FINAL

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 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 their comparatively high minimum capacity requirements, comparing them to the energy-only market in ERCOT.

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 was three years in advance of the commitment period. He noted this challenge was even greater given the uncertainty over how the coronavirus and related recession 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. 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 mitigation was most frequent for local reliability.

Discussing uplift costs, Dr. Patton reported that those costs fell significantly in 2019. He attributed 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 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, 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 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 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 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 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 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 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 produced about 66% of the value of a conventional resource because it could only be dispatched for a short time. This reliability difference would become more pronounced as investments in batteries accelerated and potentially 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 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 who have put capital at risk based on the current market design. Therefore, the EMM 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 its July 21 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 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 were no sequestration opportunities in New England due to a lack of saline aquifers for storage. She showed a 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 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 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 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 her presentation, 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 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. Summarizing the scenarios studied, he noted high penetration of renewable resources would cause cycling of gas-fired generation and 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 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. 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.

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 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 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,

David Doot, Secretary

ATTACHMENT 1

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	

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Holden Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Holyoke Gas & Electric Department	Publicly Owned Entity		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Ipswich Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Jericho Power LLC (Jericho)	AR-RG	Mark Spencer		
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	

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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	
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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