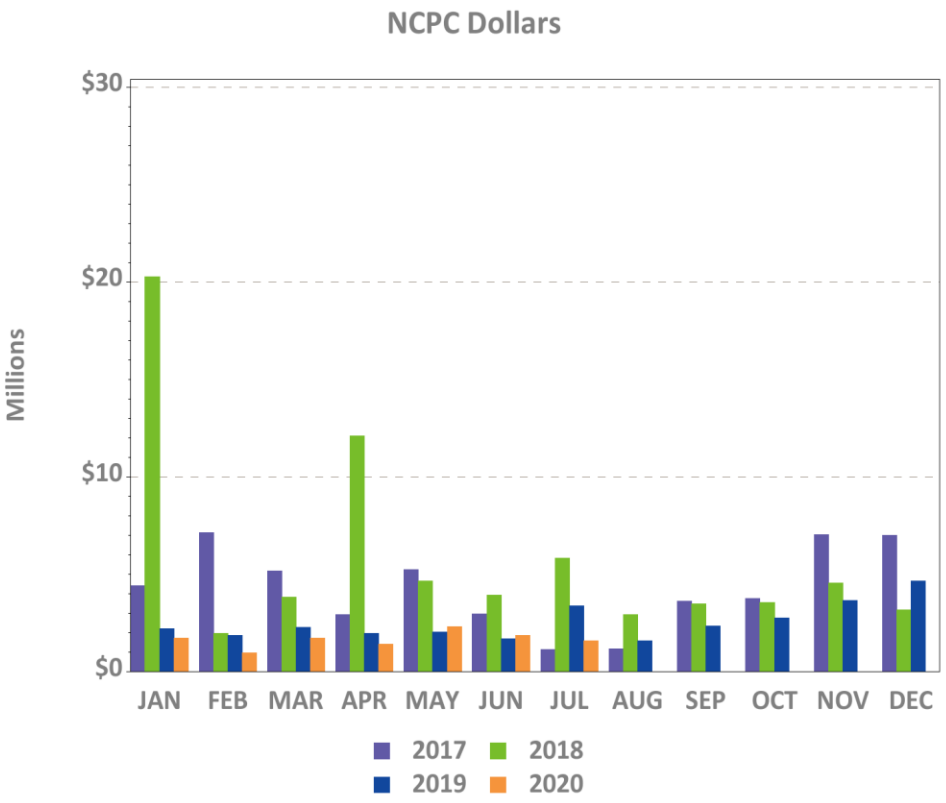
Definitions

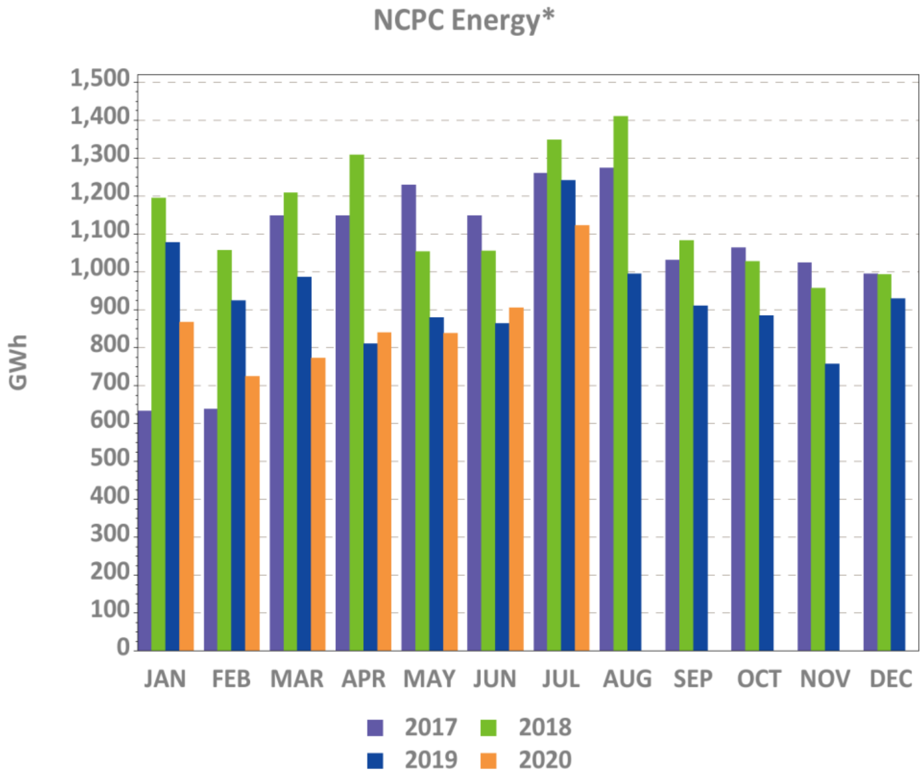
1st Contingency NCPC Payments	Reliability costs paid to eligible resources that are providing first contingency (1stC) protection (including low voltage, system operating reserve, and load serving) either system-wide or locally
2nd Contingency NCPC Payments	Reliability costs paid to resources providing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

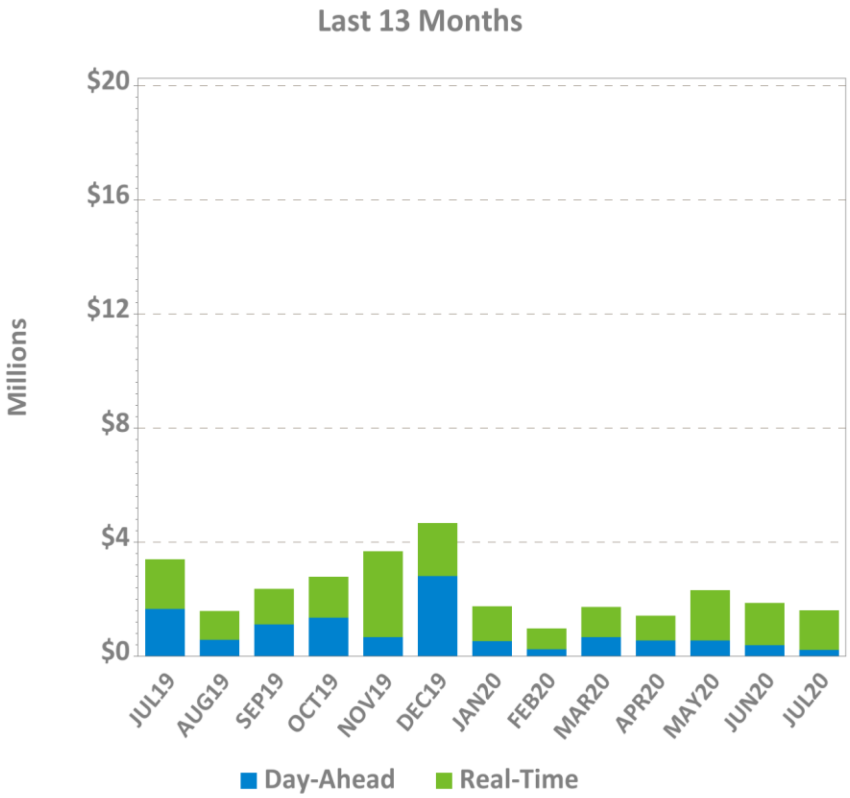
Year-Over-Year Total NCPC Dollars and Energy



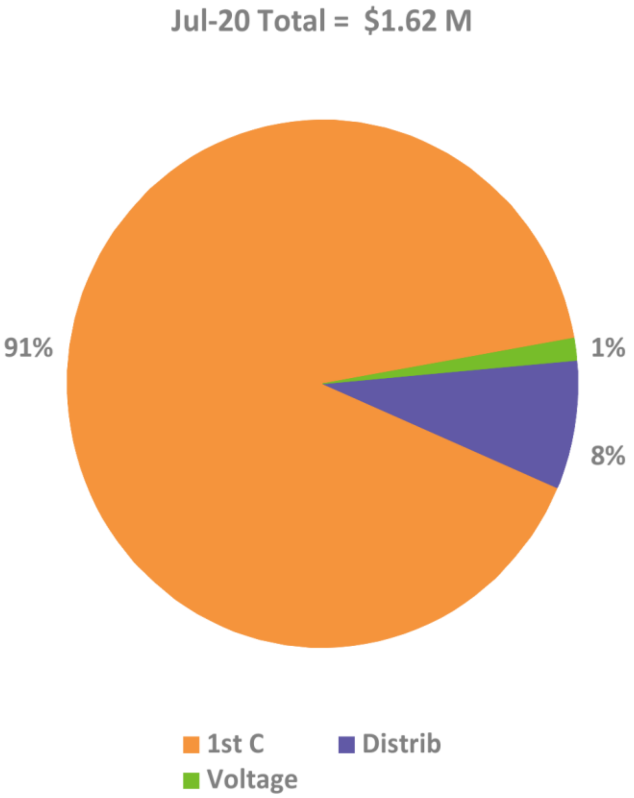


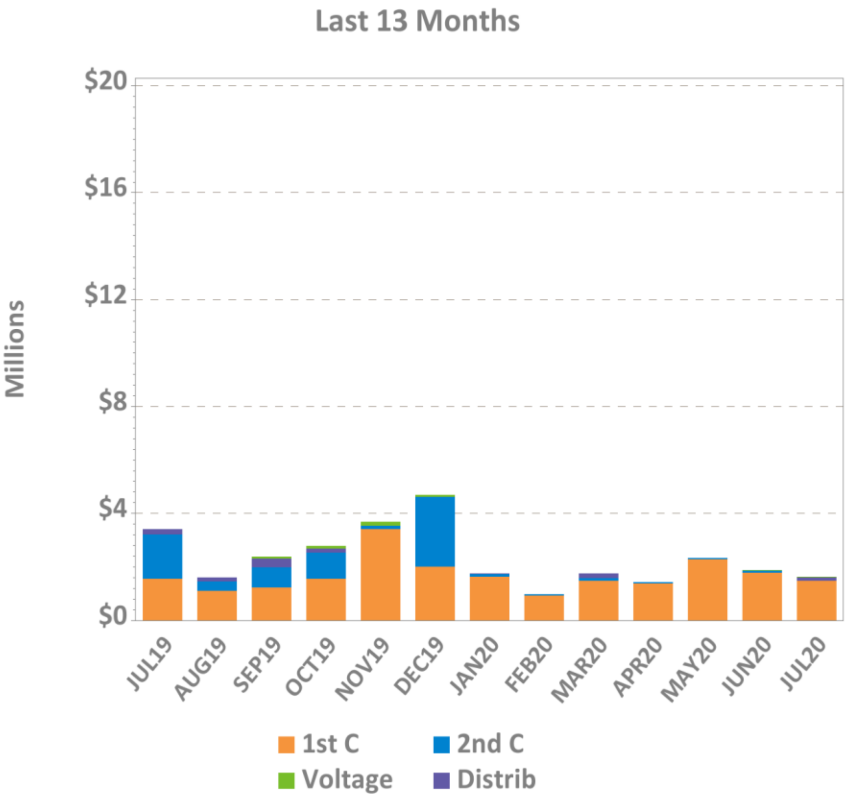
* NCPC Energy GWh reflect the DA and/or RT economic minimum loadings of all units receiving DA or RT NCPC credits (except for DLOC, RRP, or posturing NCPC), assessed during hours in which they are NCPC-eligible. Scheduled MW for external transactions receiving NCPC are also reflected. All NCPC components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

DA and RT NCPC Charges



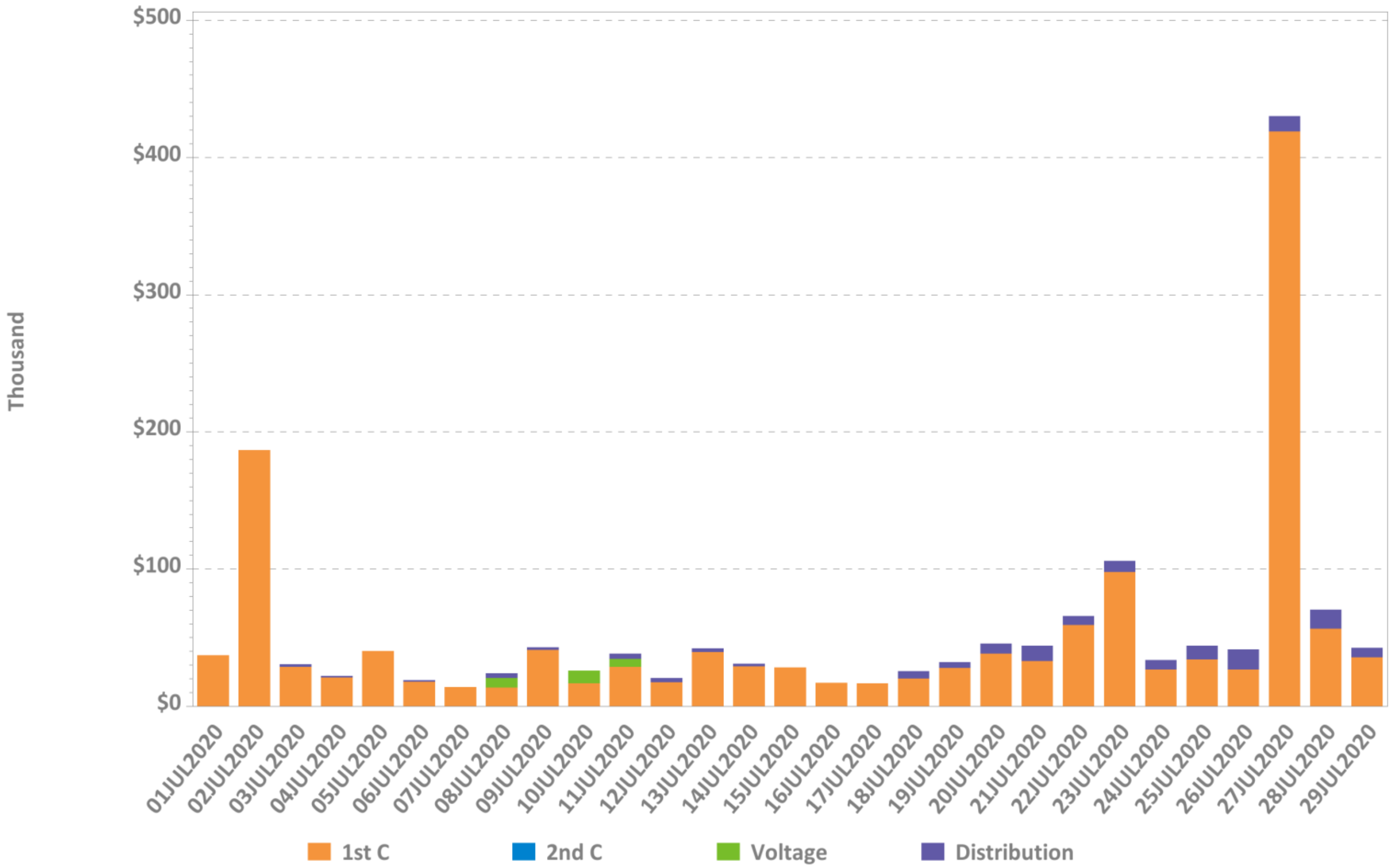
NCPC Charges by Type



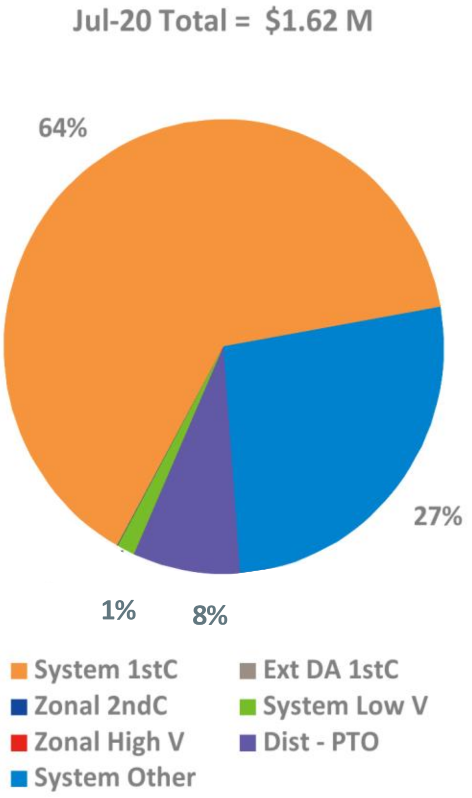


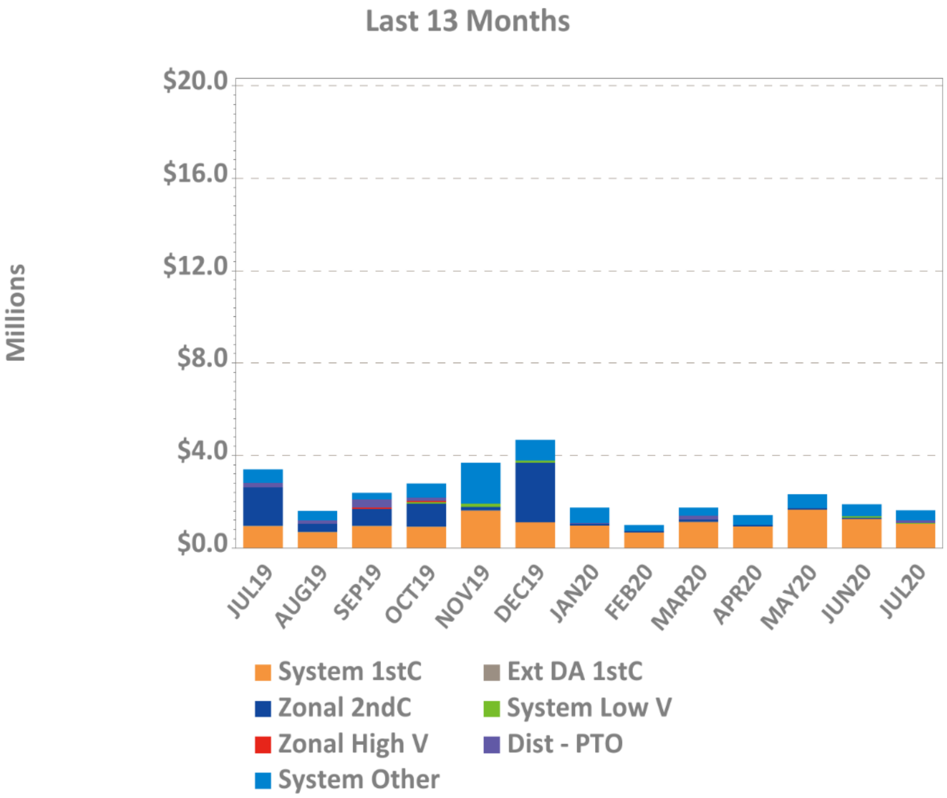
1st C – First Contingency
2nd C – Second Contingency
Distrib – Distribution
Voltage – Voltage

Daily NCPC Charges by Type



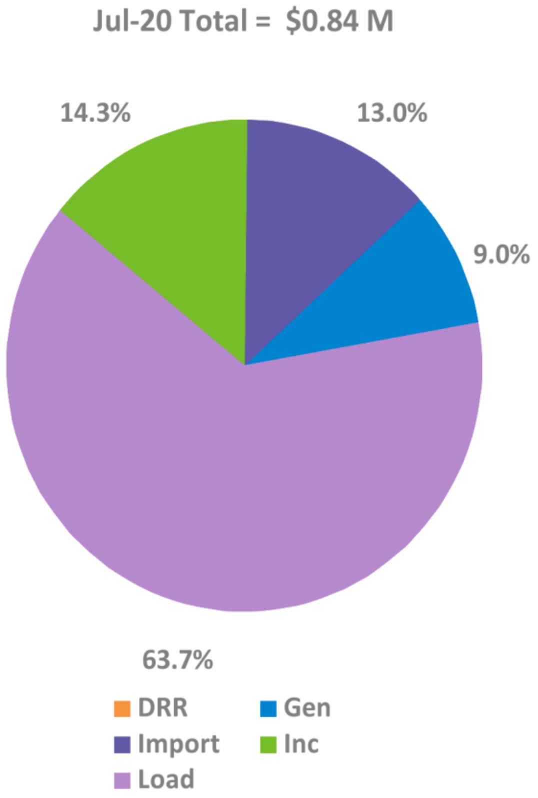
NCPC Charges by Allocation

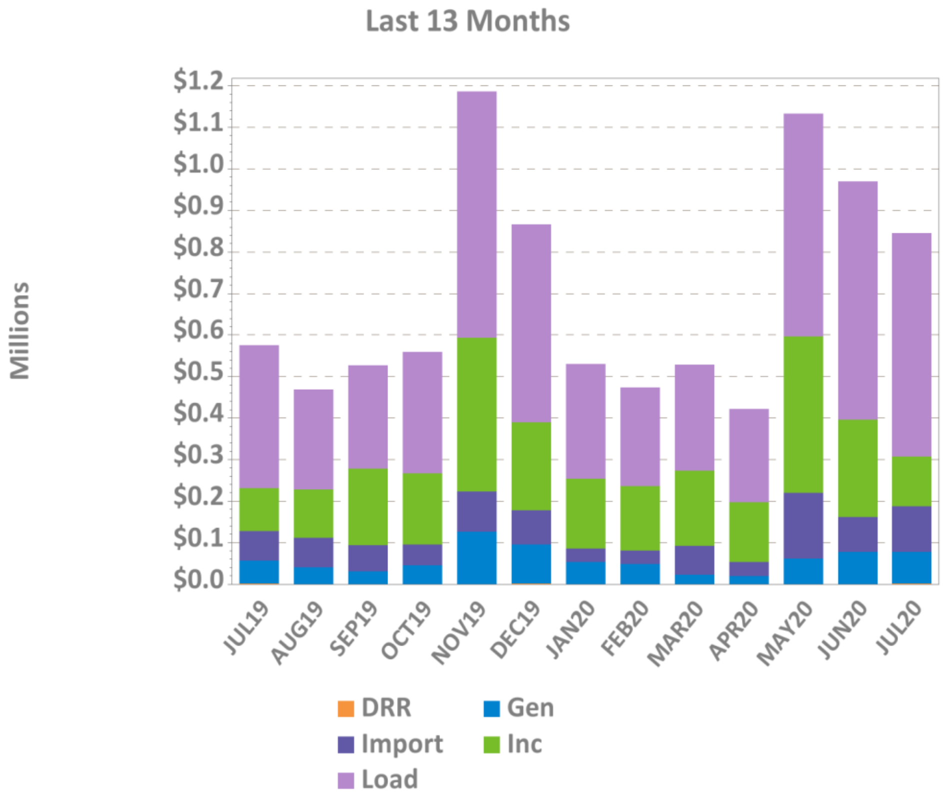




Note: 'System Other' includes, as applicable: Resource Economic Posturing, GPA, Min Gen Emergency, Dispatch Lost Opportunity Cost (DLOC), and Rapid Response Pricing (RRP) Opportunity Cost credits.

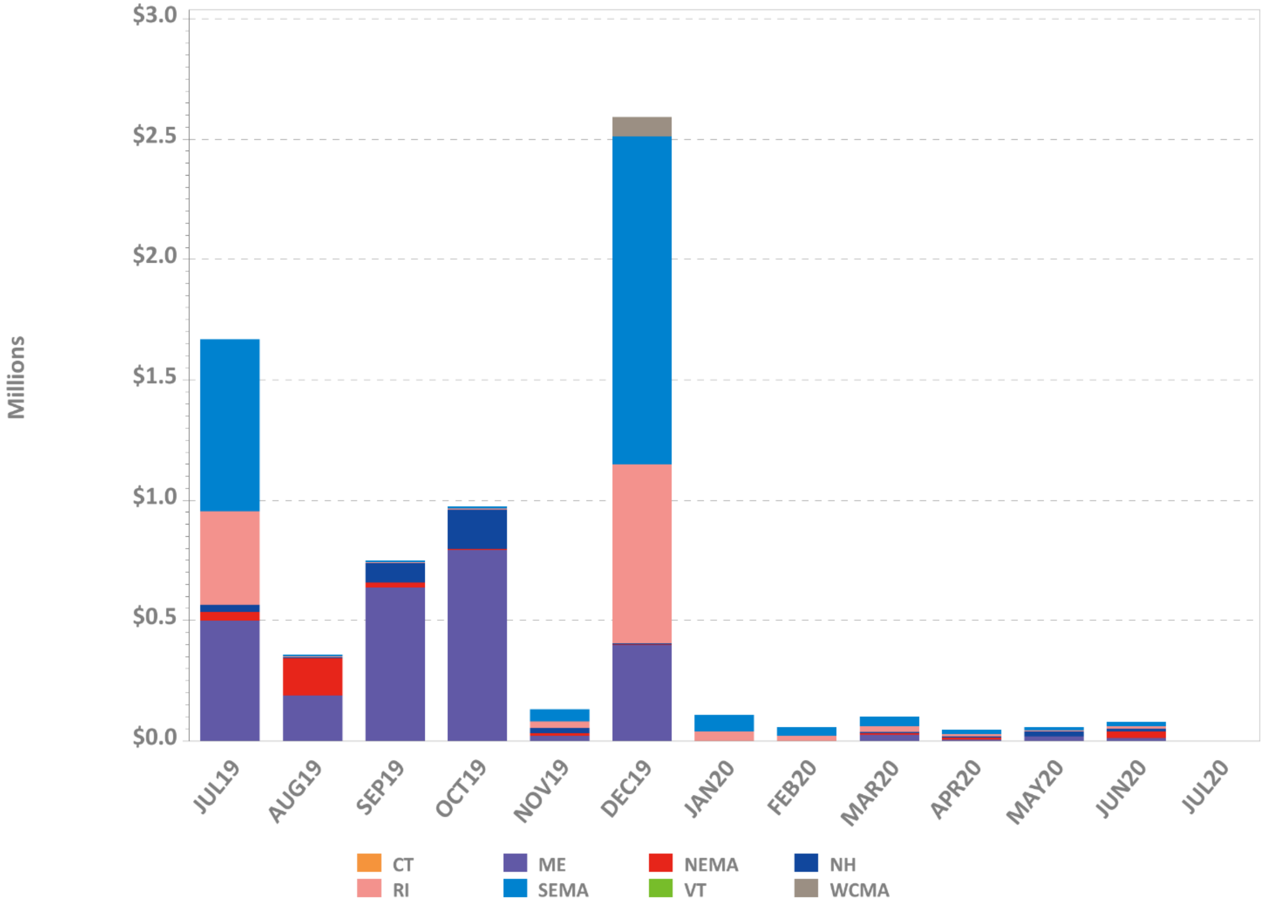
RT First Contingency Charges by Deviation Type





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

ME – Maine Region

NH – New Hampshire Region

RI – Rhode Island Region

VT – Vermont Region

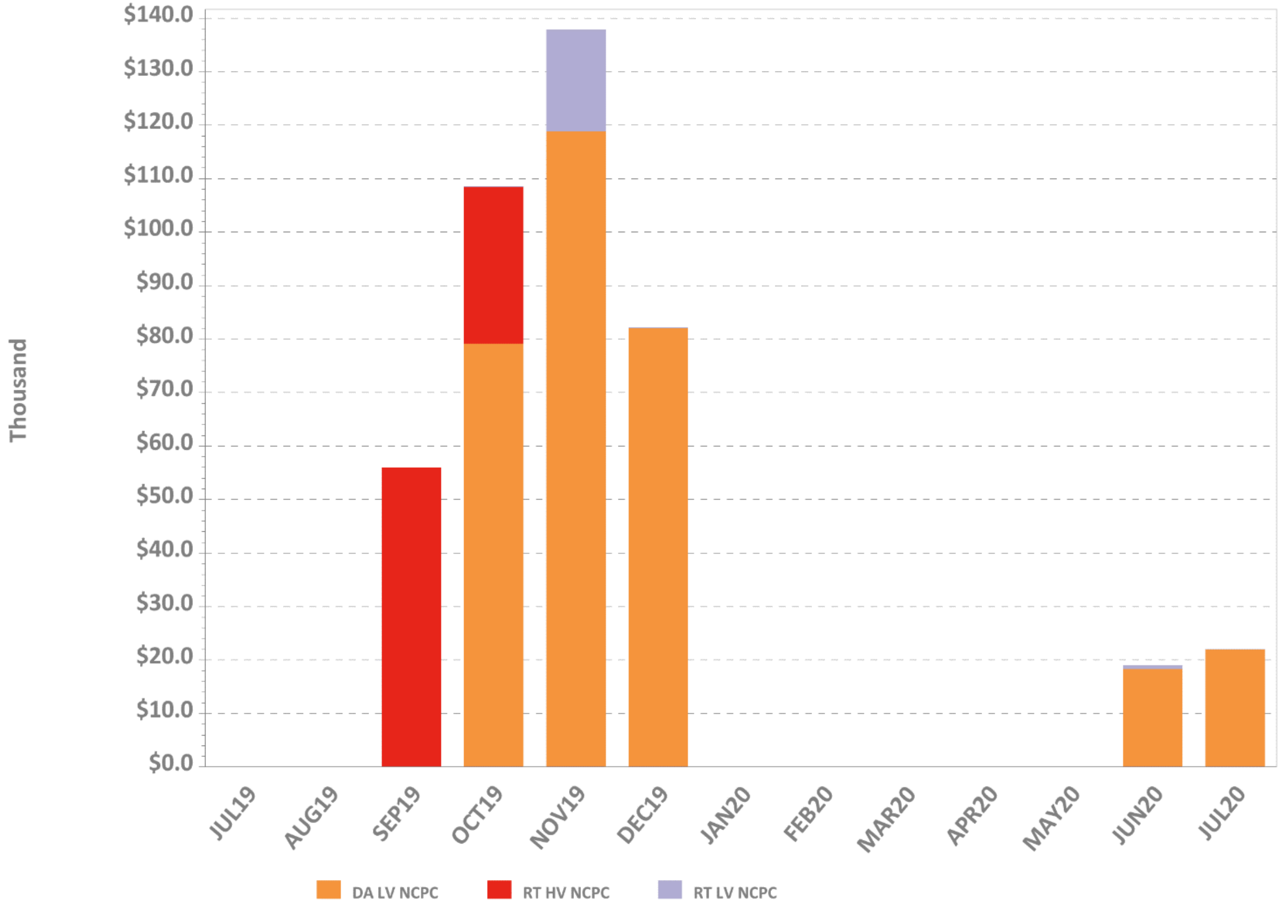
SEMA – Southeast Massachusetts Region

WCMA – Western/Central Massachusetts Region

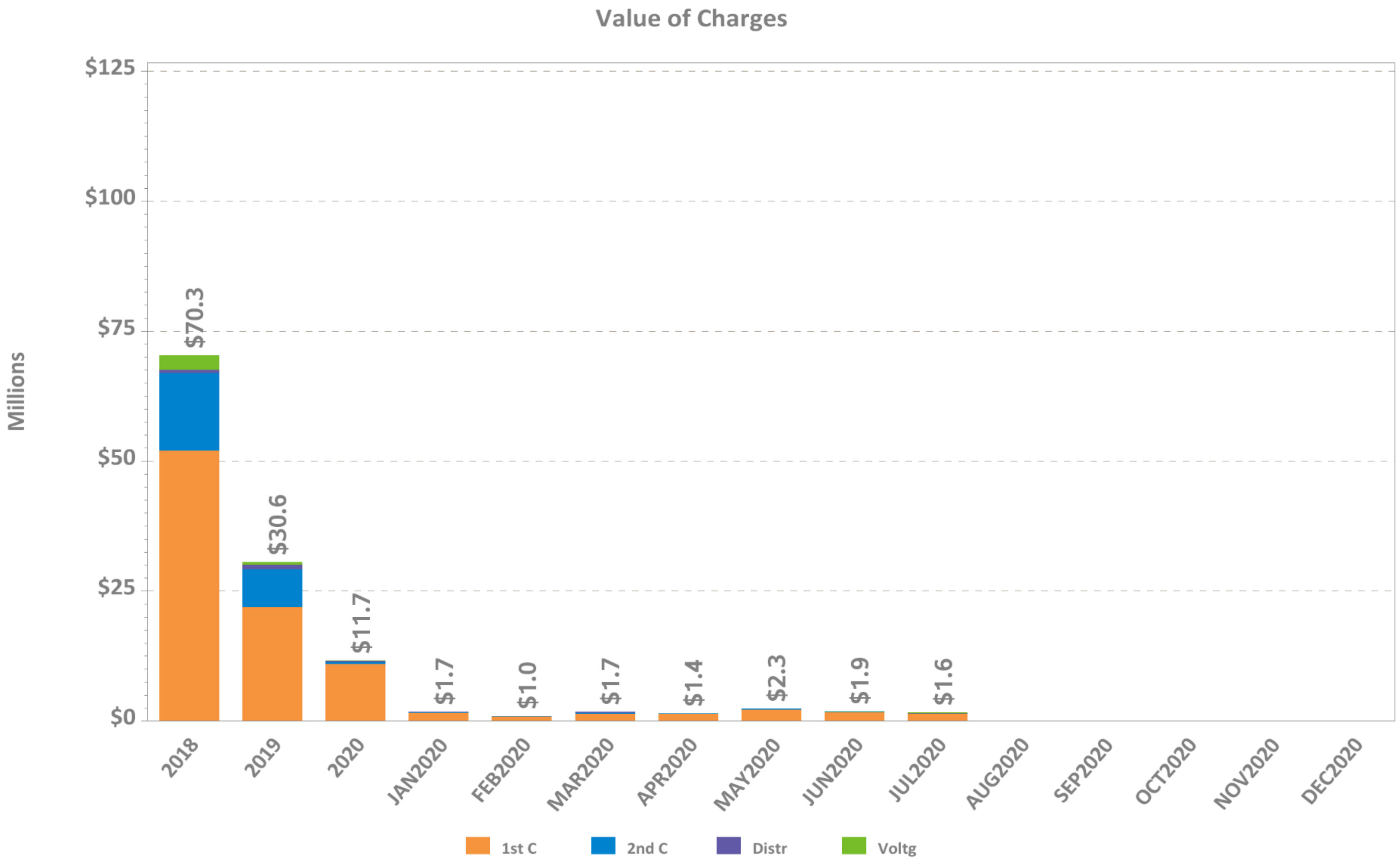
NEMA – Northeast Massachusetts Region

EXT – External Locations

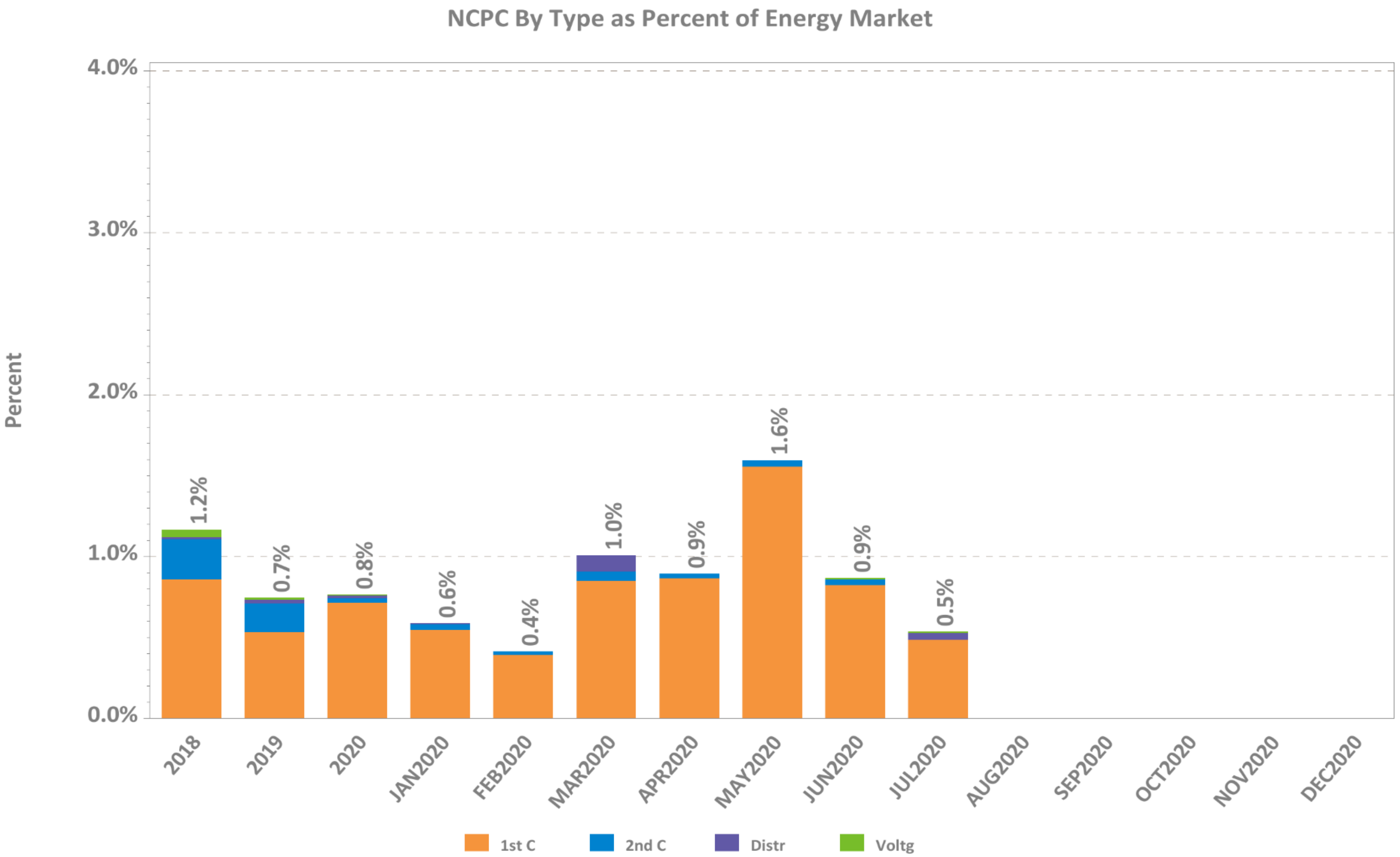
NCPC Charges for Voltage Support and High Voltage Control



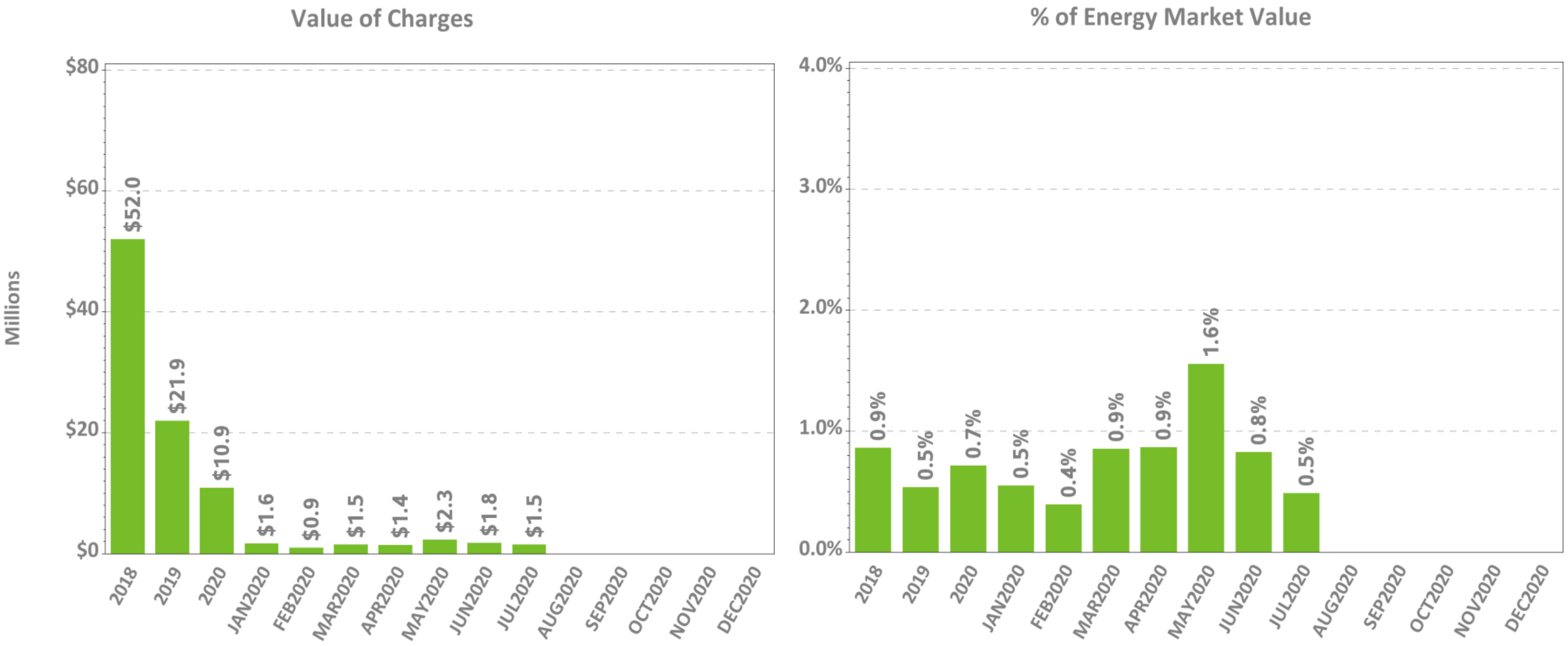
NCPC Charges by Type



NCPC Charges as Percent of Energy Market

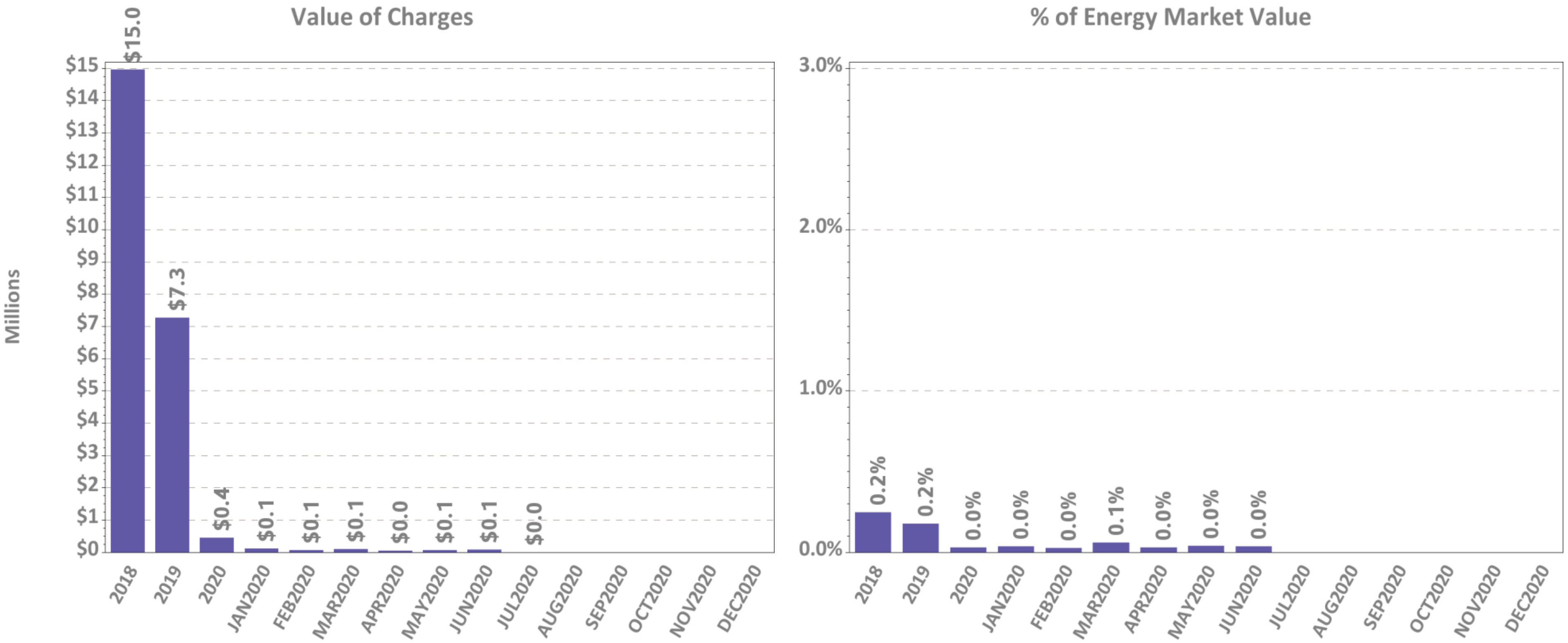


First Contingency NCPC Charges



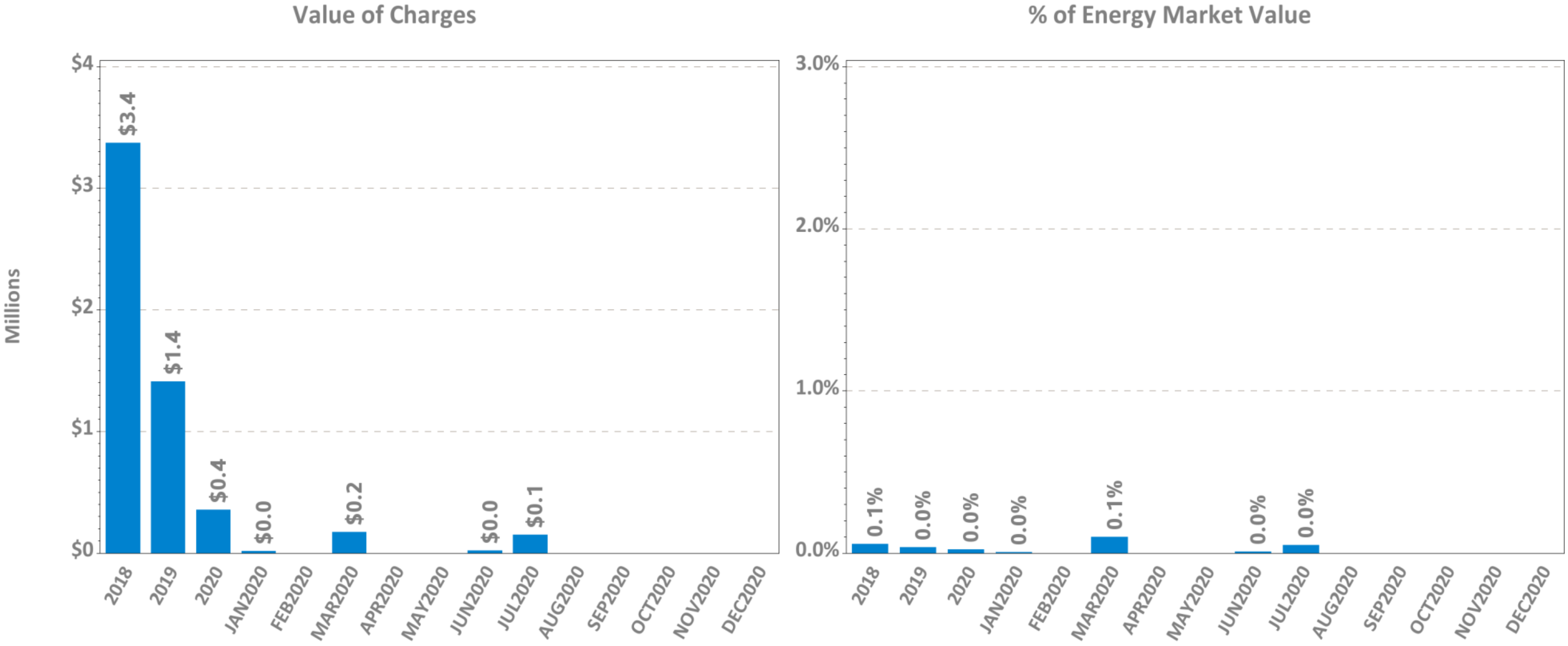
Note: Energy Market value is the hourly locational product of load obligation and price in the DA Market plus the hourly locational product of price and RT Load Obligation Deviation in the RT Market

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

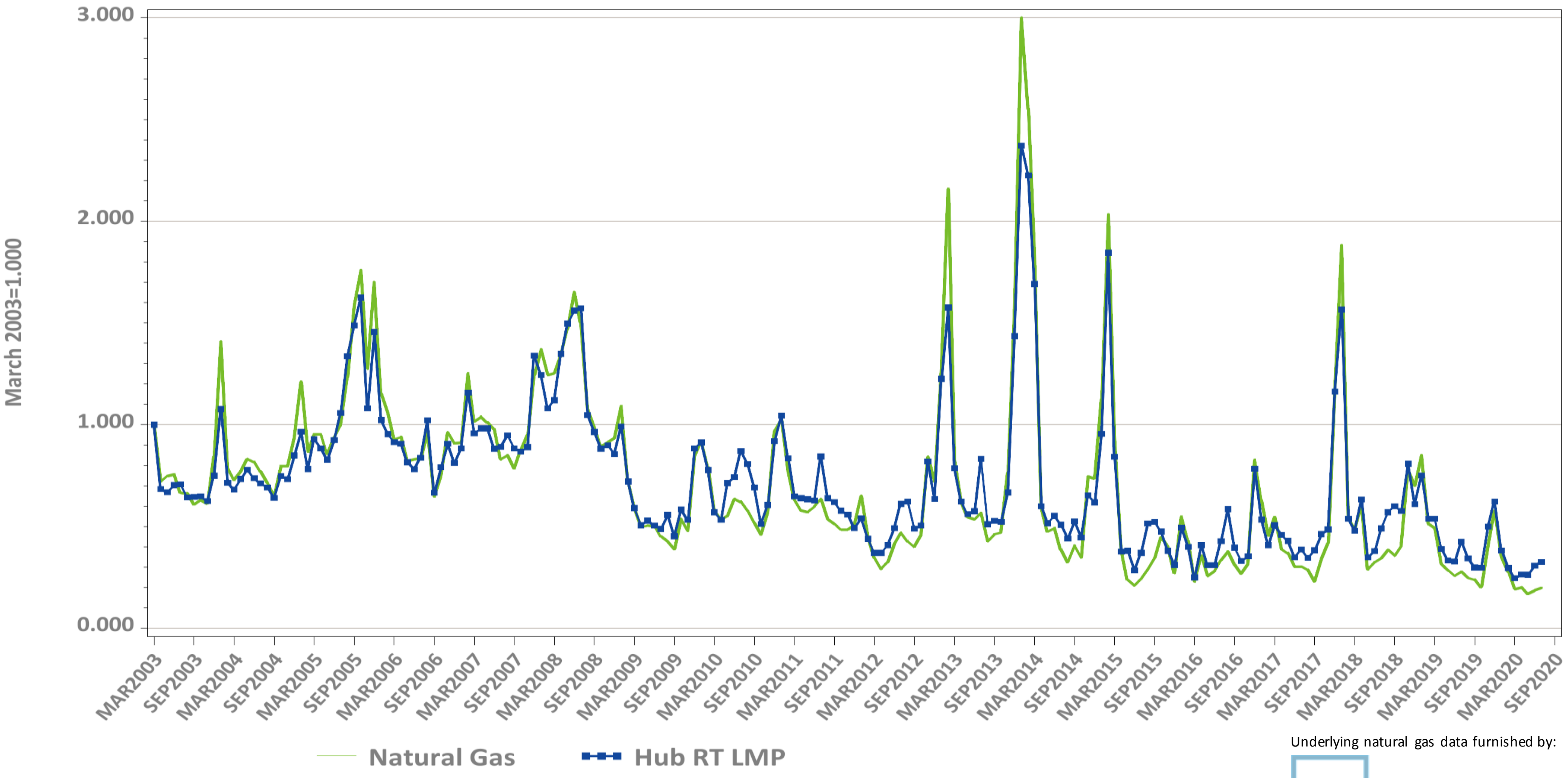
DA vs. RT LMPs ($/MWh)

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%

July-19	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$31.08	$29.30	$29.09	$29.68	$29.47	$29.82	$30.31	$29.81	$29.78
Real-Time	$29.61	$28.93	$28.95	$29.43	$28.94	$29.11	$29.38	$29.21	$29.18
RT Delta %	-4.7%	-1.3%	-0.5%	-0.8%	-1.8%	-2.4%	-3.0%	-2.0%	-2.0%
July-20	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Day-Ahead	$23.69	$23.09	$23.48	$23.76	$23.44	$23.40	$23.64	$23.59	$23.55
Real-Time	$22.54	$22.14	$22.39	$22.60	$22.33	$22.25	$22.48	$22.42	$22.37
RT Delta %	-4.9%	-4.1%	-4.6%	-4.9%	-4.8%	-4.9%	-4.9%	-5.0%	-5.0%
Annual Diff.	NEMA	CT	ME	NH	VT	RI	SEMA	WCMA	Hub
Yr over Yr DA	-23.8%	-21.2%	-19.3%	-19.9%	-20.5%	-21.5%	-22.0%	-20.9%	-20.9%
Yr over Yr RT	-23.9%	-23.5%	-22.7%	-23.2%	-22.9%	-23.5%	-23.5%	-23.2%	-23.3%

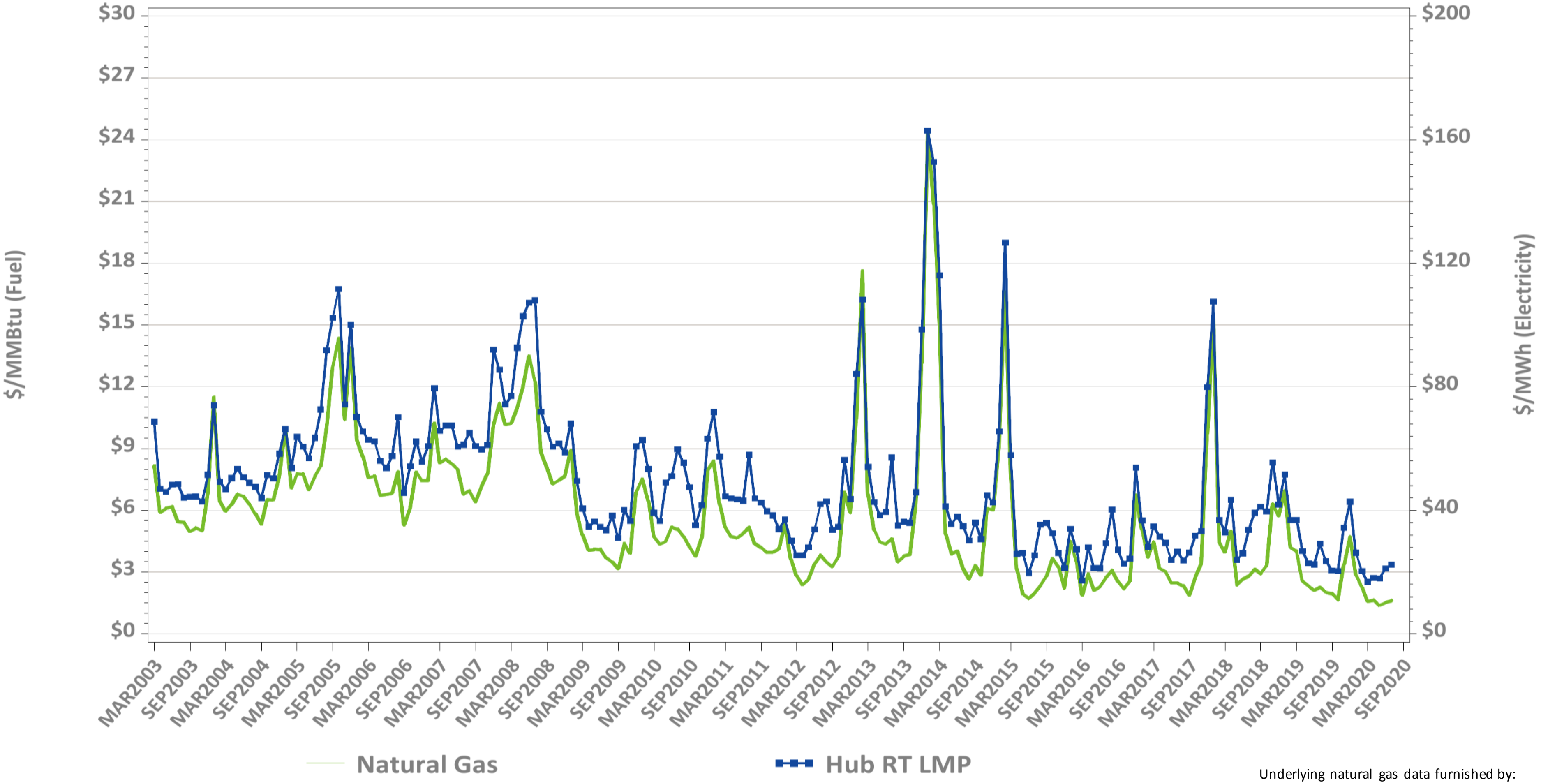
Monthly Average Fuel Price and RT Hub LMP Indexes



Underlying natural gas data furnished by:

ICE Global markets in clear view

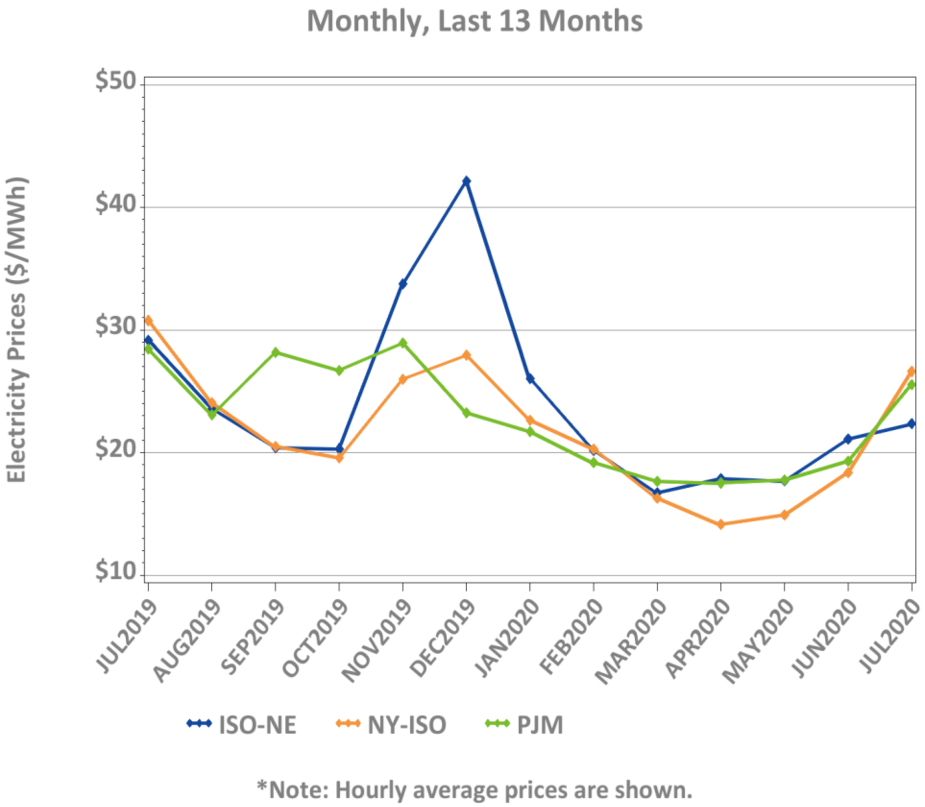
Monthly Average Fuel Price and RT Hub LMP



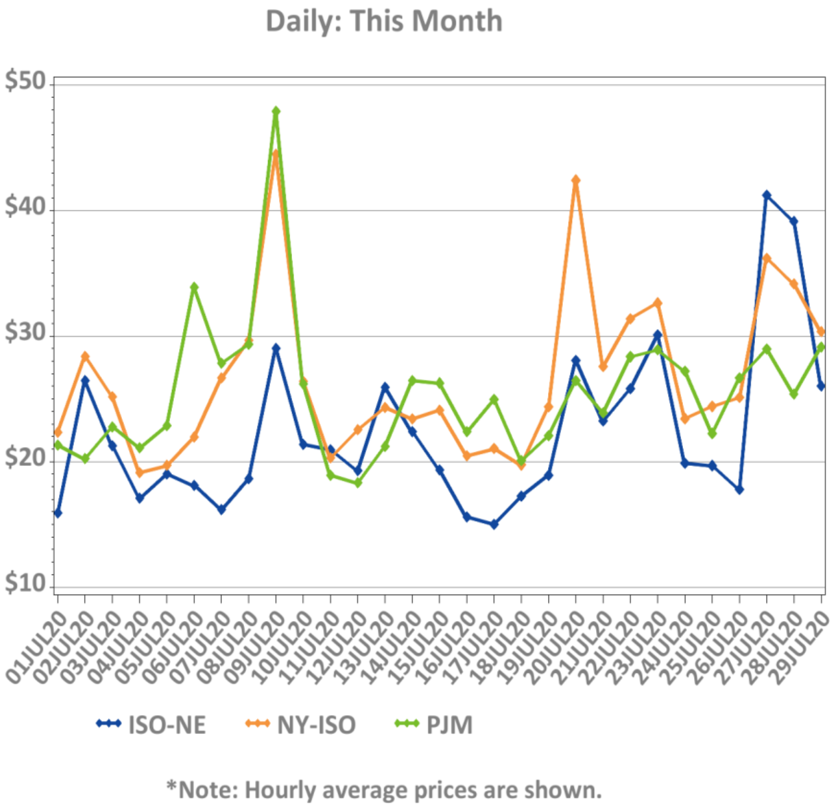
Underlying natural gas data furnished by:

ice Global markets in clear view

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

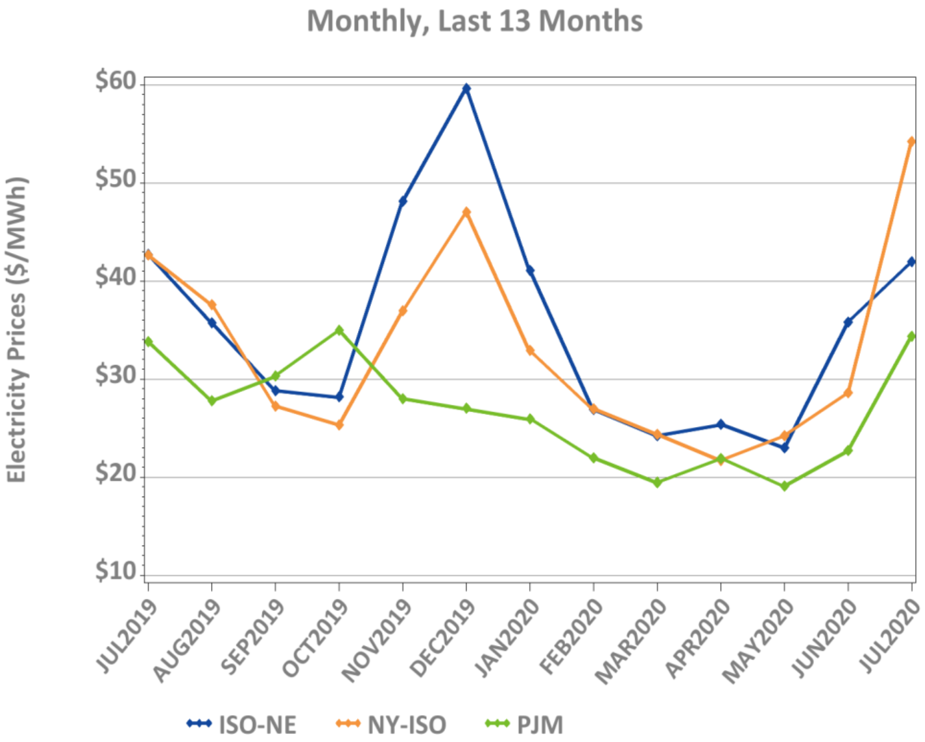


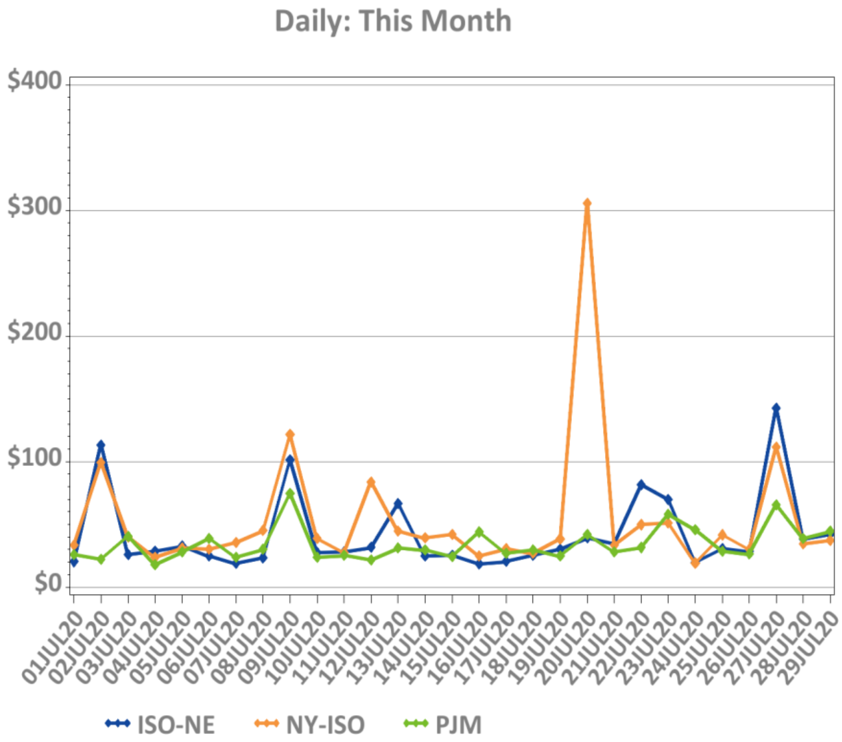
*Note: Hourly average prices are shown.



*Note: Hourly average prices are shown.

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





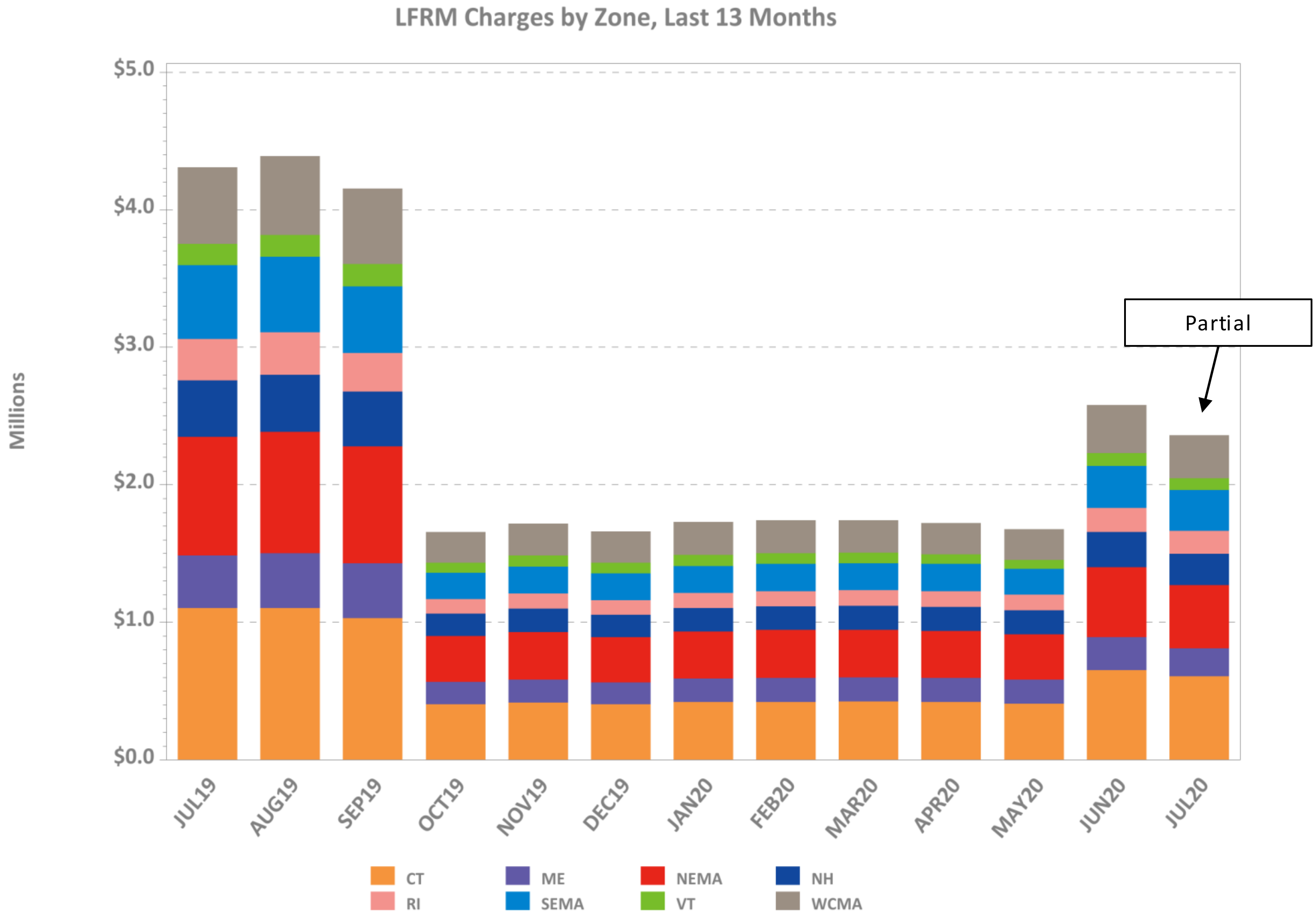
***Forecasted New England daily peak hours reflected**

Reserve Market Results – July 2020

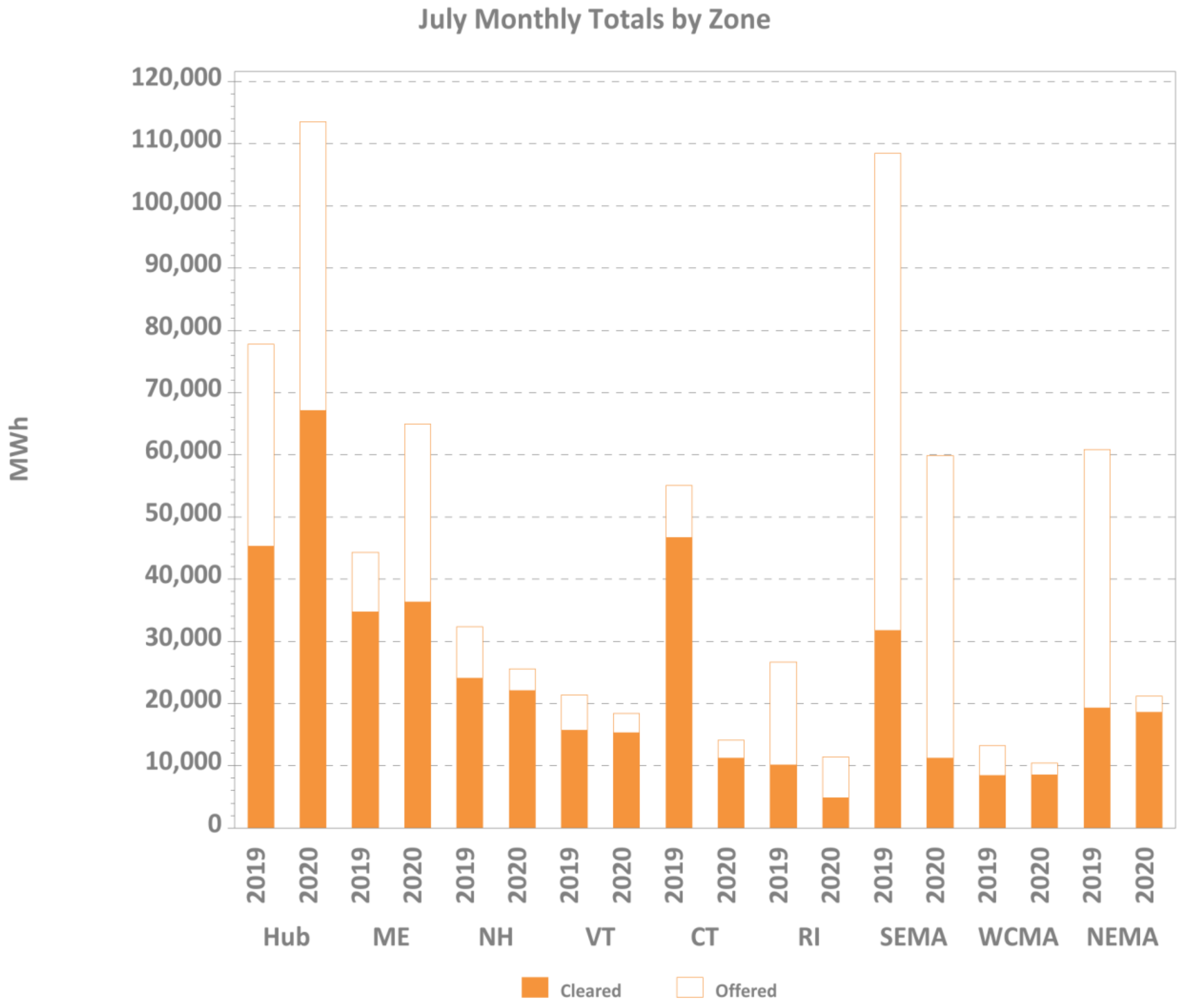
- Maximum potential Forward Reserve Market payments of $2.5M were reduced by credit reductions of $32K, failure-to-reserve penalties of $72K and failure-to-activate penalties of $10K, resulting in a net payout of $2.4M or 95% of maximum
  - Rest of System: $1.87M/1.97M (95%)
  - Southwest Connecticut: $0.07M/0.08M (92%)
  - Connecticut: $0.41M/0.43M (97%)
- $1.9M total Real-Time credits were reduced by $664K in Forward Reserve Energy Obligation Charges for a net of $1.2M in Real-Time Reserve payments
  - Rest of System: 242 hours, $661K
  - Southwest Connecticut: 242 hours, $232K
  - Connecticut: 242 hours, $187K
  - NEMA: 242 hours, $137K

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

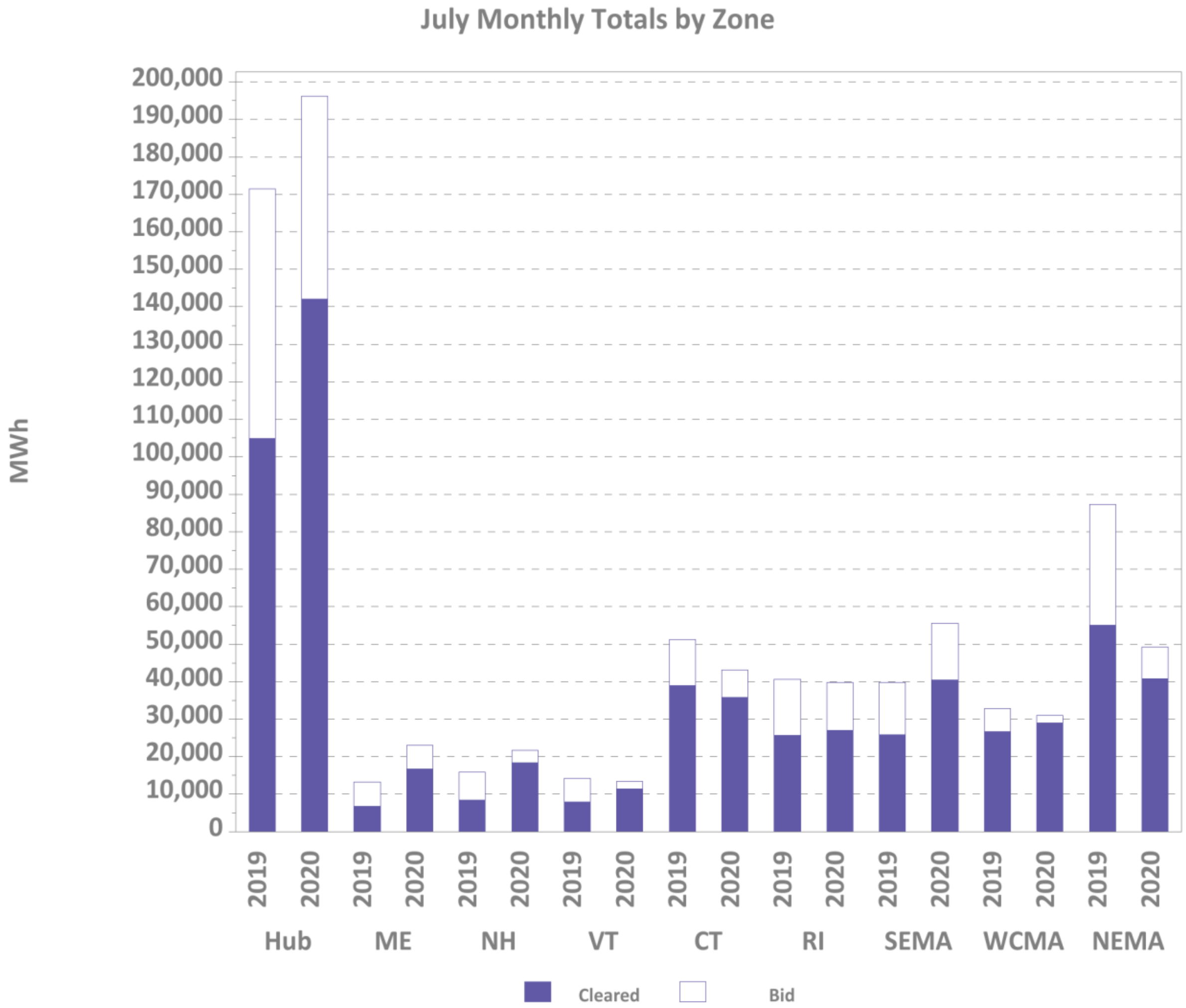
LFRM Charges to Load by Load Zone ($)



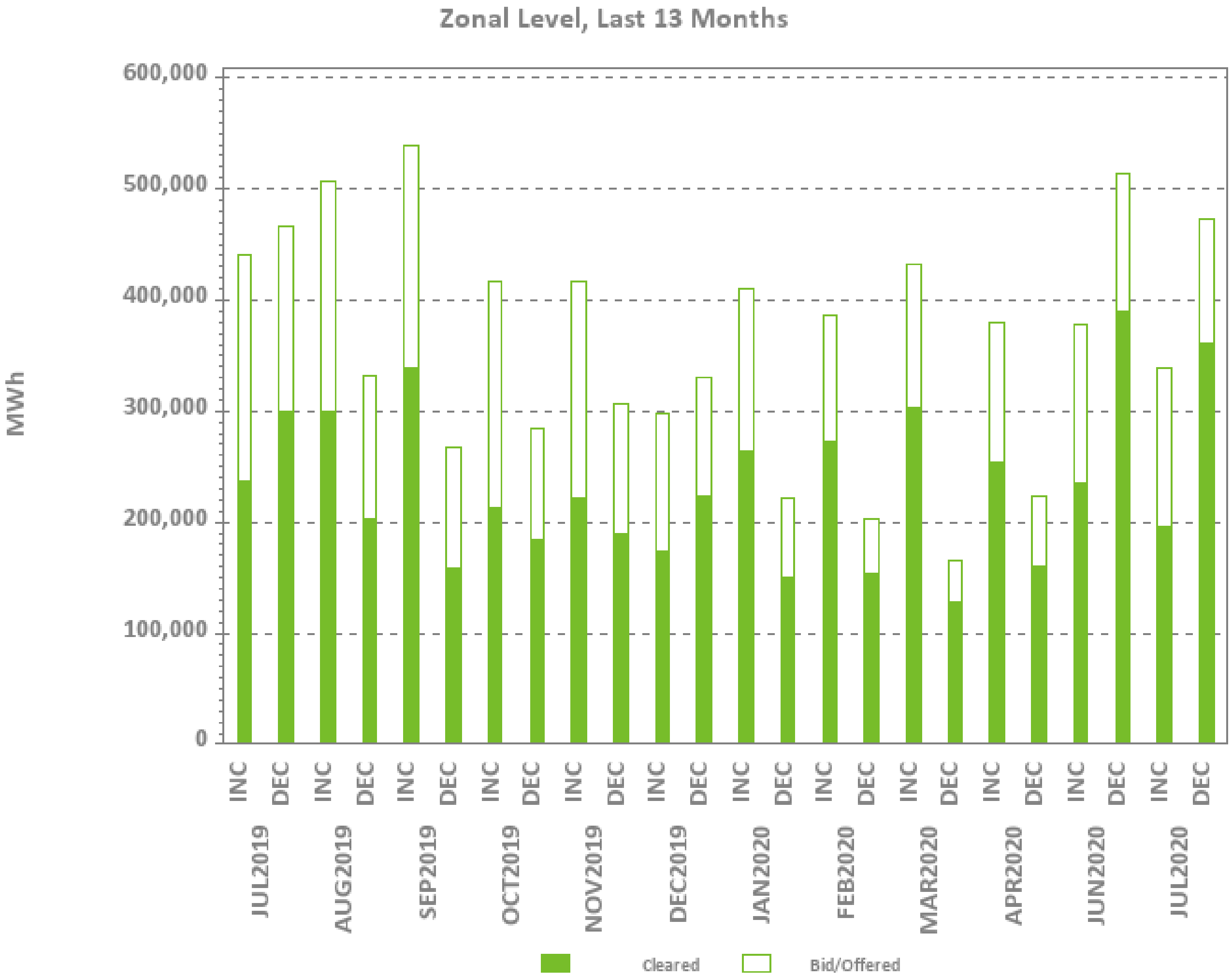
Zonal Increment Offers and Cleared Amounts



Zonal Decrement Bids and Cleared Amounts

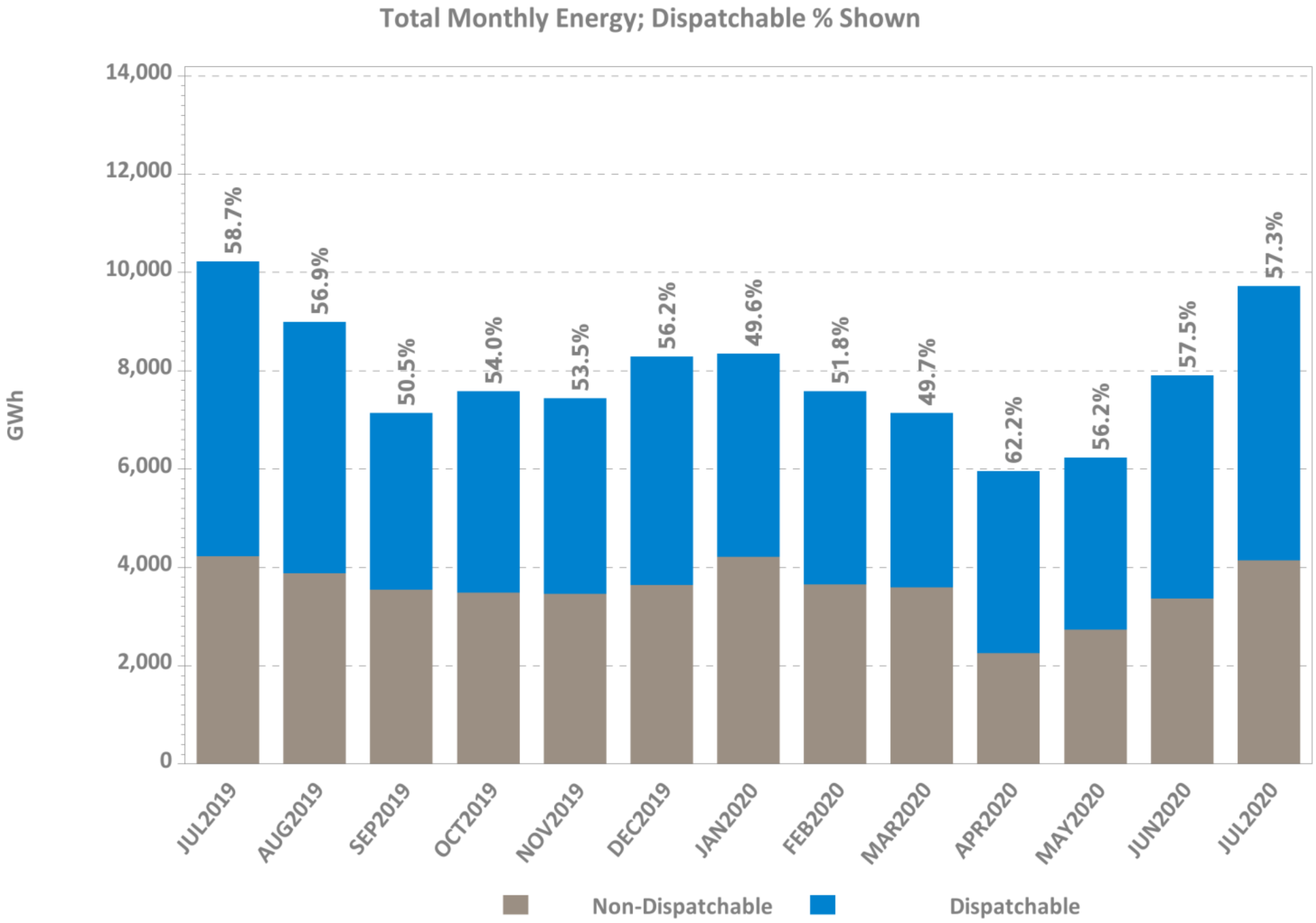


Total Increment Offers and Decrement Bids



Data excludes nodal offers and bids

Dispatchable vs. Non-Dispatchable Generation



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

REGIONAL SYSTEM PLAN (RSP)

Planning Advisory Committee (PAC)

- August 27 PAC Meeting Agenda Topics*
  - Emissions/Environmental Impacts of COVID19
  - Impacts of COVID19 to the Load Forecast
  - Boston 2028 Solutions Study – Mystic Retirement
  - Revised SEMA/RI 2029 Needs Assessment Update Follow-Up
  - SWCT Solutions Study Close-Out
  - 1191 Line Asset Condition Project

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

Economic Studies

- Three 2019 study requests were received (NESCOE, Anbaric, and RENEW)
  - RENEW scenarios modeled varying degrees of increases in Orrington-South transfer limit
  - NESCOE and Anbaric scenarios modeled different transmission and offshore wind expansion options
  - Study work is complete and results have been presented to PAC
  - NESCOE report was posted to the ISO website on June 30
  - Anbaric and RENEW reports to be completed in August
- NGRID submitted a 2020 economic study request
  - Assumptions have been agreed upon and were presented to PAC in May, June and July
  - Goal is to complete study work by Q1 2021

Environmental Issues

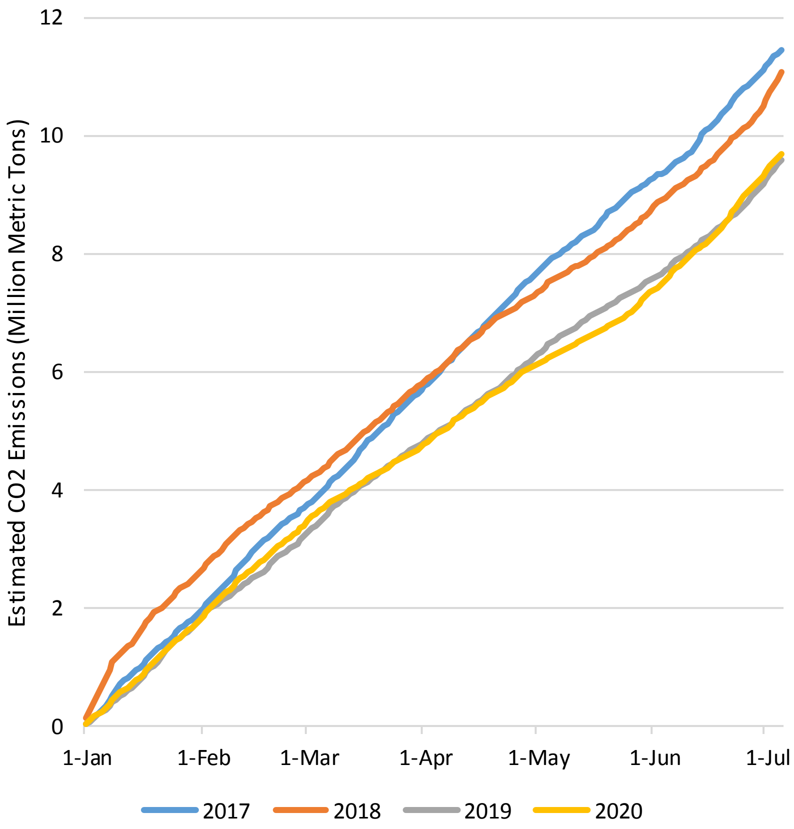
- The Environmental Advisory Group (EAG) held discussions in April and on June 25 to consider obstacles to reporting emissions from imports, and what actions could be taken to overcome the lack of publically-available information; proposal is being finalized and was discussed at the July 31 EAG meeting
  - May be able to implement later in 2020
  - This proposal will not provide near real-time emissions information
- At the August 27 PAC meeting, a presentation will be made highlighting the impacts of COVID19 to New England emissions

Environmental Matters – Carbon Dioxide (CO_2) Emissions from Native Generation (1/1 - 7/5)

Estimated Emissions Increased in 1st Half of 2020 vs. 2019

- Estimated 2020 year-to-date CO_2 system emissions increased 0.6% compared to same period in 2019 (1/1 - 7/20):
  - Coal -78.5% ⬇
  - Oil -31.2%
  - Natural Gas 6.5% ⬆
- 2020 YTD (25,375 GWh) native emitting generation exceeded 2019 YTD (24,869 GWh) by 2%
- Natural gas generation and net imports increased, replacing decline in nuclear output compared to same period in 2019

Cumulative CO_2 System Emissions (Million Metric Tons)

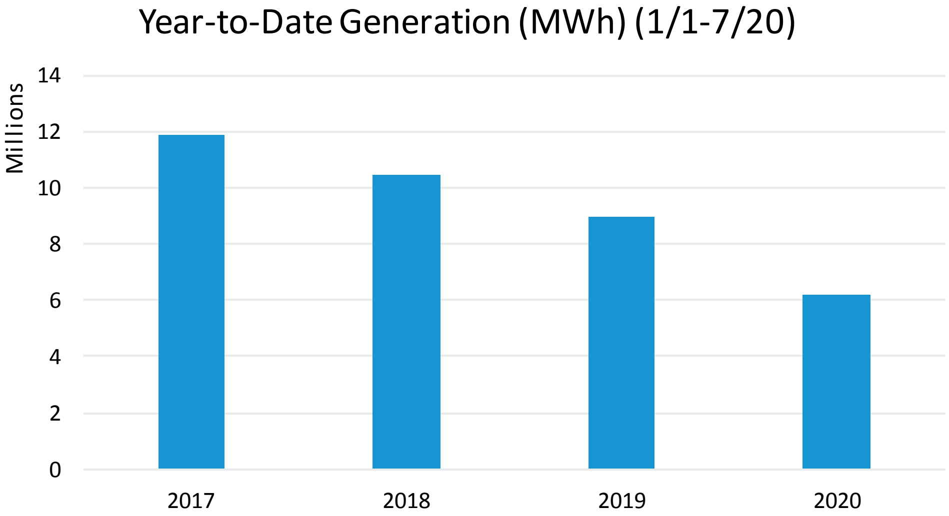


Environmental Matters – Massachusetts CO_2 Generator Emissions Cap

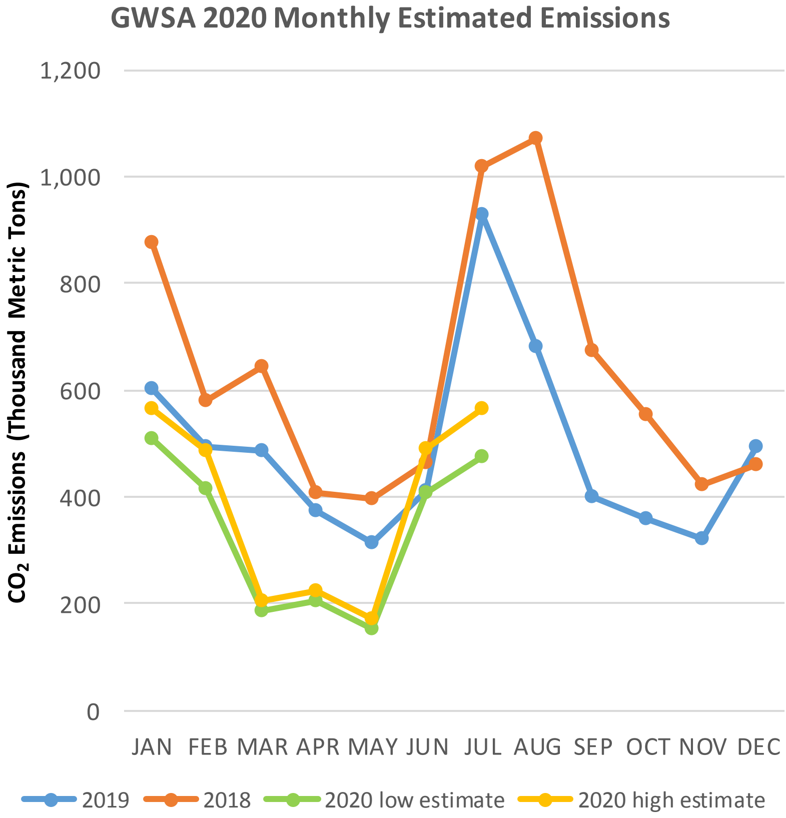
2020 MA Emissions Declined 25%, Generation Declined 31% vs. 2019

2020 CO_2 Estimated Emissions Below 2019 Trend lines

- Year-to-date generation from affected generators declined 31%, while estimated emissions declined 25% compared to same period in 2019



2020 Estimated, Past Monthly Emissions (Thousand Metric tons)



GWSA - Global Warming Solutions Act

RSP Project Stage Descriptions

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

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

New Hampshire/Vermont 10-Year Upgrades

Status as of 7/24/20

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	4
New 115 kV overhead line, Scobie Pond-Chester	Dec-15	4

New Hampshire/Vermont 10-Year Upgrades, cont.

Status as of 7/24/20

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 7/24/20

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 7/24/20

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 7/24/20

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 7/24/20

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 7/24/20

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 7/24/20

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 7/24/20

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	3
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 7/24/20

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 7/24/20

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 7/24/20

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 7/24/20

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 7/24/20

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 7/24/20

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 7/24/20

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 7/24/20

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 7/24/20

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 7/24/20

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 7/24/20

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	4

SEMA/RI Reliability Projects

Status as of 7/24/20

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	Oct-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	Oct-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 7/24/20

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-21	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*

* The ISO is reevaluating this project with updated data and assumptions.

SEMA/RI Reliability Projects, cont.

Status as of 7/24/20

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 7/24/20

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	2
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

** The ISO is reevaluating this project with updated data and assumptions.

SEMA/RI Reliability Projects, cont.

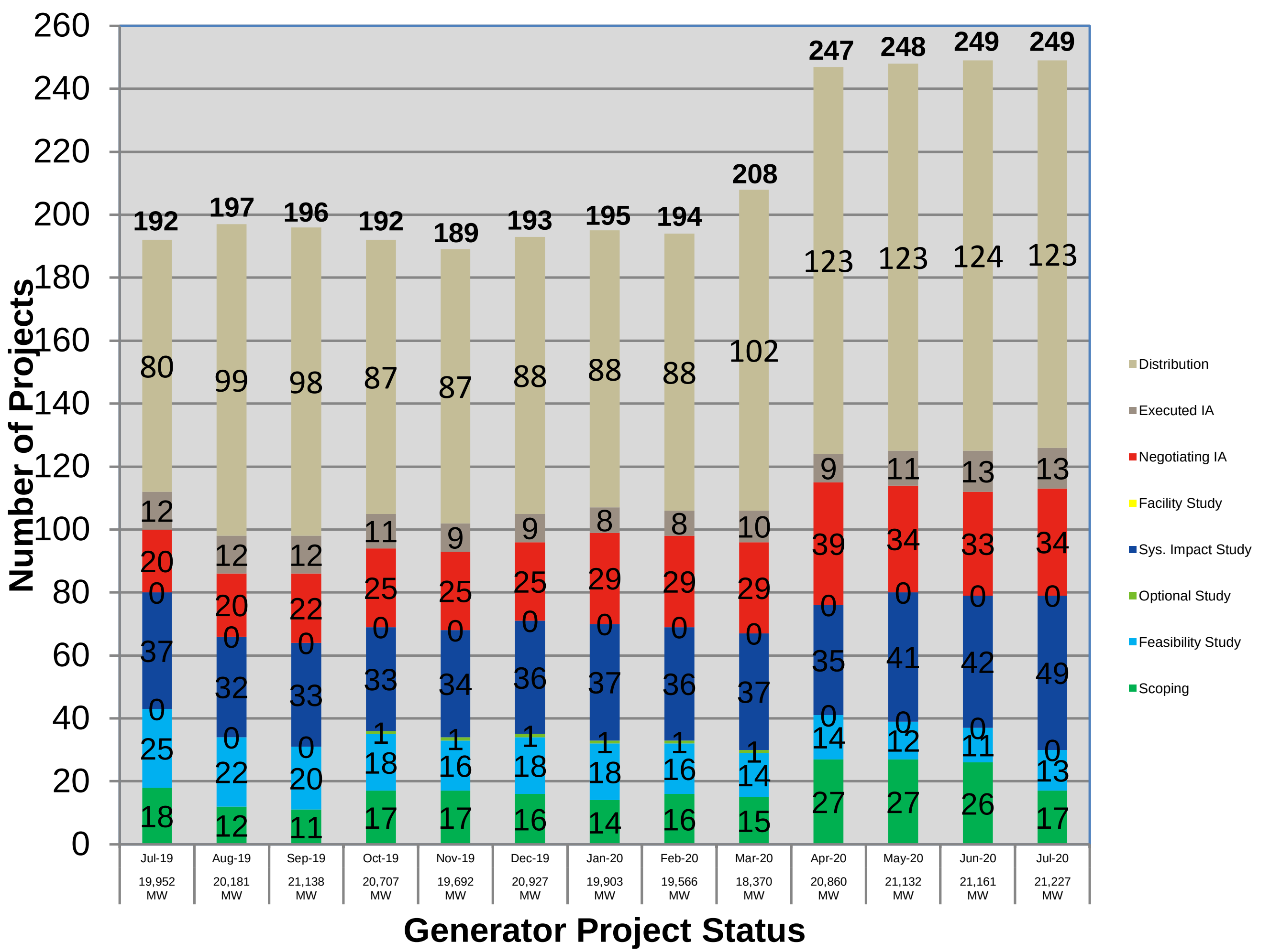
Status as of 7/24/20

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

* The ISO is reevaluating this project with updated data and assumptions.

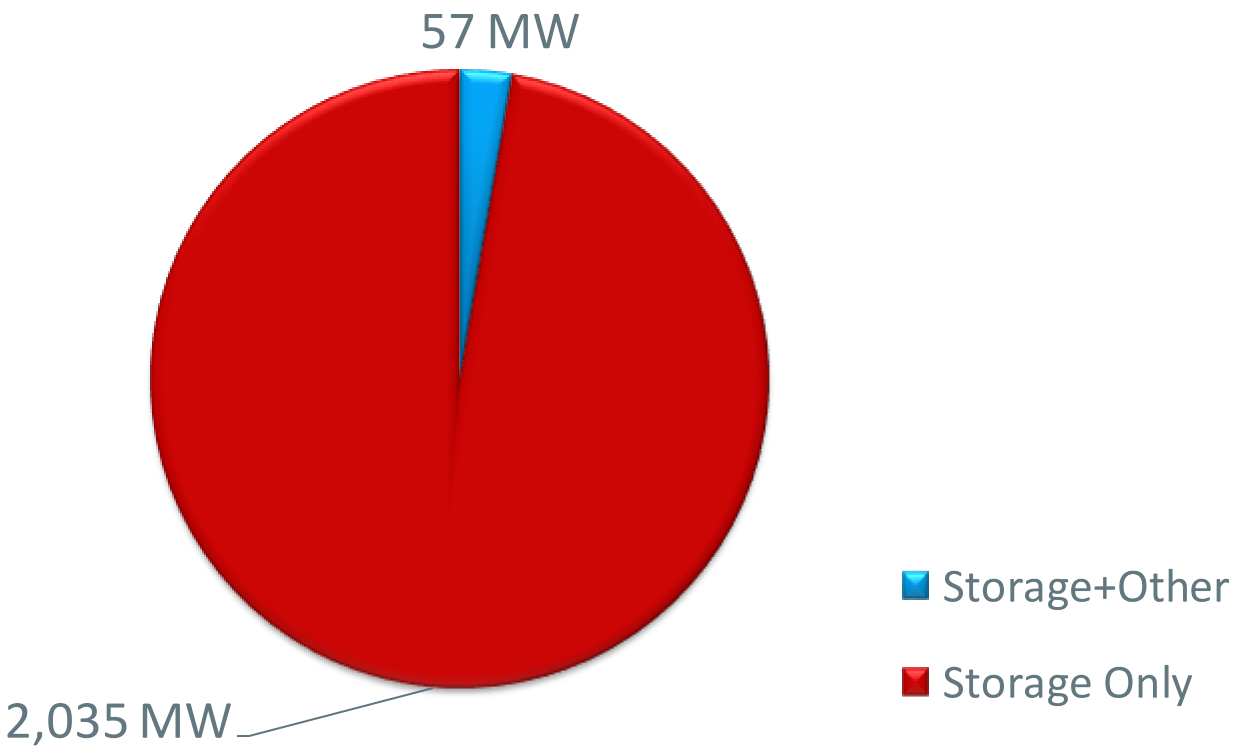
Status of Tariff Studies



Note: July 2020 is based on partial data.
As of July 2020, there are 4 ETU's in Scoping, 3 in FS, 3 in SIS, 0 in FAC, 1 Negotiating IA, and 1 with Executed IA.
https://irtt.iso-ne.com/external.aspx

What is in the Queue (as of July 23, 2020)

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



OPERABLE CAPACITY ANALYSIS

Summer 2020 Analysis

Summer 2020 Operable Capacity Analysis

50/50 **Load Forecast** (Reference)	**Sep. - 2020**[2] **CSO (MW)**	**Sep. - 2020**[2] **SCC (MW)**
Operable Capacity MW [1]	30,237	31,378
Active Demand Capacity Resource (+) [5]	411	452
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	674	674
Non Commercial Capacity (+)	7	7
Non Gas-fired Planned Outage MW (-)	2,378	2,467
Gas Generator Outages MW (-)	66	90
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)	26,785	27,854
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	-645	424

[1] Operable Capacity is based on data as of **July 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 **July 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)	**Sep. - 2020[2] CSO (MW)**	**Sep. - 2020[2] SCC (MW)**
Operable Capacity MW [1]	30,237	31,378
Active Demand Capacity Resource (+) [5]	411	452
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	674	674
Non Commercial Capacity (+)	7	7
Non Gas-fired Planned Outage MW (-)	2,378	2,467
Gas Generator Outages MW (-)	66	90
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)	26,785	27,854
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	-2,604	-1,535

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

July 31, 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]
8/8/2020	29855	400	1192	7	691	0	2100	0	28663	25125	2305	27430	1233
8/15/2020	29855	400	1192	7	615	0	2100	0	28739	25125	2305	27430	1309
8/22/2020	29855	400	1192	7	420	0	2100	0	28934	25125	2305	27430	1504
8/29/2020	30237	411	689	7	801	0	2100	0	28443	25125	2305	27430	1013
9/5/2020	30237	411	689	7	997	0	2100	0	28247	25125	2305	27430	817
9/12/2020	**30237**	**411**	**674**	**7**	**2378**	**66**	**2100**	**0**	**26785**	**25125**	**2305**	**27430**	**-645**

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

July 31, 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

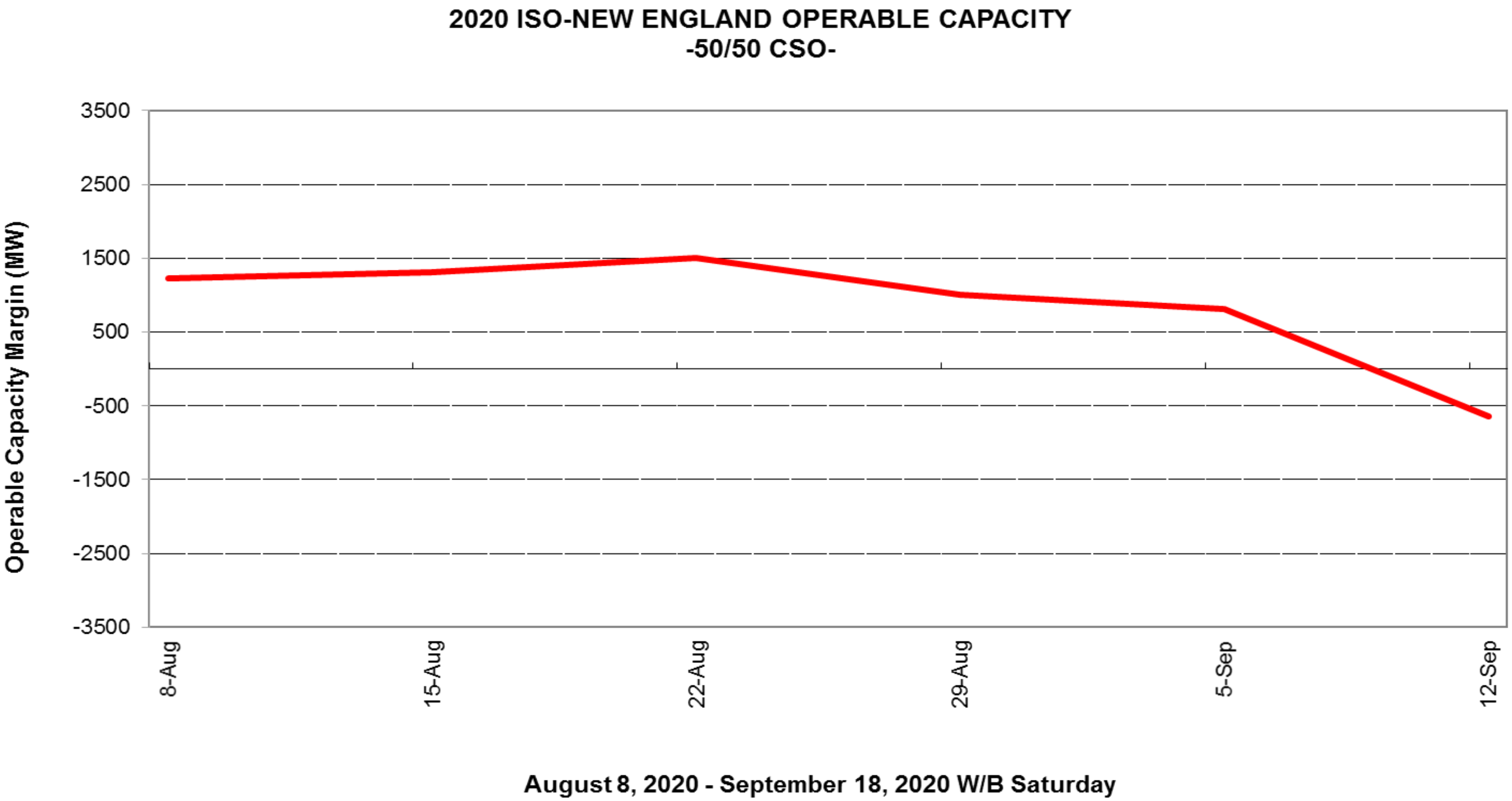
STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW [1]	Active Capacity Demand MW [2]	EXTERNAL NODE AVAIL CAPACITY MW [3]	NON COMMERCIAL CAPACITY MW [4]	NON-GAS PLANNED OUTAGES CSO MW [5]	GAS GENERATOR OUTAGES CSO MW [6]	ALLOWANCE FOR UNPLANNED OUTAGES MW [7]	GAS AT RISK MW [8]	NET OPCAP SUPPLY MW [9]	PEAK LOAD FORECAST MW [10]	OPER RESERVE REQUIREMENT MW [11]	NET LOAD OBLIGATION MW [12]	OPCAP MARGIN MW [13]
8/8/2020	29855	400	1192	7	691	0	2100	0	28663	27084	2305	29389	-726
8/15/2020	29855	400	1192	7	615	0	2100	0	28739	27084	2305	29389	-650
8/22/2020	29855	400	1192	7	420	0	2100	0	28934	27084	2305	29389	-455
8/29/2020	30237	411	689	7	801	0	2100	0	28443	27084	2305	29389	-946
9/5/2020	30237	411	689	7	997	0	2100	0	28247	27084	2305	29389	-1142
9/12/2020	**30237**	**411**	**674**	**7**	**2378**	**66**	**2100**	**0**	**26785**	**27084**	**2305**	**29389**	**-2604**

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**

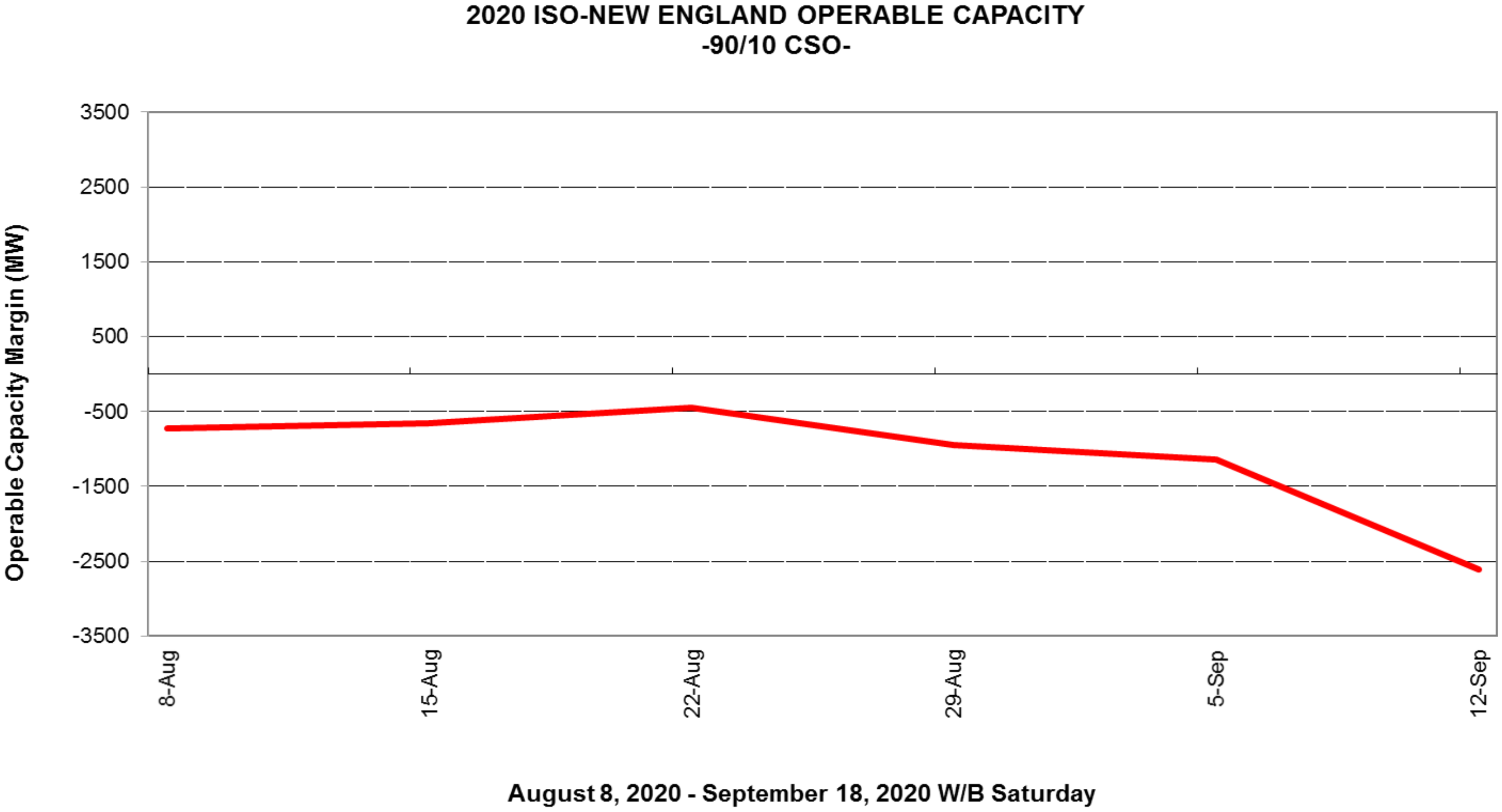
Summer 2020 Operable Capacity Analysis

50/50 Forecast (Reference)



Summer 2020 Operable Capacity Analysis

90/10 Forecast (Extreme)



OPERABLE CAPACITY ANALYSIS

Preliminary Fall 2020 Analysis

Preliminary Fall 2020 Operable Capacity Analysis

50/50 **Load Forecast** (Reference)	**Oct. - 2020[2] CSO (MW)**	**Oct. - 2020[2] SCC (MW)**
Operable Capacity MW [1]	30,446	31,378
Active Demand Capacity Resource (+) [5]	537	452
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,125	1,125
Non Commercial Capacity (+)	7	7
Non Gas-fired Planned Outage MW (-)	6,586	7,178
Gas Generator Outages MW (-)	1,911	2,212
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	20,818	20,772
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	16,459	16,459
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	18,764	18,764
Operable Capacity Margin	2,054	2,008

[1] Operable Capacity is based on data as of **July 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 **July 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 **October 17, 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.

Preliminary Fall 2020 Operable Capacity Analysis

90/10 **Load Forecast** (Extreme)	**Oct. - 2020[2] CSO (MW)**	**Oct. - 2020[2] SCC (MW)**
Operable Capacity MW [1]	30,446	31,378
Active Demand Capacity Resource (+) [5]	537	452
External Node Available Net Capacity, CSO imports minus firm capacity exports (+)	1,125	1,125
Non Commercial Capacity (+)	7	7
Non Gas-fired Planned Outage MW (-)	6,586	7,178
Gas Generator Outages MW (-)	1,911	2,212
Allowance for Unplanned Outages (-) [4]	2,800	2,800
Generation at Risk Due to Gas Supply (-) [3]	0	0
Net Capacity (NET OPCAP SUPPLY MW)	20,818	20,772
Peak Load Forecast MW(adjusted for Other Demand Resources) [2]	17,001	17,001
Operating Reserve Requirement MW	2,305	2,305
Operable Capacity Required (NET LOAD OBLIGATION MW)	19,306	19,306
Operable Capacity Margin	1,512	1,466

[1] Operable Capacity is based on data as of **July 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 **July 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 **October 17, 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.

Preliminary Fall 2020 Operable Capacity Analysis

50/50 Forecast (Reference)

ISO-NE OPERABLE CAPACITY ANALYSIS

July 31, 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]
9/19/2020	30237	411	674	7	3731	268	2100	0	25230	20841	2305	23146	2084
9/26/2020	30446	537	1025	7	4311	489	2800	0	24415	15066	2305	17371	7044
10/3/2020	30446	537	1025	7	5781	2047	2800	0	21387	15104	2305	17409	3978
10/10/2020	30446	537	1025	7	6311	1113	2800	0	21791	16076	2305	18381	3410
10/17/2020	**30446**	**537**	**1125**	**7**	**6586**	**1911**	**2800**	**0**	**20818**	**16459**	**2305**	**18764**	**2054**
10/24/2020	30446	537	1025	7	5733	815	2800	0	22667	16677	2305	18982	3685
10/31/2020	30446	537	1025	7	3642	1943	3600	0	22830	16798	2305	19103	3727
11/7/2020	30446	537	1025	7	2480	1292	3600	0	24643	17160	2305	19465	5178
11/14/2020	30446	537	1025	7	2384	1469	3600	0	24562	17936	2305	20241	4321
11/21/2020	30446	537	1025	7	1536	1274	3600	152	25453	18694	2305	20999	4454

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)

Preliminary Fall 2020 Operable Capacity Analysis

90/10 Forecast (Extreme)

ISO-NE OPERABLE CAPACITY ANALYSIS

July 31, 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

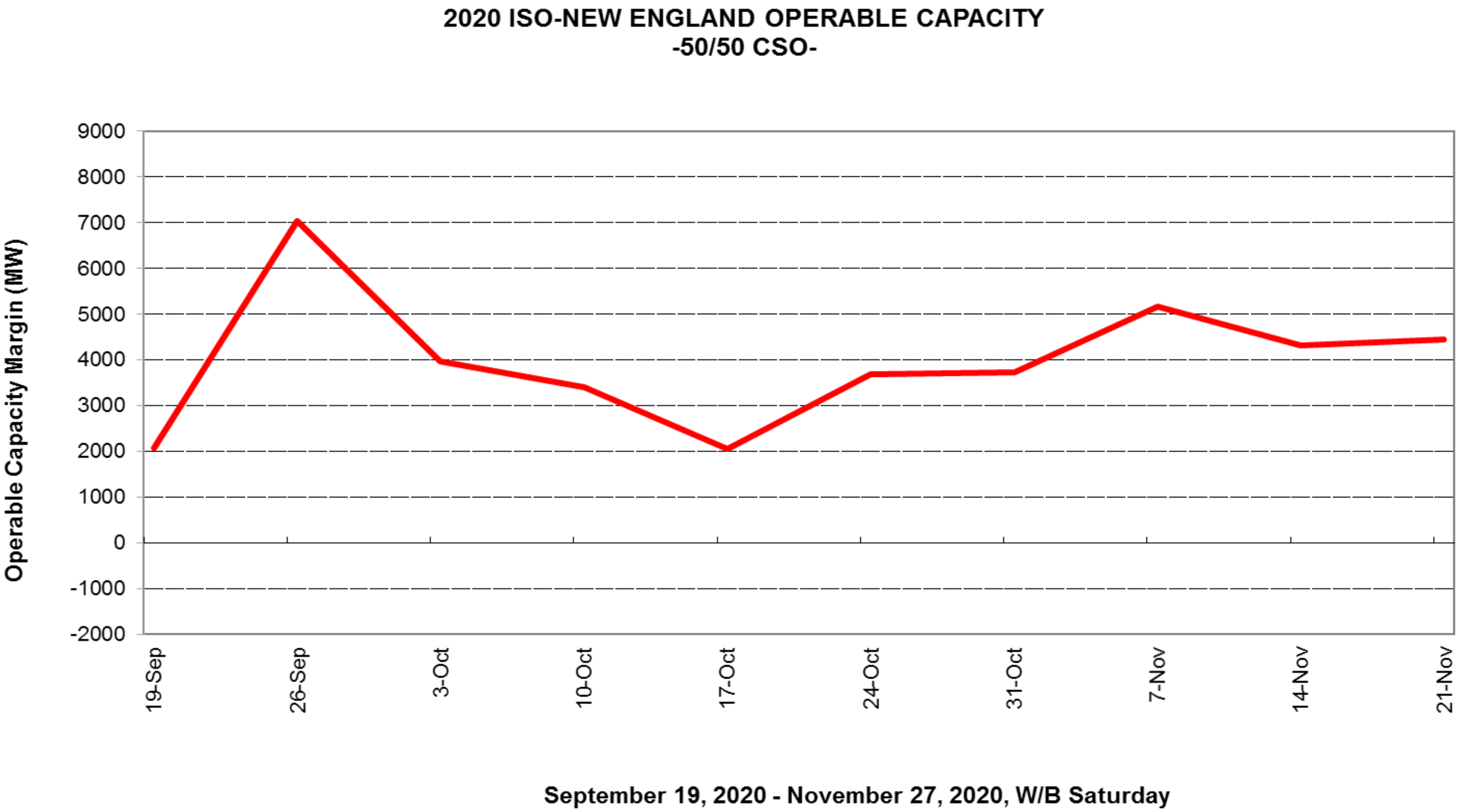
STUDY WEEK (Week Beginning, Saturday)	AVAILABLE OPCAP MW	Active Capacity Demand MW	EXTERNAL NODE AVAIL CAPACITY MW	NON COMMERCIAL CAPACITY MW	NON-GAS PLANNED OUTAGES CSO MW	GAS GENERATOR OUTAGES CSO MW	ALLOWANCE FOR UNPLANNED OUTAGES MW	GAS AT RISK MW	NET OPCAP SUPPLY MW	PEAK LOAD FORECAST MW	OPER RESERVE REQUIREMENT MW	NET LOAD OBLIGATION MW	OPCAP MARGIN MW
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]
9/19/2020	30237	411	674	7	3731	268	2100	0	25230	22512	2305	24817	413
9/26/2020	30446	537	1025	7	4311	489	2800	0	24415	15569	2305	17874	6541
10/3/2020	30446	537	1025	7	5781	2047	2800	0	21387	15608	2305	17913	3474
10/10/2020	30446	537	1025	7	6311	1113	2800	0	21791	16607	2305	18912	2879
10/17/2020	**30446**	**537**	**1125**	**7**	**6586**	**1911**	**2800**	**0**	**20818**	**17001**	**2305**	**19306**	**1512**
10/24/2020	30446	537	1025	7	5733	815	2800	0	22667	17224	2305	19529	3138
10/31/2020	30446	537	1025	7	3642	1943	3600	0	22830	17349	2305	19654	3176
11/7/2020	30446	537	1025	7	2480	1292	3600	0	24643	17721	2305	20026	4617
11/14/2020	30446	537	1025	7	2384	1469	3600	129	24433	18518	2305	20823	3610
11/21/2020	30446	537	1025	7	1536	1274	3600	1125	24480	19296	2305	21601	2879

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**

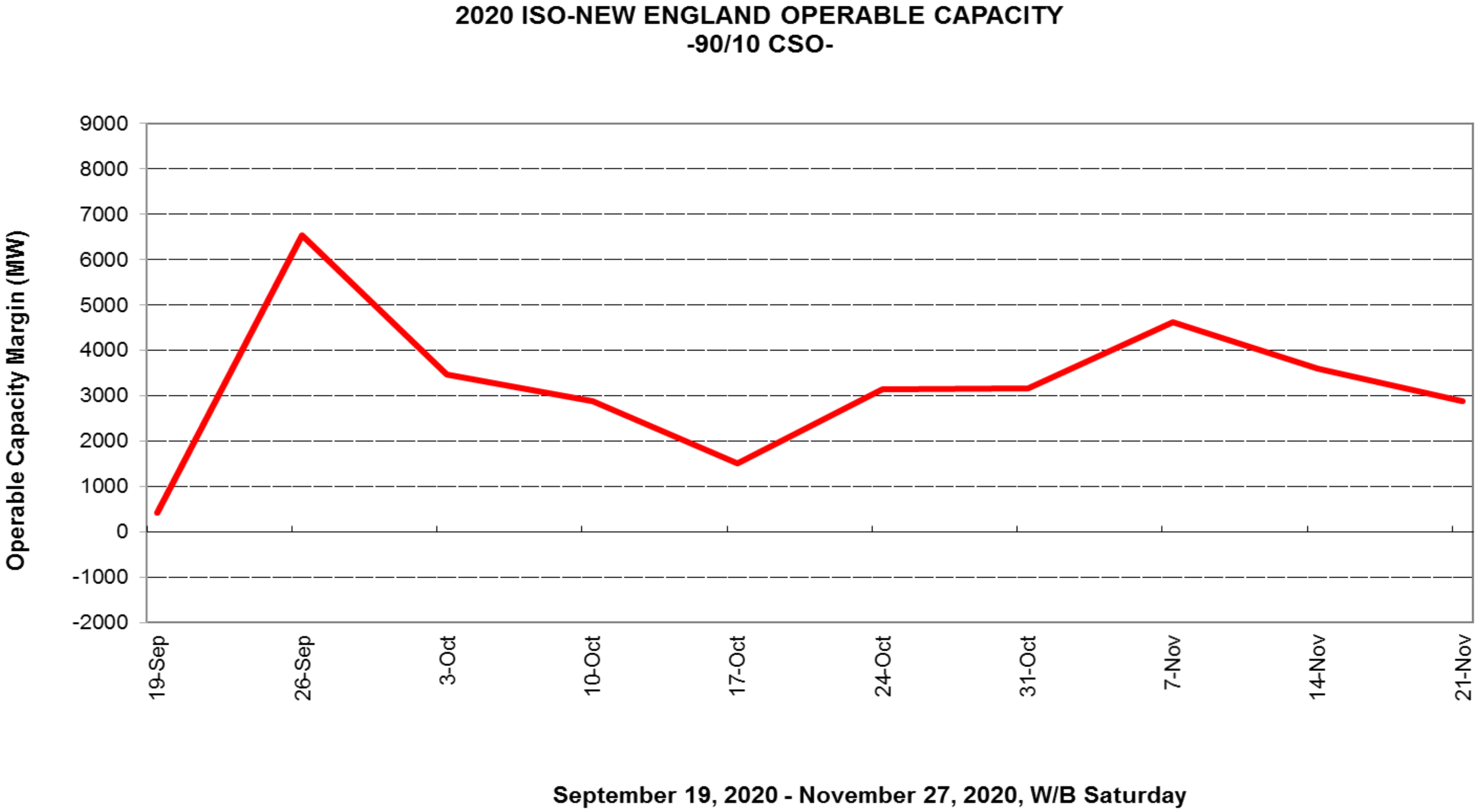
Preliminary Fall 2020 Operable Capacity Analysis

50/50 Forecast (Reference)



Preliminary Fall 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 resources <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 resources <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: July 30, 2020

RE: Revisions to ISO-NE Tariff Section III.12.8 for Gross Load Forecast Reconstitution Methodology

At the August 6, 2020 Participants Committee meeting you will be asked to support revisions to the ISO-NE Tariff Section III.12.8, as recommended by the Reliability Committee at its July 21, 2020 meeting (the "Load Forecast Reconstitution Revisions"). Background materials and a mark-up of Section III.12.8 have been included with this memo.[1]

The Load Forecast Reconstitution Revisions are designed to address how passive demand response ("PDR", which is primarily energy efficiency measures) is treated in the load forecast, and specifically to ensure that PDRs are not double-counted in the Forward Capacity Market ("FCM") (PDRs receive compensation as a supply-side resource; PDRs also reduce demand, and their demand-reducing impact becomes embedded in historical load data). To ensure that PDRs are not double-counted, ISO proposes changes to the methodology it uses to add (i.e., "reconstitute") PDR demand reductions into historical loads used in the development of a forecast of future loads. The amount reconstituted under the proposed methodology would better approximate the amount of PDRs participating as supply in the Forward Capacity Auction ("FCA"). The Load Forecast Reconstitution Revisions seek to change the methodology and reduce the level of reconstitution to the level of PDR that ISO estimates would likely get a Capacity Supply Obligation in the approaching FCA based on historical trends.

Specifically, under the proposal, instead of using the performance data that each energy efficiency program administrator submits to the ISO to reconstitute passive demand resources in the gross load forecast as has been done to date, the ISO will develop trend lines for summer and winter between the points in time when summer and winter MW values for passive demand resources are assumed to be zero (i.e. June 1, 2006 for summer and December 1, 2006 for winter) and the points in time when summer and winter MW values are reflected by the Capacity Supply Obligations (CSOs) that passive demand resources acquired in the most recent FCA for, respectively, June 1 (summer) and December 1 (winter) of the associated Capacity Commitment Period. To determine the summer and winter MW values to be added back into historical loads, the ISO will apply the resulting participation trends to, respectively, the summer months (i.e. April through November),

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[1] The ISO's presentation at the July 21 Reliability Committee meeting and the revisions the Section III.12.8 are included with this memorandum and are available at: https://www.iso-ne.com/static-assets/documents/2020/07/a6_gross_load_forecast_reconstitution_methodology_changes.zip.

and the winter months (i.e. December through March), in all the historical years covered by the trend lines. In addition, the ISO will make adjustments to account for the differences in the CSOs acquired by passive demand resources in FCAs and the CSOs acquired by passive demand resources in the annual reconfiguration auctions.

The reconstituted gross load forecast would be used in the development of the Installed Capacity Requirements and related values for the upcoming FCA. The ISO's proposal, if applied to the current CELT 2020 50/50 load forecast, would result in gross load forecasts in the future that are lower by an amount of 652 MW (for 2020) to 1355 MW (for 2029).

The Reliability Committee met and considered the ISO's proposal during the course of four meetings in April through July. At the July 21 meeting, the Reliability Committee voted to recommend Participants Committee support, with the vote narrowly passing on a roll-call Vote at 60.62% in favor.[2] Section III.12.8 is a Market Rule, and the minimum threshold for a passing vote is 60%.

During the discussions at the Reliability Committee on July 21, some Participants raised substantive concerns about the data set that ISO proposed to use beginning in 2006 to establish a trend line. They suggested that a trend line beginning in 2016 might be preferable and the ISO responded that doing so results in a methodology that does not generalize as well for all portions of the region for which the ISO is required to develop forecasts, and in a reconstitution data set that is likely less consistent with the long-range PDR trend. Other Participants supported the ISO's use of the reconstitution data set beginning in 2006 as proposed. Some Participants raised general concerns about the substantial reduction in the load forecast that would result from the reconstitution and its effect on the ICR calculation. Another Participant expressed concerns that the new methodology risks permitting PDR to clear in the FCA to levels greater than have been reconstituted into the peak load forecast used to establish the FCA demand. Other Participants welcomed the change, viewing it as providing overdue accuracy improvements in both the load forecast and the resulting ICR calculation. Some Participants indicated that the adoption of the Load Forecast Reconstitution Revisions requires a review (and possibly change) of aspects of the Market Rules regarding treatment of PDR in the FCA.

Also during the discussion at the July 21 Reliability Committee meeting, some Participants questioned why the Reliability Committee rather than the Markets Committee was voting on a Market Rule change. They referenced Section 8.2.2(a) of the Participants Agreement, which provides that the Markets Committee shall provide input and advice to the Participants Committee and the ISO on Market Rule changes. As explained by both ISO and NEPOOL counsel, though, long-standing and previously unchallenged precedent has recognized Reliability Committee authority to provide input and advice on all changes to Section 12 of Market Rule 1. That authority is found in the Participants Agreement, Section 8.2.3, which provides that the Reliability Committee shall provide input and advice to ISO and the Participants Committee with respect to the following:

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[2] The Vote was: Generation Sector – 0% in favor, 16.7%, 1 abstention; Transmission Sector – 16.7% in favor, 0% opposed, 0 abstentions; Supplier Sector – 4.18% in favor, 12.53% opposed, 5 abstentions; Publicly Owned Entity Sector – 16.7% in favor, 0% opposed, 2 abstentions; AR Sector – 6.35% in favor, 10.15% opposed, 0 abstentions; End User Sector – 16.7% in favor, 0% opposed, 0 abstentions.

"(b) Short-term and long-term load forecasts for use in ISO studies and operations and to meet requirements of regulatory agencies… [and] (m) Installed Capacity Requirements." All of Section 12 pertains directly to this subject matter. This purview of Section 12 by the Reliability Committee is consistent with how NEPOOL and the ISO agreed at the outset of the RTO to implement the Participants Agreement regarding the subject matter of Section 12. Every proposed amendment to Section 12 has gone through the Reliability Committee for vote, even for revisions that have had a strong market connection, such as the revisions related to zonal demand curves. Indeed, Section 12.8 itself, which is the subject of the Load Forecast Reconstitution Revisions, was added into the Tariff only after a vote at the Reliability Committee recommending Participants Committee support.

In some cases there have been joint Markets and Reliability Committee meetings on proposed revisions to Section 12 when a Participant or the committee officers have requested/proposed joint meetings. In this case, no one requested or proposed joint meetings. The vote by the Reliability Committee on the Section 12 changes does not preclude the Markets Committee from taking up any related Market Rule or Manual changes.

As of the date of this memo, NEPOOL counsel is not aware of any proposed Participant amendments for the upcoming vote. However, there may be a request that action on this matter be deferred until the next Participants Committee meeting in order to permit the Markets Committee a chance to discuss the market implications of these Revisions and whether further Market Rule changes are needed.

The following form of resolution can be used for Participants Committee consideration of the proposed Load Forecast Reconstitution Revisions:

> RESOLVED, that the Participants Committee supports the Load Forecast Reconstitution Revisions, as recommended by the Reliability Committee and the ISO, and as reflected in the materials distributed to the Participants Committee for its August 6, 2020 meeting, together with [any amendments made at the meeting and any additional 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 Reliability Committee.

III.12.8. Load Modeling Assumptions.

The ISO shall forecast load for the New England Control Area and for each Load Zone within the New England Control Area. The load forecasts shall be based on appropriate models and data inputs. Each year, the load forecasts and underlying methodologies, inputs and assumptions shall be reviewed with Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies. If the load forecast shows a consistent bias over time, either high or low, the ISO shall propose adjustments to the load modeling methodology to the Governance Participants, the state utility regulatory agencies in New England and, as appropriate, other state agencies to eliminate the bias.

To ensure that Demand Response Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources are not reflected as reductions in the load forecast, ~~Demand Capacity Resources~~ the ISO shall ~~be~~ reflect them~~ed~~ in historical loads~~the load forecast~~ as specified below.~~:~~

(a) The ISO shall add back into historical loads the metered MW demand reduction of Demand Response Resources dispatched by the ISO. ~~Expected reductions from an installed or forecast Demand Capacity Resource not qualifying for or not participating in the Forward Capacity Auction shall be reflected as a reduction in the load forecast that will be used to determine the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values for the relevant Capacity Commitment Period. The expected reduction from these resources will be included in the load forecast to the extent that they meet the qualification process rules, including monitoring and verification plan and financial assurance requirements. If no qualification process rules are in place for the expected reductions from these resources, they shall not be included within the load forecast.~~

(b) [Reserved.] ~~Expected reductions from an installed or forecast Demand Capacity Resource that qualifies to participate in the Forward Capacity Market, participates but does not clear in the Forward Capacity Auction, or has cleared in a previous Forward Capacity Auction and is expected to continue in the Forward Capacity Market shall not be reflected as a reduction in the load forecast that will be used to determine the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values for the relevant Capacity Commitment Period.~~

(c) [Reserved.]

(d) The ISO shall add back into historical loads summer and winter MW values to account for On-Peak Demand Resources and Seasonal Peak Demand Resources as follows:

The ISO shall develop a trend line between (i) the point when summer MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are assumed to be zero (June 1, 2006) and (ii) the point when summer MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are reflected by the Capacity Supply Obligations that those resources acquired in the most recent Forward Capacity Auction for June 1 of the associated Capacity Commitment Period. To determine the summer MW values to be added back into historical loads, the ISO shall apply the resulting trend to the summer months (April through November) in all the historical years covered by the trend line.

The ISO shall develop a trend line between (i) the point when winter MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are assumed to be zero (December 1, 2006) and (ii) the point when winter MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are reflected by the Capacity Supply Obligations that those resources acquired in the most recent Forward Capacity Auction for December 1 of the associated Capacity Commitment Period. To determine the winter MW values to be added back into historical loads, the ISO shall apply the resulting trend to the winter months (December through March) in all the historical years covered by the trend line.

The ISO shall make adjustments to forecasted loads to account for any differences between the most recently available MW values reflective of the Capacity Supply Obligations that On-Peak Demand Resources and Seasonal Peak Demand Resources acquired in each of the annual reconfiguration auctions and the MW values reflective of the Capacity Supply Obligations that those resources acquired in the corresponding Forward Capacity Auctions.

~~Any realized Demand Capacity Resource reductions in the historical period that received Forward Capacity Market payments for these reductions, or Demand Capacity Resource reductions that are expected to receive Forward Capacity Market payments by participating in the upcoming Forward Capacity Auction or having cleared in a previous Forward Capacity Auction, shall be added back into the appropriate historical loads to ensure that such resources are not reflected as a reduction in the load forecast that will be used to determine the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values for the relevant Capacity Commitment Period.~~

JULY 21, 2020 | WEBEX

Gross Load Forecast Reconstitution Methodology Changes

NEPOOL Reliability Committee

Jon Black

MANAGER, LOAD FORECASTING

Project History

- At the April 22, 2020 RC meeting, the ISO described the purpose of reconstitution and the issue with the existing reconstitution methodology
- At the May 19, 2020 RC meeting, the ISO provided an overview of the proposed gross load reconstitution methodology modifications for the Forward Capacity Auctions (FCAs), and explained why it is an improvement
  - The ISO also provided information concerning energy efficiency (EE) expiring measures and the participation of passive demand resources (PDRs) in the annual reconfiguration auctions (ARAs)
- At the June 16, 2020 RC meeting, the ISO:
  - Reviewed the proposed methodology for reconstituting PDRs for the FCAs in the gross load forecast
  - Presented the proposed methodology for adjusting the gross load forecast to reflect the amount of PDR participation in annual ARAs
  - Presented proposed Tariff revisions related to the methodologies for the FCAs and for the ARAs
- At today's RC meeting, the ISO is asking for a vote on its proposed Tariff revisions

Proposed Methodology

Summary of Resulting Improvements

- Ensures that reconstituted PDR is appropriately embedded in the gross load forecast by creating a smooth historical reconstitution time series
  - Such smoothing also enables the inclusion of FCA outcomes extending beyond the historical data currently used for reconstitution
- By calibrating to the PDR Capacity Supply Obligation (CSO) from the most recently completed FCA, the proposed reconstitution methodology results in improved accounting for:
  - The amount of PDR that participates in FCA, and not EE installations in excess of their CSO
  - EE expiring measures that are no longer participating as supply in FCM
- Provides a framework to adjust the gross load forecast to reflect differences in FCA CSOs and those of ARAs

RESPONSE TO STAKEHOLDER QUESTION

June 16, 2020 RC Meeting

Proposed PDR Reconstitution Methodology

Alternate Starting Point (Slide 1 of 2)

- Recall that the proposed methodology involves:
  1. Applying a linear fit between:
     a. The time installation of PDRs participating in FCA 1 began (i.e., when PDR equaled zero)
        - ☐ Assumed starting point for Summer is June 1, 2006
        - ☐ Assumed starting point for Winter is December 1, 2006

     b. The total seasonal PDR CSO from the most recent FCA for the corresponding Capacity Commitment Period (CCP)
        - ☐ June 1st for summer, December 1st for winter
  2. Applying the resulting June and December points in this time series to all the appropriate PDR performance months by season
- At the June 16, 2020 RC meeting, a question was raised whether a starting point of June 2016 (i.e., FCA 7 CSO value) rather than June 2006 could be utilized in the development of the reconstitution history

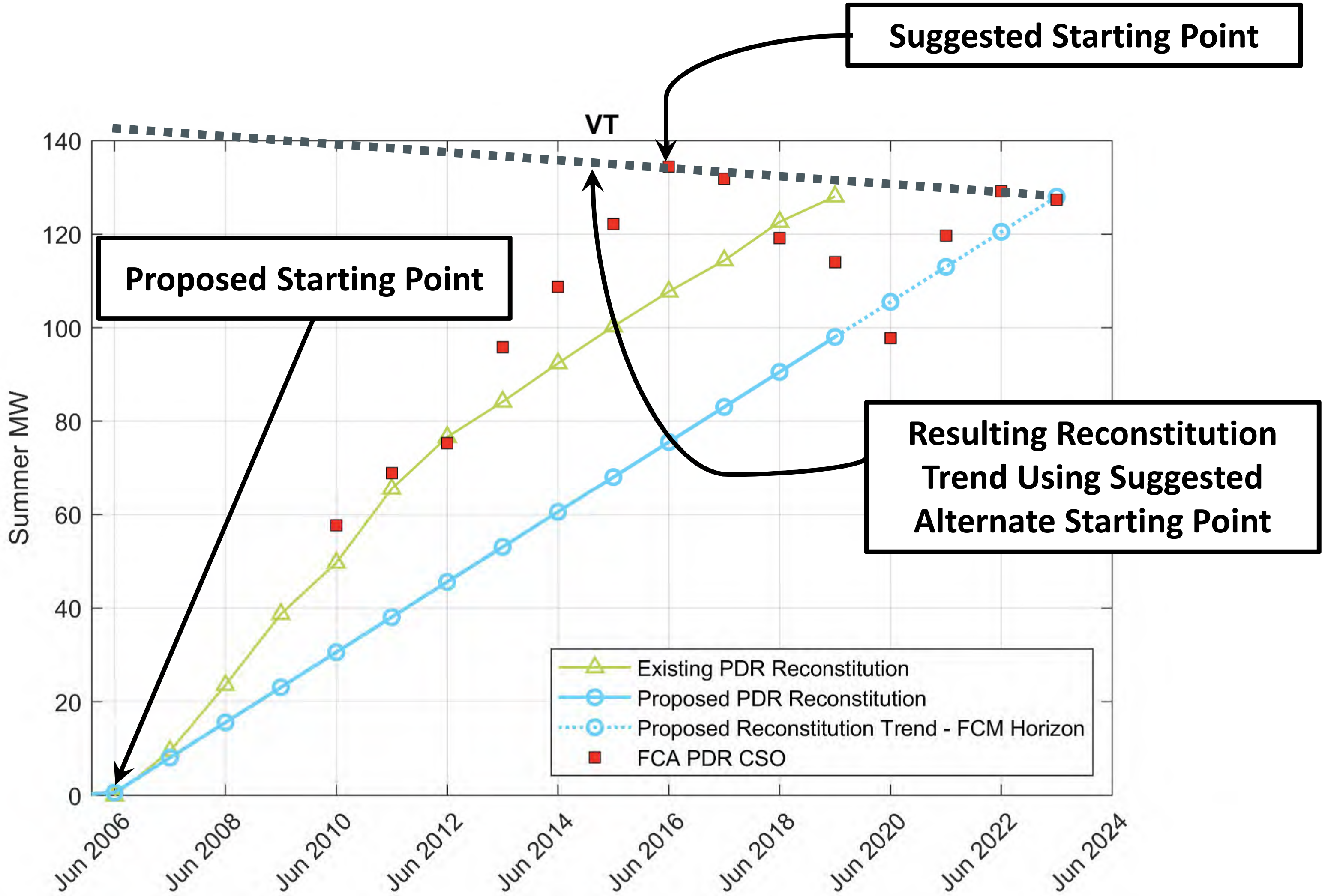
Proposed PDR Reconstitution Methodology

Alternate Starting Point (Slide 2 of 2)

- The revised reconstitution methodology needs to be implemented for all long-term gross forecast modeling, which is performed for:
  - ***The region and all states separately***
  - Both summer and winter months
- Individual state FCA CSO trends may be different from those of the aggregate region, and are an important consideration in evaluating the proposed methodology
- Application of the proposed methodology to the state of Vermont (summer) is illustrated on the following slide as it would have applied to CELT 2020
  - The proposed methodology and the use of June 2016 as a starting point are both illustrated
- Using June 2016 as a starting point results in a reconstitution trend line with a negative slope (i.e., it suggests a decreasing amount of PDR over time), which does not reflect the longer-term CSO trend

Proposed PDR Reconstitution Methodology

CELT 2020 Application – Vermont, Summer



Suggested Starting Point

Proposed Starting Point

Resulting Reconstitution Trend Using Suggested Alternate Starting Point

PROPOSED TARIFF REVISIONS

Section 12.8

Proposed Tariff Revisions to Memorialize and Reflect Modifications to the Accounting Methodology for Reconstitution

Proposed Effective Date: October 5, 2020

- The proposed tariff revisions in Section 12.8:
  1. Memorialize the current accounting methodology for the reconstitution of active demand resources by adding language in subsection (a). The previous language in subsection (a) is no longer needed and is being deleted.
  2. Delete subsection (b) because, given the new language in subsections (a) and (d), it is no no longer needed.
  3. Modify subsection (d) to memorialize the proposed accounting methodology for PDR reconstitution for the FCAs (summer and winter), and forecast adjustments to account for the ARAs. The previous language in subsection (d), which reflects the previous accounting methodology, is being deleted.
- Non-substantive changes to the preamble of Section 12.8 were shown in the Tariff sheets circulated for the June 16 RC meeting, but they were not included in the June 16 RC presentation
  - The changes to the preamble are included in this presentation
  - The term “Demand Capacity Resources” had been used in the version circulated for the June 16 RC meeting; the final version has been revised to use the more precise defined terms “Demand Response Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources”
- All Tariff language except for the preamble is included in Appendix I

Proposed Tariff Changes

Tariff Section	Tariff Change	Reason for Change
Section 12.8 Preamble	To ensure that **Demand Response Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources** are not reflected as reductions in the load forecast, ~~Demand Capacity Resources~~ the ISO shall ~~be~~ reflect them~~ed~~ in historical loads ~~the load forecast~~ as specified below.~~:~~	Include the purpose for all subsections in the preamble (formerly included in subsection (d)); use active voice

Proposed Schedule

Timeline for Revising the Existing PDR Reconstitution Methodology

Date	Topic
April 22	Provide RC with background on EE's participation in FCM, its reconstitution in the gross load forecast, and the need for revising the current reconstitution methodology
May 19	Present proposed PDR reconstitution methodology used for FCAs and other relevant information
June 16	Present proposed method for adjusting the gross load forecast to reflect the amount of PDR participation in ARAs, and tariff changes related to changes to PDR reconstitution
July 21	RC review and vote of proposed changes
August 6	PC vote of proposed changes
August 6	File with FERC proposed tariff changes with a requested effective date of October 5, 2020
Q4 2020	RC Kick off 2021 CELT forecast using the revised reconstitution methodology; the revised reconstitution methodology will be implemented for 2021 (assuming FERC acceptance of the ISO's proposed revisions to Section III.12.8 (d))

Questions

APPENDIX I

Tariff Revisions (Except Preamble)

Proposed Tariff Changes

Tariff Section	Tariff Change	Reason for Change
Section 12.8 (a)	(a) The ISO shall add back into historical loads the metered MW demand reduction of Demand Response Resources dispatched by the ISO. ~~Expected reductions from an installed or forecast Demand Capacity Resource not qualifying for or not participating in the Forward Capacity Auction shall be reflected as a reduction in the load forecast that will be used to determine the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values for the relevant Capacity Commitment Period. The expected reduction from these resources will be included in the load forecast to the extent that they meet the qualification process rules, including monitoring and verification plan and financial assurance requirements. If no qualification process rules are in place for the expected reductions from these resources, they shall not be included within the load forecast.~~	The new language reflects the current reconstitution methodology for active demand resources; the old language is no longer needed.

Proposed Tariff Changes, cont.

Tariff Section	Tariff Change	Reason for Change
Section 12.8 (b)	[Reserved.] ~~Expected reductions from an installed or forecast Demand Capacity Resource that qualifies to participate in the Forward Capacity Market, participates but does not clear in the Forward Capacity Auction, or has cleared in a previous Forward Capacity Auction and is expected to continue in the Forward Capacity Market shall not be reflected as a reduction in the load forecast that will be used to determine the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values for the relevant Capacity Commitment Period.~~	This language is no longer needed because: (1) new language in subsections (a) and (d) address, respectively, active and passive demand resources; therefore, language for “Demand Capacity Resources” is no longer needed; and (2) the new accounting methodology uses CSOs, not Qualified Capacity, so this subsection does not fit within the new methodology.

Proposed Tariff Changes, cont.

Tariff Section	Tariff Change	Reason for Change
Section 12.8 (d)	(d) The ISO shall add back into historical loads summer and winter MW values to account for On-Peak Demand Resources and Seasonal Peak Demand Resources as follows: The ISO shall develop a trend line between (i) the point when summer MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are assumed to be zero (June 1, 2006) and (ii) the point when summer MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are reflected by the Capacity Supply Obligations that those resources acquired in the most recent Forward Capacity Auction for June 1 of the associated Capacity Commitment Period. To determine the summer MW values to be added back into historical loads, the ISO shall apply the resulting trend to the summer months (April through November) in all the historical years covered by the trend line.	This language memorializes the accounting methodology for PDR reconstitution for the FCAs (summer values)

Proposed Tariff Changes, cont.

Tariff Section	Tariff Change	Reason for Change
Section 12.8 (d)	The ISO shall develop a trend line between (i) the point when winter MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are assumed to be zero (December 1, 2006) and (ii) the point when winter MW values for On-Peak Demand Resources and Seasonal Peak Demand Resources are reflected by the Capacity Supply Obligations that those resources acquired in the most recent Forward Capacity Auction for December 1 of the associated Capacity Commitment Period. To determine the winter MW values to be added back into historical loads, the ISO shall apply the resulting trend to the winter months (December through March) in all the historical years covered by the trend line.	This language memorializes the accounting methodology for PDR reconstitution for FCAs (winter values)

Proposed Tariff Changes, cont.

Tariff Section	Tariff Change	Reason for Change
Section 12.8 (d)	The ISO shall make adjustments to forecasted loads to account for any differences between the most recently available MW values reflective of the Capacity Supply Obligations that On-Peak Demand Resources and Seasonal Peak Demand Resources acquired in each of the annual reconfiguration auctions and the MW values reflective of the Capacity Supply Obligations that those resources acquired in the corresponding Forward Capacity Auctions.	This language memorializes the adjustments to account for the ARAs.

Proposed Tariff Changes, cont.

Tariff Section	Tariff Change	Reason for Change
Section 12.8 (d)	~~Any realized Demand Capacity Resource reductions in the historical period that received Forward Capacity Market payments for these reductions, or Demand Capacity Resource reductions that are expected to receive Forward Capacity Market payments by participating in the upcoming Forward Capacity Auction or having cleared in a previous Forward Capacity Auction, shall be added back into the appropriate historical loads to ensure that such resources are not reflected as a reduction in the load forecast that will be used to determine the Installed Capacity Requirement, Local Sourcing Requirements, Maximum Capacity Limits and Marginal Reliability Impact values for the relevant Capacity Commitment Period.~~	Previous language is no longer needed.

APPENDIX II

Acronyms

Acronyms

- ARA – Annual Reconfiguration Auction
- CELT – Capacity, Energy, Loads and Transmission
- CSO – Capacity Supply Obligation
- DG – Distributed Generation
- EE – Energy Efficiency
- FCA – Forward Capacity Auction
- FCM – Forward Capacity Market
- FERC – Federal Energy Regulatory Commission
- ICR – Installed Capacity Requirement
- ISO – ISO New England
- LFC- Load Forecast Committee
- PA – Energy Efficiency Program Administrator

Acronyms

- PC – NEPOOL Participants Committee
- PDR – Passive Demand Resources
- RC – NEPOOL Reliability Committee

ISO new england

memo

To: Participants Committee

From: Marc Lyons, Secretary, Reliability Committee

Date: July 21, 2020

Subject: Actions of the Reliability Committee from the July 21, 2020 Meeting

This memo is to notify the Participants Committee ("PC") of the actions taken by the Reliability Committee ("RC") at its July 21, 2020 meeting. All Sectors had a quorum.

(Agenda Item 1.A) Meeting Minutes

ACTION: APPROVED

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

RESOLVED, that the Reliability Committee approves the minutes for June 16, 2020 meeting of the Reliability Committee, as circulated for the July 21, 2020 meeting, with such further non-substantive changes as the Chair and Vice-Chair may approve.

The motion was then voted. Based on a voice vote, the motion passed with none opposed and no abstentions.

(Agenda Item 3.1) (66.67% Vote) SR Litchfield Solar Project - Proposed Plan Application (PPA) ES-20-G167

ACTION: APPROVED

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

Resolved, the Reliability Committee recommends that ISO New England Inc. determine that implementation of the SR Litchfield Solar Project described in Proposed Plan Application ("PPA"), ES-20-G167 from Eversource Energy ("ES"), as detailed in their June 23, 2020 transmittal to ISO New England and distributed to the committee for the July 21, 2020 meeting, will not have a significant adverse effect on the stability, reliability or operating characteristics of the transmission facilities of the applicant, the transmission facilities of another Transmission Owner or the system of a Market Participant.

Resolved, the Reliability Committee recommends that ISO New England Inc. determine that implementation of the Vineyard Wind Revisions Project described in Proposed Plan Applications ("PPAs") VW-10-G01-Rev. 1, VW-19-T01-Rev. 1, VW-19-T02-Rev. 1, VW-19-T03-Rev. 1, VW-19-T04-Rev.1, and VW-19-T05-Rev. 1 from Vineyard Wind ("VW"), as detailed in their July 7, 2020 transmittal to ISO New England and distributed to the committee for the July 21, 2020 meeting, will not have a significant adverse effect on the stability, reliability or operating characteristics of the transmission facilities of the applicant, the transmission facilities of another Transmission Owner or the system of a Market Participant.

The motion was then voted. Based on a voice vote, the motion passed with none opposed and no abstentions.

(Agenda Item 4.1) (66.67% Vote) PTF Cost Allocation - TCA Application VELCO-20-TCA-03

ACTION: APPROVED

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

Resolved, the Reliability Committee has reviewed the requested $6.603M (Estimated Costs 2019-2025) of Transmission Upgrade costs for work to address asset condition issues at the Berlin Substation by replacing obsolete relays, breakers and circuit switchers. Expand and relocate the control building to accommodate protection and control systems, communication systems and add high-speed protection as described in TCA Application VELCO-20-TCA-03 submitted to ISO New England on July 8, 2020 by Vermont Electric Power Company (VELCO); and the Reliability Committee recommends that ISO New England approve, as consistent with the criteria set forth in Section 12C of the ISO New England Open Access Transmission Tariff for receiving regional support and inclusion in Pool-Supported PTF Rates, the requested $6.603M as eligible for Pool-Supported PTF cost recovery and with none of the costs associated with such upgrades being considered Localized Costs.

The motion was then voted. Based on a voice vote, the motion passed with none opposed and no abstentions.

(Agenda Item 6.0) (60.0% Vote) Gross Load Forecast Reconstitution Methodology Changes

ACTION: APPROVED

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

Resolved, the Reliability Committee recommends Participants Committee support for revision of Section III.12.8 of the ISO New England Operating Tariff as part of the Gross Load Forecast Reconstitution Methodology Changes and as distributed to the committee for the July 21, 2020 meeting, together with such other changes as discussed and agreed to at the meeting, and such other non-material changes as may be approved by the Chair and Vice-Chair of the Reliability Committee following the meeting.

The motion was then voted. Based on a roll call vote, the motion passed with 60.62% in favor. (Generation Sector – 0.0% in favor, 16.70%, 1 abstention, Transmission Sector – 16.7% in favor, 0.0% opposed, 0 abstentions, Supplier Sector – 4.18% in favor, 12.53% opposed, 5 abstentions, Publicly Owned Sector – 16.7% in favor, 0.0% opposed, 2 abstentions, Alternative Resource Sector – 6.35% in favor, 10.15% opposed, 0 abstentions, End User Sector – 16.7% in favor, 0.0% opposed, 0 abstentions)

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

The following activity, as more fully described in the attached litigation report, has occurred since the report dated July 10, 2020 ("last Report") was circulated. New matters/proceedings since the last Report are preceded by an asterisk '*'. Page numbers precede the matter description.

COVID-19

1	Jul 8-9 Tech Conf: Impacts of COVID-19 on the Energy Industry (AD20-17)	Jul 16	FERC invites post-technical conference comments on any or all of the topics discussed at the tech. conf., as well as on any of the questions outlined in the Jul 1 supplemental notice of the tech. conf.; comment date Aug 31
1	Remote ALJ Hearings (AD20-12)	Jul 13	Office of ALJs posts "Remote Hearing Guidance for Participants", including information on WebEx and SharePoint, the two platforms that will be used for all remote hearings

I. Complaints/Section 206 Proceedings

2	206 Proceeding: FCM Pricing Rules Complaints Remand (EL20-54)	Jul 13-29	ISO-NE, ISO-NE EMM, Avangrid, CPV Towantic, Dominion, FirstLight, HQUS, MMWEC, National Grid, NHEC, NTE Energy, Talen, Vistra, NEPGA, EPSA, CT AG, CT DEEP, CT PURA, MA DPU (out-of-time) intervene; initial briefs due Aug 24, 2020
3	Exelon PP-10 Complaint (EL20-52)	Jul 13	Avangrid answers Jun 23 Motion to Lodge Anbaric letter and Anbaric comments
		Jul 15	Anbaric answers ISO-NE and Avangrid answers
		Jul 27	NEPOOL, ISO-NE, NEPGA, Vistra answer Exelon's Jul 10 answer
		Aug 3	Exelon answers NEPOOL's and ISO-NE's Jul 27 answers
4	NERA Petition: FERC Jurisdiction Over Customer-Side-of-the-Retail-Meter Energy Sales (EL20-42)	Jul 15	Oxenham's file answer to NERA's Jun 30 Answer
		Jul 16	FERC unanimously dismisses (on procedural grounds) NERA Petition
4	Liberty Complaint – Eversource/ISO-NE Failure to Correct Nov 2018 Meter Data Error/Load Assignment (EL20-27)	Jul 16	FERC denies Complaint
5	206 Investigation Terminated: ISO-NE Implementation of *Order 1000* Exemptions for Immediate Need Reliability Projects (EL19-90)	Jul 17	CT/MA Parties request rehearing of *Order Terminating Proceeding*
		Jul 20	LS Power, MMWEC/NHEC request rehearing of *Order Terminating Proceeding*; CT/MA Parties file errata to their Jul 17 request; FERC action required on or before Aug 17, 2020
5	206 Proceeding: RNS/LNS Rates and Rate Protocols (ER20-2054; EL16-19-002)	Jul 15	TOs file reply comments in support of Settlement Agreement II
		Jul 29	MA DPU intervenes

II. Rate, ICR, FCA, Cost Recovery Filings

8	FCA15 De-List Bids Filing (ER20-2317)	Jul 20	National grid intervenes

	9	Mystic 8/9 Cost of Service Agreement (ER18-1639)	Jul 17	***Jul 2018 Order***: FERC modifies the discussion in the July 2018 Order, reaches the same result, grants clarification in part, and denies clarification in part
			Jul 17	***Dec 2018 Order***: FERC modifies the discussion in the Dec 2018 Order, sets aside the Order in part, grants clarification in part, denies clarification in part, and directs additional compliance
			Jul 17	***Mar 2019 Compliance Filing***: FERC accepts in part, and rejects in part, the Mar 1, 2019 compliance filing and directs a further compliance filing due on or before Sep 15, 2020
			Jul 28	***ROE Paper Hearing***: FERC reopens record to allow parties an opportunity to present written evidence applying the FERC's *Opinion 569-A* ROE methodology to the facts of this proceeding; initial briefs due Sep 28, 2020; responses to those initial briefs, Oct 28, 2020
*	12	2020/2021 Power Year Transmission Rate Filing (ER09-1532; RT04-2)	Jul 31	PTO AC submits informational filing identifying adjustments to regional transmission service charges for the Jun 1, 2020 to May 31, 2021 period (RNS Rate of $129.26/kW-year and a Schedule 1 formula rate of $1.745 kW-year, increases of $17.32 /kW-year and $0.152/kW-year, respectively); this filing will not be noticed for public comment
*	12	ISO Securities: Authorization for Future Drawdowns (ES20-46)	Jul 13	FERC authorizes continued ISO-NE drawdowns under its $20 million Revolving Credit Line and $4 million line of credit supporting the Payment Default Shortfall Fund through Jul 12, 2022

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

*	12	Information Policy §2.3 Revisions (ER20-2518)	Jul 28	ISO-NE and NEPOOL file enhancements/ clarifications to Info Policy; comment date Aug 18
			Jul 29-30	Calpine, Exelon intervene
*	12	DAM Offer Window Modification (ER20-2511)	Jul 27	ISO-NE and NEPOOL files changes to extend by 30 minutes the Day-Ahead Energy Market ("DAM") offer window; comment date Aug 17
			Jul 28-30	Calpine, Exelon, FirstLight, PSEG intervene
	13	EE CSOs During Scarcity Conditions (ER20-1967)	Jul 21	FERC accepts EE Changes, eff. Aug 1, 2020
			Aug 1	EE Changes become effective
	14	Inventoried Energy Program (Chapter 2B) Remand (ER19-1428)	Jul 17	MPUC, Sierra Club/UCS request rehearing of *IEP Remand Order*
			Jul 20	MA AG, NECOS/ENE, NH PUC/NH OCA request rehearing of *IEP Remand Order*
	15	*Order 841* Compliance Filings (Electric Storage in RTO/ISO Markets) (ER19-470)	Aug 4	FERC conditionally accepts *Order 841* Compliance Filing II, eff. Dec 19, 2019, with a limited number of revisions to become eff. Jan 1, 2026

IV. OATT Amendments / TOAs / Coordination Agreements

	20	CIP IROL Cost Recovery Rules (ER20-739)	Jul 27	FERC issues Notice of Denial by Operation of Law of the IROL-Critical Facility Owners' Jun 25 request for reh'g of *CIP IROL Cost Recovery Order,* though it indicated that the request would be addressed in a future order (which can be issued up until the record of the proceeding is filed with the Court of Appeals)
	21	*Order 845* Compliance Filing II (ER19-1951-002)	Jul 17	ISO-NE, NEPOOL, PTO AC submit *Order 845* Compliance Filing II; comment date Aug 7

V. Financial Assurance/Billing Policy Amendments

	22	Billing Policy Enhancements and Clean-Up Changes (ER20-1862)	Jul 24	FERC accepts changes, eff. Jul 27, 2020

VI. Schedule 20/21/22/23 Changes

*	22	Schedule 22: NSTAR/Vineyard Wind LGIA (ER20-2489)	Jul 23	NSTAR files LGIA; comment date Aug 13
*	22	Schedule 21-NEP: DWW E&P Agreement (ER20-2454)	Jul 17	NEP files E&P Agreement; comment date Aug 7
*	22	Schedule 21-UI: LCSA: UI/ NextEra (ER20-2449)	Jul 17	UI files LCSA with NextEra to recover NextEra's Category B Load Ratio Share of the revenue requirement for UI's Localized Facilities under Schedule 21-UI; comment date Aug 7
			Jul 20	Eversource intervenes
*	23	Schedule 21-FG&E Annual Informational Filing (ER09-1498)	Jul 31	FG&E submits annual update to its Revenue Requirement recovered through the ISO-NE Tariff and Schedule 21-FG&E for the Jun 1, 2020 – May 31, 2021 period

VII. NEPOOL Agreement/Participants Agreement Amendments

No Activity to Report

VIII. Regional Reports

*	24	LFTR Implementation: 47th Quarterly Status Report (ER07-476)	Jul 15	ISO-NE files its 47th quarterly report
*	24	IMM Quarterly Markets Reports - 2020 Spring (ZZ20-4)	Jul 31	IMM files Spring 2020 Report

IX. Membership Filings

*	24	August 2020 Membership Filing (ER20-2581)	Jul 31	***New Members***: Blueprint Power Technologies (Provisional Member) and Advanced Energy Economy (Fuels Industry Participant); and ***Terminations***: New Hampshire Industries Inc. and The Energy Council of Rhode Island; comment date Aug 21
	25	June 2020 Membership Filing (ER20-1943)	Jul 30	FERC accepts (i) the memberships of: Actual Energy, Borrego Solar Systems, Paper Birch Energy, Priogen Power, and Standard Normal Energy; (ii) the termination of the Participant status of: Royal Bank of Canada, Wallingford Energy II and Agera Energy; and (iii) the name changes of: Versant Power and IPKeys Power Partners, Inc.

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

	26	NOI: Virtualization and Cloud Computing Services in BES Operations (RM20-8)	Jul 31	AEE, Amazon, Microsoft file reply comments
	28	Report of Comparisons of Budgeted to Actual Costs for 2019 for NERC and the Regional Entities (RR20-3)	Jul 21	NERC supplements report with final, audited 2019 financial report for Texas RE; comment date Aug 11

XI. Misc. - of Regional Interest

	28	*Opinion 569-A*: FERC's Base ROE Methodology (EL14-12; EL15-45)	Jul 22	FERC issues Notice of Denial by Operation of Law of requests for reh'g of *Opinion 569-A,* though it indicated that the request would be addressed in a future order (which can be issued up until the record of the proceeding is filed with the Court of Appeals)
*	29	VTransco Rate Schedule Cancellations (ER20-2507)	Jul 27	VTransco files notice of cancellation of 2 rate schedules no longer in use; comment date Aug 17
	29	Termination of IA and NITSA between Versant Power & Houlton Water Company (ER20-1919/1914)	Jul 24 Jul 27	FERC accepts NITSA termination notice, eff. May 15, 2020 FERC accepts IA termination notice, eff. May 15, 2020
	30	NSTAR TSA Cancellations (ER20-1896)	Jul 23	FERC accepts Transmission Service Agreement cancellations, eff. Jul 27, 2020
*	30	D&E Agreement: NSTAR-Mayflower Wind (ER20-1855)	Jul 14	FERC accepts Agreement, eff. May 19, 2020

XII. Misc. - Administrative & Rulemaking Proceedings

	31	Hybrid Resources Tech Conf (Jul 23, 2020) (AD20-9)	Jul 13 Jul 23 Jul 29	FERC issues supplemental notice of tech conf. FERC holds tech. conf. Speaker materials posted to eLibrary
	33	Increasing Market & Planning Efficiency Through Improved Software Tech Conf (AD10-12)	Jul 10	Speaker materials from Jun 23-25 tech. conf. posted to eLibrary
	33	NOPR – Electric Transmission Incentives Policy (RM20-10)	Jul 16	AEP, ITC Holding, the N. California Transmission Agency, and WIRES file reply comments
	34	*Order 872*: Pricing and Eligibility Changes to PURPA Regulations (RM19-15)	Jul 16	FERC issues final order approving revisions to its PURPA regulations

XIII. Natural Gas Proceedings

	43	Iroquois ExC Project (CP20-48)	Jul 10 Jul 28 Jul 30 Jul 31	NYS DEC files comments on Sensitive Species Habitat Assessment Rpt Iroquois responds to NYS DEC Jul 10 comments Iroquois files supplemental information FERC issues data request; response date Aug 7

XIV. State Proceedings & Federal Legislative Proceedings

No Activity to Report

XV. Federal Courts

*	45	2013/14 Winter Reliability Program Remand Proceeding (20-1289)	Jul 30	TransCanada appeals *2013/14 Winter Reliability Program Order on Remand and Compliance*; appearances due Aug 31, 2020
	46	*Allegheny Defense Project v. FERC* (19-1098)	Jul 23	DC Circuit issues *per curiam* order staying issuance of the mandate through Oct 5, 2020, as requested by the FERC
	48	Opinion 569/569-A: FERC's Base ROE Methodology (16-1325, 20-1227)	Jul 10	Court consolidates FirstEnergy and Transource cases; Transource directed to file a Docketing Statement and Statement of Issues by Aug 10, 2020

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Patrick M. Gerity, NEPOOL Counsel

DATE: August 4, 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 August 4, 2020. If you have questions, please contact us.

COVID-19

- **Jul 8-9 Tech Conf: Impacts of COVID-19 on the Energy Industry (AD20-17)**

On July 8-9, 2020, the FERC convened a Commissioner-led technical conference to explore the potential longer-term impacts of the emergency conditions caused by COVID-19 on FERC-jurisdictional entities "in order to ensure the continued efficient functioning of energy markets, transmission of electricity, transportation of natural gas and oil, and reliable operation of energy infrastructure today and in the future, while also protecting consumers". The conference included consideration of: (i) the energy industry's ongoing and potential future operational and planning challenges due to COVID-19 and as the situation evolves moving forward; (ii) the potential impacts of changes in electric demand on operations, planning, and infrastructure development; (iii) the potential impacts of changes in natural gas and oil demand on operations, planning, and infrastructure development; and (iv) issues related to access to capital, including credit, liquidity, and return on equity. Comments and speaker opening statements are posted in eLibrary.

Since the last Report, on July 16, 2020, the FERC invited all interested parties to file post-technical conference comments on any or all of the topics discussed at the July 8-9 technical conference, as well as to respond to the questions outlined in the July 1, 2020 supplemental notice of technical conference. Comments must be submitted on or before August 31, 2020.

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

All hearings before Administrative Law Judges ("ALJs") will be held remotely through video conference software until further notice.[2] The Presiding Judge in each remote hearing will ensure that the participants have access to an IT Day prior to the hearing to allow all participants, witnesses, and the public who will attend the hearing to learn more about the remote hearing software and to get their technical questions answered by the appropriate FERC staff. Since the last Report, on July 13, 2020, the Office of ALJs posted "Remote Hearing Guidance for Participants", including information on WebEx and SharePoint, the two platforms that will be used for all remote hearings.

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

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

Entities may seek waiver of FERC orders, regulations, tariffs and rate schedules, including motions for waiver of regulations that govern the form of filings, as appropriate, to address needs resulting from steps they have taken in response to the coronavirus. The FERC committed to take action on any such motions as expeditiously as possible.[3] In addition, FERC's regulations that require that filings with the FERC be notarized or supported by sworn declarations are waived through September 1, 2020.[4]

- **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[5] 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 took the action given the President's proclamation of a National Emergency, the unprecedented risk to health and safety currently presented by personal contact, and to be 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.

I. Complaints/Section 206 Proceedings

- **206 Proceeding: FCM Pricing Rules Complaints Remand (EL20-54)**

In response to the February 2, 2018 remand by the United States Court of Appeals for the District of Columbia Circuit ("DC Circuit")[6] (where the DC Circuit found that the FERC did not adequately explain why it allowed ISO-NE to forego an offer floor for its seven-year price lock period despite previously rejecting PJM's request to remove the offer floor for its three-year price lock period), the FERC instituted this proceeding, pursuant to section 206 of the FPA, finding preliminarily that ISO-NE's new entrant rules may be unjust and unreasonable.[7] The FERC established paper hearing procedures and posed the following questions, which need to be addressed in initial briefs due on or before ***August 24, 2020***:[8]

(a) ***to evaluate the need for the price lock in its entirety***: (i) how many resources have taken advantage of the price lock to date? (ii) is a price lock still needed to incent new entry in ISO-NE? (iii) does the price lock lead to unreasonable price suppression in the entry year? (iv) does the price lock with the zero-price offer rule result in unreasonable price suppression in years 2-7? (v) is the price lock unduly discriminatory? and (vi) if the price lock is retained, should the term be shortened and, if so, what would be a just and reasonable term?

(b) ***to evaluate retaining the price-lock and adding an offer floor***: (i) how would an offer floor be implemented? (2) would an offer floor require significant market redesign? and (iii) what would be the timeline for implementing an offer floor in ISO-NE?

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

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

[5] 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.

[6] *New England Power Generators Assoc. v FERC*, 881 F.3d 202 (DC Cir. 2018) (granting NEPGA's and Exelon's petitions for review of orders accepting the Forward Capacity Market's ("FCM") 7-year price lock-in (EL14-7) and capacity-carry-forward rules (EL15-23)).

[7] *ISO New England Inc.*, 172 FERC ¶ 61,005 (Jul 1, 2020) ("*FCM Pricing Rules Complaints Remand Order*").

[8] Notice of the initiation of this proceeding was published in the *Fed. Reg.* on July 9, 2020 (Vol. 85, No. 132) p. 41,237. Aug. 24, 2020 is the first business day that is 45 days after publication.

(c) ***to evaluate whether to impose an alternative replacement rate***: (i) are there alternative approaches to the current price-lock that would be sufficient to incent new entry? (ii) how would these alternative approaches address any concerns related to unreasonable price suppression? and (iii) how would these alternative approaches address any concerns related to undue discriminatory or preferential treatment?

Interventions were due on or before ***July 22, 2020***. Responses to initial briefs will be due ***September 23, 2020*** (30 days after the date that the initial briefs are due). No additional answers or briefs will be permitted. In order to accept the changes originally filed, the FERC must provide some analysis and explanation why it changed course. The FERC established July 9, 2020 (the date of publication in the *Federal Register*) as the refund effective date. The FERC noted its expectation that it would issue a final order in this proceeding within the 180-day period contemplated under FPA section 206(b). Interventions were filed by NEPOOL, ISO-NE, ISO-NE EMM, Avangrid, Brookfield, Calpine, CPV Towantic, Dominion, Energy New England ("ENE"), Eversource, Exelon, FirstLight, HQUS, LS Power, Massachusetts Attorney General ("MA AG"), MMWEC, National Grid, NESCOE, NHEC, NextEra, NRG, NTE Energy, Talen, Vistra, NEPGA, EPSA, CT AG, CT DEEP, CT PURA, MA DPU (out-of-time), PJM EMM, 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).

- **Exelon PP-10 Complaint (EL20-52)**

On June 10, 2020, Constellation Mystic Power, LLC ("Exelon") filed a complaint against ISO-NE requesting that the FERC prohibit ISO-NE from (i) implementing changes to Planning Procedure No. 10 (Planning Procedure to Support the Forward Capacity Market),[9] which it asserted would significantly affect the rates, terms and conditions of jurisdictional services by dramatically changing the way in which ISO-NE conducts its annual transmission security review of capacity auction retirement bids and the Network Model upon which the capacity auction is based, and (ii) violating the requirements of its Tariff for *Order 1000* competitive transmission procurements. Exelon requested fast track processing, a shortened 14-day answer period (which was not granted), and an order by August 4, 2020, which Exelon asserted would provide ISO-NE time to revise its transmission security review currently underway should the Complaint be granted.

ISO-NE's response, as well as comments, protests and answers, to the Complaint were due on or before June 30, 2020, and were filed by ISO-NE, ISO-NE IMM, NEPOOL, Anbaric, EMCOS, FirstLight, MA AG, NEPGA, NESCOE, TOs (Avangrid, Eversource, Nat'l Grid and VELCO), Versant Power (out-of-time), Vistra, and EPSA. Doc-less interventions only were filed by Brookfield, Calpine, Dominion, ENE, Footprint, LS Power, MMWEC, NextEra, NRG, Southern Power, CT AG, CT DEEP, CT PURA, MA DPU, and the NY TOs. Also, on June 23, Exelon moved to lodge a June 16 letter from Anbaric to ISO-NE. ISO-NE opposed that motion on July 8. On July 10, Exelon answered ISO-NE and protesters.

Since the last Report, Avangrid answered Exelon's June 23 motion to lodge the Anbaric letter and Anbaric's comments. On July 15, Anbaric answers ISO-NE and Avangrid's answers. On July 27, NEPOOL, ISO-NE, NEPGA, and Vistra answered Exelon's July 10 answer. 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) or Sophia Browning (202-218-3904; sbrowning@daypitney.com).

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[9] The PP-10 Revisions were supported by the Participants Committee at its June 4 meeting by a vote of 99.12% in support (only Exelon opposing).

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

On July 16, 2020, the FERC unanimously dismissed[10] (on procedural grounds) the April 14, 2020 petition of the New England Ratepayers Association ("NERA").[11] Rather than address the issues raised by NERA in the petition, the FERC exercised its broad discretion not to address the issues on the merits, finding "the issues presented in the Petition do not warrant a generic statement from the Commission at this time" and finding no specific controversy or harm to be addressed.[12] In so doing, the *NERA Order* leaves in place for now state net metering programs that NERA had sought to invalidate, and leaves for another day a decision on the jurisdictional issues underlying the petition. In separate concurring opinions, both Commissioners McNamee and Danly addressed the need to resolve the jurisdictional issues, with Commissioner Danly stating a concern that the *NERA Order* could well result in a "patchwork quilt of conflicting decisions" if the jurisdictional issues are addressed by federal district courts across the country. "Confusion, delay and inconsistent rules—some of which will apply to individual states or parts of states—will be the inevitable result."[13] Challenges, if any, to the *NERA Order* will be due on or before August 17, 2020. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

Also on July 16, 2020, the FERC denied Liberty's February 28, 2020 Meter Data Error Complaint.[14] As previously reported, Liberty Power Holdings, LLC ("Liberty") filed the 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 described in the Complaint, provided a basis for the correction beyond the three-month period for RBA submissions.[15] The amount in dispute was $191,440 plus interest ("Disputed Amount").

In denying the Complaint, the FERC found that ISO-NE's refusal to correct the November 2018 billing error did not violate the ISO-NE Tariff or the filed rate doctrine.[16] Rather, the FERC found, ISO-NE followed the applicable Tariff provisions with respect to Liberty's untimely request for a billing adjustment and, therefore, Liberty was not entitled to the requested November 2018 billing adjustment.[17] Liberty's failure to review the

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[10] *New England Ratepayers Assoc.*, 172 FERC ¶ 61,042 (July 16, 2020) ("*NERA Order*").

[11] The NERA petition 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.

[12] *Id.* at PP 35-36.

[13] Danly, Commissioner, concurring at P 4.

[14] *Liberty Power Holdings LLC v. Eversource Energy Co. and ISO New England Inc.*, 172 FERC ¶ 61,031 (July 16, 2020) ("*Liberty Complaint Order*").

[15] *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.

[16] *Liberty Complaint Order* at P 27.

[17] *Id.* at P 23.

data in a timely fashion was the reason that the error was not discovered by the deadline.[18] The FERC disagreed with Liberty that section 6.3.1 of the ISO-NE Billing Policy applied.[19] Unless Liberty challenges the *Liberty Complaint Order* on or before August 17, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

Challenges to the FERC's June 18, 2020 order terminating this FPA Section 206 proceeding[20] were filed by CT PURA/CT OCC/MA AG ("CT/MA Parties"), LS Power and MMWEC/NHEC. As previously reported, in the *Order Terminating Proceeding*, the FERC found (i) "insufficient evidence in the record to find under FPA section 206 that [ISO-NE's] implementation of the exemption for immediate need reliability projects is unjust, unreasonable, or unduly discriminatory or preferential;[21] (ii) "insufficient evidence in the record to find that ISO-NE implemented the immediate need reliability project exemption in a manner that is inconsistent with or more expansive than [the FERC] directed";[22] and (iii) that ISO-NE complies with the five criteria established for the immediate need reliability project exemption.[23] The requests for rehearing challenged the FERC's decision not to act under Section 206 and are pending, with FERC action required on or before August 17, 2020 (the first business day that is 30 days from the day that CT/MA Parties request for rehearing was filed), or the requests will be deemed denied by operation of law. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **RNS/LNS Rates and Rate Protocols Settlement Agreement II (ER20-2054; EL16-19-002)**

On June 15, 2020, the Transmission Owners submitted, on behalf of the Settling Parties, an uncontested Joint Offer of Settlement ("Settlement Agreement II") to resolve all issues in Docket No. EL16-19, a Section 206 proceeding first instituted by the FERC on December 28, 2015.[24] Recall that, as previously reported, the first joint offer of settlement filed ("Settlement Agreement I") was contested[25] and subsequently rejected by the FERC.[26] The Tariff changes included with Settlement Agreement II were considered through the Participants Processes

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[18] Id. at

[19] *Id.* at P 24.

[20] *ISO New England Inc.*, 171 FERC ¶ 61,211 (June 18, 2020) ("*Order Terminating Proceeding*").

[21] *Order Terminating Proceeding* at PP 1, 11.

[22] *Id.* a P 11.

[23] *Id.*

[24] *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.

[25] Settlement Agreement I was opposed by FERC Trial Staff and "Municipal PTF Owners" (Braintree, Chicopee, Middleborough, Norwood, Reading, Taunton, and Wallingford).

[26] 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. 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. However, the FERC found insufficient detailed information to enable it to apply any of the approaches available to it to approve a contested settlement and remanded the proceeding (EL16-19) to Chief Judge Cintron to resume hearing procedures. *ISO New England Inc. Participating Transmission Owners Admin. Comm., et al.*, 167 FERC ¶ 61,164 (May 22, 2019) ("*RNS Rate/Rate Protocol Settlement I Order*").

(Transmission and Participants Committee review), and supported by the Participants Committee at its June 4, 2020 meeting (Agenda Item # 13).

Comments on Settlement Agreement II were due on or before July 6, 2020. NEPOOL filed comments supporting the Tariff changes included with Settlement Agreement II. FERC Trial Staff filed comments not opposing Settlement Agreement II. On July 15, 2020, the TOs filed reply comments supporting Settlement Agreement II. On July 29, 2020, the MA DPU intervened. Settlement Agreement II is now before Presiding Judge Coffman for certification to the Commission.

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,[27] 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*).[28] However, the FERC's orders were challenged, and in *Emera Maine,*[29] the DC Circuit vacated the FERC's prior orders, and remanded the case for further proceedings consistent with its order. The FERC's determinations in *Opinion 531* are thus no longer precedential, though the FERC remains free to re-adopt those determinations on remand as long as it provides a reasoned basis for doing so.

- ***Base ROE Complaints II & III (EL13-33 and EL14-86) (consolidated)***. The second (EL13-33)[30] and third (EL14-86)[31] 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%

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

[28] *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*").

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

[30] 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%.

[31] 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.

and 10.90%, respectively.[32] 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[33] also went to hearing before an ALJ, Judge Glazer, who issued his initial decision on March 27, 2017.[34] 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.[35] 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.[36] The FERC indicated its intention that the methodology be its policy going forward, including in the four currently pending New England proceedings (*see*, however, *Opinion 569-A* (EL14-12; EL15-45) in Section XI below). The FERC established a paper hearing on how its proposed methodology should apply to the four pending ROE proceedings.[37]

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

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[32] *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*").

[33] 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.

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

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

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

[37] *Id.* at 19.

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%.[38] 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[39] 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.

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*[40] 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

- **FCA15 De-List Bids Filing (ER20-2317)**

Pursuant to Market Rule 1 § 13.8.1(a), ISO-NE submitted on July 2, 2020 a filing describing the Permanent De-List Bids and Retirement De-List Bids that were submitted on or prior to the FCA15 Existing Capacity Retirement Deadline. ISO-NE reported that the Existing Capacity Retirement Deadline for FCA15 was March 13, 2020 and it received 1 Permanent De-List Bid, 13 Retirement De-List Bids, and 0 substitution auction test prices from 10 Lead Market Participants. The bids were for resources located in the CT, VT, ME, South Eastern Massachusetts, and Western Central MA Load Zones, with 241.256 MWs of aggregate capacity. All but four of the Bids were for resources under 20 MW or that did not meet the affiliation requirements that would have required

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[38] *Id.* at P 59.

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

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

IMM review, with two (representing 20.712 MWs) requiring substitution auction test price reviews because the Bids were for greater than 3 MWs. The IMM did review the remaining four Bids (from four separate suppliers) for 213.376 MWs of capacity. The IMM's determination regarding those bids is described in the version of the filing that was filed confidentially as required under §13.8.1(a) of Market Rule 1.

ISO-NE reported that, because the Energy Security Improvements ("ESI") filing described in Section III below (ER20-1567) is still pending and FCA15 participants will receive final mitigated prices from the Internal Market Monitor ("IMM") before there is a FERC determination on the ESI filing, the IMM provided Participants with conditional retirement notifications that included a price under the current Market Rules, and a price to be used under each of the ISO-NE and NEPOOL ESI alternatives, should one of those be accepted.

Comments on this filing were due on or before July 23; none were filed. Doc-less interventions were filed by NEPOOL, Eversource, National Grid, and NRG. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

Since the last Report, the FERC issued four orders in this proceeding (three on July 17; one on July 28, 2020). Each of the orders addressed in part or in whole the Cost-of-Service Agreement ("COS Agreement")[41] among Constellation Mystic Power ("Mystic"), Exelon Generation Company ("ExGen") and ISO-NE, which is to provide compensation for the continued operation of the Mystic 8 & 9 units from June 1, 2022 through May 31, 2024.

July 2018 Order. As long reported, the FERC's initial order in this proceeding, issued July 13, 2018,[42] accepted the COS Agreement but suspended its effectiveness and set the matter for accelerated hearings and settlement discussions. The *July 2018 Order* was approved by a 3-2 vote, with dissents by Commissioners Powelson and Glick. Challenges to the *July 2018 Order* were filed by NESCOE, ENECOS, MA AG, and the NH PUC. The FERC issued a tolling order on September 10, 2018 to afford itself additional time to consider the requests for rehearing, which remained pending until last month.

In a July 17, 2020 order on the requests for rehearing, the FERC modified the discussion in the *July 2018 Order*, but nevertheless reached the same result, denying each of the requests for rehearing.[43] The FERC's July 2020 order did grant a clarification requested by the MA AG, that, "before Mystic may include any capital expenditure in its cost-of-service rate, it must demonstrate, and the [FERC] must determine, that such an expenditure is just and reasonable."[44] The order denied a request for clarification by ENECOS.[45]

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

[42] *Constellation Mystic Power,* 164 FERC ¶ 61,022 (July 13, 2018) ("*July 2018 Order*"), *clarif. granted in part and denied in part, reh'g denied*, 172 FERC ¶ 61,043 (July 17, 2020).

[43] *Constellation Mystic Power, LLC*, 172 FERC ¶ 61,043 (July 17, 2020) (order granting clarification in part, denyin clarification in part, and addressing arguments raised on rehearing of *July 2018 Order*).

[44] *Id.* at P 25.

[45] ENECOs requested that the FERC "clarify that [Mystic] can assign no more than a third of Everett's fixed costs to ISO-NE under the proposed [COS Agreement]" was among the issues set for, and addressed based on the record developed at, the hearings in this proceeding. Accordingly, the FERC did not address the request in its July 17, 2020 order on these issues.

Dec 2018 Order. Following hearings, the FERC's December 20, 2018 order conditionally accepted the COS Agreement.[46] The *Dec 2018 Order* directed Mystic to submit a compliance filing (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 *Dec 2018 Order* were filed by Constellation Mystic Power, CT Parties, EDF, ENECOS, MA AG, NESCOE, NextEra, and Repsol. On February 15, 2019, the FERC issued a tolling order to afford it additional time to consider the requests for clarification and/or rehearing.

In its July 17 order addressing the requests for rehearing of the *Dec 2018 Order*, the FERC modified the discussion in the *Dec 2018 Order*, set aside that Order in part, granted clarification in part, denied clarification in part, and directed additional compliance.[47] Specifically, the FERC set aside the parts of the *Dec 2018 Order* that required the COS Agreement to include a sliding scale or other revenue crediting mechanism and the part that required Mystic to true-up revenues. The FERC granted clarification requested by Mystic that the FERC did not intend to re-state its prudence standard in the Dec 2018 Order (stating that its prudence standard differs from the prudence analysis that will be used in applying the standard). The FERC denied clarifications requested by Mystic,[48] NESCOE,[49] and ENECOS.[50]

Mar 2019 Compliance Filing. Mystic submitted its compliance filing required pursuant to the *Dec 2018 Order* on March 1, 2019 ("Mar 19 Compliance Filing"). As previously reported, 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.

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[46] *Constellation Mystic Power, LLC*, 165 FERC ¶ 61,267 (Dec. 20, 2018) ("*Dec 2018 Order*"), *set aside in part, clarification granted in part and clarification denied in part*, 172 FERC ¶ 61,044 (July 17, 2020).

[47] *Constellation Mystic Power, LLC*, 172 FERC ¶ 61,044 (July 17, 2020) (order on clarification, directing compliance, and addressing arguments raised on rehearing of *Dec 2018 Order*).

[48] Mystic challenged the Fuel Supply Charge as a component of its cost-of-service rate and, as a result, subject to FERC review and approval. The FERC found the request for clarification moot given its finding that that a revenue crediting mechanism for third party sales was no longer necessary to ensure that the Fuel Supply Charge is just and reasonable.

[49] NESCOE requested clarification on whether the COS Agreement's clawback provision would apply to consumer-funded investments and repairs in connection with both Mystic 8 and 9 and Everett. The FERC stated that the clawback mechanism for Everett's capital costs suggested by NESCOE would not apply to payments that Mystic received under a jurisdictional rate, but rather would apply to payments that Everett received under the non-jurisdictional Everett Agreement. Order at P 43.

[50] ENECOS requested clarification of the FERC's finding that Exelon's August 2003 booking of accumulated depreciation against the plant value of Mystic 8 & 9 effected a permanent reduction in that plant value that cannot be restored through subsequent accounting treatment.

In addition, Mystic's compliance filing included for informational purposes changes to the Fuel Supply and Terminal Services Agreements.

In its July 17, 2020 order on the Mar 19 Compliance Filing, the FERC accepted, with one exception, the Mar 19 Compliance Filing and directed a further compliance filing due on or before September 15, 2020.[51] In that further compliance filing, Mystic must reflect the 2004 transfer in lieu of foreclosure[52] in its original cost study. When it makes that further compliance filing, the FERC encouraged Mystic to correct any ministerial or typographical errors, such as those identified by NESCOE.[53]

ROE Paper Hearing. The *Dec 2018 Order* established a paper hearing to determine the just and reasonable ROE to be used in setting charges under Mystic's COS Agreement. On April 19, 2019, Mystic, 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.

In a July 28, 2020 order,[54] the FERC reopened the record to allow parties an opportunity to present written evidence applying the FERC's *Opinion 569-A* ROE methodology to the facts of this proceeding. Initial briefs are due on or before September 28, 2020; responses to those initial briefs, October 28, 2020.

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

- **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.[55] 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*[56] decision. In its *Order Rejecting Filing*, the FERC required the TOs to continue collecting their ROEs currently on file, subject to a future FERC order.[57] 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.[58] 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).

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[51] *Constellation Mystic Power, LLC*, 172 FERC ¶ 61,045 (July 17, 2020) (order on compliance and directing further compliance).

[52] In 2004, a group of creditors acquired the units from the then-owner in exchange for extinguishing the debt owed by those owners. Because the units changed ownership as a consequence of the transfer in lieu of foreclosure, Mystic should have included the transaction in the original cost study. The FERC rejected Mystic's assertion that the transfer in lieu of foreclosure did not represent a sale or purchase.

[53] *Id.* at P 54.

[54] *Constellation Mystic Power, LLC*, 172 FERC ¶ 61,093 (July 28, 2020).

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

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

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

[58] *Id.* at P 36.

- **2020/21 Power Year Transmission Rate Filing (ER09-1532; RT04-2)**

On July 31, 2020, the Participating Transmission Owners ("PTOs") Administrative Committee ("PTO AC") submitted a filing identifying adjustments to regional transmission service charges under Section II of the ISO Tariff for the period June 1, 2020 through May 31, 2021. The filing reflected the charges to be assessed under annual transmission formula rates, reflecting actual 2019 cost data, Forecasted Annual Transmission Revenue Requirements associated with projected PTF additions for the 2019 Forecast Period, and the Annual True-up including associated interest. The PTO AC states that the annual updates results in a Pool "postage stamp" RNS Rate of $129.26 /kW-year effective June 1, 2020, an increase of $17.32 /kW-year from the charges that went into effect on June 1, 2019. In addition, the annual update to the Schedule 1 formula rate results in a charge of $1.745 kW-year, a $0.152/kW-year increase from the Schedule 1 charge that last went into effect on June 1, 2019. This filing will be reviewed at the August 18-19 Reliability/Transmission Committee summer meeting. The filing will not be noticed for public comment. If there are questions on this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- **ISO Securities: Authorization for Future Drawdowns (ES20-46)**

On July 13, 2020, the FERC authorized continued ISO-NE drawdowns under a $20 million Revolving Credit Line and a $4 million line of credit supporting the Payment Default Shortfall Fund,[59] each of which are with TDBank, and have a term of ending June 30, 2021.[60] Unless the July 13 order is challenged, this proceeding will be concluded, If you have any questions concerning this matter, please contact Paul Belval (860-275-0381; pnbelval@daypitney.com).

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

- **Information Policy §2.3 Revisions (ER20-2518)**

On July 28, 2020, ISO-NE and NEPOOL jointly filed revisions to Section 2.3 the Information Policy. Specifically, the revisions are designed (i) to improve and clarify communications with Participants regarding the status of Participants emerging from bankruptcy and (ii) to provide ISO-NE with greater flexibility when disclosing confidential information of defaulting Participants to the FERC, courts of competent jurisdiction (esp. bankruptcy courts), and/or other agencies. The revisions do not modify the type of information that will be disclosed on weekly notices and do not affect the confidentiality and non-disclosure obligations of Participants under the Information Policy. The revisions were supported by the Participants Committee at its June 4 meeting (Consent Agenda Item #1). An October 1, 2020 effective date was requested. Comments on this filing are due on or before August 18, 2020. Thus far, doc-less interventions have been filed by Calpine and Exelon. 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).

- **DAM Offer Window Modification (ER20-2511)**

On July 27, 2020, ISO-NE and NEPOOL jointly filed revisions to Market Rule 1 Section 1.10.1A to extend by 30 minutes the Day-Ahead Energy Market ("DAM") offer window. Also included with the DAM Offer Window modification were two Offer Cap clean-up changes, one to add Demand Reduction Offers to the consolidated offer floor provisions of Section III.1.9.1.2, the other to remove "Energy Offer Cap" from Section III.1.10.1A(e)(ii). The revisions were supported by the Participants Committee at its June 4 meeting (Consent Agenda Item #2). A September 30, 2020 effective date was requested. Comments on this filing are due on or before August 17, 2020. Thus far, doc-less interventions have been filed by Calpine, Exelon, FirstLight, and PSEG. If you have any questions

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[59] *ISO New England Inc.*, 172 FERC ¶ 62,017 (July 13, 2020) (continuing authorization through July 12, 2022).

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

concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **EE CSOs During Scarcity Conditions (ER20-1967)**

On July 21, 2020, the FERC accepted changes jointly filed by ISO-NE and NEPOOL to address an implementation issue regarding the treatment of energy efficiency resources ("EE") during Capacity Scarcity Conditions ("EE Changes").[61] The EE Changes remove EE Capacity Supply Obligations ("CSOs") from the denominator of the balancing ratio outside of measure hours, so that EE will be absent from both the numerator and the denominator of the ratio in those hours. The EE Changes are designed to eliminate the undercollection problem and associated mutual insurance pool charges, and to more appropriately allocate Pay For Performance ("PFP") proceeds, all while more fully honoring the FERC's directive in the *2014 PFP Order* to calculate performance payments for EE only when scarcity conditions occur during measure hours. Unless the July 21 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

Green Mountain Power ("GMP")'s May 4, 2020 request for a limited waiver from the revised definition of Settlement Only Resources[62] as applied to GMP's Searsburg wind power facility[63] (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) remains pending before the FERC.[64] No comments on GMP's waiver request were filed before the May 22, 2020 comment date. NEPOOL filed a doc-less intervention. If you have any questions concerning this matter, please contact Pat Gerity (860-275-0533; pmgerity@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").[65] 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

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[61] *ISO New England Inc.*, Docket No. ER20-1967 (July 21, 2020) (unpublished letter order).

[62] *See* ER20-1582 below.

[63] 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.

[64] 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.

[65] This filing was submitted in response to the requirements of the *Mystic Waiver Order,* which directed ISO-NE, in part, to submit permanent Tariff revisions reflecting improvements to its market design to better address regional fuel security concerns. *See ISO New England Inc.*, 164 FERC ¶ 61,003 (July 2, 2018), *reh'g requested* ("*Mystic Waiver Order*").

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.

Comments and protests were filed by Avangrid, API, Calpine/Vistra, Cogentrix, Dominion, Excelerate, Exelon, FirstLight, IECG, MA AG/NH OCA, MMWEC, NECOES/ENE, NESCOE, Repsol, NEPGA, NRG, PIOs, ISO-NE IMM, Potomac Economics, CT DEEP, MPUC, VT PUC, AEE, EPSA, National Hydropower Assoc., and the National Gas Supply Association ("NGSA"). On June 1 NEPOOL and NESCOE filed answers to some of the pleadings submitted. Doc-less interventions were filed by Acadia Center, Brookfield RTM, CT OCC, CT AG, CLF, ENE, Environmental Defense Fund, Eversource, National Grid, NextEra, NRDC/Sustainable FERC Project, PSEG, Repsol, Shell, UCS, Vistra, AWEA, APPA, EPSA, Helix Maine, Public Citizen, Sierra Club, and Vote Solar. On June 5, Calpine/Vistra and NEPGA answered NESCOE's May 15 protest. On June 10, FirstLight answered NEPOOL's and NESCOE's answers. ISO-NE submitted its answer to various pleadings on June 16. On June 22, NESCOE filed a second answer, to the June 5 answers by NEPGA and Calpine/Vistra. NESCOE, and the MA AG answered ISO-NE's Jun 16 answer on June 30, And, finally, NEPOOL answered ISO-NE's out-of-time answer on July 1.

There has been no activity in this proceeding since the last Report and this matter remains pending before the FERC. If you have any questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@daypitney.com) or Rosendo Garza (860-275-0660; rgarza@daypitney.com).

- **Inventoried Energy Program (Chapter 2B) Remand (ER19-1428)**

Rehearing has been requested of the FERC's June 18, 2020 order accepting the ISO-NE's Inventoried Energy Program ("IEP"), eff. May 28, 2019.[66] The *IEP Remand Order* was issued following voluntary remand from the DC Circuit of challenges to the FERC's August 6, 2019 notice[67] that the IEP became effective by operation of law (because the FERC indicated was unable to act on ISO-NE's IEP filing on or before its statutory deadline "because of a lack of quorum"). In accepting the IEP in the *IEP Remand Order*, the FERC agreed with ISO-NE that "the current market design contains a "misaligned incentives" problem, such that fuel secure resources may not be sufficiently incented to make additional investments in energy supply arrangements, which may have adverse efficiency and reliability consequences under the existing market rules" and found that the IEP "is a reasonable short-term solution to compensating, in a technology-neutral manner, resources that provide fuel security."[68] The FERC stated that the IEP "will help ISO-NE address winter energy security in light of the misaligned incentives in the market, while ISO-NE finishes developing a long-term market solution."[69]

Challenges to the *IEP Remand Order* were filed by MA AG, MPUC, and jointly by NECOS[70] and ENE, NH PUC and NH OCA, and by Sierra Club and UCS. The requests for rehearing are pending, with FERC action required on or before August 17, 2020 (the first business day that is 30 days from the day that the first requests for rehearing were filed), or the requests will be deemed denied by operation of law. If you have

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[66] *ISO New England Inc.*, 171 FERC ¶ 61,235 (June 18, 2020) ("*IEP Remand Order*").

[67] Requests for rehearing of the August 6, 2019 notice ("IEP Notice") were filed by the MA AG, Clean Energy Advocates, NECOS/ENE, NESCOE, MPUC, NH PUC/NH OCA. Those requests, which challenged the IEP Notice on substantive and procedural grounds, were similarly denied by operation of law. On October 7, 2019, the FERC provided notice that the "Commission took no action on the requests for rehearing within 30 days of their filing … and that the requests for rehearing were denied by operation of law." As summarized in previous Reports, petitions for review of those notices were filed with the DC Circuit (Case No. 19-1224). On April 14, 2020, the FERC filed a motion for voluntary remand with the DC Circuit to allow the FERC to issue an order addressing the filing since it then had a quorum in this proceeding. The DC Circuit granted the motion on April 21, 2020.

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

[69] *Id.* at P 34.

[70] "NECOS" are Belmont, Block Island Utility District, Braintree, Georgetown, Groveland, Hingham, Littleton (MA) Electric Light Dept., Merrimack, Middleborough, Middleton, North Attleborough, Norwood, Pascoag, Reading, Rowley, Stowe, Taunton, and Wellesley.

questions concerning this proceeding, please contact Sebastian Lombardi (860-275-0663; slombardi@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. Given the passage of time, monthly reporting on this matter will cease with this Report. Should the FERC in the future issue an order in this proceeding, that order will be summarized in the next Report to be issued. Until then, should 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*[71] compliance filing.[72] For the majority of the revisions, 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.[73]

Order 841 Compliance Filing II (ER19-470-004). On August 4, 2020, the FERC conditionally accepted[74] the February 10, 2020 compliance filing jointly filed by ISO-NE and NEPOOL[75] in response to the *Order 841*

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[71] *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*").

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

[73] 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.

[74] *ISO New England Inc.*, 172 FERC ¶ 61,125 (Aug. 4, 2020) ("*Order 841 Compliance Filing II Order*").

[75] 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; (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.

Initial Compliance Filing Order, subject to a two further compliance filings, one due on or before November 2, 2020, and the other on or before August 4, 2021.

The ***November 2020 compliance filing*** must address concerns that the FERC raised with respect to the application of transmission charges to electric storage resources. Finding that ISO-NE "has failed to demonstrate that an electric storage resource that is self-scheduled to charge at a fixed MW quantity is providing a service that warrants exempting its *full* self-scheduled charging MW from transmission charges," the FERC directed ISO-NE to file, on or before November 2, 2020, proposed Tariff revisions: (i) specifying that it will not apply transmission charges to electric storage resources when they are dispatched to withdraw energy to provide voltage support and reactive control, provide operating reserves, provide regulation, balance energy supply and demand on an economic basis, or address a reliability concern; and (ii) applying transmission charges to electric storage resources when they are not being dispatched to provide one of those tariff-defined services.[76] The November 2020 compliance filing must also modify section III.1.10.6(d)(ii) to either (i) eliminate any suggestion that a host utility could be allowed, through an unwillingness to support the necessary registration, metering, and accounting of the electric storage resource, to decide whether an electric storage resource may participate in the ISO-NE markets; or (ii) to clarify how the section does not serve as a barrier to the participation of electric storage resources.

The ***August 4, 2021 compliance filing***[77] must include proposed revisions to Tariff section III.1.10.6(d) to specify how ISO-NE will account for State of Charge and Duration Characteristics of electric storage resources in the Day-Ahead Energy Market. If ISO-NE intends to rely on new bidding parameters, it must define those bidding parameters in its Tariff and explain in its transmittal how those bidding parameters will be incorporated into its Day-Ahead Energy Market engine. If ISO-NE intends to rely on "other means," it must specify those other means with sufficient detail in its Tariff and explain in its transmittal how those other means will account for State of Charge and Duration Characteristics of electric storage resources in the Day-Ahead Energy Market.

Challenges, if any, to the *Order 841 Compliance Filing II Order* must be filed on or before September 3, 2020. 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*[78] remain pending before the FERC. As previously reported, the *Fuel Security Retention Proposal Order* accepted ISO-NE's Proposal[79]

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[76] *Order 841 Compliance Filing II Order* at P 52.

[77] The FERC explained that it directed a one-year compliance window to allow ISO-NE sufficient time to develop a solution to account for State of Charge that recognizes the technical complexities of the issue as well as ISO-NE's existing software constraints, given ISO-NE is in the process of conducting various Day-Ahead Energy Market initiatives, including replacement of its Day-Ahead software.

[78] *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.

[79] 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

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.[80] On February 1, 2019, the FERC issued a tolling order to afford 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).

- **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

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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").

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

[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.

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]

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

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

[86] *Id.* at P 57.

[87] *Id.* at P 58.

[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).

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 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, 2018, the Indicated New England EDCs answered the August 14/16 answers. On August 27, 2018, the FERC issued a tolling order to afford 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, 2018, ISO-NE answered Clean Energy Advocates' answer. On May 7, 2018, the FERC issued a tolling order to afford 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 July 30, 2020, TransCanada petitioned the DC Circuit for review of the FERC's April 1, 2020 order on compliance and remand that found (for a second time) that the bid results from the 2013/14 Winter Reliability

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

[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.

Program were just and reasonable (*"2013/14 Winter Reliability Program Order on Compliance and Remand*").[94] That order followed a second series of filings[95] in response to an earlier DC Circuit Order remanding this matter back to the FERC.[96] In its *2013/14 Winter Reliability Program Order on Compliance and Remand*, the FERC did not find convincing challenges by TransCanada and the MA AG to ISO-NE's recommendation that was an "insufficient demonstration of market power to warrant modification of program."[97]

Although TransCanada requested rehearing of the *2013/14 Winter Reliability Program Order on Compliance and Remand* on May 1, 2020, and the FERC issued a June 1, 2020 tolling order to afford it additional time to consider TransCanada's request for rehearing, the DC Circuit's *Allegheny* decision, which recently held that tolling orders "are not the kind of action on a rehearing application that can fend off a deemed denial and the opportunity for judicial review", makes clear that TransCanada's request was deemed denied as of June 1, 2020 (triggering the 60-day period during which a petition for review of the FERC's order(s) can be filed with an appropriate federal court. With TransCanada's filing of the July 30 appeal, and absent any further FERC activity prior to the filing of the record in the DC Circuit proceeding,[98] reporting on this matter will move to Section XV in future Reports. 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 July 27, 2020, the FERC issued a notice (i) that the rehearing of the *CIP IROL Cost Recovery Order*[99] requested June 25, 2020 by the IROL-Critical Facility Owners[100] may be deemed denied by operation of law and (ii) providing for further consideration ("Notice"). In accordance with *Allegheny*, while the *CIP IROL Cost Recovery Order*[101] may now be appealed to a federal court of appeals within 60 days of the Notice, the FERC retains the right to address the rehearing request in a future order, modifying or setting aside its order, in whole or in part, up until the record of the proceeding is filed with a court of appeals.[102] As previously

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[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*. In this Order, the FERC also provided the further reasoning requested by the DC Circuit for this finding.

[95] The second series of filings followed the FERC's "*2013/14 Winter Reliability Program Remand Order*", *ISO New England Inc.*, 156 FERC ¶ 61,097 (Aug. 8, 2016).

[96] *TransCanada Power Mktg. Ltd. v. FERC,* 2015 U.S. App. LEXIS 22304 (D.C. Cir. 2015) (remanding the FERC's decision in ER13-2266 back the FERC to either offer a reasoned justification for the order in ER13-2266 or to revise its disposition to ensure that the Program rates are just and reasonable; the DC Circuit agree with TransCanada that the record upon which the FERC had to that point relied was devoid of any evidence regarding how much of the 2013/14 Winter Reliability Program cost was attributable to profit and risk mark-up (and without which the FERC could not properly assess whether the Program's rates were just and reasonable).

[97] ISO-NE submitted a compliance filing on Jan. 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 in its compliance filing, accepted in the *2013/14 Winter Reliability Program Order on Compliance and Remand*, that there was "insufficient demonstration of market power to warrant modification of program."

[98] Under 16 USC § 825l(a), the FERC retains the right to address the rehearing request in a future order, modifying or setting aside its order, in whole or in part, up until the record of the proceeding is filed with a court of appeals. *See* n. 102 *supra*.

[99] *ISO New England Inc.*, 171 FERC ¶ 61,160 (May 26, 2020) ("*CIP IROL Cost Recovery Order*").

[100] "IROL-Critical Facility Owners" are Calpine, Cogentrix, Cross-Sound Cable, FirstLight, NextEra, NRG, and Vistra.

[101] *ISO New England Inc.*, 171 FERC ¶ 61,160 (May 26, 2020) ("*CIP IROL Cost Recovery Order*").

[102] *See* 16 USC § 825l(a) ("Until the record in a proceeding shall have been filed in a court of appeals, … the [FERC] may at any time, upon reasonable notice and in such manner as it shall deem proper, modify or set aside, in whole or in part, any finding or order made or issued by it under the provisions of this chapter.").

reported, the *CIP IROL Cost Recovery Order* accepted Schedule 17, which sets forth 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"). Importantly, in accepting Schedule 17, the FERC found that "Schedule 17 permits recovery only of CIP costs incurred on or after the effective date of a section 205 filing made by an IROL-Critical Facility Owner to recover such costs".[103] It is this determination that was at the heart of IROL-Critical Facility Owners' request for rehearing, which argued that, as a result, the *CIP IROL Cost Recovery Order* ultimately establishes a rate that is unjust, unreasonable, and inconsistent with the clear cost recovery right Congress established in FPA section 219. IROL-Critical Facility Owners have until September 25, 2020 to appeal the *CIP IROL Cost Recovery Order* to a federal court. If you have any questions concerning this proceeding, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 845* Compliance Filing II (ER19-1951-002)**

On July 17, 2020, ISO-NE, NEPOOL and the PTO AC submitted an additional compliance filing ("*Order 845* Compliance Filing II") in response to the March 19, 2020 order[104] conditionally accepting the first set of changes filed in response to the requirements of *Order 845* ("*Order 845* Compliance Filing I").[105] The changes in Order 845 Compliance Filing II were considered and supported by the Participants Committee at its June 4 meeting (Agenda Item #7). Comments on Order 845 Compliance Filing II are due on or before August 7, 2020. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

V. Financial Assurance/Billing Policy Amendments

- **FAP Enhancements and Clean-Up Changes (ER20-2145)**

On June 24, 2020, ISO-NE and the NEPOOL jointly filed enhancements and clean-up changes to the Financial Assurance Policy ("FAP"). Among other things, the filing included: (i) updates and enhancements to the credit insurance provisions; (ii) updates to the form letter of credit and related provisions; and (iii) miscellaneous revisions, including a change to the retention period for financial assurance after membership termination and a conforming change in the FCM Charge Rate calculation (collectively, the "FAP Changes"). A September 10, 2020 effective date was requested. The FAP Changes were unanimously supported by the Participants Committee at its June 23 meeting (Agenda Item #2). Comments on this filing were due on or before July 15; none were filed. Doc-less interventions were submitted by Calpine, Eversource, National Grid, NRG, and Financial Marketers Coalition. This matter is pending before the FERC. If you have any questions concerning this matter, please contact Paul Belval (pnbelval@daypitney.com; 860-275-0381).

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[103] *Id.* at PP 1, 27. "Section 2.2(A) of proposed Schedule 17 would permit IROL-Critical Facility Owners to make FPA section 205 filings to recover costs incurred by the IROL Critical Facility Owner *during the period in which the subject facility is designated as an IROL-Critical Facility*. While the parties dispute the meaning of the italicized language, that language is appropriately read in conjunction with the requirement that IROL-Critical Facility Owners submit individual FPA section 205 filings to recover such costs … Thus, we find that, read in context with the remainder of section 2.2(A), the italicized language would allow IROL-Critical Facility Owners to recover only those costs incurred on or after the effective date of the relevant individual FPA section 205 filing."

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

[105] The *Order 845 Compliance Filing Order* identified a number of ways in which *Order 845* Compliance Filing I only partially or did not comply at all with *Order 845.* The *Order* directed changes that needed to include additional justification for proposed changes or revisions that make no modification to the *pro forma* LGIA/LGIP in the following areas: Stand-Alone Network Upgrades definition, Interconnection Customer's ability to exercise the option to build; Option to Build Cost Recovery; Determination of Contingent Facilities; requesting interconnection service below generating facility capacity; Provisional Interconnection Service; definition of Surplus Interconnection Service; Surplus Interconnection Service process;

- **Billing Policy Enhancements and Clean-Up Changes (ER20-1862)**

On July 24, the FERC accepted the enhancements and clean-up changes to the Billing Policy jointly filed by ISO-NE and NEPOOL.[106] Among other things, the changes: (i) update the definition of Non-Hourly Charges (to include any pass-through charges where ISO-NE acts as agent (including communications related charges, OASIS- related charges, and fees related to the Shortfall Funding Arrangement); (ii) modify the timing of Statements for Non-Hourly Charges (from the first Monday after the tenth of each calendar month to the first Monday after the ninth of each calendar month); (iii) reflect the issuance (rather than the sending) of Invoices and Remittance Advices; (iv) change the timing for payment instructions; (v) limit distributions from late payment accounts (to only those Market Participants not in a Payment Default at the time of a distribution); and (vi) limit the frequency for the use of pre-payments (to five in any rolling 365-day period), limiting the risk that prepayment provisions are being used to deflate financial assurance obligations. In accepting the changes, the FERC noted that it was not persuaded by the Plant-E comments protesting the change that would limit for all the frequency for the use of pre-payments.[107] The changes were accepted effective July 27, 2020, as requested. Unless the July 24 order is challenged, with any challenges due on or before August 24, 2020, this matter will be concluded. If you have any questions concerning this matter, please contact Paul Belval (pnbelval@daypitney.com; 860-275-0381).

VI. Schedule 20/21/22/23 Changes

- **Schedule 22: NSTAR/Vineyard Wind LGIA (ER20-2489)**

On July 23, Eversource filed an executed, non-conforming LGIA by and among ISO-NE, NSTAR and Vineyard Wind, LLC (“Vineyard Wind”), designated as Original Service Agreement No. LGIA-ISONE/NSTAR-20-01 under Schedule 22 of the ISO-NE OATT. The LGIA is non-conforming in that it contains certain deviations in Appendix C.3 necessary to reflect unique characteristics of the proposed interconnection -- the location of the met gathering station(s) and the layout of the facility due to its location in offshore federal waters rather than onshore. A July 10, 2020 effective date was requested. Comments on this filing are due August 7. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-NEP: DWW E&P Agreement (ER20-2454)**

On July 17, New England Power Company (“NEP”) filed under Schedule 21-NEP an Engineering & Procurement Agreement (“E&P Agreement”) between NEP and DWW REV I, LLC (“DWW”). The E&P Agreement (designated as Service Agreement No. E&P-NEP-01) is to facilitate NEP’s performance of preliminary engineering and certain procurement-related activities in connection with the interconnection of DWW’s Revolution Wind project, a proposed 704 MW offshore wind generating facility project, to NEP’s transmission system at the 115kV Davisville substation in Washington County, Rhode Island, prior to the parties entering into an LGIA. A June 17, 2020 effective date was requested. Comments on this filing are due on or before August 7. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-UI: LCSA: UI/NextEra (ER20-2449)**

On July 17, UI filed under Schedule 21-UI a Localized Costs Sharing Agreement (“LCSA”) by and between UI and NextEra Energy Marketing (“NextEra”). UI filed the LCSA so that it can recover NextEra’s Category B Load Ratio Share of the revenue requirement for UI’s Localized Facilities under Schedule 21-UI.[108] A July 1, 2020 effective date was requested. Comments on this filing are due August 7. Thus far, Eversource

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[106] *ISO New England Inc. and New England Power Pool Participants Comm.*, 172 FERC ¶ 61,089 (July 24, 2020).

[107] *Id.* at PP 15-16.

[108] NextEra entered into the Agreement on behalf for its affiliate Nutmeg Solar, LLC, whose electric generating facility consists of a 19.9 MW solar array located in Enfield, Connecticut within the NU Local Network / Connecticut Reliability Region outside of UI’s native load service area.

filed a doc-less intervention. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **Schedule 21-VP: 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, "Interested Parties shall have the opportunity to conduct discovery seeking any information relevant to implementation of the [Attachment P] Rate Formula. . . ." and follow a dispute resolution procedure set forth there. In accordance with those provisions, the MPUC identified certain disputes with the 2019 Annual Update, all of 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-VP: Recovery of Bangor Hydro/Maine Public Service Merger-Related Costs (ER15-1434-001 *et al.*)**

The MPS Merger Cost Recovery Settlement, filed by Emera Maine on May 8, 2018 to resolve all issues pending before the FERC in the consolidated proceedings set for hearing in the *MPS Merger-Related Costs Order,*[109]and certified by Settlement Judge Dring[110] to the Commission,[111] remains pending before the FERC. As previously reported, under the Settlement, permitted cost recovery over a period from June 1, 2018 to May 31, 2021 will be $390,000 under Attachment P of the BHD OATT and $260,000 under the MPD OATT. If you have any questions concerning these matters, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com).

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

On July 31, 2020, Fitchburg Gas & Electric ("FG&E") submitted its data and schedules used to calculate its annual transmission revenue requirement for Non-PTF Local Network Transmission Service, Firm Point-to-Point Transmission Service and Non-Firm Point-to-Point Transmission Service as set forth in Schedule 21-FG&E covering the June 1, 2020– May 31, 2021 period. FG&E reported that its annual revenue requirement reflected in FG&E's rates effective June 1, 2020, is $1,378,521. The FERC will not notice this filing for public comment, and absent further activity, no further FERC action is expected. If there are questions on this matter, please contact Pat Gerity (860-275-0533; pmgerity@daypitney.com.

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[109] *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.

[110] 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.

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

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*[112] *and 531-B*[113] 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).

- **LFTR Implementation: 47th Quarterly Status Report (ER07-476; RM06-08)**

ISO-NE filed the 47th of its quarterly status reports regarding LFTR implementation on July 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 LFTR design and financial assurance issues, including an ongoing evaluation of the FTR market and risk associated with FTRs and LFTRs, it is currently focused on higher priority market-design initiatives. These status reports are not noticed for public comment.

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

On July 31, 2020, the IMM filed with the FERC its Spring 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 Spring 2020 Report will be discussed with the Markets Committee at its August 11-13 meeting.

IX. Membership Filings

- **August 2020 Membership Filing (ER20-2581)**

On July 31, 2020, NEPOOL requested that the FERC accept (i) the memberships of: Blueprint Power Technologies Inc. (Provisional Member); and Advanced Energy Economy Inc. (Fuels Industry Participant); and (ii)

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

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

the termination of the Participant status of two End Users, New Hampshire Industries Inc. and The Energy Council of Rhode Island ("TEC-RI"). Comments on this filing are due on or before August 21, 2020.

- **July 2020 Membership Filing (ER20-2277)**

On June 30, 2020, NEPOOL requested that the FERC accept the memberships of: Hampshire Power (Supplier Sector); Invenia Technical Computing Corp. ("Invenia") (Supplier Sector); and Power Ledger Pty. Ltd. (GIS-Only Participant). Comments on this filing were due on or before July 21, 2020; none were filed. This matter is pending before the FERC.

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

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

- **June 2020 Membership Filing (ER20-1943)**

On July 30, the FERC accepted (i) the memberships of: Actual Energy (Supplier Sector); Borrego Solar Systems, Inc. (AR Sector, DG Sub-Sector); Paper Birch Energy, LLC [Related Person to CS Berlin Ops/Berlin Station (Generation Sector Group Seat)]; Priogen Power LLC (Supplier Sector); and Standard Normal Energy LLC (Supplier Sector); (ii) the termination of the Participant status of: Royal Bank of Canada (Supplier Sector) (May 1, 2020); Wallingford Energy II, LLC [Related Person to Jericho Power (AR Sector; RG Sub-Sector)] (May 1, 2020); Agera Energy LLC (Supplier Sector) (June 1, 2020); and (iii) the name changes of: Versant Power (f/k/a Emera Maine) and IPKeys Power Partners, Inc. (f/k/a IPKeys Power Partners LLC).[114] The membership of Borrego Solar System fully activates the AR Sector's DG Sub-Sector. Accordingly, the AR Sector Voting Share, as well as each of the other five Sector's Voting Share (before any re-allocation of unused Provisional Member Voting Share), will be 16.5%. Comments on this filing were due on or before June 22, 2020; none were filed. This matter is pending before the FERC.

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

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

- **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

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[114] *New England Power Pool Participants Comm.*, Docket No. ER20-1943 (July 30, 2020) (unpublished letter order).

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.

- **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, filed on February 21, 2020, to the following Reliability Standards: 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.

Since the last Report, the FERC issued a notice of revised information collections that would impact these Reliability Standards and requested that comments on the collections of information be filed in this proceeding on or before September 22, 2020.[115]

- **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.[116] 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. NERC filed its second informational filing on June 19, 2020. With respect to Project 2016-02, NERC reported that it “continues to target a December 2021 filing to the Commission.” With respect to Project 2019-02, NERC reported that it “now anticipates filing the proposed Reliability Standards with the Commission in December 2020 (deferred from the original target date of September 2020).”

- **Revised Reliability Standard: CIP-002-6 (RM20-17)**

On June 12, 2020, NERC filed for approval a revised Reliability Standard -- CIP-002-6 (Cyber Security – BES Cyber System Categorization), and associated implementation plan, VRFs and VSLs (together, the “CIP-002 Changes”). NERC stated that the CIP-002 Changes improve upon the currently effective standard by clarifying the criterion for Transmission Owner Control Centers and tailoring the language to better reflect the risk posed by these Control Centers if unavailable or compromised. As of the date of this Report, the FERC has not noticed a proposed rulemaking proceeding or otherwise invited public comment.

- **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

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[115] *See Fed. Reg.* July 24, 2020 (Vol. 85, No. 143) pp. 44,875-44,880.

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

system ("BES") operations; and (ii) whether the CIP Reliability Standards impede the voluntary adoption of virtualization or cloud computing services ("NOI").[117] On March 25, 2020, Joint Associations[118] requested an extension of time to submit comments and reply comments. On April 2, the FERC granted Joint Associations' request and extended the deadline for initial comments on the NOI to July 1, 2020; the deadline for reply comments, July 31, 2020. Comments were filed by NERC, the ISO/RTO Council ("IRC"), Accenture, Amazon Web Services ("Amazon"), Bonneville, the Bureau of Reclamation, Barry Jones, Georgia System Operations, GridBright, Idaho Power, Microsoft, MISO, MISO Transmission Owners, Siemens Energy Management, Tri-State Generation and Transmission Association, VMware, Inc., AEE, American Association for Laboratory Accreditation ("A2LA"), APPA, Canadian Electricity Assoc., EEI, NRECA, and Waterfall Security Solutions. Reply comments were due on or before July 31, 2020, and were filed by AEE, Amazon and Microsoft. This matter is pending before the FERC.

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

On January 23, 2020, the FERC issued a NOPR[119] proposing to approve the retirement of 74 of the 77 Reliability Standard requirements requested to be retired by NERC in these two dockets[120] in connection with the first phase of work under NERC's Standards Efficiency Review[121] ("*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."[122] 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.[123] Comments were filed by J. Applebaum, Bonneville Power Administration ("BPA"), NERC, and the Western Area Power Administration ("WAPA").

NERC Notice of Withdrawal of VAR-001-6. On May 14, 2020, NERC withdrew its proposed changes to VAR-001-6.

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

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

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

[120] 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).

[121] 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.

[122] *Id.* at P 1.

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

- **Report of Comparisons of Budgeted to Actual Costs for 2019 for NERC and the Regional Entities (RR20-3)**

On May 29, 2020, NERC filed comparisons of actual to budgeted costs for 2019 for NERC and the seven Regional Entities operating in 2019, including NPCC. The Report includes comparisons of actual funding received and costs incurred, with explanations of significant actual cost-to-budget variances, audited financial statements, and tables showing metrics concerning NERC and Regional Entity administrative costs in their 2019 budgets and actual results. Comments on this filing were due on or before June 19, 2020; none were filed.

On July 21, 2020, NERC supplemented its May 29, 2020 filing to include the final, audited 2019 financial report for Texas Reliability Entity, Inc. ("Texas RE") (not available to be included at the time of the May 29 filing). Any comments on this report as supplemented are now due on or before August 11, 2020.

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.[124] 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.

- ***Opinion 569-A*: FERC's Base ROE Methodology (EL14-12; EL15-45)**

In an Opinion which could impact the resolution of New England ROE cases (TO Base ROE and Mystic 8/9 COS Agreement ROE), the FERC refined, in ruling on a MISO ROE proceeding, its methodology for setting the ROE that electric utilities earn on electric transmission investments.[125] The refinements to the FERC's methodology include:

  - The use of the Risk Premium model instead of only relying on the DCF model and CAPM under both prongs of FPA Section 206. The FERC stated that "the defects of the Risk Premium model do not outweigh the benefits of model diversity and reduced volatility resulting from the averaging of more models."

  - Adjusting the relative weighting of long- and short-term growth rates, increasing the weight for the short-term growth rate to 80% and reducing to 20% the weight given to the long-term growth rate in the two-step DCF model.

  - Modifying the high-end outlier test to treat any proxy company as high-end outlier if its cost of equity estimated under the model in question is more than 200% of the median result of all the potential proxy group members in that model before any high- or low-end outlier test is applied, subject to a natural break analysis. This is a shift from the 150% threshold applied in *Opinion 569*. By raising the threshold to 200%, the FERC believes it will reduce the risk that rational results are inappropriately excluded. Continued application of the natural break analysis will allow the exclusion of ROEs that are truly irrational or anomalously high.

  - Calculating the zone of reasonableness in equal thirds, instead of using the quartile approach that was applied in *Opinion 569*. The FERC found that the quartile approach, which excluded the bottom eighth and top eighth of the overall zone of reasonableness, was inappropriate because it

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

[125] *Ass'n of Buss. Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 569-A, 171 FERC ¶ 61,154 (2020) ("*Opinion 569-A*").

ignores some "potentially lawful ROEs" when determining which ranges of ROEs should be considered presumptively just and reasonable.

A more detail summary and background of Opinion 569-A prepared by NEPOOL counsel was posted with the materials for and discussed at the May 19, 2020 Transmission Committee meeting. EEI, FirstEnergy, Louisiana PSC, and MISO Complaint-Aligned Parties requested rehearing and/or clarification of *Opinion 569-A*.

Since the last Report, on July 22, 2020, the FERC issued a notice (i) that those requests for rehearing of the *Opinion 569-A* may be deemed denied by operation of law and (ii) providing for further consideration. Petitions to the Federal Courts for review of *Opinion 569-A* have been filed with the DC Circuit by Alliant, DTE, FirstEnergy the MISO TOs, Ameren/ITC Companies, Petitioners,[126] Transource, and Resale Power Group of Iowa. (*see* Section XV below).

- **VTransco Rate Schedule Cancellations (ER20-2507)**

On July 27, 2020, VTransco filed a notice of cancellation of two agreements,[127] both entered into in 2006, among Vermont Electric Power Company, Inc. ("VELCO"), Central Vermont Public Service Corporation ("CVPS"), Green Mountain Power Corporation ("GMP"), and VTransco, which are no longer in use. VTransco requested that the notice of cancellation be accepted for filing as of July 30, 2020. Comments on this filing are due on or before August 17, 2020. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement Cancellation: CL&P-NTE CT (ER20-2327)**

On July 6, 2020, CL&P filed a notice of cancellation of its Design, Engineering and Procurement Agreement (the "D&E Agreement") with NTE Connecticut, LLC ("NTE CT"). The D&E Agreement, which set forth the terms and conditions under which CL&P would undertake certain preliminary design and engineering activities on the Interconnection Facilities that were identified in ISO-NE's studies, prior to execution of a Standard Large Generator Interconnection Agreement ("LGIA"), expired when an LGIA was signed on June 16, 2020. CL&P requested that the notice of cancellation be accepted for filing as of June 1, 2020. Comments on this filing were due on or before July 27, 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).

- **Termination of IA and NITSA between Versant Power & Houlton Water Company (ER20-1919/1914)**

On July 24 and 27, respectively, the FERC accepted Versant Power's notice of termination of the Network Integration Transmission Service Agreement ("NITSA")(ER20-1914) and the Interconnection Agreement (ER20-1919) between itself and Houlton Water Company ("Houlton"), each of which expired by its terms on May 15, 2020, the date Houlton directly interconnected its electric system with that of New Brunswick Power.[128] Unless the July 24 or 27 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).

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[126] "Petitioners" are the Assoc. of Bus. Advocating Tariff Equity, Coalition of MISO Transmission Customers, IL Industrial Energy Consumers, IN Industrial Energy Consumers, MN Large Industrial Group, WI Industrial Energy Group, American Municipal Power (AMP"), Cooperative Energy, Hoosier Energy Rural Elec. Coop., MS Pub. Srvc. Comm., MO Pub. Srvc. Comm., MO Joint Mun. Elec. Util. Comm., Org. of MISO States, Southwestern Elec. Coop., and Wabash Valley Power Assoc.

[127] The Agreements are an Amended and Restated Three Party Transmission Agreement and an Amended and Restated Three Party Agreement.

[128] *Versant Power*, Docket No. ER20-1914 (July 24, 2020) (unpublished letter order).

- **NSTAR Transmission Service Agreement Cancellations (ER20-1896)**

On July 23, the FERC accepted NSTAR's notice of cancellation of various transmission service agreements no longer active but not yet previously cancelled.[129] The cancellation notices were accepted effective as of July 25, 2020, as requested. Unless the July 23 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **D&E Agreement: NSTAR-Mayflower Wind (ER20-1855)**

On July 14, 2020, the FERC accepted for filing an executed Preliminary Engineering and Design Agreement ("Agreement") between NSTAR and Mayflower Wind Energy LLC ("Mayflower Wind").[130] The Agreement, designated as Service Agreement No. IA-NSTAR39, sets forth the terms and conditions under which NSTAR will undertake certain preliminary design and engineering activities to determine whether NSTAR can develop a co-optimized solution for serving reliability needs and the interconnection needs of Mayflower Wind's large generating facility using NSTAR's existing rights of way. The Agreement was accepted effective as of May 19, 2020, as requested. Unless the July 14 order is challenged, this proceeding will be concluded. If you have any questions concerning this matter, please contact Pat Gerity (pmgerity@daypitney.com; 860-275-0533).

- **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[131] 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).

XII. Misc. - Administrative & Rulemaking Proceedings

- **Carbon Pricing in RTO/ISO Markets Tech Conf (Sep 30, 2020) (AD20-14)**

On June 17, 2020, the FERC issued a notice that it would convene a Commissioner-led technical conference on September 30, 2020. The purpose of the conference will be to discuss considerations related to state adoption of mechanisms to price carbon dioxide emissions, commonly referred to as carbon pricing, in regions with FERC-jurisdictional organized wholesale electricity markets. Supplemental notices will be issued prior to the conference with further details regarding the agenda, how to register to participate, and the format (including whether the technical conference will be held in-person or electronically).

The September 30 conference is a response to (i) the April 14, 2020 request by Interest Parties,[132] who asserted that a technical conference "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

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[129] *Eversource Energy Service Co.*, Docket No. ER20-1896 (July 23, 2020) (unpublished letter order).

[130] *NSTAR Elec. Co.*, Docket No. ER20-1855 (July 14, 2020) (unpublished letter order).

[131] 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.

[132] "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.

organized markets" complementing "state, regional, and national discussions currently taking place" as well as to (ii) the more than 30 sets of comments on the request that were filed.

- **Hybrid Resources Technical Conference Tech Conf (Jul 23, 2020) (AD20-9)**

On July 23, 2020, the FERC convened a technical conference to discuss technical and market issues prompted by growing interest in projects that are comprised of more than one resource type at the same plant location ("hybrid resources"). The focus was on generation resources and electric storage resources paired together as hybrid resources. Speaker materials have been posted to the FERC's eLibrary.

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

Energy Trading Institute's[133] December 16, 2019 request that the FERC hold a technical conference and conduct a rulemaking to update the requirements adopted in *Order 741*[134] and Section 35.47 of the FERC's regulations addressing credit and risk management in the markets operated by RTO/ISOs remains pending. As previously reported, ETI, citing a recent filing by NYISO (which it protested),[135] 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 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,[136] and an independent consultant.[137] This matter remains pending before the FERC.

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[133] 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."

[134] *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.

[135] *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).

[136] "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").

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

- **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)[138] and terminated the DOE NOPR rulemaking proceeding (RM18-1).[139] In terminating the DOE NOPR proceeding, the 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 to afford 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[140] 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

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

[139] 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 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.

[140] 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."

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”[141] 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 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 Tech Conf (Jun 23-25, 2020) (AD10-12)**

On June 23-25, the FERC held its 11th annual technical conference addressing increasing Real-Time and Day-Ahead market efficiency through improved software. FERC Staff facilitated a discussion to explore research and operational advances with respect to market modeling that appear to have significant promise for potential efficiency improvements. Speaker materials have not yet been posted in eLibrary.

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

On March 20, 2020, the FERC issued a NOPR[142] proposing to revise its existing transmission incentives policy and corresponding regulations.[143] 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 <u>and</u> an additional 50 basis point adder for transmission projects that demonstrate *ex post* cost savings that fall in the 90th percentile of transmission projects studied over the same sample period, as measured at the end of construction.
- ♦ ***ROE for Reliability Benefits***. A 50 basis point adder for transmission projects that can demonstrate potential reliability benefits by providing quantitative analysis, where possible, as well as qualitative analysis.
- ♦ ***Abandoned Plant Incentive***. 100 percent of prudently incurred costs of transmission facilities selected in a regional transmission planning process that are cancelled or abandoned due to factors that are beyond the control of the applicant. Recovery from the date that the project is selected in the regional transmission planning process.
- ♦ ***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.

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[141] For purposes of these proceedings, “Clean Energy Advocates” are NRDC, Sierra Club and UCS.

[142] *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, 170 FERC ¶ 61,204 (Mar. 20, 2020) (“*Electric Transmission Incentives NOPR*”).

[143] 18 CFR 35.35 (2020).

- ♦ ***Updated Date Reporting Processes***. Information to be obtained on a project-by-project basis, information collection expanded, updated reporting process.

A more detailed summary of the NOPR was distributed to the Transmission Committee and discussed at its March 25, 2020 meeting. Over 80 sets of comments on the proposed revisions were filed on or before the July 1, 2020[144] comment date, including comments by: Avangrid, EDF Renewables, EMCOS, Eversource, Exelon, LS Power, MMWEC/NHEC/CMEEC, National Grid, NESOCE, NextEra, UCS, CT PURA, and Potomac Economics. Reply comments were filed by AEP, ITC Holding, the N. California Transmission Agency, and WIRES. The NOPR is now pending before the FERC. If you have any questions concerning this matter, please contact Eric Runge (617-345-4735; ekrunge@daypitney.com).

- ***Order 872*: Pricing and Eligibility Changes to PURPA Regulations (RM19-15)**

On July 16, 2020, the FERC issued its final rule[145] approving pricing and eligibility revisions to its long-standing regulations implementing sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 ("PURPA").[146] 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.[147] Order 872 implements the following significant revisions:

- ***State Flexibility in Setting QF Rates***: Previous regulations required that rates paid to qualifying facilities (QFs) under PURPA must be at "avoided costs" of the purchasing utility, with the QF electing whether to accept avoided cost rates that vary over a contract period or a fixed rate for the duration of the contract. *Order 872* eliminates that requirement; instead, states will have the option of requiring energy rates (but not capacity rates) in QF power sales contracts to vary with changes in the purchasing utility's "as-available" avoided costs at the time energy is delivered. If a state exercises this option, then a QF cannot elect to fix the energy rate but can continue to receive a fixed capacity rate for the term of its agreement with the purchasing utility. In addition, *Order 872* allows states in an ISO/RTO market to set the rate for as-available energy at a variable rate equal to the ISO/RTO LMP, based on a rebuttable presumption (rather than a *per se* rule as FERC proposed in its NOPR) that the LMP represents the as-available avoided costs of utilities located in that market. These regulations provide greater flexibility to the states in determining whether such rates accurately reflect the purchasing utility's avoided cost at the time of delivery. *Order 872* also permits states to set energy and capacity rates pursuant to competitive solicitation processes but only so long as those processes are transparent and nondiscriminatory. FERC, however, declined to adopt a NOPR proposal to permit states with retail competition to relieve their utilities from PURPA's mandatory purchase obligation.
- ***Decreases (to 5 MW) the Threshold for Rebuttable Presumption of Access to Nondiscriminatory, Competitive Markets***. PURPA regulations previously provided a rebuttable presumption that certain 20 MW or larger QFs located in ISO/RTO markets had nondiscriminatory access to those markets and exempted utilities from any purchase obligations from such resources. *Order 872* reduces the threshold from 20 MW to 5 MW (rather than 1 MW as proposed in the NOPR). QFs above 5 MW can challenge the presumption that they have nondiscriminatory access to wholesale markets based on a list of factors

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[144] The *Electric Transmission* Incentives NOPR was published in the *Fed. Reg.* on Apr. 2, 2020 (Vol. 85, No. 64) pp. 18,784-18,810. Requests for extension of time to file comments were filed by American Manufacturers, APPA/TAPS, and State Entities; WIRES and EEI each opposed the requested extensions. No extension of time to file comments was granted.

[145] *Qualifying Facility Rates and Requirements; Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, Order No. 872, 172 FERC ¶ 61,041 (July 16, 2020) ("*Order 872*").

[146] 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.

[147] 16 U.S.C. § 824a–3; PURPA, Sec. 210(a)-(b).

specified in *Order 872*, including barriers to connecting to the transmission grid and lack of affiliation with entities participating in RTO/ISO markets. This modification does not apply to QFs that are cogenerators, which are still subject to the 20 MW threshold.

- ***Updates the "One-Mile Rule"***. Under current PURPA regulations, a small power production facility must be 80 MW or less to be eligible for QF treatment. To prevent gaming of that rule (QF certification of multiple projects that, if combined, would otherwise exceed the 80 MW cap), *Order 872* establishes two irrebuttable presumptions: (1) facilities under common ownership located less than one mile apart that use the same energy resource will be aggregated into a single project for purposes of QF eligibility; and (2) facilities under common ownership located more than 10 miles apart that use the same energy resource will be presumed to be separate projects for QF eligibility. *Order 872* also establishes a rebuttable presumption that facilities under common ownership located more than one mile apart but less than 10 miles apart are located on a separate site and are not aggregated in determining whether they fall below the 80 MW cap. The FERC explained that this rule also will be applied to QFs developed by unaffiliated developers and later acquired by a single entity.
- ***Clarifies When a QF Establishes Its Entitlement to a Purchase Obligation***. *Order 872* requires a utility to purchase the power only from QFs that can demonstrate commercial viability and a financial commitment pursuant to objective and reasonable state-defined criteria. The FERC clarified that, to the extent that a permitting factor is relied upon, a QF need only show that it has applied for all required permits and paid all applicable fees, but not that it has obtained such permits or has a reasonable likelihood of obtaining such permits.
- ***Provides for Certification Challenges***. *Order 872* provides that interested stakeholders may challenge a QF self-certification or self-recertification. Challenges to recertifications, however, will be limited to those QFs making substantive changes (e.g., a change in electrical generating equipment that increases power production capacity by the greater of 1 MW or 5 percent of the previously certified capacity, or a change in ownership in which an owner increases its equity interest by at least 10 percent from the equity interest previously reported).

Order 872 will become effective 120 days after its publication in the Federal Register (which as of the date of this Report has not yet happened). Challenges, if any, to *Order 872* must be filed on or before August 17, 2020.

- ***Orders 864/864-A*: Public Util. Trans. ADIT Rate Changes (RM19-5)**

On November 21, 2019, the FERC issued its final rule ("*Order 864*")[148] 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[149] that were applicable to public utilities with stated rates. *Order 864* became 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.[150] Specifically, the FERC clarified that public utilities with transmission stated rates that have a

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[148] *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).

[149] *Public Util. Trans. Rate Changes to Address Accumulated Deferred Income Taxes*, 165 FERC ¶ 61,117 (Nov. 15, 2018) ("*ADIT NOPR*").

[150] *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*").

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 method used to make provision for excess and deficient ADIT will be subject to case-by-case determination in a later rate proceeding.[151]

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 – The following New England compliance filings have been submitted:

Date Filed	Docket	Transmission Provider	Date Accepted
Aug 4, 2020	ER20-2607	NEP – Seabrook Transmission Support Agreement	pending
Jul 31, 2020	ER20-2594	VTransco	pending
Jul 30, 2020	ER20-2551	New England Power	pending
Jul 30, 2020	ER20-2553	NEP – LSA with MECO/Nantucket	pending
Jul 15, 2020	ER20-2429	CMP	pending
Jun 29, 2020	ER20-2219	New England Power	pending
Jun 23, 2020	ER20-2133	Versant Power	pending
May 18, 2020	ER20-1839	VETCO	Pending
Feb 26, 2020	ER20-1089	New England Elec. Trans. Corp.	pending
Feb 26, 2020	ER20-1088	New England Hydro Trans. Elec. Co.	pending
Feb 26, 2020	ER20-1087	New England Hydro Trans. Corp.	pending

- **DER Participation in RTO/ISOs (RM18-9)**

In *Order 841*[152] (*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*.[153] 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,[154] 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,

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[151] *Order 864-A* at PP 18-19

[152] *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*").

[153] *Elec. Storage Participation in Mkts. Operated by Regional Trans. Orgs. and Indep. Sys. Operators*, 157 FERC ¶ 61,121 (Nov. 17, 2016) ("*Storage NOPR*").

[154] 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.

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, 2019, 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.

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

As previously reported, *Order 860,*[155] issued three years after the FERC's *Data Collection NOPR,*[156] (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. As recently extended (*see* below), *Order 860* will become effective April 1, 2021, and submitters will have until close of business on August 2, 2021 to make their initial baseline submissions. Submitters will be required to obtain in Spring 2021 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,[157] or FERC-generated ID and that all reportable generation assets have an code from the Energy Information Agency ("EIA") Form EIA-860 database or a FERC-assigned Asset ID. Requests for rehearing and/or clarification of *Order 860* were denied,[158] 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.

Effective Date Extended by 6 Months. On May 6, 2020, EEI requested a four-month extension of implementation of *Order 860*. EPSA supported that request on May 13, 2020. On May 20, the FERC issued a notice extending the effective and associated implementation dates of *Order 860* by *six* months. The new

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[155] *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).

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

[157] 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.

[158] *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*").

Order 860 effective date will be April 1, 2021, and the deadline for baseline submissions to and including August 2, 2021. First change in status filings under these new timelines will be due August 31, 2021.

- ***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*,[159] 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 Quadrant ("WEQ") of the North American Energy Standards Board ("NAESB").[160] The Version 003.2 Standards included NAESB's Version 003.1 revisions, which were the subject of an earlier NOPR.[161] 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.[162] 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 to afford 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.

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

On May 21, 2020, the FERC issued a Proposed Policy Statement that would clarify its policy regarding requests for waiver of tariff provisions.[163] The *Proposed Policy Statement* sets forth the approach the FERC would take going forward to ensure compliance with the filed rate doctrine and the rule against retroactive making. The proposed policy will both clarify and modify waiver standards, and in some instances, make it harder to obtain waivers.

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

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

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[159] *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*.

[160] *Standards for Business Practices and Communication Protocols for Public Utilities*, 167 FERC ¶ 61,127 (May 16, 2019) ("*NAESB WEQ v. 003.2 Standards NOPR*").

[161] *Standards for Business Practices and Communication Protocols for Public Utilities*, 156 FERC ¶ 61,055 (July 21, 2016), ("*WEQ v. 003.1 NOPR*").

[162] *Order 676-I* was published *Fed. Reg.* on Feb. 25, 2020 (Vol. 85, No. 37) pp. 10,571-10,586.

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

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

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

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

The FERC proposed to incorporate its current four-part analysis[164] in considering both requests for prospective waiver and petitions for remedial relief, but cautioned that it would apply that analysis only in those limited circumstances where the request for remedial relief would not violate the filed rate doctrine or the rule against retroactive ratemaking due to adequate prior notice, or the requested relief is within the FERC's authority to grant under FPA section 309 or NGA section 16.

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

With respect to prospective requests to waive the 60-day prior notice requirement under FPA section 205(d) (or the 30-day prior notice requirement under NGA section 4(d)), which the FERC has discretion to waive "for good cause shown," the FERC proposes to leave in effect its policy of generally granting such waivers,[165] to the extent that entities seek an effective date no earlier than the day *after* the date a rate change is submitted to the FERC.

Comments on the Proposed Policy Statement were due on or before June 18, 2020 and were filed by the IRC, AEE, APPA, AWEA/SEIA, EEI, EPSA, Indicated Generators,[166] INGAA, Kansas Electric Power Coop. ("KEPC"), NGA, NGSA, NRECA, Public Citizen, Sunflower Electric Power, and TAPS. Reply comments were filed

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

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

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

by APPA, Joint Trade Associations,[167] KEPC, and the Sustainable FERC Project. The proposed Policy Statement is pending before the FERC.

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

On May 21, 2020, the FERC issued a Policy Statement that applies to natural gas and oil pipelines, with certain exceptions to account for the statutory, operational, organizational and competitive differences among the electric, natural gas and oil pipeline industries, the FERC's ROE methodology adopted in *Opinion No. 569-A*.[168] Specifically, the FFERC revised its policy and will determine natural gas and oil pipeline ROEs by averaging the results of the DCF and CAPM, but will not use the risk premium model discussed in *Opinion 569/569-A* ("Risk Premium").[169] In addition, the FERC clarified its policies governing the formation of proxy groups and the treatment of outliers in proceedings addressing natural gas and oil pipeline ROEs. Finally, the FERC encouraged oil pipelines to file revised FERC Form No. 6, page 700s for 2019 reflecting the revised ROE policy. This Policy Statement became effective May 27, 2020.[170] On July 7, the FERC issued a notice that pipelines choosing to file updated FERC Form No. 6, page 700 data consistent with the ROE Policy Statement should file such data on or before July 21, 2020.

Complainant-Aligned Parties[171] answered the New England TO's May 10 supplemental comments. On June 15, 2020, Joint Parties[172] submitted supplemental comments arguing that the FERC should use the midpoint, rather than the median, as the measure of central tendency for public utilities that file individually to establish a ROE. Joint Parties' comments were opposed by Six Cities.[173] WIRES submitted supplemental comments on June 18, 2020 requesting that the FERC take further action in this proceeding to "resolve the uncertainty surrounding its base ROE methodology and establish a policy consistent with the recommendations made in these comments" (recommending a framework that employs all four of the previously proposed ROE models, including the Expected Earnings model, along with certain modifications, to ensure that ROEs attract capital investment in needed transmission infrastructure). On June 24, EEI and WIRES requested the FERC issue a NOI regarding the FERC's policy for determining base ROE applicable to the electric industry as a whole. Six Cities answered Joint Parties on June 30. APPA answered EEI and WIRES' June 24 motion.

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

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

[169] As previously reported, the FERC issued a notice of inquiry on March 21, 2019 seeking information and views to help the FERC explore whether, and if so how, it should modify its policies concerning the determination of ROE to be used in designing jurisdictional rates charged by public utilities.[169] The FERC also sought comment on whether any changes to its policies concerning public utility ROEs should be applied to interstate natural gas and oil pipelines. This NOI followed *Emera Maine*, which reversed *Opinion 531*, and seeks to engage interests beyond those represented in the *Emera Maine* proceeding (see EL11-66 *et al.* in Section I above).

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

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

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

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

- **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[174] seeks comments from interested parties on four broad issue categories: (1) project need, including whether precedent agreements are still the best demonstration of need; (2) exercise of eminent domain; (3) environmental impact evaluation (including climate change and upstream and downstream greenhouse gas emissions); and (4) the efficiency and effectiveness of the FERC certificate process. Pursuant to a May 23 order extending the comment deadline by 30 days,[175] 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*[176] 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.[177] 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."[178] 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.[179] BP was

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[174] The NOI was published in the *Fed. Reg.* on Apr. 26, 2018 (Vol. 83, No. 80) pp. 18,020-18,032.

[175] *Certification of New Interstate Natural Gas Facilities*, 163 FERC ¶ 61,138 (May 23, 2018).

[176] *BP America Inc.*, Opinion No. 549, 156 FERC ¶ 61,031 (July 11, 2016) ("*BP Penalties Order*").

[177] *BP America Inc.,* 152 FERC ¶ 63,016 (Aug. 13, 2015) ("*BP Initial Decision*").

[178] *BP Penalties Order* at P 3.

[179] *BP America Inc.*, 147 FERC ¶ 61,130 (May 15, 2014) ("*BP Hearing Order*"), *reh'g denied,* 156 FERC ¶ 61,031 (July 11, 2016).

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 to afford 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 rehearing is issued), but indicated that interest will continue to accrue on unpaid monies during the pendency of the stay.[180]

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[181] 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.[182]

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.

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[180] *BP America Inc.*, 156 FERC ¶ 61,174 (Sep. 12, 2016) ("*Order Staying BP Disgorgement*").

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

[182] 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.

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

  - ***Iroquois ExC Project (CP20-48)***
    - 125,000 Dth/d of incremental firm transportation service to ConEd and KeySpan by building and operating new natural gas compression and cooling facilities at the sites of four existing Iroquois compressor stations in Connecticut (Brookfield and Milford) and New York (Athens and Dover)
    - Three-year construction project; service request by November 1, 2023
    - Application for a certificate of public convenience and necessity pending.
    - Since the Last Report, the NYS DEC filed comments on the Sensitive Species Habitat Assessment Report that had been filed in this proceeding, to which Iroquois responded. In addition, Iroquois filed supplemental information on July 30 and was requested by the FERC to respond on or before August 7 to a data request asking for information on the EC Project's first year O&M costs and expected revenues.

- **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.[183] 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*.[184] 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,[185] and proceeded to find that the NY DEC was obligated to act on the application within one year, failed to do so, and so waived its authority under section 401 of the CWA.
    - The FERC authorized the Companies to construct and operate pipeline, compression, and ancillary facilities in McKean County, Pennsylvania, and Allegany, Cattaraugus, Erie, and Niagara Counties, New York ("Northern Access Project") in an order issued February 3,

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

[184] *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).

[185] 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).

2017.[186] 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.[187] 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,[188] provided a "more clearly articulate[d] basis for denial."
- On August 27, 2019, Applicants requested an additional order finding on additional grounds that the NY DEC waived its authority over the Northern Access 2016 Project under Section 401 of the CWA, even if the NY DEC and Sierra Club prevail in their currently pending court petitions challenging the basis for the Commission's Waiver Order.[189]

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 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

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[186] *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*").

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

[188] 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).

[189] *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).

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).

- **2013/14 Winter Reliability Program Order on Compliance and Remand (20-1289)**
  Underlying FERC Proceeding: ER13-2266[190]
  Petitioner: TransCanada

On July 30, 2020, TransCanada Power Marketing ("Petitioner") again petitioned the DC Circuit Court of Appeals for review of the FERC's action on the 2013/2014 Winter Reliability Program, this time in the FERC's April 1, 2020 *2013/14 Winter Reliability Program Order on Compliance and Remand*.[191] Among other submissions, TransCanada must file by August 31, 2020 a docketing statement, statement of issues, and any procedural motions. Dispositive motions and a Certified Index to the Record must be filed by September 14. Appearances by others in this case must be filed by August 31, 2020.

- **ISO-NE's Inventoried Energy Program (Chapter 2B) Proposal (19-1224***; 19-1247; 19-1252; 19-1253)(consolidated); Underlying FERC Proceeding: ER19-1428**[192]
  Petitioners: ENECOS (Belmont et al.) (19-1224); MA AG (19-1247); NH PUC/NH OCA (19-1252); Sierra Club/UCS (19-1253)

At the unopposed request of the FERC, the Court 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, 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 rehearing". (As reported in Section III above, the FERC issued the *IEP Remand Order* on June 18, 2020.) 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.

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[190] 171 FERC ¶ 61,003 (Apr. 1, 2020) ("*2013/14 Winter Reliability Program Order on Compliance and Remand*") (accepting ISO-NE's January 23, 2017 compliance filing, finding that the bid results from the 2013/14 Winter Reliability Program were just and reasonable, and providing for this finding the further reasoning requested by the DC Circuit in *TransCanada Power Mktg. Ltd. v. FERC*, 811 F.3d 1 (DC Cir. 2015) ("*TransCanada*").)

[191] In TransCanada, the DC Circuit granted TransCanada's prior petition in part, and directed the FERC to either better justify its determination or revise its disposition to ensure that the rates under the Program are just and reasonable. *TransCanada* at 1.

[192] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

- ***Order 841* (Electric Storage Participation in RTO/ISO Markets) (19-1142, 19-1147) (consol.)**
  Underlying FERC Proceeding: RM16-23; AD16-[193]
  Petitioners: NARUC, APPA et al.

On July 10, 2020, the DC Circuit denied the petitions filed by NARUC and APPA et al.[194] for review of *Orders 841* and *841-A* (Electric Storage Participation in RTO/ISO Markets).[195] Writing for the Court, Judge Wilkins summarized the case and the Court's ruling as follows:

> In this consolidated action, the Court must once again referee the [FPA]'s jurisdictional line separating the [FERC]'s jurisdiction over the federal wholesale market and States' jurisdiction over facilities used in local distribution. This time, Petitioners argue FERC is off-sides in Order No. 841 by prohibiting States from barring electric storage resources on their distribution and retail systems from participating in federal markets. We find no foul here, so we deny the Petitions.

In explaining its reasoning, the Court did acknowledge that "Petitioners are likely correct that litigation will follow" as States try to navigate the line between Federal and State jurisdiction and should they challenge, as they will be free to do, the application of *Order 841* to their own state regulations or imposed conditions. But, "[b]ecause the challenged Orders do nothing more than regulate matters concerning federal transactions — and reiterate ordinary principles of federal preemption — they do not facially exceed FERC's jurisdiction under the [FPA]." Having failed "to show that Order Nos. 841 and 841-A run afoul of the Federal Power Act's jurisdictional bifurcation or that they are otherwise arbitrary and capricious …. we therefore deny the petitions."

No petitions for rehearing *en banc* were filed, effectively concluding this proceeding.

Other Federal Court Activity of Interest

- **Allegheny Defense Project v. FERC (17-1098)**
  Underlying FERC Proceeding: CP15-138[196]
  Petitioner: Allegheny Defense Project

On June 30, in a decision[197] that will likely have a profound effect on current and future proceedings before the FERC, the DC Circuit ruled that the Natural Gas Act ("NGA") does not allow FERC to delay appellate review of its substantive orders through its common practice of issuing tolling[198] orders. The decision at the very least modifies—if not wholly overrules—a long-unbroken line of cases that rejected as premature appeals from FERC orders while applications for rehearing were pending. While the case was decided under the NGA,[199] there is

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[193] 162 FERC ¶ 61,127 (Feb. 15, 2018) ("*Order 841*"); 167 FERC ¶ 61,154 (May 16, 2019) ("*Order 841-A*").

[194] "APPA et al." are APPA, NRECA, EEI, and AMP.

[195] *NARUC v FERC*, ___F.3d___, 2020 WL 3886199 (D.C. Cir. Jul. 10, 2020).

[196] *Transcontinental Gas Pipe Line Co., LLC*, 159 FERC ¶ 62,181 (Feb. 3, 2017); *Transcontinental Gas Pipe Line Co., LLC*, 161 FERC ¶ 61,250 (Dec. 6, 2017).

[197] *Allegheny Def. Project v. FERC*, 964 F.3d 1, 2020 WL 3525547 (D.C. Cir. June 30, 2020).

[198] A tolling order is a brief order issued within 30 days of receiving an application for rehearing that does not address the merits of the rehearing request, but rather explicitly "grants" rehearing for the purpose of giving the agency more time to consider the arguments. FERC then treats the tolling order as indefinitely suspending the 30-day statutory deadline in order to afford more time to fully address the rehearing request. FERC has for decades routinely issued tolling orders in response to identical language in both the NGA and the FPA that requires any party seeking to challenge a FERC order on appeal to first request a rehearing before FERC, and FERC to act within 30 days after receiving any such requests. If FERC does not act within that time, the rehearing request is deemed denied and the FERC order is final and ripe for appeal.

[199] In this case, the Petitioners challenged the FERC's use of a tolling order in response to their applications for rehearing of a FERC order that issued a certificate of public convenience and necessity to the Atlantic Sunrise Project. Those rehearing applications were pending for nine months before the FERC ruled on them. When the appeals were filed, the FERC and others sought to use the pending rehearing requests as the basis for dismissing the petitions as "incurably premature." Since the applications for rehearing did not stay the FERC's issuance of the certificate, the petitioners also sought a stay from the FERC, which FERC did not act on for almost seven months.

little doubt that the court's rejection of FERC's long-standing tolling policy will impact proceedings arising under the FPA as well.

Following issuance of the decision, the FERC asked the Court for a stay of issuance of the mandate in this case for 90 days (the Court had ordered that the mandate be issued on July 7, 2020). The FERC argued that the stay would permit the FERC time to assess how to implement the Court's decision and would also allow the federal government to consider whether to file a petition for writ of certiorari in the Supreme Court. Petitioners opposed the FERC's motion. On July 23, 2020, the Court issued a *per curiam* order staying issuance of the mandate through October 5, 2020, as requested by the FERC. Also of note, On July 2, 2020, Chairman Chatterjee and Commissioner Glick issued a joint statement asking Congress to consider providing FERC with additional time to act on rehearing requests.

- **FERC orders on PG&E Bankruptcy (19-71615) (9th Cir.)**
  Underlying FERC Proceeding: EL19-35, EL19-36[200]
  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 determination of whether any rejections of power purchase contracts by [PG&E] should be authorized."[201] 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. Remote hearings are scheduled for August 14.

The Court ordered the parties to submit supplemental briefs by July 8, 2020 addressing the impact on this appeal of the confirmation of PG&E's bankruptcy plan. (PG&E has since successfully emerged from bankruptcy). While the parties agreed in their July 9 briefs that the case is moot given PG&E's voluntary assumption of its contracts in its reorganization plan, there was disagreement over whether the FERC's orders should be vacated. Final resolution is pending before the 9th Circuit.

While the rehearings and requests for stay were still before the FERC, the pipeline sponsors of the Atlantic Sunrise Project proceeded to condemn land and begin construction activities. By the time the first panel of the court heard oral arguments on the petitions for review, the project had been built and in service for two months.

[200] *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).

[201] Declaratory Judgment at 1-2, *PG&E v. FERC*, (Bankr. N.D. Cal. June 7, 2019).

- **PennEast Project (18-1128)**
Underlying FERC Proceeding: CP15-558[202]
Petitioners: NJ DEP, DE and Raritan Canal Commission, NJ Div. of Rate Counsel

Abeyance continues of the appeal before the DC Circuit of the FERC's orders granting certificates of public convenience and necessity to PennEast Pipeline Company, LLC ("PennEast")[203] for the construction and operation of a new 116-mile natural gas pipeline from Luzerne County, Pennsylvania, to Mercer County, New Jersey, along with three laterals extending off the mainline, a compression station, and appurtenant above ground facilities ("PennEast Project"). The cases are being held in abeyance "pending final disposition of any post-dispositional proceedings [ ] before the United States Supreme Court resulting from the Third Circuit's decision in No. 19-1191 (In re: PennEast Pipeline Company, LLC (3rd Cir. Sep. 10, 2019)), or other action that resolves the obstacle PennEast poses". That decision held that the Eleventh Amendment barred condemnation cases brought by PennEast in federal district court in New Jersey to gain access to property owned by the State or its agencies, thus calling into question the viability of PennEast's proposed project route, and the certificates issued in the underlying case. Until the Third Circuit case is resolved, which is in the midst of proceedings before the Supreme Court, the DC Circuit will not take up this case. Since the last Report, on June 29, 2020, a Joint Status Report was filed, noting developments since the May 4, 2020 Status Report, and reporting that none of the events "constitute any of the conditions that [the DC Circuit] enumerated in its October 1, 2019 Order as triggering an obligation to file a motion governing future proceedings."

- **Opinion 569/569-A: FERC's Base ROE Methodology (16-1325, 20-1227, 20-1240)**
Underlying FERC Proceeding: EL14-12; EL15-45[204]
Petitioners: MISO TOs, FirstEnergy, Transource Energy

The MISO Transmission Owners (TOs), FirstEnergy and Transource have appealed *Opinion 569/569-A*. The MISO TOs' case has been consolidated with previous appeals that had been held in abeyance, with the lead case number assigned as 16-1325. Motions to govern future proceedings in the MISO TOs' case are now due August 10, 2020. The FirstEnergy case was assigned case number 20-1227; the Transource case, 12-1240. On July 10, 2020, the Court consolidated the FirstEnergy and Transource cases. Initial submissions in the FirstEnergy case were filed July 30, 2020. Dispositive motions and a certified index to the record are due August 14, 2020. Transource was directed to file a Docketing Statement and Statement of Issues by August 10, 2020.

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[202] *PennEast Pipeline Co., LLC*, 162 FERC ¶ 61,053 (Jan. 19, 2018), *reh'g denied*, 163 FERC ¶ 61,159 (May 30, 2018).

[203] 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.

[204] *Transcontinental Gas Pipe Line Co., LLC*, 159 FERC ¶ 62,181 (Feb. 3, 2017); *Transcontinental Gas Pipe Line Co., LLC*, 161 FERC ¶ 61,250 (Dec. 6, 2017).

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IV. OATT Amendments/Coordination Agreements

V. Financial Assurance/Billing Policy Amendments

VI. Schedule 20/21/22/23 Updates

VII. NEPOOL Agreement/Participants Agreement Amendments

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XIV. State Proceedings & Federal Legislative Proceedings

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NEPOOL
NEW ENGLAND POWER POOL

TO: NEPOOL Participants Committee Members and Alternates

CC: NESCOE, NECPUC, and ISO-NE

FROM: Nancy Chafetz, Chair of NEPOOL Participants Committee

DATE: July 23, 2020

RE: Transition to the Future Grid: Discussions on Potential Future Pathways/Market Frameworks

---

I am writing to inform you of proposed plans for discussions on potential alternative pathways to support New England's transition to a future grid. As I have previously indicated, those discussions began during our summer meeting and will continue at the August 6, 2020 Participants Committee meeting. The alternative pathways discussion will run in parallel to, but separate from, the ongoing future grid study process. This memo provides additional information on the current plans for these parallel "Transition to the Future Grid" efforts.

****

Last year, the ISO received multiple requests from NESCOE, NEPGA and other stakeholders for the region to dedicate market development and planning resources in 2020 to assess and explore market and reliability issues in light of state energy and environmental laws. NEPOOL's elected officers, working with NESCOE and ISO-NE representatives, responded to those requests first with general consensus to a proposed study process that would commence following the filing of the Energy Security Improvements proposals. As was reflected in a document circulated to and discussed with NEPOOL members, NESCOE and the ISO at the March Participants Committee meeting, this contemplated study process would assess New England's future grid, perform an analysis to determine whether, in the future, the markets will provide what is needed to assure reliable operations of the grid, and then identify potential market approaches to address any anticipated future gaps.

Further, in its July 2019 request, NESCOE had specifically asked that ISO-NE plan to allocate resources in 2020 "to support states and stakeholders in analyzing and discussing potential future market frameworks that contemplate and are compatible with the implementation of state energy and environmental laws." At the March Participants Committee meeting, a commitment was made to begin parallel but separate discussions at the summer meeting of potential future market frameworks in light of expected changes to New England's grid.

FUTURE GRID STUDY PROCESS

Discussions are ongoing, via a joint effort between the NEPOOL Reliability and Markets Committees, to define and assess New England's grid of the future. Currently, NEPOOL members and state officials are working to develop future scenarios and related input assumptions to inform the to-be-conducted study. As noted above, this study process will include a gap analysis to help determine whether, in the future state envisioned, there are projected to be any operational or reliability gaps and to explore thereafter market approaches to address any future gaps identified.

POTENTIAL PATHWAYS TO NEW ENGLAND'S FUTURE GRID

During our virtual summer meeting, as promised at the March Participants Committee meeting, we heard from four informative speakers who shared their thoughts, insights and experiences on the opportunities and challenges associated with transitioning electric grid systems. There is a great deal of interest among many members and state officials in continuing the dialogue so that stakeholders can identify and better understand the various potential future market frameworks for our region.

NEPOOL will provide an opportunity and forum for regional stakeholders to identify, explore and evaluate together potential alternative pathways/market frameworks that may help to support New England's evolving grid. A key goal for these discussions is to broaden the understandings and perspectives of all interests around the NEPOOL stakeholder table. The plan for August and September is to take time during Participants Committee meetings to hear specifics about the fundamental elements, mechanics, and/or design components of potential pathways that could be pursued to help transition New England to its future grid. These sessions are intended to provide sufficient grounding for discussions and evaluation starting in October of the various tradeoffs associated with each identified pathway to inform future decision-making.

We will discuss two of the potential pathways at the August 6 Participants Committee meeting (upon completion of regular business): (i) Forward Clean Energy Market ("FCEM"): Kathleen Spees – Principal, The Brattle Group; and (ii) Carbon Pricing: Joe Cavicchi – Principal, Analysis Group. At the September 3, 2020 Participants Committee meeting, other potential pathways will be discussed.

With the benefit of the education on various alternative pathways, we will then explore together implications and tradeoffs associated with the pathways (i.e., the pros and cons of each pathway). We will be asking later for your written input to help frame those discussions.

We have a successful history in New England of working together to advance the knowledge and understanding of the challenges we confront and the various potential solutions that might help address those challenges. As these planned Future Grid discussions proceed within the NEPOOL stakeholder process, it is my hope that we'll engage with openness and in close collaboration with each other.

I look forward to engaging with you all on potential pathways forward for our region.

TRANSITION TO NEW ENGLAND'S FUTURE GRID

Forward Clean Energy Market

A MARKET-BASED OPTION FOR STATES TO ACHIEVE THEIR CLEAN ELECTRICITY GOALS

PRESENTED BY
Kathleen Spees

STUDY CO-AUTHORS
Samuel Newell
Walter Graf
David Luke Oates
Judy Chang

Full studies:

HIGH-LEVEL FCEM PROPOSAL AND NEW ENGLAND ECONOMIC IMPACT ANALYSIS (LINK)

DETAILED FCEM DESIGN PROPOSAL WITH STATE DESIGN OPTIONS (LINK)

July 2020

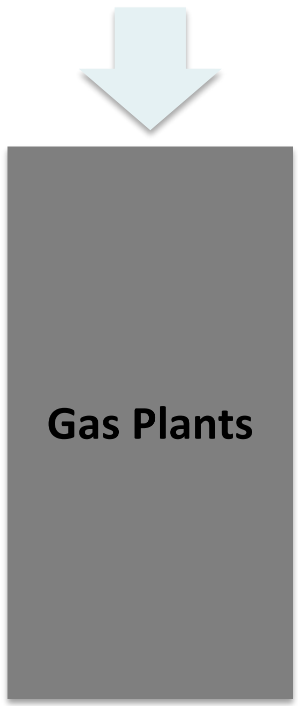
THE Brattle GROUP

First: What Are We Trying to Do Here?

Current ISO Markets Are Designed to Achieve:

Reliable & Low-Cost Electricity

Markets designed for this purpose will attract and retain….



Gas Plants

Market forces may drive carbon emissions up or down

But by 2050 New England Needs:

Reliable, Low-Cost & Carbon-Free Electricity

Storage

DR

Hydro

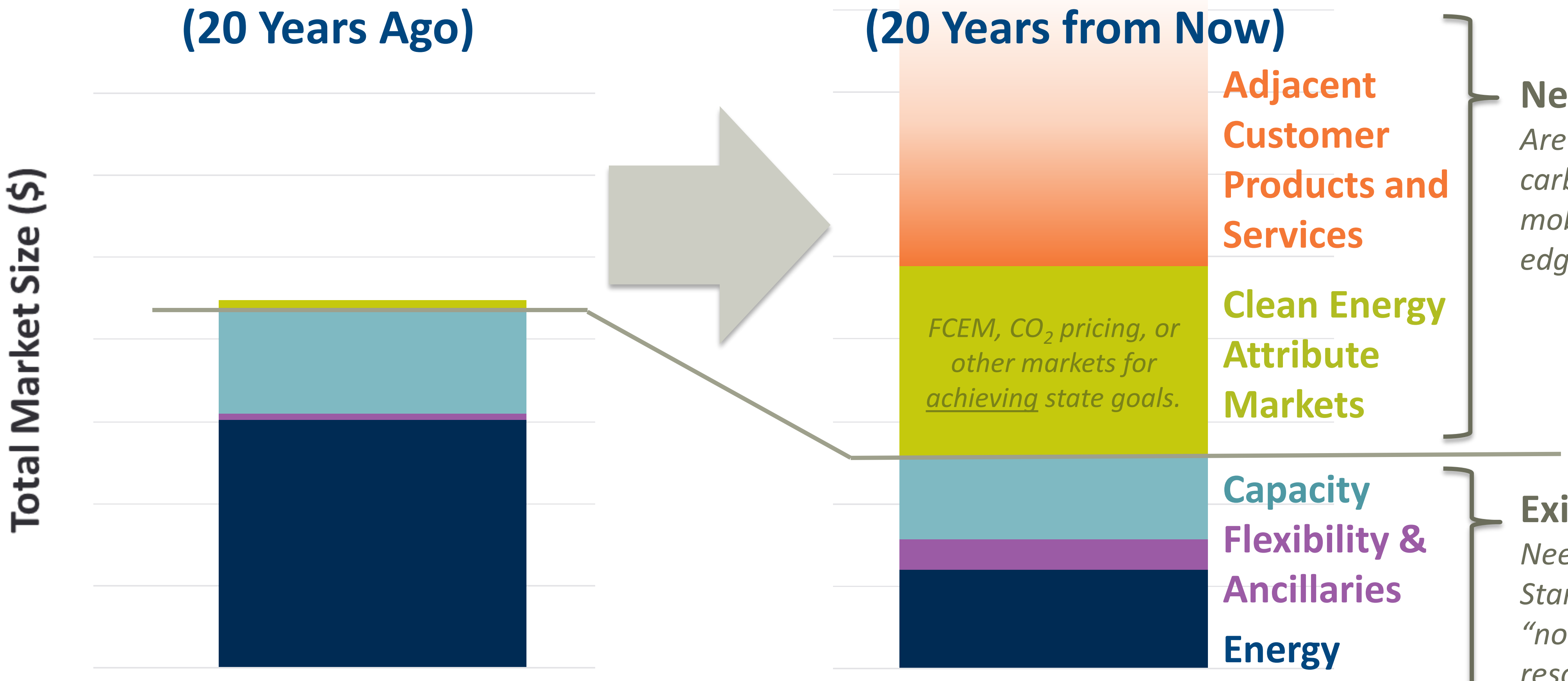
Solar

Wind

Nuclear

Market drives 80% carbon reductions at least cost

Second: What Do the "Future Markets" Look Like?



Best Market Design (20 Years Ago)

Best Market Design (20 Years from Now)

Adjacent Customer Products and Services

FCEM, CO_2 pricing, or other markets for achieving state goals.

Clean Energy Attribute Markets

Capacity

Flexibility & Ancillaries

Energy

New Markets

Are needed to meet carbon objectives & mobilize the grid edge

Existing Markets

Need to be re-thunk. Start by assuming that "nontraditional" resources are the new normal

Current Markets

Designed for …. Dispatchable thermal plants, inelastic demand

Future Markets

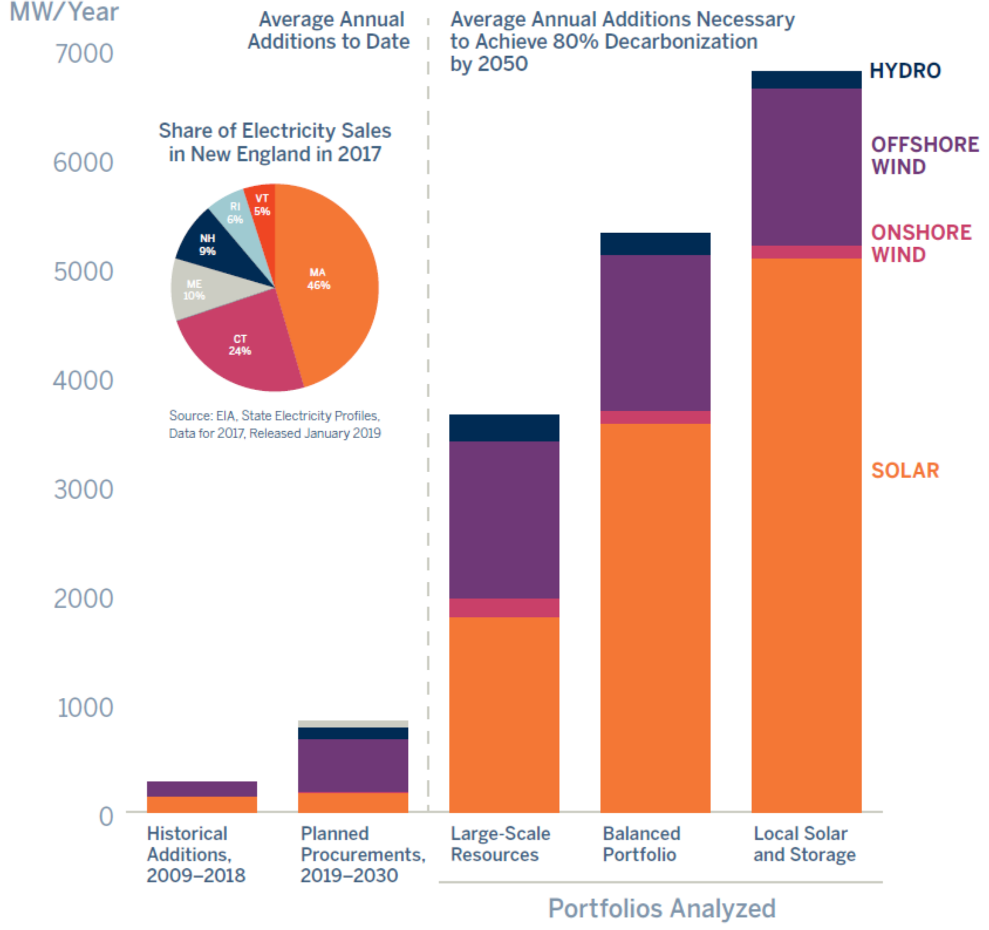
Intermittent wind & solar, storage, EVs, DR, interties, prosumers

Third: How Do We Get There?

- **Thousands of MW of new clean resources** will need to be built every year to meet policy goals and customer demand
- **Missing building block in the "future markets":** Some of the states may want to utilize a market-based option achieve their policy goals (not just accommodate)
- We developed the Forward Clean Energy Market (FCEM) as one tool that states could use for mobilizing private investment to meet their goals through a competitive market

New England Clean Energy Needs

Average Annual Clean Energy Additions Needed to Achieve "80 by 50" Goals



Source: Brattle Study "*Achieving 80% GHG Reduction in New England by 2050*"

Refresher: What is the Forward Clean Energy Market?

Design concept originated in the IMAPP process with input from many states & stakeholders. Developed across two studies…

HIGH-LEVEL FCEM PROPOSAL AND NEW ENGLAND ECONOMIC IMPACT ANALYSIS (LINK)

A Dynamic Clean Energy Market in New England

PREPARED BY

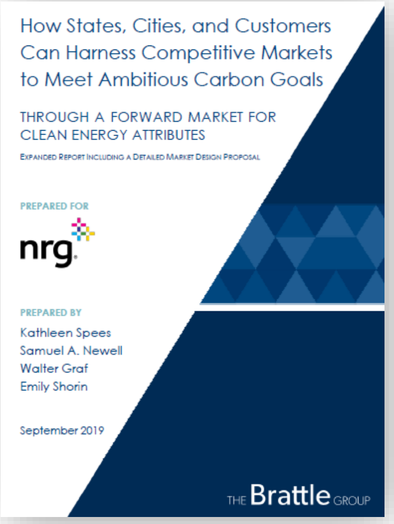
The Brattle Group
Kathleen Spees
Judy Chang
David Luke Oates
Tony Lee

Coalition Partners
Conservation Law Foundation
Brookfield Renewable
NextEra Energy Resources
National Grid
Robert Stoddard

November 2017

THE Brattle GROUP

DETAILED FCEM DESIGN PROPOSAL WITH STATE DESIGN OPTIONS (LINK)



How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals

THROUGH A FORWARD MARKET FOR CLEAN ENERGY ATTRIBUTES

EXPANDED REPORT INCLUDING A DETAILED MARKET DESIGN PROPOSAL

PREPARED FOR

nrg

PREPARED BY

Kathleen Spees
Samuel A. Newell
Walter Graf
Emily Shorin

September 2019

THE Brattle GROUP

How Does FCEM Fit into the Range of "Achieve" Options that the States Might Consider?

FCEM is one promising option for New England states to consider for part or all of their clean energy procurement goals

Integrated Resource Planning

State Contracting

More Targeted
Bundled contracts
Technology-specific
Regionally limited

More Competitive
Unbundled attributes
Regional
Technology neutral

Forward Clean Energy Attribute Market

More Targeted
Technology-specific or new resource carve-outs

More Competitive
Region-wide
Technology neutral

Carbon Pricing

More Targeted
Electricity sector only
Lower carbon price

More Competitive
Region-wide
Economy-wide
Higher carbon price

FCEM is a family of approaches that can be tailored to the specific needs of each state and the broader New England region

What is the Forward Clean Energy Market?

The FCEM would be a centralized, forward auction in which buyers and sellers could voluntarily exchange clean energy attribute credits (CEACs)

Voluntary Buyers

States · Retailers · Companies · Cities · Utilities · Public Power

Qualified Sellers

Wind · Solar · Nuclear · Hydro · Other Qualified Clean Energy

- 3-year forward auction
- Unbundled CEAC product
- 7-12 year price lock-in for new resources

Design Overview

The FCEM could incorporate the best practices of existing wholesale electricity markets while enabling states to express their own policy goals

- **Unbundled Clean Energy Attributes** to maximize competition across markets and technologies
- **States and Customers Choose** their own demand quantities and willingness to pay (no costs shifted to non-participants)
- Broad **regional competition**
- **Technology-neutral** qualification and payments (option for technology carve-outs)
- Mechanisms to **mitigate regulatory risk** and ensure financeability at competitive costs
- Option for **product definition** that matches the underlying objective (carbon abatement), or combine with higher carbon prices to achieve similar outcomes
- **Alignment with energy, ancillary, and capacity markets**

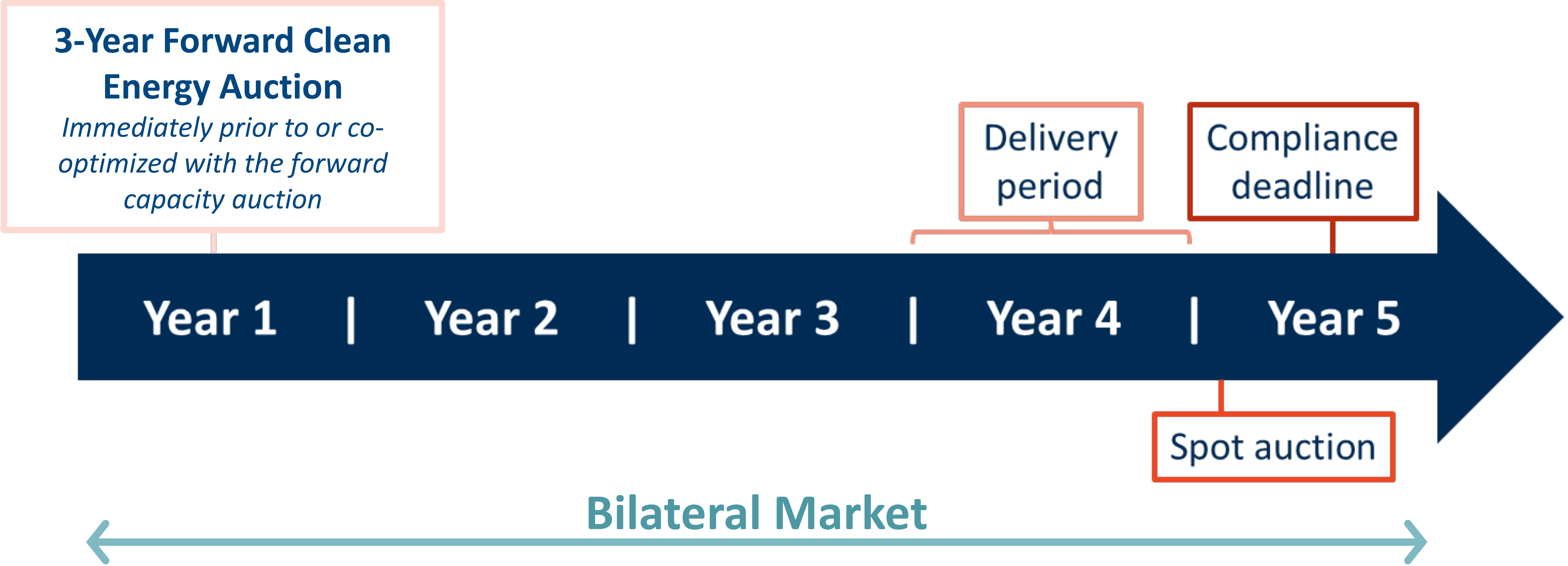
Design Overview: Basic Framework is Straightforward, But There are a Number of Options to Consider

Design Element	Approach
Product Definition	• The product is an unbundled Clean Energy Attribute Credit (CEAC), similar to an unbundled Renewable Energy Credit (REC) • Optional Variation: Design option for a "dynamic" CEAC accounting approach that awards more CEACs to resources that displace more carbon emissions. This approach can readily enable batteries and focus incentives toward achieving more carbon abatement faster
Demand Participation in the Forward Auction	• State demand would be expressed as a sloping demand curve that will buy higher quantities if supply is available at lower cost • Additional voluntary demand bids can be submitted by cities, public power entities, customers, companies, retail providers, or others. These bids are expressed as price-quantity pairs, representing the willingness to pay for CEACs • Optional Variation: Buyers will have an option to submit a preference for "targeted" resource types, for example to meet carve-outs for preferred technologies such as storage or offshore wind. The auction may procure these resource types even if they are higher cost than "base" resources, although the buyer can specify a limited willingness to pay such a premium
Technology-Neutral Supply Participation	• Resources are not restricted by type, location, or generation profile; any new or existing clean resources can participate, including hydro, wind, solar, nuclear, storage, or other • Storage resources can participate if their charging and discharging profiles displace system carbon emissions; they offer the value of carbon abatement when discharging, net of any additional carbon emissions they cause when charging
Forward Auction	• Forward auction three years before the one-year delivery period to align with development timeline of new clean resources • 7-12 year commitment period is available to new resources, over which time the price is locked-in to guarantee revenue stability
Bilateral and Spot Markets	• Ongoing trading before and during the delivery year, with a final spot auction after the delivery year. Producers can adjust their positions until the spot auction when any net deficit must be remedied; retailers can continually adjust their positions until the compliance deadline at which point retailers must meet their clean energy obligation or face a compliance penalty
Monitoring and Mitigation	• Targeted mitigation measures to prevent large suppliers from exercising market power through physical or economic withholding
Wholesale Market Alignment	• Operates well with existing wholesale markets and maintains incentives to maximize energy, flexibility, and reliability value to the grid • CEAC-based revenues are counted as "in-market" in the capacity market, i.e. not subject to minimum offer price rule (MOPR) provisions
Competitive Retail Market Alignment	• In states with retail choice, the CEAC is implemented as an obligation on retail providers to meet a certain fraction of their delivered load through clean energy, e.g. 50% by 2030 • Retailers can comply either by making their own CEAC supply arrangements (with self-supply volumes netted out of auction settlements), or by relying on the centralized auctions (passing the costs on to customers) • Retailers compete to offer innovative retail energy options to customers, including additional (up to 100%) clean energy. Retailers can participate in forward, bilateral, and spot markets and develop hedging strategies to minimize cost and risk

What Are the Key Design Features and Choices?

Procurement and Compliance Timeline

Three-year forward procurements are designed to align with developer needs, while fully enabling bilateral agreements retailer self-supply at all timeframes



3-Year Forward Clean Energy Auction

Immediately prior to or co-optimized with the forward capacity auction

Delivery period

Compliance deadline

Year 1 | Year 2 | Year 3 | Year 4 | Year 5

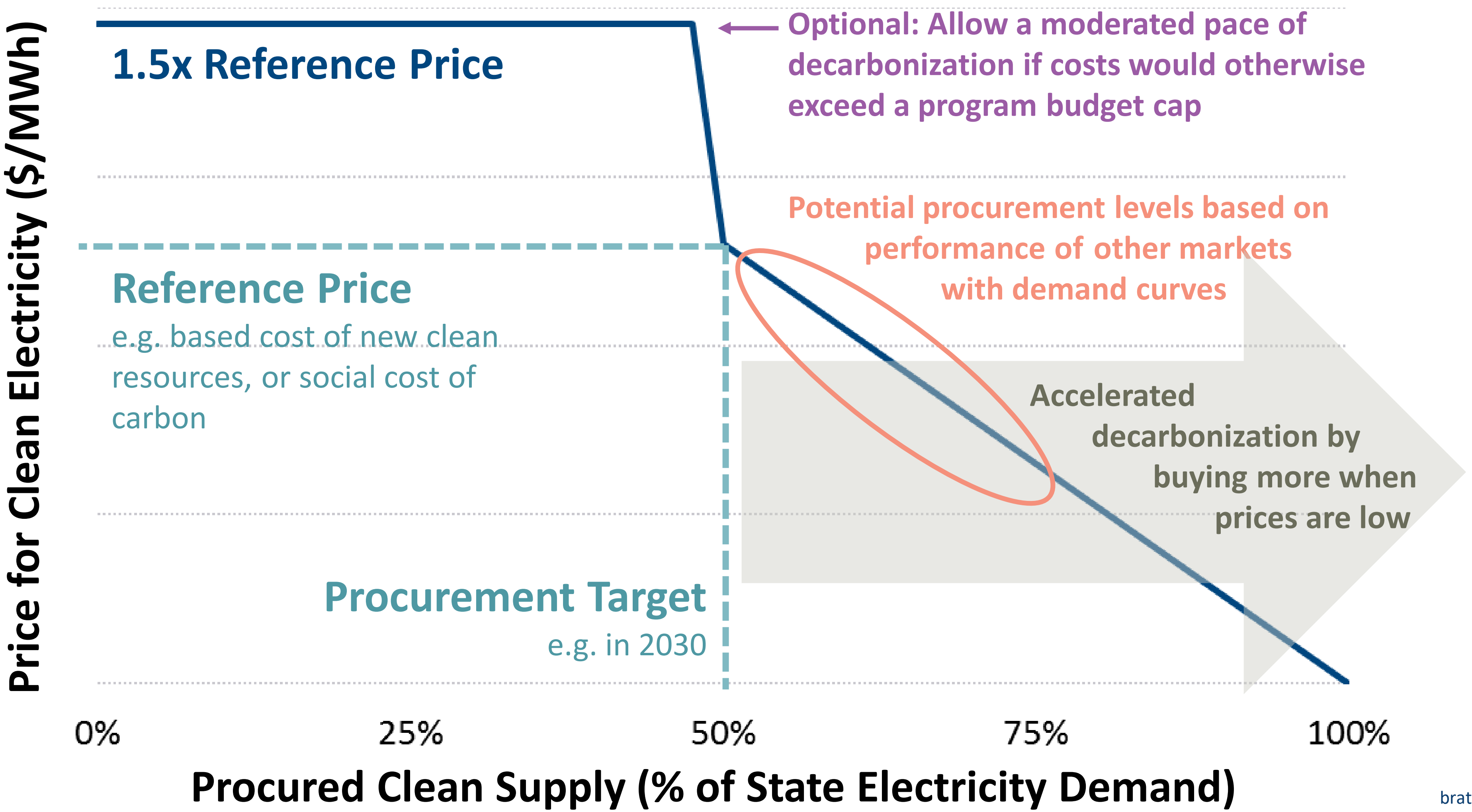
Spot auction

Bilateral Market

Pre-auction: Voluntary long-term contracts and forward hedges
Post-auction: Producers and retailers use exchange trades and short-term contracts to manage position relative to obligations and banking value

Each State Could Translate Its Own Procurement Target into a Downward-Sloping Demand Curve

Illustrative State Demand Curve for CEACs



1.5x Reference Price

Optional: Allow a moderated pace of decarbonization if costs would otherwise exceed a program budget cap

Potential procurement levels based on performance of other markets with demand curves

Reference Price

e.g. based cost of new clean resources, or social cost of carbon

Accelerated decarbonization by buying more when prices are low

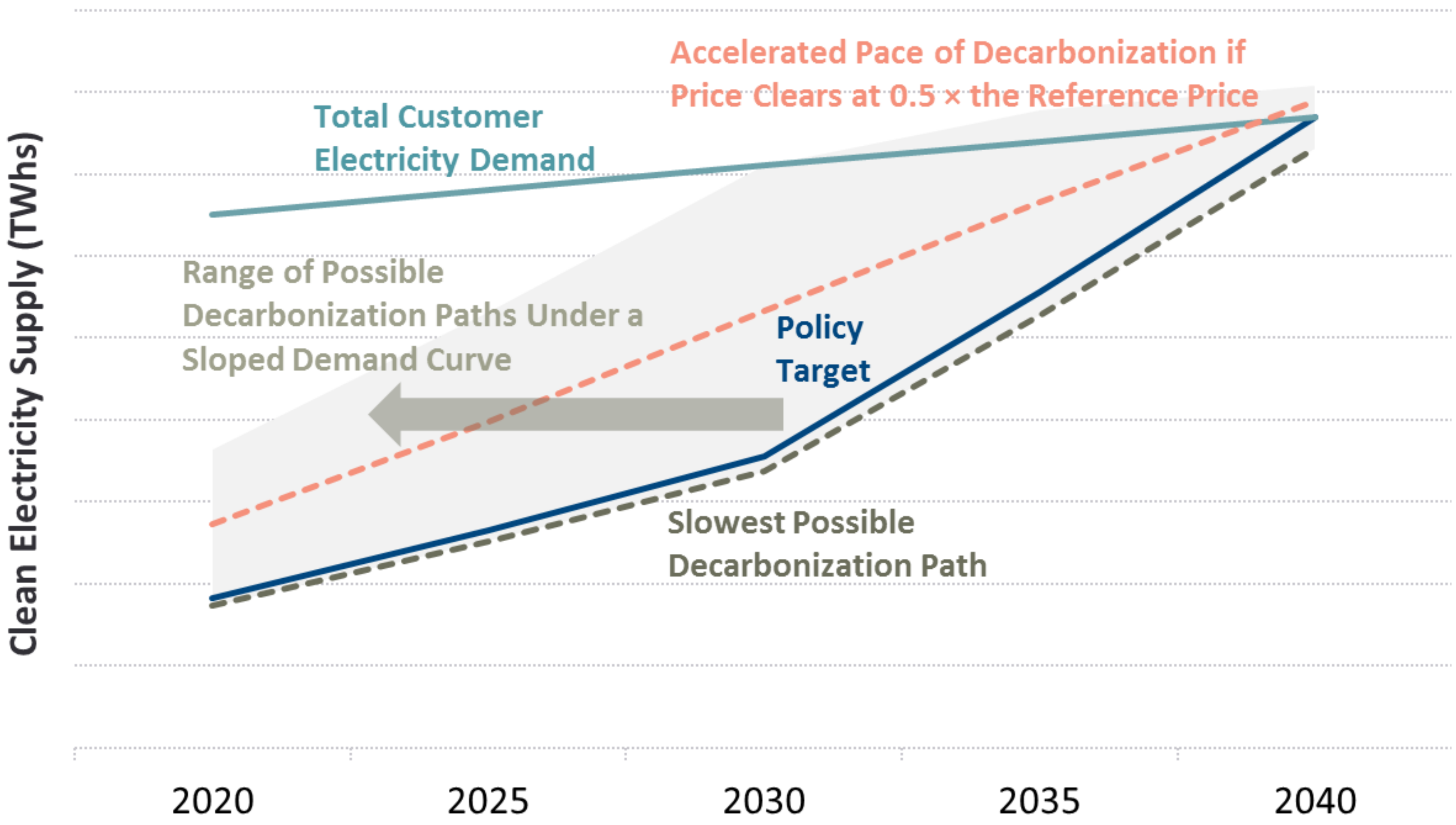
Procurement Target

e.g. in 2030

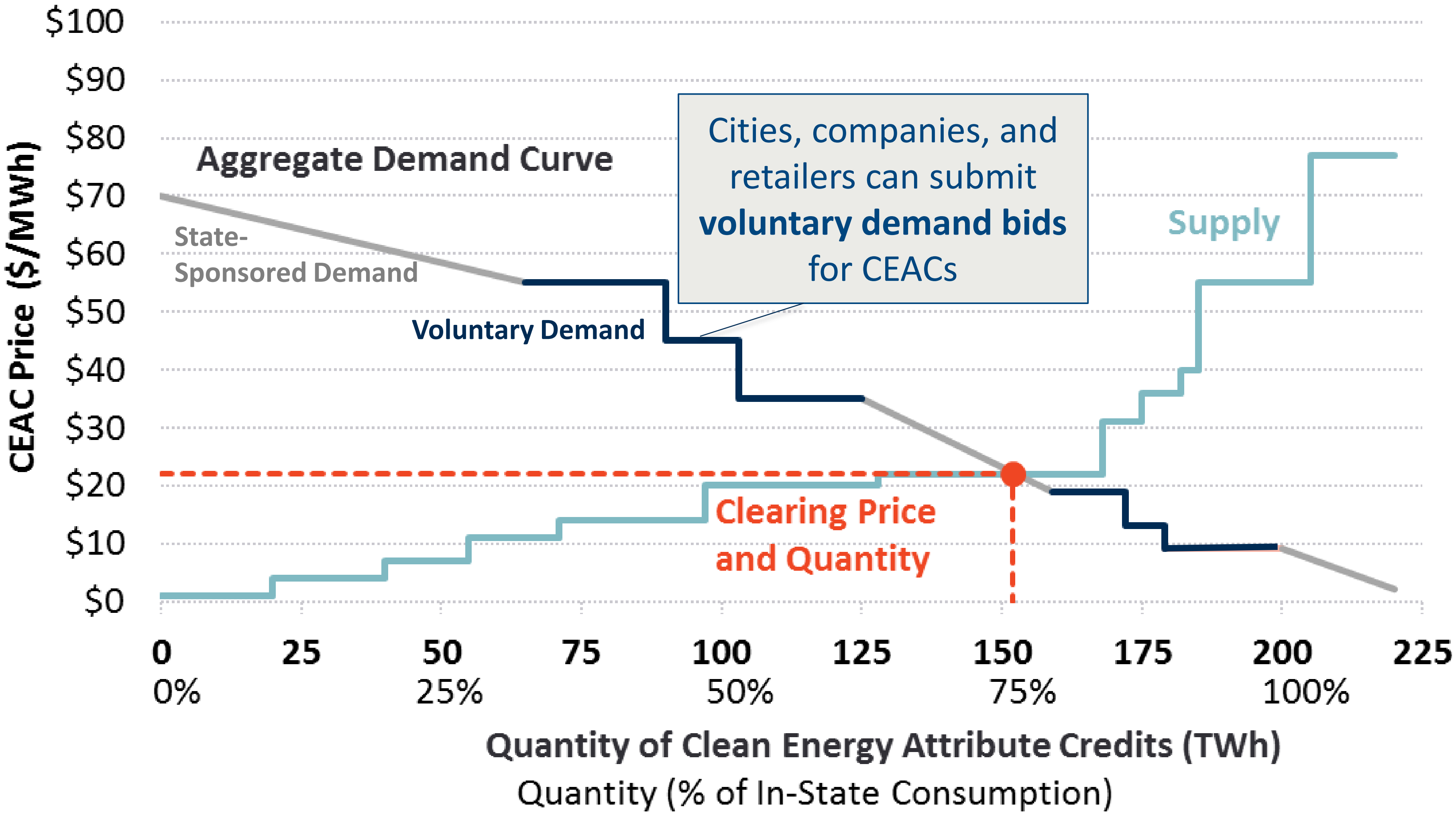
By How Much Could a Demand Curve Accelerate a State's Clean Electricity Goals?

Potential Pathways to Decarbonization with a Sloping Demand Curve

Example of a State with Clean Energy Targets of 25×2030, 50×2030, and 100×2040



Auction Clearing at a Competitive Price



Cities, companies, and retailers can submit **voluntary demand bids** for CEACs

Design Option: "Targeted" Resources to Comply with Technology-Specific Requirements

States submit the demand for clean energy and the maximum willingness to pay. States can choose to purchase:

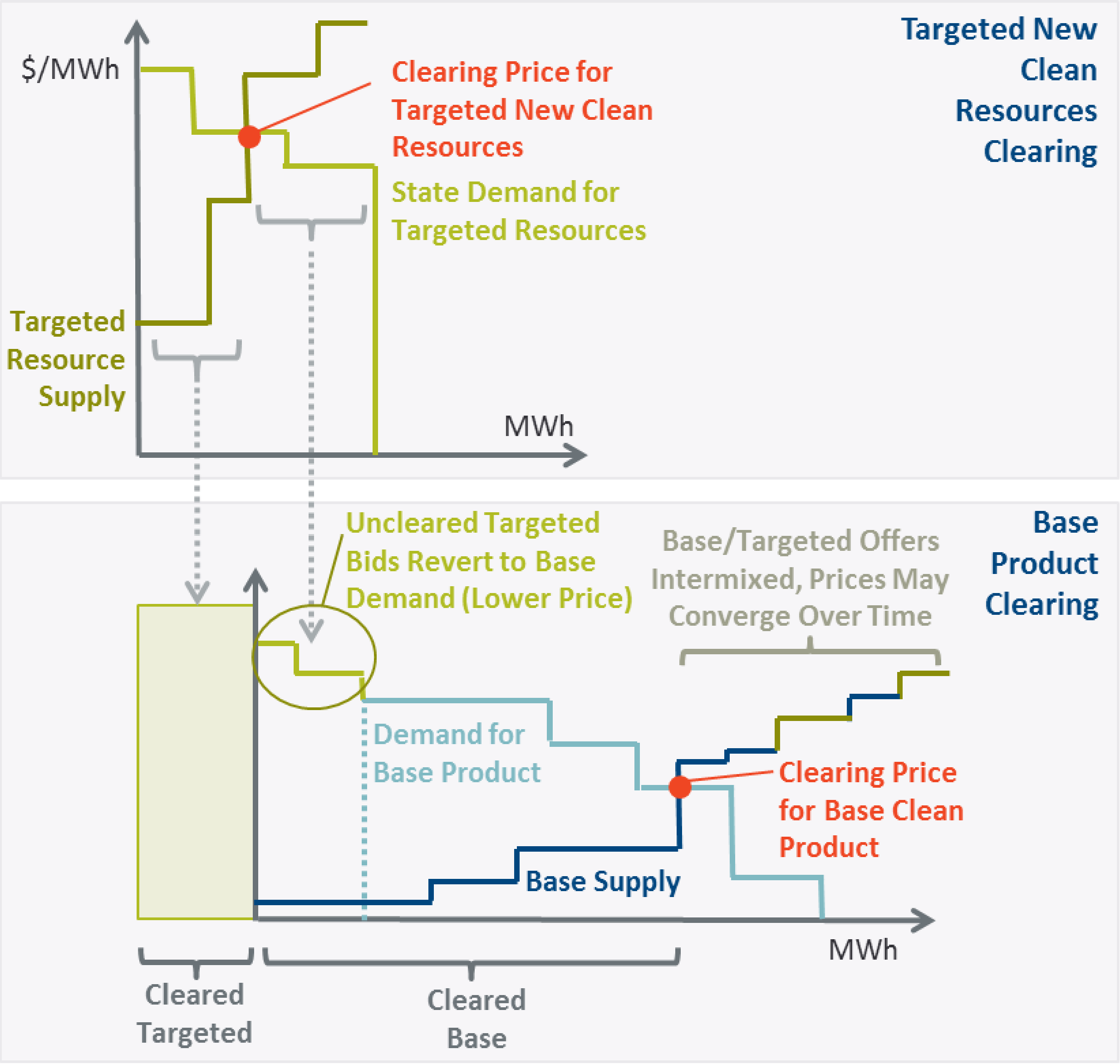
"Base" Resources

- Procures the least cost clean supply, whether new or existing
- All resources can participate (hydro, wind, solar, nuclear, storage), no restrictions by type or location
- 1-year commitments for existing resources; ~7-12 year price lock-in for new
- State commitment to submit demand bids in future years, e.g. for 10 years

"Targeted" Resources

- State carve-outs for new resources
- State has option to define a specific type (e.g. for emerging technologies)
- ~7-12 year anchor price lock-in (resources eligible as "base" supply in years 8+)
- No state commitment to submit demand in future years
- "Contingent bid" option: If targeted resource prices are too high, demand will revert to purchase lower-cost "base" resources

Illustration of Auction Clearing with Targeted Resources



Risk Sharing and Financeability

The FCEM intentionally places most **fundamentals-based and asset-specific risks on sellers** who would then manage the risks. A few key **design features could be used to mitigate regulatory risks and support financeability**:

- **Multi-Year Commitment Period** of around 7-12 years locks in prices for new resources
- **Multi-Year Forward Period** supports development and financing of new resources
- **Sloped Demand Curve** mitigates year-to-year price volatility, improving revenue certainty over time
- To enhance confidence in the market, states could make **durable commitments** to rely on the FCEM for a minimum timeframe & quantity

Allocate Risks to Customers	Allocate Risks to Sellers	
Regulatory Risks	**Market Fundamentals**	**Asset-Specific Risks**
• Unanticipated changes to state policy • Unpredictable changes to state demand bids • Rule changes	• Resource mix • Load growth • Fuel prices • Transmission development • Energy, capacity, and ancillary service prices	• Construction delays • Unanticipated asset costs • Asset performance

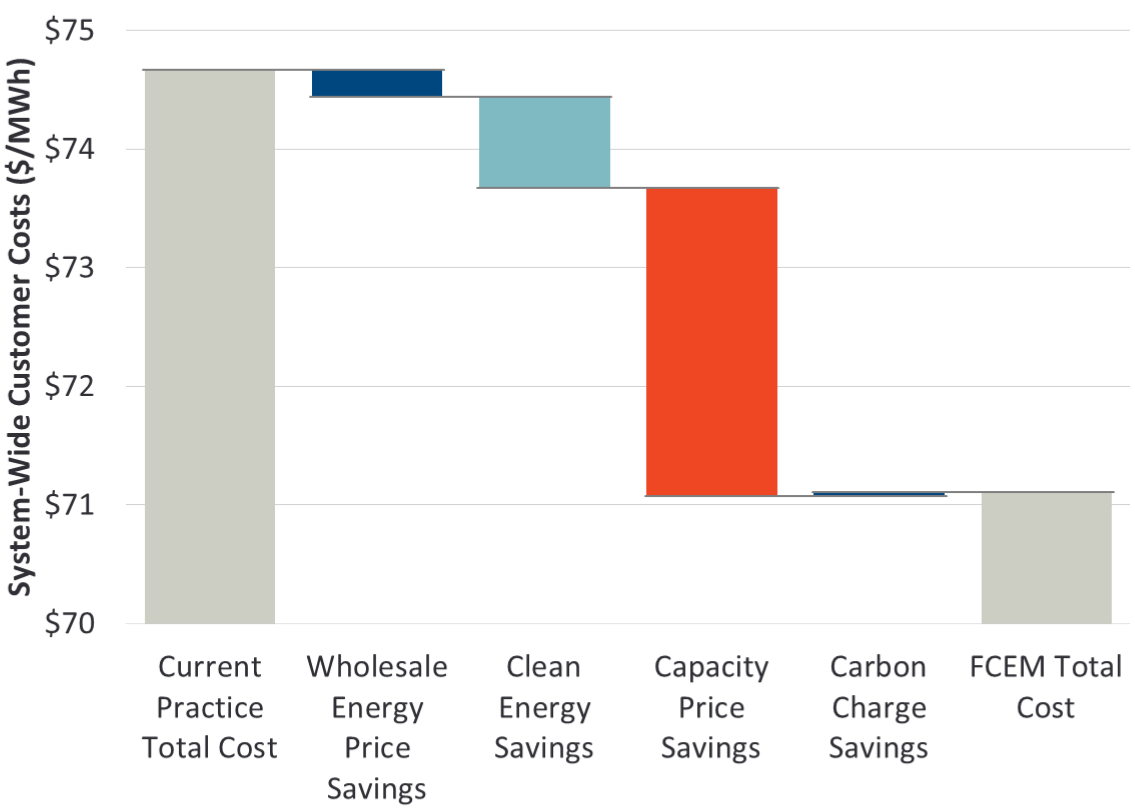
How Does FCEM Compare to the Other Options for <u>Achieving</u> State Goals?

Customer Cost Savings Relative to Current Practice

Our New England simulations in Brattle's GridSIM model estimated that **FCEM could save customers $3.60/MWh** *or approximately* **$4,500 million** *over ten years compared to current practice*

Example: New England Customer Cost Savings

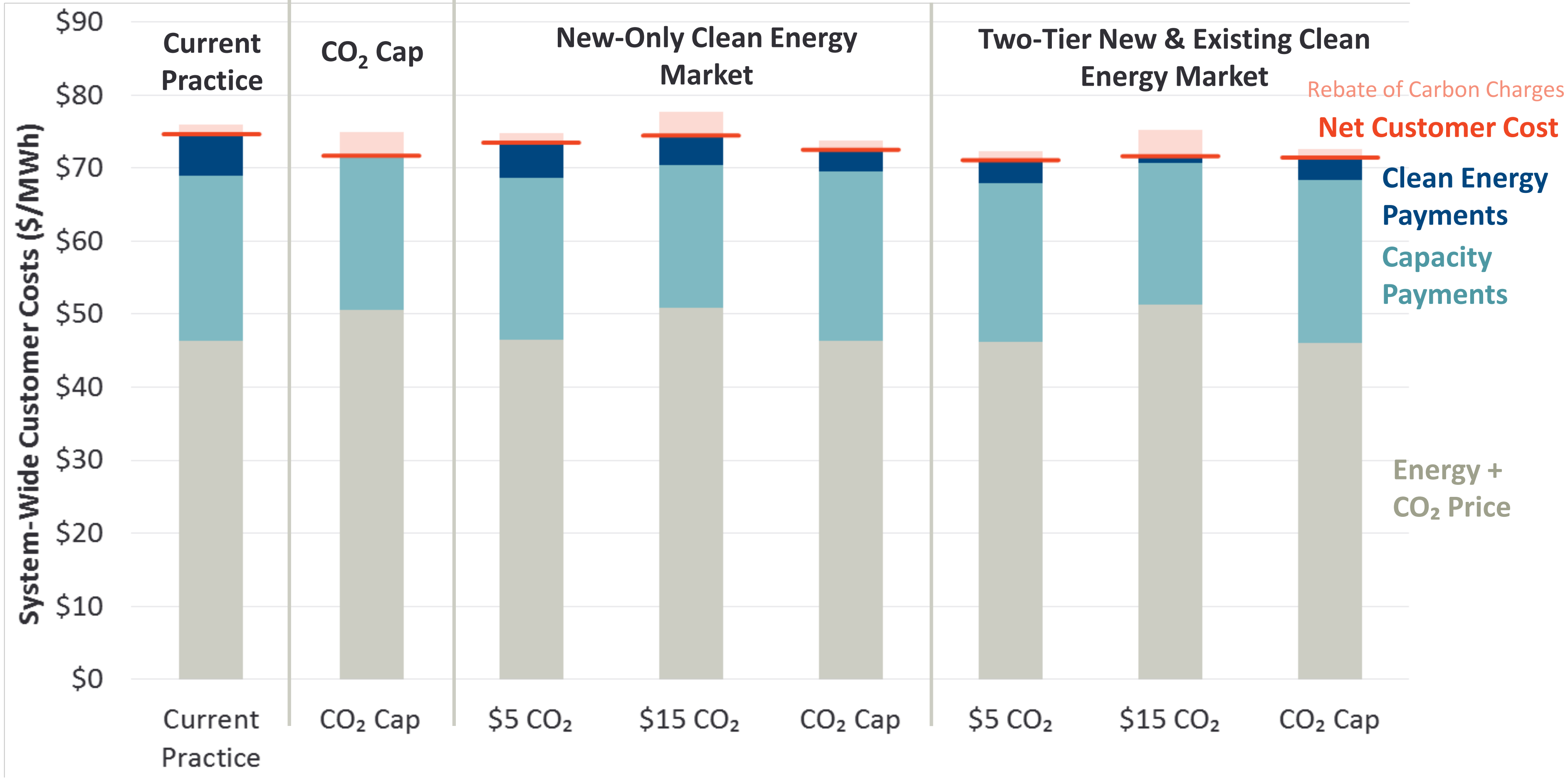
Forward Clean Energy Market vs. Current Practice



Source: Kathleen Spees, Judy Chang, DL Oates, and Tony Lee, "A Dynamic Clean Energy Market in New England," November 2017, The Brattle Group. Modeling results reported over a ten year period 2020-2029.

Size of Customer Benefits Varied Depending on Carbon Price and FCEM Design Choices

Our modeling analysis indicated that a range of market-based FCEM and carbon pricing approaches achieved customer benefits. Some more than others!



Note: Simple average of nominal costs from 2020-2029.

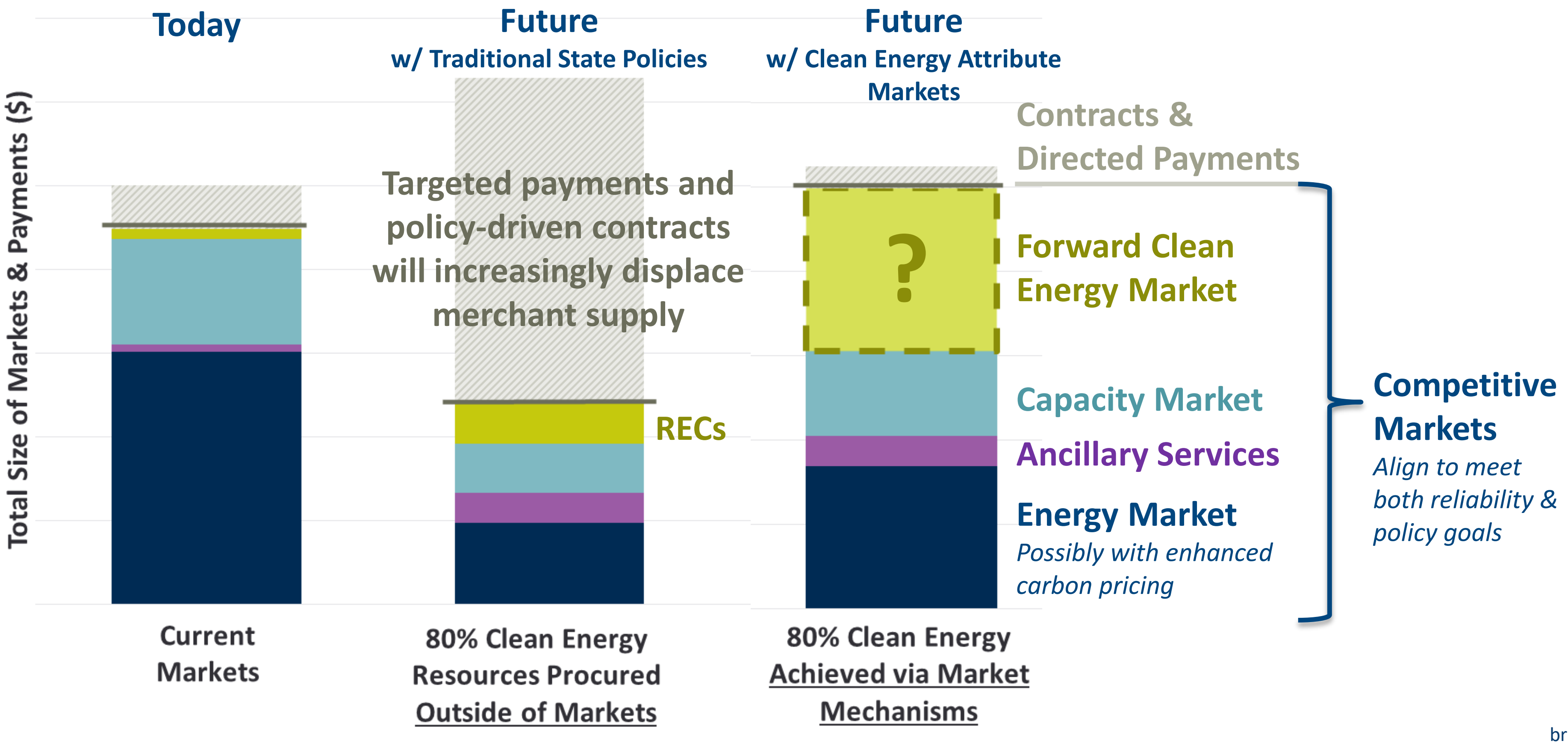
FCEM Can Be Implemented With or Without Higher Carbon Prices

Many economists will advise to focus exclusively on carbon pricing to meet policy goals (and our simulations demonstrate the value). But FCEM offers several benefits beyond considering carbon pricing alone:

- Carbon pricing maximizes benefits if implemented regionally and economy-wide (may not be politically feasible in the near term)
- Carbon prices acceptable to all states are likely too low to achieve policy goals
- FCEM does not require states, cities and companies to agree on a common price or policy goal
- FCEM avoids the “leakage” problems from carbon prices that differ between markets
- States & customers pay to meet their own goals (no cost-shifting to non-participants)
- Lower developer risk with FCEM than carbon pricing

Alignment with Wholesale Markets

The FCEM can align with the merchant investment model, competitive retail markets & enable competitive co-optimization with energy and capacity markets



Why Consider Variations of the FCEM?

FCEM offers a few advantages specifically in the New England region

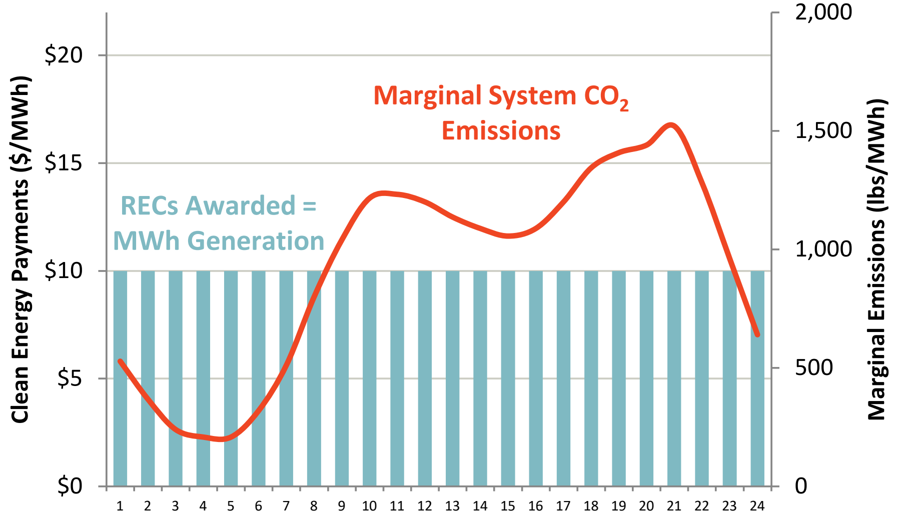
- States don’t have to agree on a single goal or carbon price
- States can opt in to the design (or not)
- States can choose how much to buy via FCEM (versus contracts or other approaches)
- Buyer-pays approach ensures no cross-subsidization among the states
- Leverages design features proven to attract new investments at competitive prices in the power sector (demand curve, forward auction, price lock-in, broad competition)
- Fills in one of the critical missing building blocks of the decarbonized “future markets”

Review the full study: Linked Here

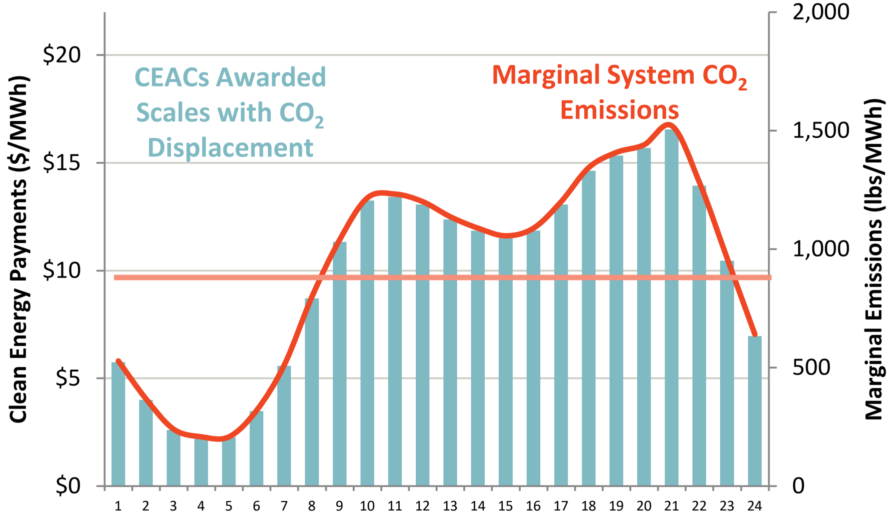
Appendix:
Dynamic Clean Energy Attribute Product Definition

Dynamic CEAC Product: Achieves More Carbon Abatement at Lower Cost

Design Option: Transition to a more advanced product design that focuses incentives on carbon abatement


Traditional RECs:
Equal Incentives Across all Hours

- Flat incentives over every hour
- Incentive to offer at negative energy prices during excess energy hours when displacing other clean supply


"Dynamic" CEACs:
Incentives Scale to Carbon Displacement

- Payments scale in proportion to marginal CO_2 emissions (by time and location)
- Incentive to produce clean energy when and where it avoids the most CO_2 emissions
- No incentive to offer at negative prices

Dynamic CEACs

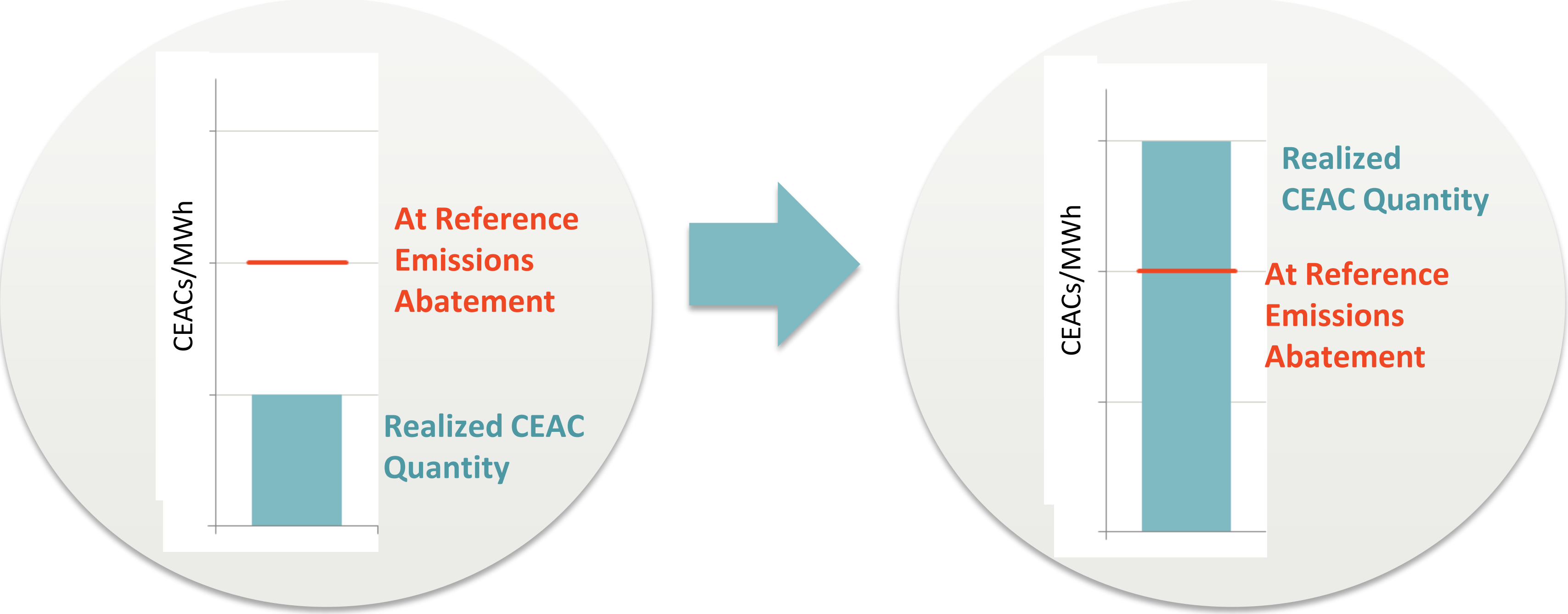
Clean energy suppliers earn CEAC awards (and thus payments) that scale in proportion to carbon abatement value:

$$\text{CEACs} = \text{Physical Generation} \times \frac{\text{Realized Abatement Rate}}{\text{Standard Abatement Rate}}$$

- **CEACs:** annual quantity of CEACs awarded to the clean resource. The rate of CEACs awarded per physical MWh produced may be greater than the average across all clean suppliers (if displacing primarily coal) or less than the average across all clean suppliers (if displacing primarily other clean supply)
- **Physical Generation:** the as-metered MWh produced by the clean resource
- **Standard Abatement Rate:** the standard quantity of marginal carbon displacement required to produce one CEAC (e.g. 1,100 lbs/MWh). This value adjusts over time with the average abatement value across the clean fleet
- **Realized Abatement Rate:** the measured marginal carbon abatement value of the resource in question, based on the time and place of clean energy production

Incentives for Clean Energy in the **Right Locations**

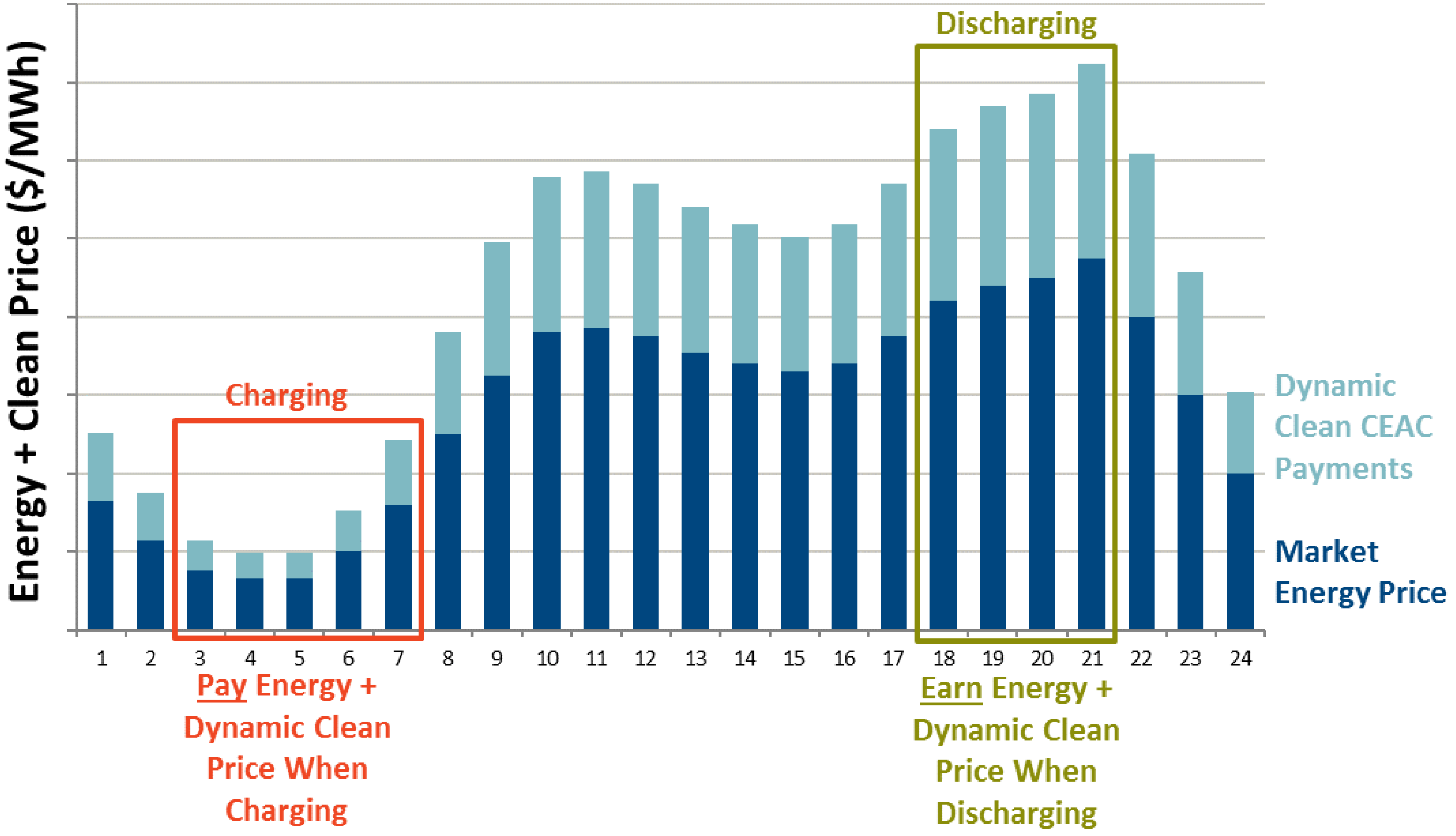
Varying the CEAC awards across locations in a way that reflects carbon emissions displaced will focus incentives to develop new clean energy where they are most valuable



Incentives at the **Right Times** (Including for Storage)

Dynamic CEACs incentivize clean energy at the right times to displace the most CO_2 emissions, enabling storage to compete with other technologies

Illustration of Storage Participation with Dynamic CEACs



Further Reading

How States, Cities, and Customers Can Harness Competitive Markets to Meet Ambitious Carbon Goals Through a Forward Market For Clean Energy Attributes

Sponsored by NRG (link)

A Dynamic Clean Energy Market in New England

Sponsored by Conservation Law foundation, Brookfield Renewable, NexEra Energy Resources & National Grid (link)

Harmonizing Environmental Policies with Competitive Markets: Using Wholesale Power markets to Meet State and Customer Demand for a Cleaner Electricity Grid More Cost Effectively (link)

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Carbon Pricing for New England

Joseph Cavicchi

NEPOOL Participants Committee Meeting
August 6, 2020

ANALYSIS GROUP

Disclaimer

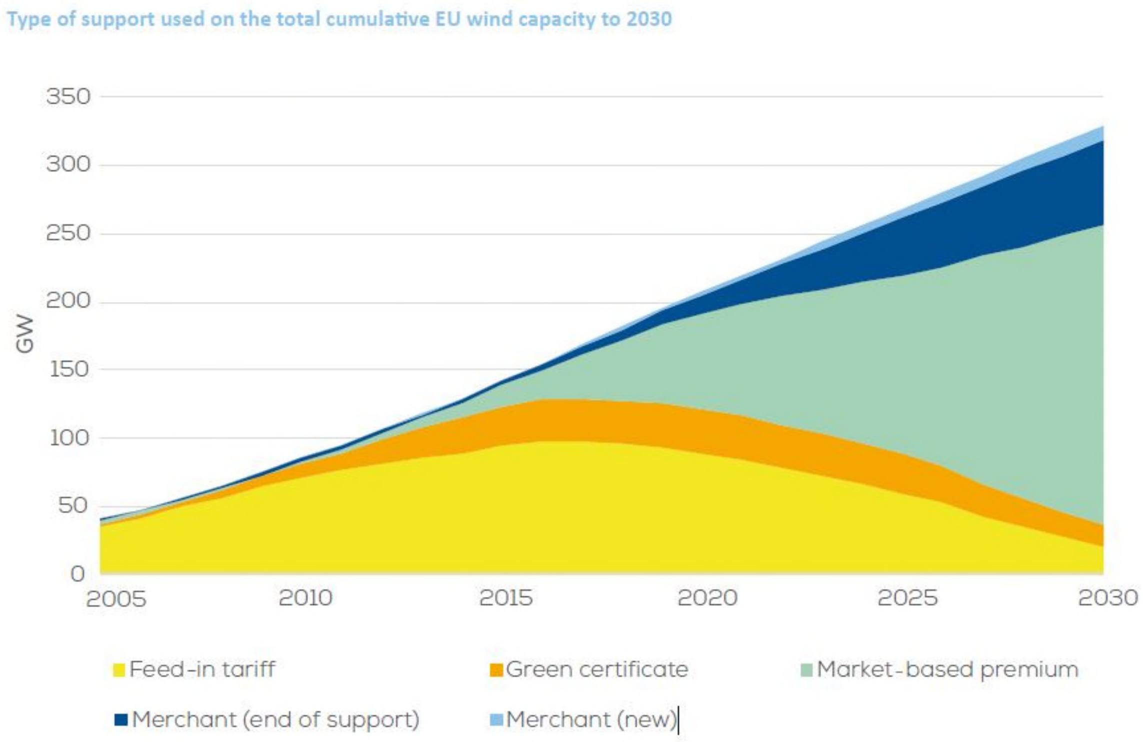
Much of the material presented herein is included in the Analysis Group, Inc. June 2020 report, Carbon Pricing for New England, Context, Key Factors, and Impacts. This report was prepared at the request of the New England Power Generators Association, but is an independent report by Joseph Cavicchi and Paul Hibbard of Analysis Group, Inc. and the report's analysis and conclusions reflect the independent judgment of the authors alone, and do not necessarily align with NEPGA or NEPGA's members.

The full report is available at: https://www.analysisgroup.com/Insights/publishing/carbon-pricing-for-new-england-context-key-factors-and-impacts/

Overview

Experience with markets that include the cost of carbon is evolving:

- In western Europe state supported long-term renewable resource contracts are expiring over the next several years creating demand for innovative generation resource financial hedging arrangements that will become more important as renewable resource costs decline.



- Wind farms relying on feed-in premiums and contracts for differences will represent the majority of assets with almost 230 GW or 67% of the total European capacity. This capacity will be partially exposed to the market.
- In 2030 fully market-exposed wind capacity could represent 90 GW, most of it being older projects no longer receiving financial support.

Source: WindEurope, The value of hedging: New approaches to managing wind energy resource risk, November 2017.

Experience with markets that include the cost of carbon is evolving:

- Similar to the US, corporate PPAs that provide innovative generation resource financial hedging arrangements are becoming more important as renewable resource costs decline.

Figure 4: European PPA deal flow

Source: inspiratia | dataLive, July 2019

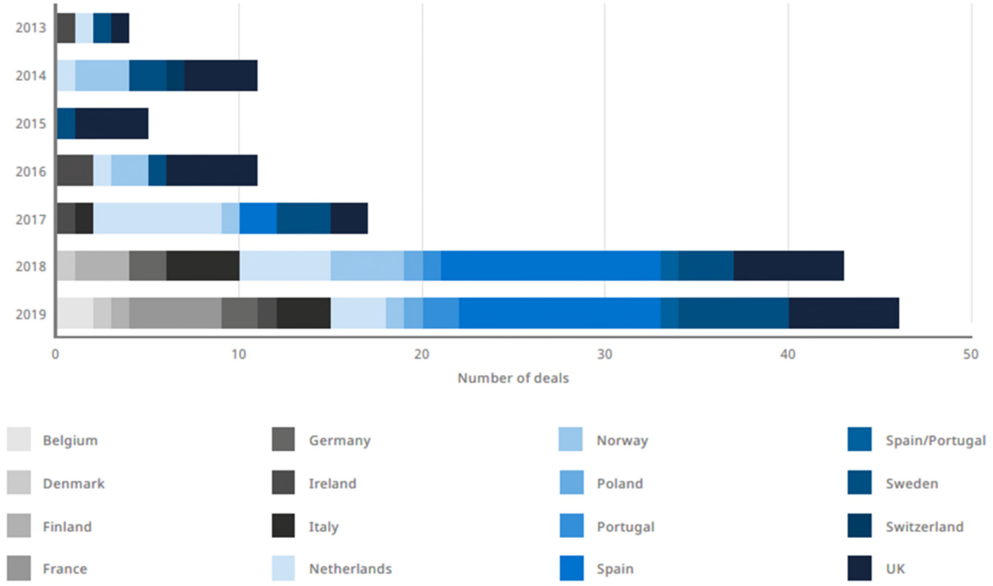
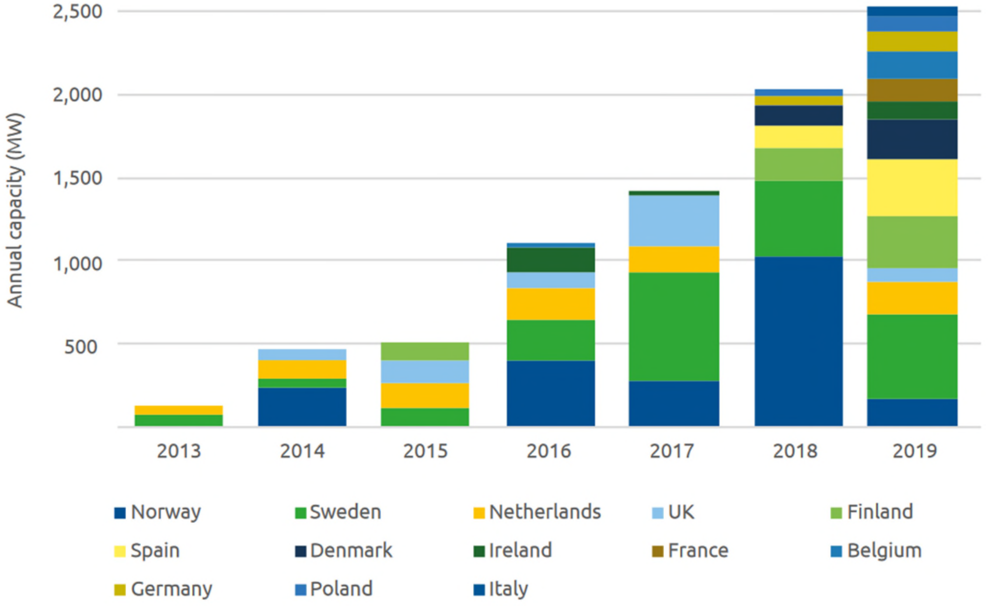


FIGURE 1
Corporate PPAs by year and country



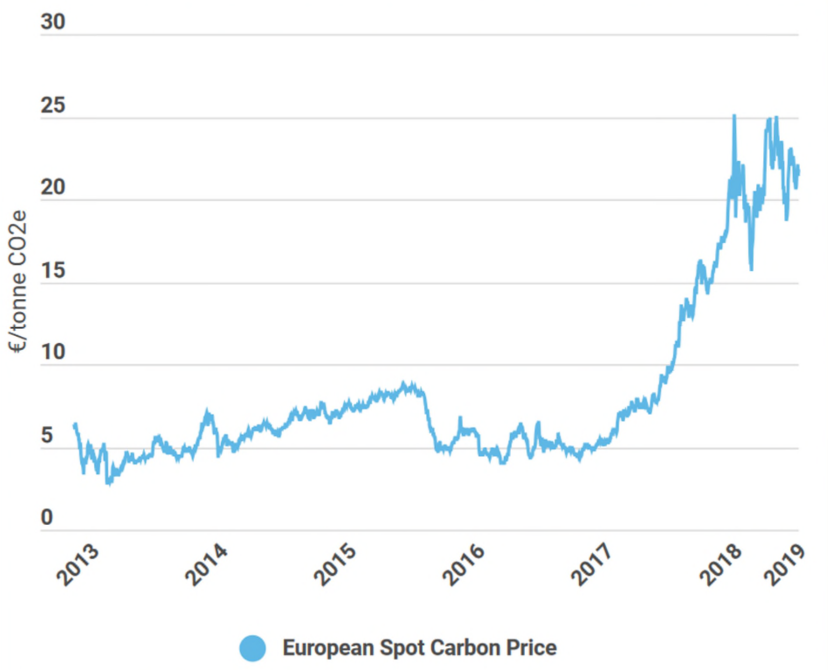
Source: WindEurope

Sources: Europe's Subsidy-free Transition – The Road to Grid Parity, DLA PIPER, December 2019.
Introduction to Corporate Sourcing of Renewable Electricity in Europe, Re-Source, January 2020.

Experience with markets that include the cost of carbon is evolving:

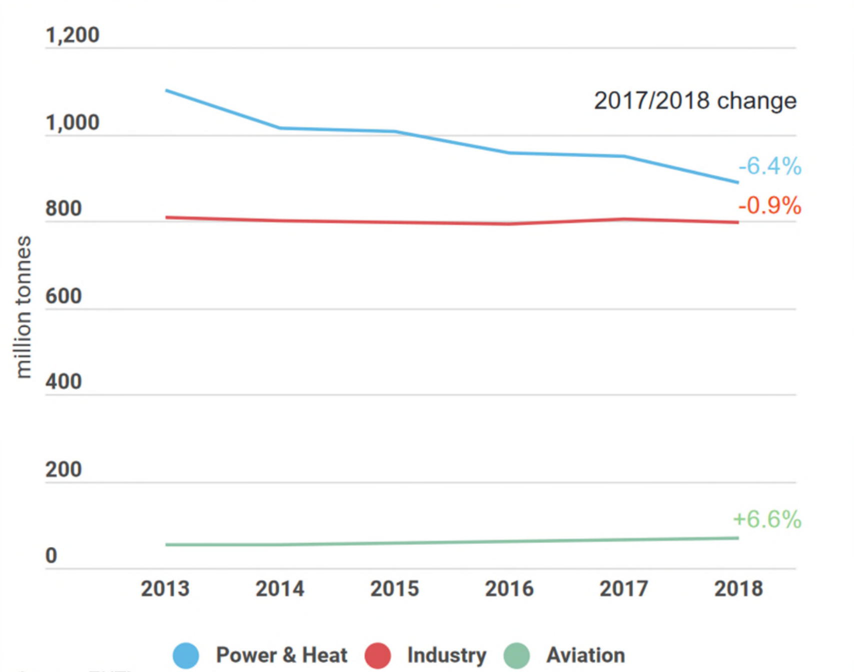
- Increased recognition that carbon pricing levels must be high enough to incentivize efficient decision making and support innovation.

FIG 1: PRICE DEVELOPMENT IN THE EU ETS SINCE JANUARY 2013



Source: Intercontinental Exchange (ICE)

FIG 2: EU ETS EMISSIONS, 2013-2018



Source: EUTL

Source: Mazzoni, M., Ruf, P., The European Carbon Market: The Impact of Higher Carbon Prices on Utilities and Industries, ICIS, May 2019.

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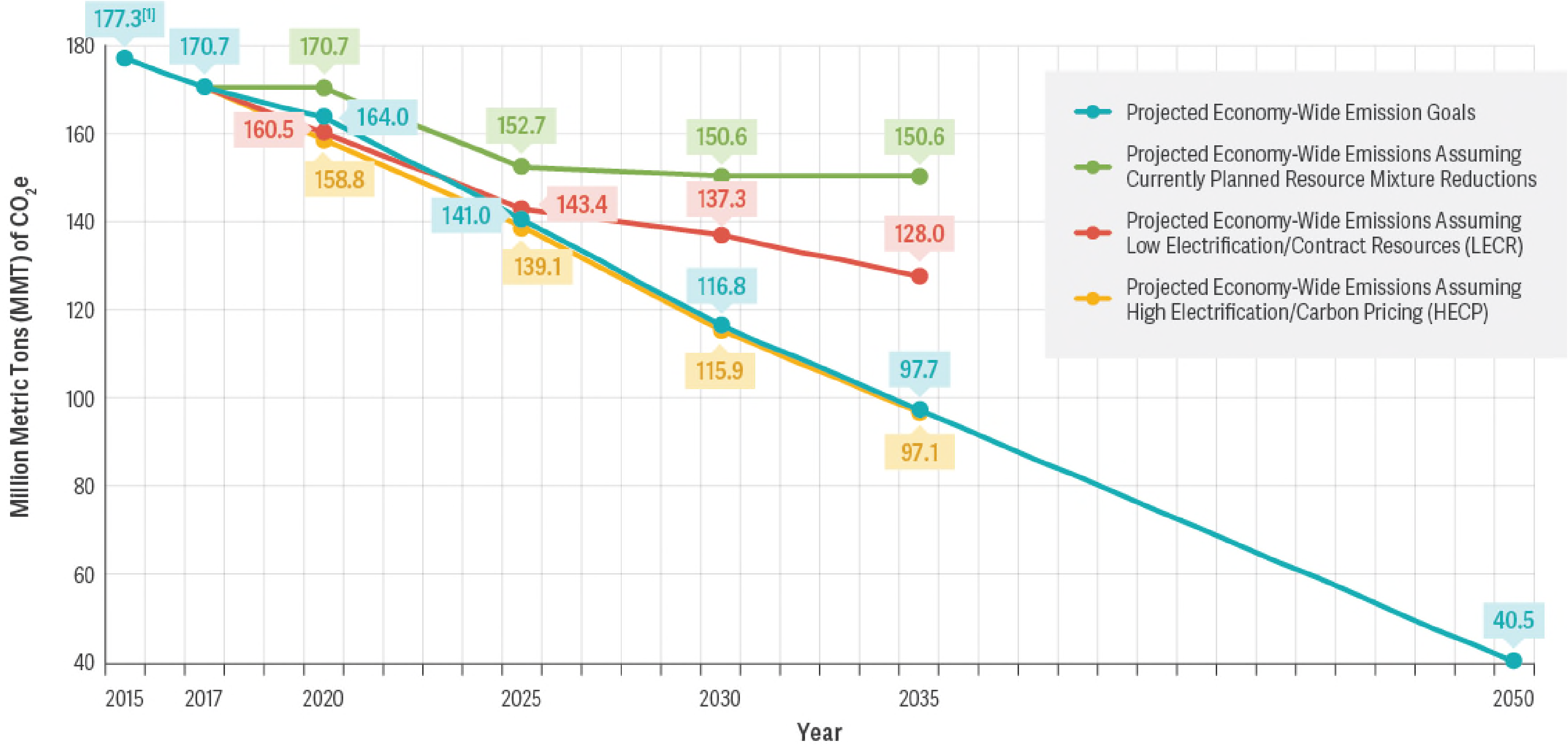
AG Report: Key Findings

- Achieving greenhouse gas emission (GHG) reductions on the trajectory envisioned by New England states requires significant growth in the use of electricity for transportation and heating.
- An effective multi-sector price on carbon can help guide the region through a challenging transformation:
  - Provides appropriate price signals to energy consumers that allows for a more accurate assessment of the trade-offs when assessing electricity as a fuel for transportation and heating as opposed to fossil fuels.
  - Signals to investors in low and zero-emission technologies a commitment to incorporate the social costs of continued reliance on fossil fuels.
  - Allows for technology-neutral competition among both existing and new zero-emission resources in the electric sector, providing incentives to minimize costs and pursue innovation.
  - Provides a platform for private investments in innovative approaches to reduce GHG emissions.
  - Reduces incentives for future state directed investments in zero-emission resources.
  - Avoids the potential for stranded investment costs that can result when long-term contract prices are likely to no longer be economic.
- A progressively increasing price on CO_2 emissions that falls in a range of $25–35/short ton CO_2 in 2025 and $55–70/short ton CO_2 in 2030 and 2035 can support market-based investment in clean-energy technologies going forward.

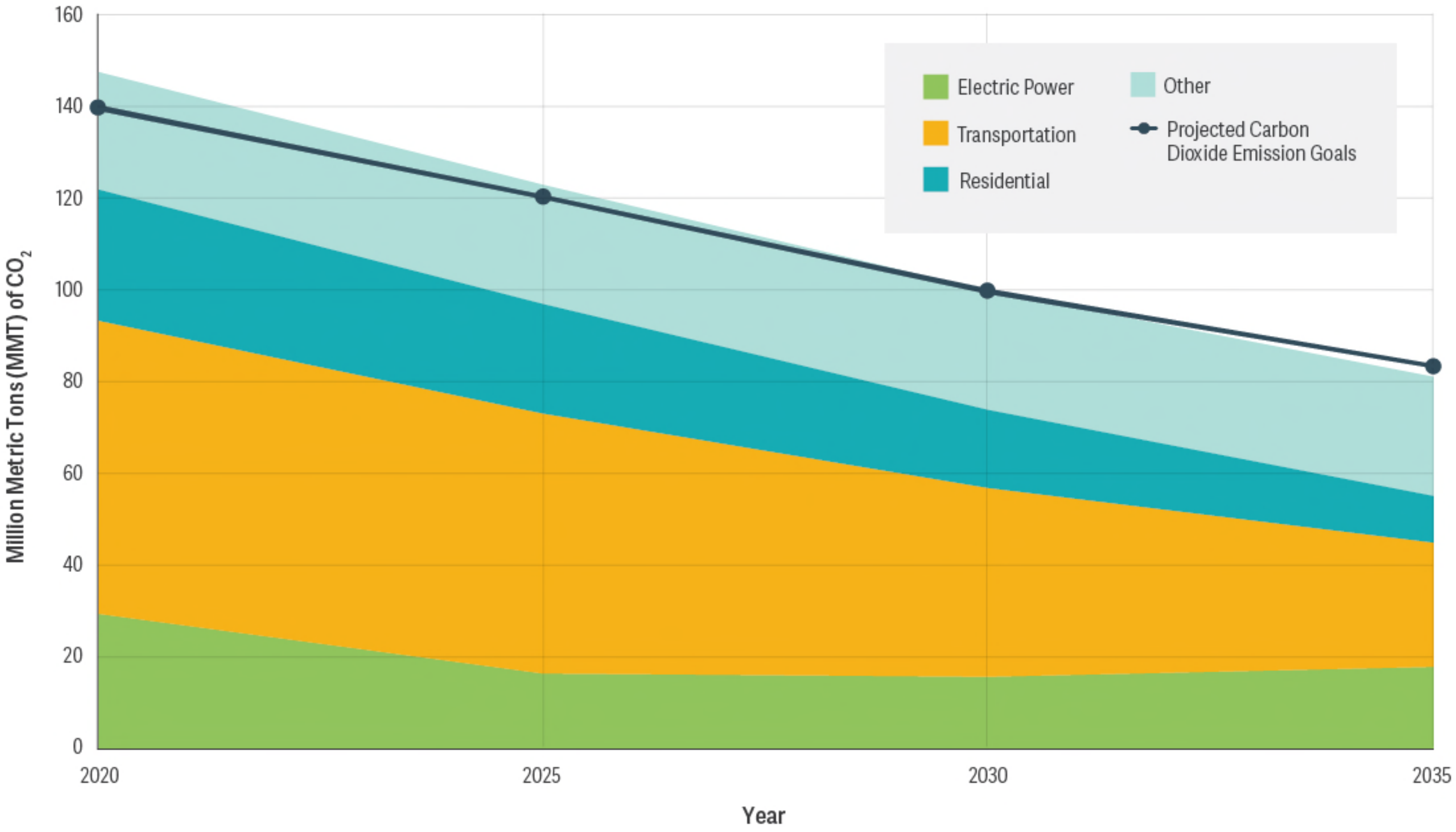
AG Report: Key Findings

New England Emission Reduction Standards Compared with Power Sector Emission Reductions from Currently Planned Renewable Resource Additions and Increased Electrification



AG Report: Key Findings

Projected CO2 Emissions Changes by Sector: High Electrification

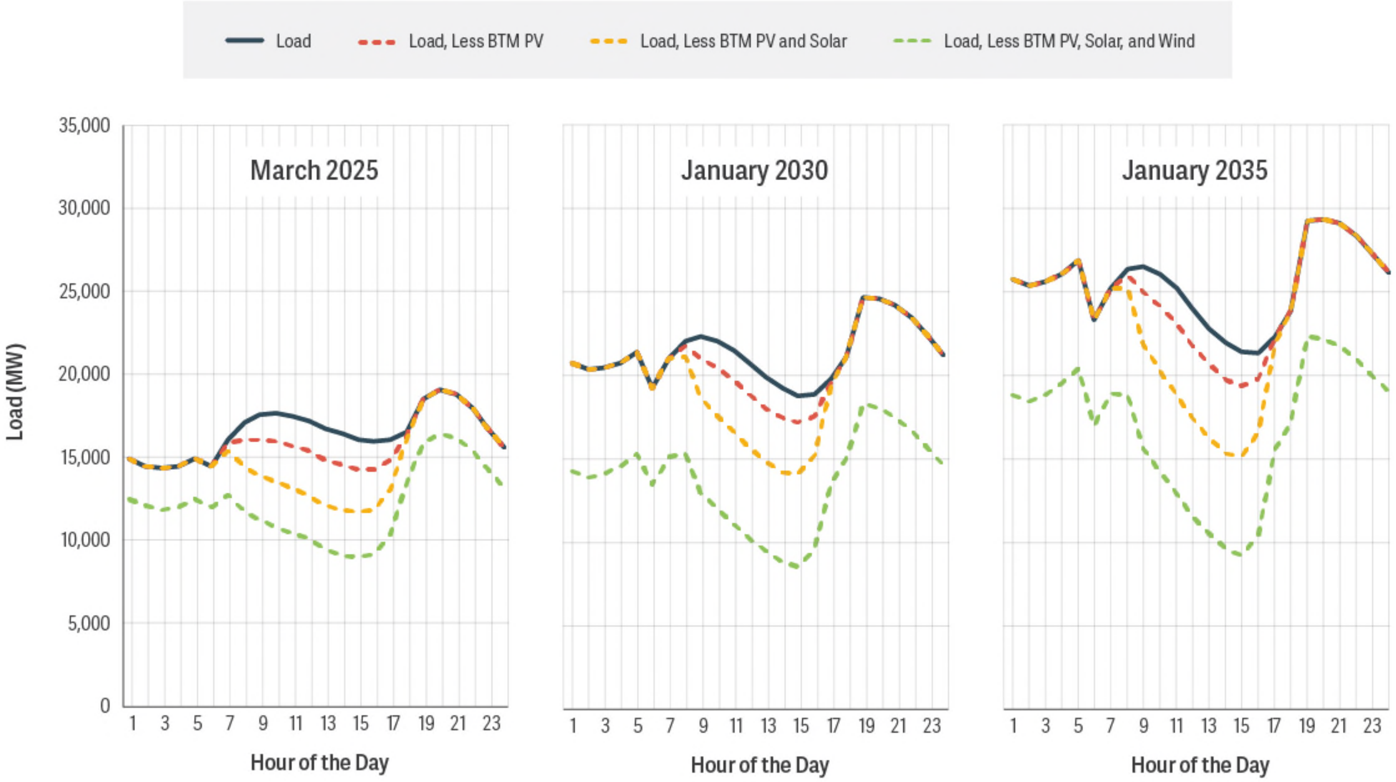


AG Report: Key Findings

Estimated Average Annual Consumer Energy Costs for Households that Adopt Electric Vehicles and Convert Home Heating System from Fuel Oil to Electric Heat Pumps

AG Report: Key Findings

Average Ramp-Ups for the Month that the Peak Ramp Occurs – High Electrification (HECP) Winter



Note:

[1] The reported months are those in which the maximum ramp-up net of renewables occurs.

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Implementation: The Pathway to Efficient Decarbonization

- The pathway will be the most important driver of the cost, technological, and reliability challenges customers and industry stakeholders face. The transformation will:
  - Require investments in transportation, heating, and power system infrastructure
  - Accelerate the development and commercialization of a wide array of energy-related technologies and services.
  - Change the location, size, fuel needs, and operational characteristics of the power supply infrastructure.
- The implementation of an effective multi-sector price on carbon can help guide the transformation:
  - The key considerations associated with the introduction of a multi-sector carbon price are well understood.
  - Regional agreement is critical to develop a framework upon which carbon prices can be established.
  - The disposition of the carbon revenues requires careful evaluation.
- New England’s GHG reduction objectives can be met more efficiently with effective multi-sector carbon pricing.

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AG Report: Methodology

Analytic Method

- **Production Cost Modeling:** Use of production cost model to simulate the operation of the New England power system for 2025, 2030, and 2035 and identify the carbon price.
- **Base Case and Resource Mixture:** Existing and expected energy demand, supply resources, unit retirements, and unit operational characteristics are consistent with recent analyses of the New England Independent System Operator (ISO-NE). Generating resources include offshore wind generation projects that have received regulatory approval and additions envisioned in current state law/policy.
- **Electrification:** Hourly load profile is modified to reflect increased electricity demand.
  - High Electrification (HECP): assumes up to (1) 25% (2025), 60% (2030), and 90% (2035) of consumers driving light-duty vehicles (LDVs) switch to electric vehicles; and (2) 25% (2025), 50% (2030), and 75% (2035) of residential homes currently heating with oil, propane, or natural gas switch to electric heat.
  - Low Electrification (LECR): assumes up to (1) 25% (2025), 35% (2030), and 60% (2035) of consumers driving light-duty vehicles (LDVs) switch to electric vehicles; and (2) 12.5% (2025), 17.5% (2035), and 30% (2035) of residential homes currently heating with oil, propane, or natural gas switch to electric heat.

Modeled Resource Mixture

	Low Electrification/Contract Resources (LECR)			High Electrification/Carbon Pricing (HECP)		
	2025	2030	2035	2025	2030	2035
Existing Derated Capacity After Retirements (Excludes BTM PV)	28,818	29,895	30,923	28,818	30,465	32,543
Assumed Additions (Derated Capacity)						
Solar Additions	7	115	0	577	685	570
Battery Storage Additions	50	250	700	50	250	2200
Onshore Wind Additions	0	182	0	0	182	182
Additional Renewable Resources Distant from Load	0	0	0	0	0	1090
Offshore Wind Additions	1020	480	0	1020	960	0
Installed Capacity (Derated Capacity)	**29,895**	**30,923**	**31,623**	**30,465**	**32,543**	**36,585**
Imports	1,188	1,188	1,188	1,188	1,188	1,188
Total Capacity	**31,083**	**32,110**	**32,810**	**31,653**	**33,730**	**37,772**
Assumed Behind-the-Meter PV and Energy Efficiency						
Behind-the-Meter PV	950	1,183	1,392	950	1,183	1,392
Energy Efficiency in Peak Hour	5,519	6,725	8,477	5,982	8,292	10,311

Notes:

[1] Capacity represents the total existing capacity at the start of each year prior to adding additional resources. Onshore wind, offshore wind, and solar capacity is derated at factors of 26%, 30%, and 28.5%, respectively. For additional detail, see source [B].

[2] Existing capacity as of 2025 includes approved renewable resource additions and expected or at-risk unit retirements of approximately 5,500 MW of capacity of aging coal-, oil- and gas-fired generation stations.

[3] Between 2019 and 2025, 5,238 MW of capacity is expected to come online. These additions include approved offshore wind, the Canadian Interconnection, and others.

[4] Import capacity is obtained from the 2019 CELT Report.

[5] The *2016 Act to Promote Energy Diversity* directed Massachusetts electricity distribution companies to procure 1,600 MW of offshore wind by 2027. In May 2018, it was announced that the 800 MW Vineyard Wind project had been selected. The *2018 Act to Advance Clean Energy* authorizes state officials to procure an additional 1,600 MW by 2035. See sources [C], [D], and [E].

[6] In June of 2019, the Connecticut state government passed *An Act Concerning the Procurement of Energy Derived from Offshore Wind* which enabled the Commissioner of Energy and Environmental Protection to issue solicitations totaling up to 2,000 MW. All 2,000 MW must be reached by the end of 2030. See sources [C], [F]

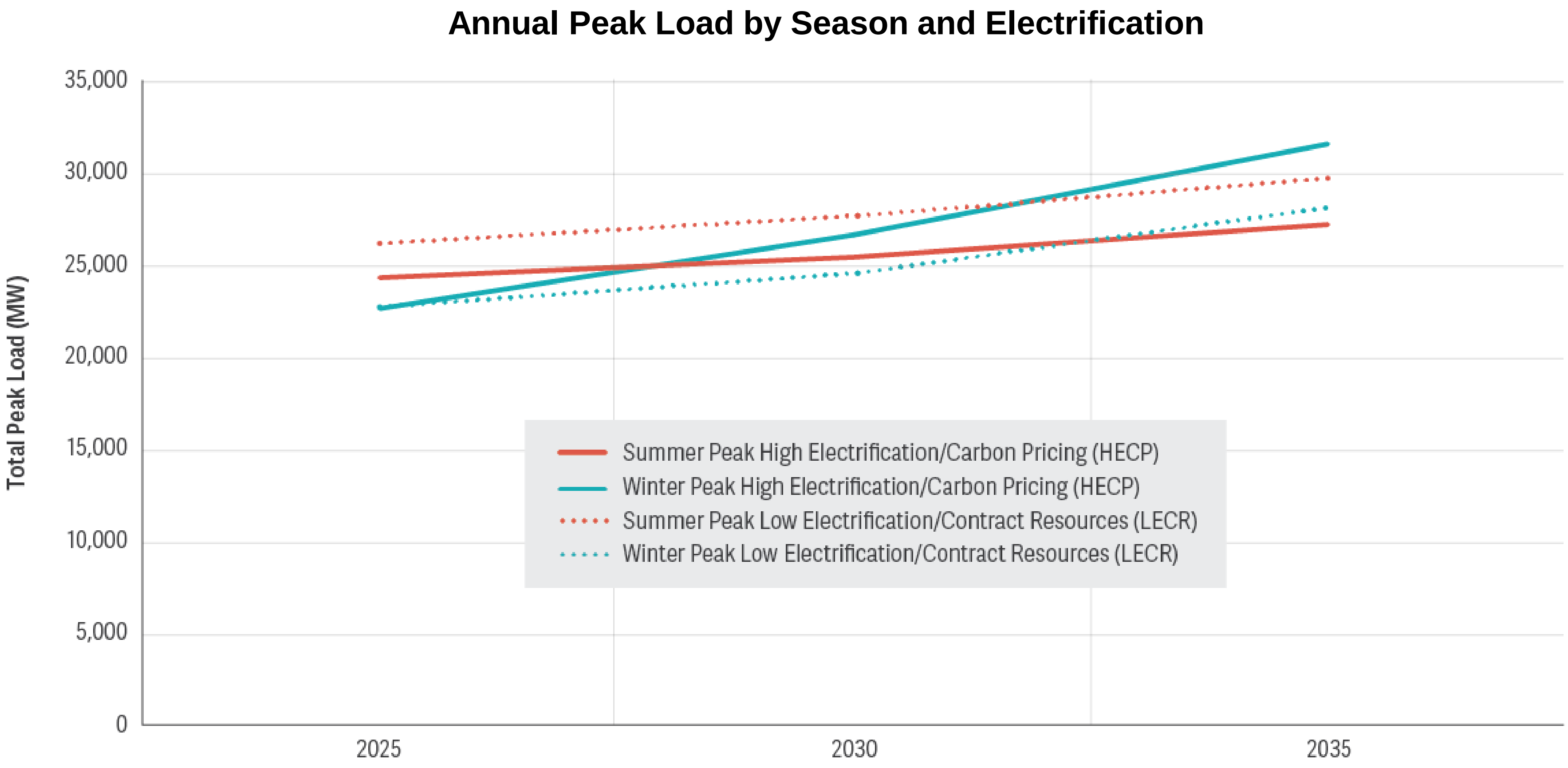
[7] In 2018, Rhode Island issued an RFP for 400 MW of offshore wind. In May 2018 it was announced they had selected Deepwater Wind's 400 MW Revolution Wind Project. See sources [C], [G].

Electrification Assumptions & Methodology

- **Electric Vehicles:**
  - Assumed EV market share increase according to electrification scenarios.
  - Assumed the increased electricity demand is allocated equally to all 365 days in the year
  - Assumed battery charging concentrated in the overnight hours (75 percent between 6 PM – 5 AM and 25 percent between 5 AM – 6PM).
- **Heating Electrification:**
  - Assumed electric heating market share increase according to electrification scenarios.
  - Allocate the annual increase in electricity consumption to the daily level based on a representative weather year, consistent with that assumed in the model.
  - The increase in daily electricity demand is distributed geographically based on a ratio of potential switching household in each ISO-NE zone to the total potential switching households.
  - The daily increase is allocated using an estimated New England daily heating load profile from Electric Power Research Institute.

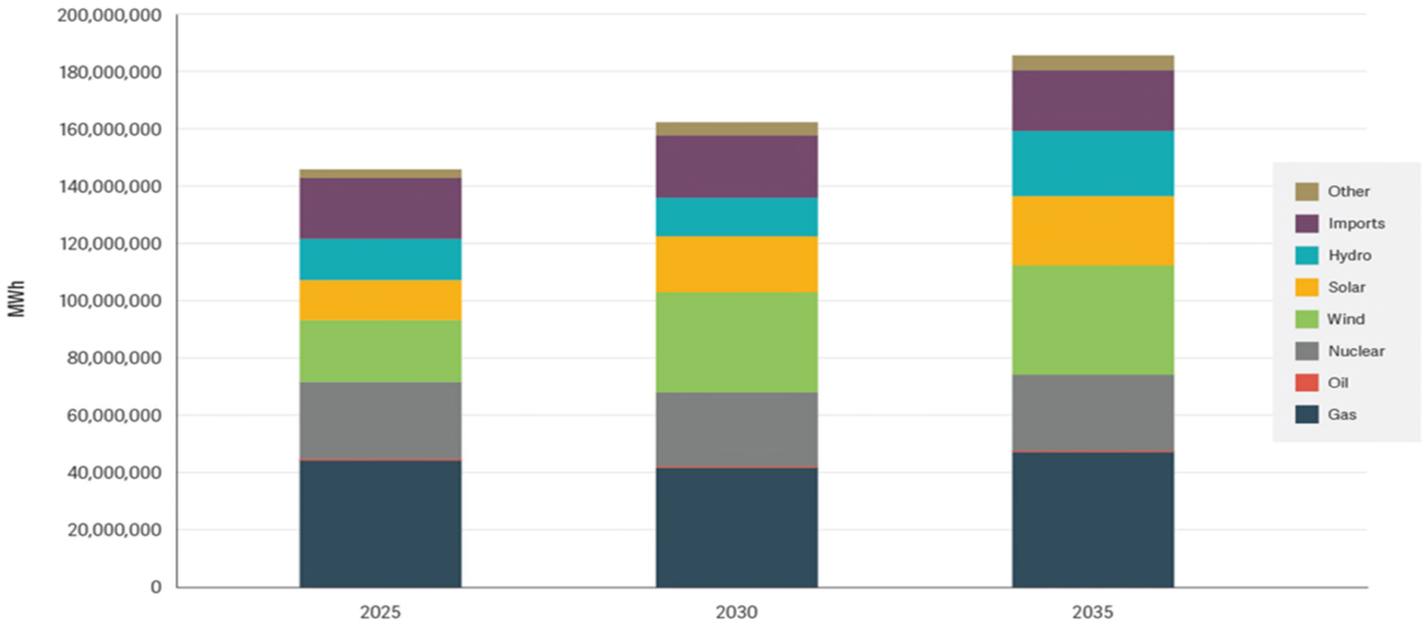
AG Report: Detailed Modeling Results

The Growth in the Winter Peak Demand Is Substantial



Significant Growth In Renewable Resources Needed to Support Region's Objectives

Generation Mixture – High Electrification (HECP)



Notes:

[1] Imports = Imports between ISO-NE and HQ, independent of the New England Clean Energy Connect contract and imports/exports between ISO-NE and NYISO and NB. The NECEC contract appears in the Hydro category; Other = landfill gas, biomass, refuse. Solar includes both utility-scale and behind-the-meter.

[2] The HECP scenario assumes 25% (2025), 50% (2030), and 75% (2035) of residential homes currently heating with gas, oil, or propane switch to electric heating and 25% (2025), 60% (2030), and 90% (2035) of consumers driving light-duty vehicles switch to electric vehicles. It also assumes additional EE (25% increase over assumed 2035 EE) and adds additional storage and zero-emission resources needed to accommodate increased electrification and maintain New England's progress towards meeting its carbon reduction standard. Finally, it adds a $25/short ton price on carbon in 2025, $65/short ton in 2030, and $70/short ton in 2035.

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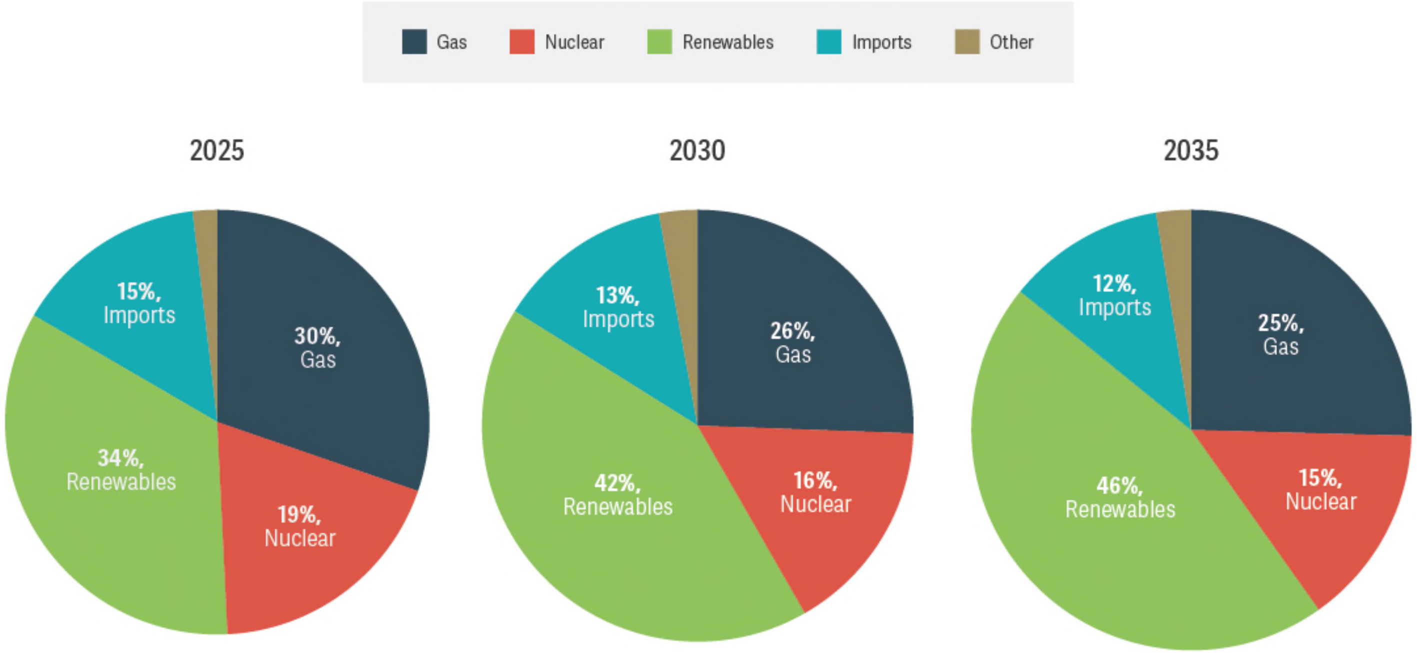
Significant Growth In Renewable Resources Needed to Support Region’s Objectives

Generation Mixture – High Electrification (HECP)



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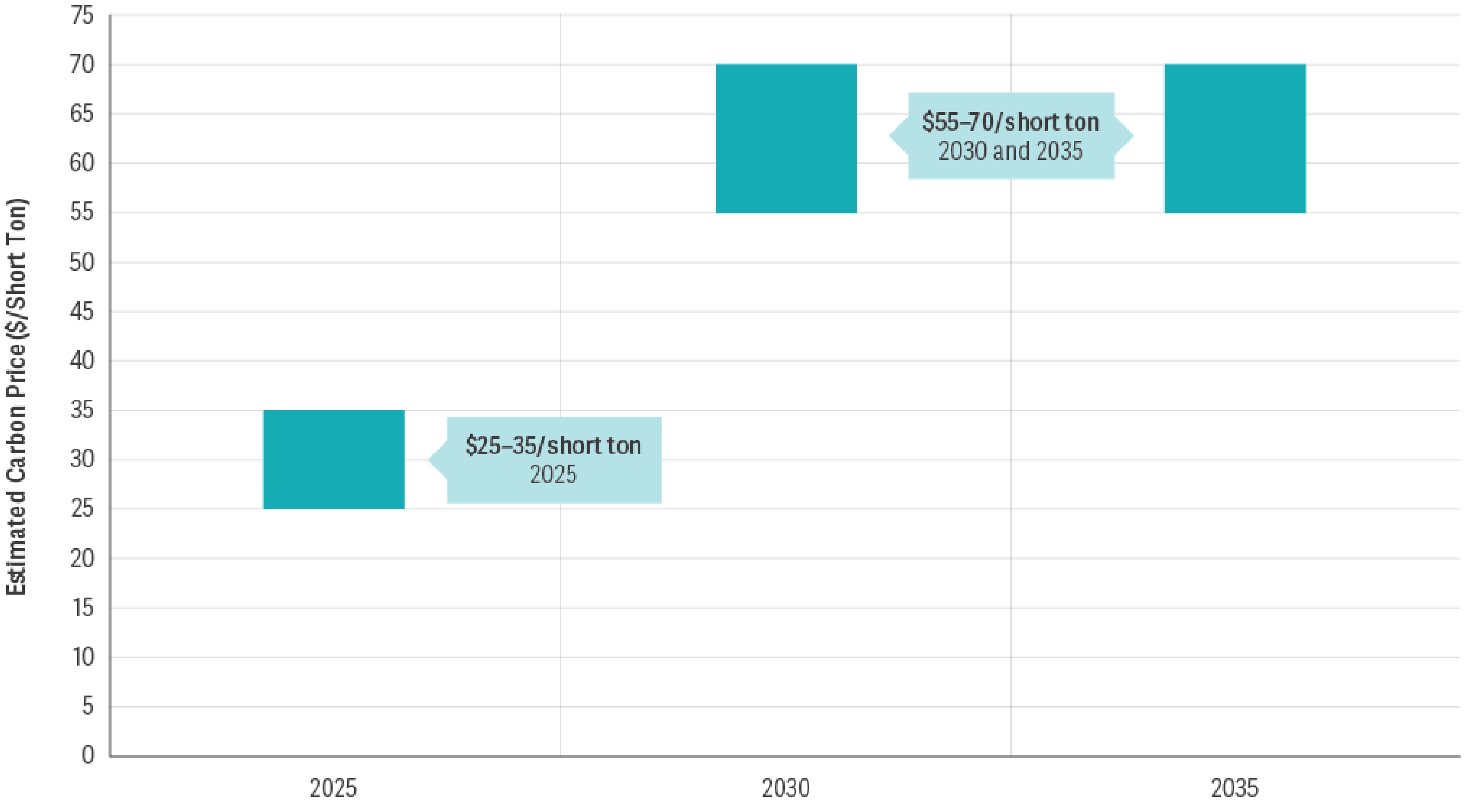
A progressively increasing price on emissions of CO_2 can support future investment in renewable resources



$25–35/short ton
2025

$55–70/short ton
2030 and 2035

A progressively increasing price on emissions of CO_2 can support future investment in renewable resources

- To meet projected GHG reductions in 2030 and 2035, additional offshore wind and/or renewable resources distant from consumer loads are necessary:
  - Resources require higher CO_2 emissions price to be viable without subsidies.
  - Wide range in carbon pricing reflects uncertainty in the costs for more advanced renewable resources.
- CO_2 pricing improves the efficiency of the wholesale markets:
  - Spurs innovation.
  - Minimizes consumer cost.
  - Reliably addresses the rapid rising electricity demand associated with electrification.
- Residual carbon revenues can be returned to consumers using approaches that maintain the benefits of the price signals and while diminishing the financial impacts.

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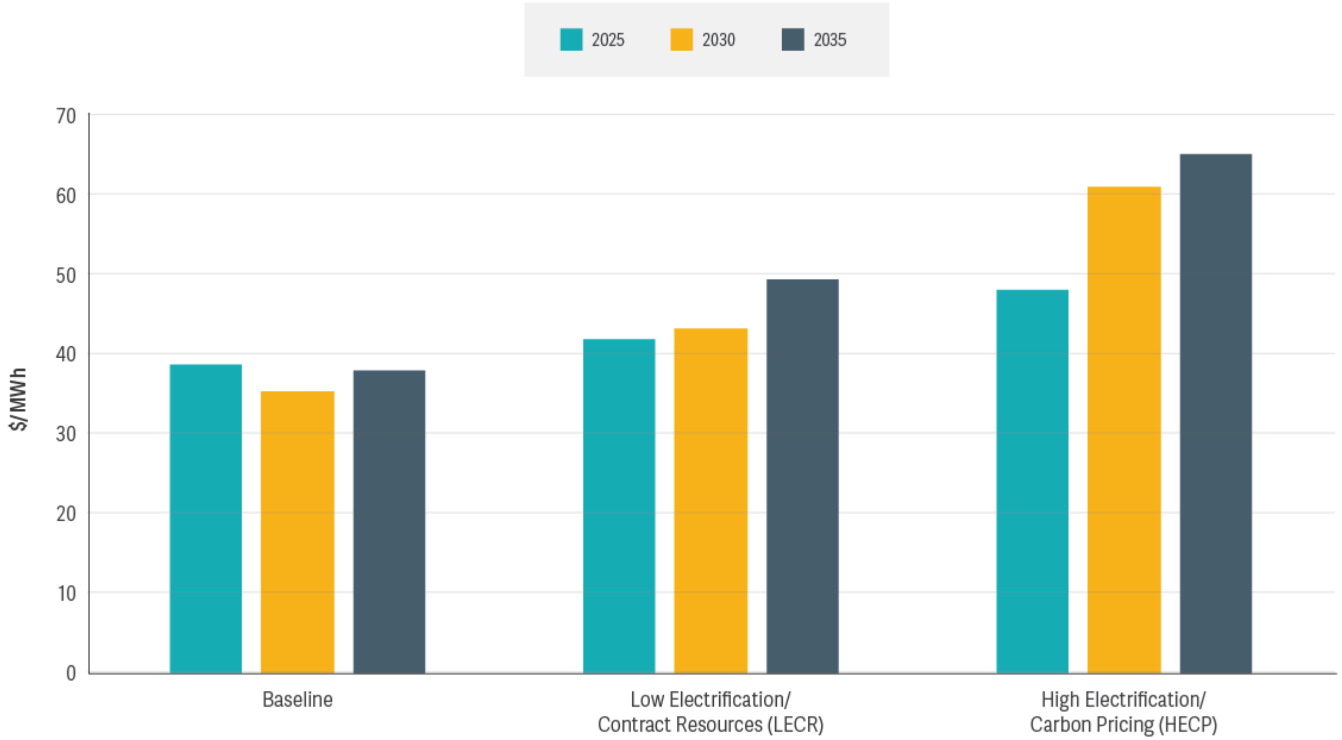
Carbon pricing impact on projected wholesale energy prices

Projected Annual ISO-NE Locational Marginal Prices (LMPs)
Assuming a Carbon Price



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Additional Observations

- Addition of several thousand megawatts of large-scale renewable resources will put downward pressure on wholesale energy prices as the frequency of zero-price energy hours grows.
  - Risks longer-term financial prospects for the increased quantities of renewable resources.
- With technological evolution, the risk of contracting with resources that appear uneconomic grows.
  - Could lead to increased costs for consumers.
- The commitment to a durable market attribute that appropriately incorporates the cost of carbon allows all resources to compete and ensures not only that zero-emission resources are compensated equitably, but that all other resources whose production is needed to ensure reliable system operations are compensated equitably.
- Consumers can be expected to respond to price signals and adopt new technologies to minimize costs as electricity becomes a more significant part of the monthly budget.

Additional Observations

- Replacing considerably more of the remaining fossil fuel resource output with off-shore wind and battery storage would not readily eliminate the region’s reliance on fossil fuel resources.
- The impact of increased additions of off-shore wind and battery storage resources requires:
  - Recognition that there can be multi-day periods of sustained reduced renewable generation where load will likely be met by dispatchable gas resources
  - Battery charge/discharge patterns that need to accommodate multi-day system operational needs.
  - Consistent operation of the most efficient gas-fired resources with more capacity operating in the winter and spring seasons.

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Implementation: The Pathway to Efficient Decarbonization

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The implementation of an effective multi-sector price on carbon can help guide the transformation

- The key considerations associated with the introduction of a multi-sector carbon price are well understood.
- Regional agreement is critical to develop a framework upon which carbon prices can be established.
- The disposition of the carbon revenues requires careful evaluation.