FINAL

The 2019 Summer Meeting of the NEPOOL Participants Committee was held at Gurney's Resort, Newport, Rhode Island, on Tuesday, June 25, and Wednesday, June 26, pursuant to notice duly given, followed on Thursday, June 27, by meetings between modified Sector groups and ISO Board Members, and state regulators and officials, respectively. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. All motions acted on at the meeting were voted on Tuesday, June 25. 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 meeting.

JUNE 25, 2019 SESSION

The June 25, 2019 session began at 8:30 a.m. with Ms. Chafetz offering welcome remarks.

EXECUTIVE SESSION: APPROVAL OF BALLOTING FOR PROPOSAL REGARDING AGE LIMITS FOR ISO BOARD NOMINATIONS

Before going into executive session, Ms. Chafetz explained the matter to be discussed in executive session related to a proposed amendment to the Participants Agreement (PA) that would authorize the Joint Nominating Committee (JNC) to waive the current 70-year old age limit for candidates presented for election to the ISO Board. Referring to materials circulated in advance of the meeting and posted with the meeting materials, she explained to the Committee that the authority proposed for the JNC under the amendment would mirror the authority the JNC had to waive the three consecutive full-term limit. She also explained that the ISO made clear that it was not willing to engage in broad negotiations at that time about other changes to the PA.

Mr. Doot reviewed that, under the NEPOOL process for considering changes to the PA, the Committee needed first to authorize by a 66.67% Vote the balloting of the amendment. If balloting was authorized, the amendment would then need to be balloted and the ballots returned would need both to meet the Minimum Response Requirement and to achieve a 70% Vote in favor. The ISO would also need to approve execution of the amendment, and the amendment would need to be filed with and accepted by the FERC. The JNC, based on all feedback and discussion, would then recommend a slate of three candidates for consideration by the Participants Committee later in the year.

The Committee began discussions while still in general session and while ISO representatives were still in the room. Ms. Janice Dickstein, ISO Vice President, Human Resources, responded to some member questions, referring to the ISO memorandum that had been circulated and posted in advance of the meeting. She noted that not only is the pool of potentially qualified candidates reduced by the current age limit concerns, but that Mr. Roberto Denis, whose second term ends in 2020, would be ineligible for a third term if the age limit remained in place as drafted. The ISO confirmed that, while it would prefer elimination of the age limit or a higher age limit, the proposal was acceptable to the ISO.

Members began conveying their views on the matter with the ISO representatives present. Those views reinforced views summarized in the materials circulated and posted in advance of the meeting. There was discussion about the potential timing for JNC notice of any waiver and the NEPOOL process for soliciting NEPOOL feedback on the potential waiver before it was granted. During that discussion members were assured by current JNC members present and with Ms. Dickstein's affirmation, of the following: (1) that the Participants Committee would have the opportunity for timely review in executive session of the Board members being considered for an age or term limit waiver before the JNC were to grant any such waiver; and (2) that the JNC acts by consensus where it has not approved actions that are strenuously opposed by one or more of the JNC members. A number of members noted that those assurances were important to and required for their willingness to support the proposal.

ISO representatives and guests then left the room and the Committee went into executive session. At the conclusion of discussions in executive session, the following motion was duly made and seconded:

> RESOLVED that the Participants Committee authorizes and directs the Balloting Agent (as defined in the Second Restated NEPOOL Agreement) to circulate ballots for the approval of changes to Section 9.2.3 of the Participants Agreement, substantially in the form circulated to this Committee in advance of this meeting, to each Participant for execution by its voting member or alternate on this Committee or such Participant's duly authorized officer, together with such non-material changes as the Participants Committee Chair and Vice-Chairs may approve; and
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> FURTHER RESOLVED that the Chair of the Participants Committee is authorized to execute an amendment on behalf of NEPOOL reflecting those changes if those changes are approved in balloting.

The Committee approved the motion with a 76.88% Vote in favor (Generation Sector – 11.19%; Transmission Sector – 16.79%; Supplier Sector – 13.59%; AR Sector – 16.04%; Publicly Owned Entity Sector – 16.46%; and End User Sector – 2.81%). (See Vote 1 on Attachment 2).

GENERAL SESSION

The Committee came out of executive session at 10:00 a.m. and was joined by ISO representatives and guests. Ms. Chafetz welcomed the members, alternates, federal and state officials and guests who were present.

APPROVAL OF MAY 3, 2019 MEETING MINUTES

Ms. Chafetz referred the Committee to the preliminary minutes of the May 3, 2019 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of the May meeting were unanimously approved, with an abstention noted by Michael Kuser.

CONSENT AGENDA

Ms. Chafetz referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Mr. Doot noted that Consent Agenda Item #3 included some but not all of the required updates to the Tariff definitions (those not included stricken from the applicable footnote in the revised Consent Agenda). As a result, the Reliability Committee would be considering further definitional changes for consideration by the Participants Committee at its August meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved, with an abstention noted by Michael Kuser.

NESTED EXPORT-CONSTRAINED CAPACITY ZONE CHANGES

Ms. Chafetz referred the Committee to a package of Markets Committee-recommended changes to the Forward Capacity Market (FCM) rules, circulated and posted with the meeting materials in advance of the meeting. She described that those FCM rule changes would accommodate nested export-constrained Capacity Zones in the FCM, which may be modeled for the Capacity Commitment Period beginning June 1, 2023 (CCP14) and would clarify certain data submittal of costs and revenues for Static De-list and Export Bids in the FCM. She reported that the Markets Committee recommended Participants Committee support for this package of Tariff revisions at its June 12, 2019 meeting and, but for the timing of the Markets Committee recommendation, this matter would have been on the Consent Agenda.

The following motion was duly made, seconded, and unanimously approved without discussion and with abstentions noted by Brookfield, Calpine, Jericho, Verso, and Michael Kuser:

> RESOLVED, that the Participants Committee supports the package of Tariff revisions to the Forward Capacity Market rules, as recommended by the Markets Committee at its June 12, 2019 meeting, and as reflected in the materials distributed to the Participants Committee for its June 25, 2019 meeting, together with such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Markets Committee.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the May 3 meeting, which had been circulated and posted in advance of the meeting and invited questions. There were no questions on those summaries.

Mr. van Welie stated that he would like to take the opportunity to continue a conversation initiated by the states at the 2019 New England Conference of Public Utilities Commissioners (NECPUC) Symposium concerning whether the markets original objectives are still relevant, particularly given state procurements in fulfillment of policy goals. He observed that some states clearly believed the market should better accommodate state policies, perhaps by allowing state sponsored resources to enter the market without mitigation, while other states still strongly supported achieving desired outcomes through the competitive markets. Notwithstanding those differences among the states, he believed all could agree that the region’s power system was undergoing a dramatic and rapid transformation. When competitive markets were introduced, he continued, they allowed for the rapid deployment of gas-fired generation, followed by significant investments in energy efficiency and distributed resources, including solar photovoltaic (PV) and demand-side resources. The states' efforts to contract for new, renewable energy was accelerating the change in the generation mix, as evidenced by the ISO's interconnection queue. He stated that the rapid introduction of low- and zero-marginal-cost resources would have a significant impact on energy market prices over time, particularly in the off-peak seasons, and would make merchant resources much more dependent on revenues from the capacity market and the ancillary services markets as their energy market revenues decrease. Further, as states pursue decarbonization policy goals through other supplementary measures, such as emissions limitations, it would become increasingly more difficult for the region's high-carbon resources to continue operating. That combination of factors, he predicted, would lead to retirements in the existing fleet with a likely result that the region's energy constraints would become more severe during periods of very cold weather when the gas pipelines were constrained.

Against this backdrop, Mr. van Welie stated the ISO still believed that the markets' primary objectives remained relevant and the ISO's objective remains to maintain competitive markets that are balanced between buyers and sellers. The ISO also recognized the New England market design had to be adapted to address the power system's transformation over this period, particularly as long-term decarbonization strategies begin to tie other sectors of the economy to the power system. He referred to the ISO's Strategic Themes, which were recently distributed to the Participants Committee, that outlined the ISO's goal to ensure reliability through competitive markets, including ensuring appropriate price formation for needed reliability services, and making the necessary adjustments to accommodate evolving state policies and new resources coming on the system. The Strategic Themes went beyond the markets to incorporate other changes that would be necessary as a result of the evolution of the power supply, noting state-sponsored behind-the-meter (BTM) resources would have a profound impact not only on system operations but also on the transmission infrastructure, and interconnection of grid-scale renewable resources would have a big impact on the transmission system. Those changes he predicted would clearly push the region to innovate and to make changes to operations and planning practices. Noting his interest in the presentation the following day by National Grid's representative concerning how National Grid was managing this transition in the United Kingdom (UK), Mr. van Welie reported that he had recently attended a U.S./European forum on energy transition. He reported being struck by how similar the discussions were on both sides of the Atlantic, including the importance of appropriate pricing in markets for reliability services, the need for new reliability services as the power system changes operational dynamics, the transmission investments needed in order to enable the deliverability of renewable energy, and the adaptation of operational practices to these new realities.

Mr. van Welie suggested that New England was rapidly catching up to Europe and California with respect to the deployment and integration of renewable energy, and was ahead of those regions with its energy security constraints. He noted that he had not identified another region with winter constraints like New England's, making New England's situation more complex than other regions seeking to decarbonize. New England had a strong, proven record of solving difficult problems and while the journey appeared challenging, he was confident that the region would work together to produce the innovative solutions that would enable the region's transition to a low-carbon power system.

The Committee then commented and asked questions. A member commented that he hoped the ISO, in its role as the independent arbitrator for reliability in the region, would take a more proactive role going forward rather than a highly reactive role, settling for Reliability-Must-Run (RMR) agreements to retain resources needed for system reliability. Mr. van Welie agreed and said the ISO was committed to solving the challenges through the markets. He noted that other regions taking a power system through a transformation to a low-carbon system each required a balancing energy source, which was predominantly hydro or gas. He stated the ISO would continue to push to try to make sure there was sufficient revenue in the wholesale market to pay for the services that are needed.

Referring to Mr. van Welie's comment that circumstances would incent innovation, a member predicted that the region would have to innovate more quickly over the next 20 years.

In terms of timing, a member asked how this impacted the Chapter 3 discussions underway. Mr. van Welie responded that energy security design was the current focus but would naturally lead to other conversations. Mr. van Welie disagreed with the observations by a member that the ISO's objectives have changed or should change from where they started 20 years ago. He explained that the ISO still viewed the primary objective to ensure reliability through a competitive wholesale power structure. He stressed the need for a set of services from generators in order to accomplish that objective. Concerning whether the market should support additional objectives, as for example market-based solutions to environmental objectives, Mr. van Welie stated that the ISO had concluded such efforts would exceed its jurisdiction and mission as currently defined.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), reviewed highlights from the June COO report that had been circulated in advance of the meeting and posted on the NEPOOL and ISO websites. Summarizing, he reported that May temperatures were quite cool.

Real-Time loads were down 5% from loads previously, with average loads of 11,500 MW, the lowest since 2003. He then summarized the following: (i) total Energy Market value was $226 million, down $27 million from April 2019 and $21 million from May 2018; (ii) average natural gas prices in May were 8.9% lower than in April; (iii) average Real-Time Hub locational marginal prices (LMPs) ($22.89/MWh) were 15% lower than April LMPs; (iv) average daily (peak hour) Day-Ahead cleared physical Energy, as a percent of forecasted load, was 99.1% in May, up from 97.8% in April (the lowest value for the month of May was 94% on May 21); and (v) daily Net Commitment Period Compensation (NCPC) for May totaled $2.1 million, up $0.1 million from April and down $2.6 million from May 2018. May 2019 NCPC was 0.9% of the total Energy Market value and was comprised of (a) $1.6 million in first contingency payments, down $0.4 million from April, and (b) $465,000 in second contingency payments, up $248,000 from April (due to transmission-related outages in Maine). He reported that Pilgrim Station shut down on May 31, which was the second nuclear unit retired in New England over the past several years. He said that May 31 also marked two new resources coming on-line, a fast-start unit in Southeast Massachusetts (SEMA) and a dual-fueled unit in Connecticut, totaling about 1,000 MW.

With respect to June, Dr. Chadalavada observed that the modest temperatures during the first two weeks of June produced low Real-Time loads and NCPC. He said most of the load cleared in the Day-Ahead Market. He reported that June 1 marked the implementation of the do-not-exceed (DNE) dispatch limit for intermittent resources, which was a must-offer requirement that was placed on mostly wind and hydro resources as part of the continuing implementation path for that resource category. He reported that there was an approximately 125 MW increase in resources offered in the Day-Ahead Energy Market as a result of those market changes, but there was no appreciable change in LMPs given the low load conditions and fairly modest amounts of capacity participating.

Focusing on the future, he reported that the Boston Needs Assessment had been published. He stated the ISO would issue its first request for proposals (RFP) for competitive transmission solutions in late 2019/early 2020. He said that the FCA14 process had begun with the ISO receiving a record number (over 700) Show of Interest applications (SOIs) representing about 18,500 MW of potential new resources. He reported that Maine, for FCA14, would be modeled as a nested zone within the Northern New England zone.

In response to questions from the Committee, Dr. Chadalavada noted that the ISO was continuing to study how passive demand resources are functioning in the market, and would report on the results of those studies to the extent permissible under the Information Policy. He acknowledged concerns voiced by generator representatives over the record number of SOIs in light of pending proposals to reduce the chance for new resources to profit from shedding their Capacity Supply Obligations (CSOs) before becoming commercial. While the ISO agreed there was a problem, it did not support the solution proposed by generators and was working through the stakeholder process a different solution of its own to provide incentives to supply without creating unreasonable barriers to new entry. As for timing, he was uncertain whether a solution could be implemented in time for FCA14. Responding to a question regarding the impact of the Pilgrim shutdown on out-of-merit commitments, Dr. Chadalavada said that the ISO expected little or no need for out-of-merit commitments if all the transmission lines on the SEMA interface were in-service and loads were under 18,000 MW. Whether such commitments would be needed for loads above 18,000 MW would depend on what resources cleared in the Day-Ahead Energy Market.

FERC REGIONAL UPDATE

Ms. Chafetz welcomed, introduced and thanked FERC Staff for their attendance and participation. Ms. Jette Gebhart, Deputy Director, Office of Energy Market Regulation (OEMR), then provided remarks. She began by making clear that her remarks were her views and opinions, and not those of the Commission. She introduced the other representatives of FERC staff who were present.

Ms. Gebhart described OEMR's functions, summarizing that, in 2018, OEMR had handled approximately 5,500 electric, 1,500 pipeline, and 700 oil rate filings. Following this summary, she noted that OEMR was working through the compliance filings submitted in response to Commission orders on energy storage and generator interconnections.

Ms. Gebhart highlighted the July 15, 2019 publicly-noticed pre-filing conference to discuss New England's upcoming fuel security filing. She explained that holding a pre-filing discussion in this way was somewhat unusual, but had been structured to ensure discussion of the filing could be accomplished without violating the Commission's *ex parte* rules. She said Staff hoped to become better informed about how the proposals would affect other aspects of the New England Markets and various stakeholders. She urged that those communicating with the Commission on this and other matters take into account that a number of the Commissioners were still relatively new to the Commission. Accordingly, they would benefit from receiving historic and contextual information relating to filings they receive, as well as a clear understanding of the impact of those filings on various interest groups. She acknowledged that NEPOOL had many different interests at the table with differing views on changes being proposed. She said the Commission benefits from hearing from a variety of perspectives, not only on the fuel security issues to be addressed on July 15, but on other important issues facing the region.

Next, Ms. Gebhart summarized the following priorities of Chairman Neil Chatterjee, that he had highlighted in previous public remarks:

- Review of liquefied natural gas (LNG) facility applications
- Cyber security issues facing both the electric sector and natural gas pipelines
- Energy storage, as set forth in Order 841, as well as continuing the FERC’s work on aggregation of distributed energy resources (DER)
- Refinements to transmission-related matters before the Commission
    - ♦ Order 1000 – was it working? Where could it be improved?
    - ♦ Was the right transmission being built?
    - ♦ Transmission rate issues, with Notices of Inquiry on setting base returns on equity (ROEs) and transmission rate incentives
- The ongoing inquiry, initiated in January 2018, into ensuring resilient electric bulk power facilities.

She went on to observe that the other Commissioners also had their individual priorities and interests. Leaving Commissioner LaFleur, who would speak later in the meeting, to outline her own priorities, Ms. Gebhart said Commissioner Glick spoke in public often about his interest in the increasing deployment on the grid of renewable resources and new technologies and the FERC’s consideration of climate change in its work. Commissioner McNamee’s public statements had emphasized the FERC’s work on LNG, and had recently raised jurisdictional questions over the authority of the FERC versus the states relating to energy storage.

Focusing more broadly, she noted that three of the four sitting Commissioners came to their current positions from backgrounds different from those of other recent Commissioners. Notwithstanding changes on the Commission, she explained, the traditional role of FERC Staff, which is to provide sound, thorough and balanced legal and technical advice, did not change. She then concluded her update, inviting questions from the Committee.

Responding to a question regarding the Chairman's priority on transmission and what he thought the right transmission is, Ms. Gebhart stated she could not speak for the Chair. She went on to note that the Commission continues to hear from a variety of sectors about the need to interconnect new generation and was very aware, given recent and pending proceedings on interconnection queues and delays, the issues faced there. In response to how FERC Staff was keeping up with the rapid technology changes and how those changes influenced Staff's thinking on filings before the Commission, Ms. Gebhart stated that each of the Commissioners had publicly recognized the changes, including the new technologies, facing the grid and its many sectors. By way of example, she noted that the FERC had in recent years done more thinking about storage and DER, and how to ensure fair treatment of new technologies. She acknowledged that, as technology, the grid and policies change, incremental changes may be needed where a "one size fits all" solution may not be viable. The just and reasonableness of any proposal at the time proposed is what Staff must focus on. She was asked how Commissioners' political backgrounds might affect how Staff prepares the record and their recommendations. Ms. Gebhart responded that Staff works to provide Commissioners with all the background and relevant information they need to address the questions before them.

ISO CFO REPORT: 2020/2021 ISO BUDGETS

Mr. Robert Ludlow, the ISO's Chief Financial Officer (CFO), referred the Committee to the presentation of the ISO's 2020 and 2021 preliminary Operating and Capital Budgets (Budgets) included with the materials posted in advance of the meeting. He reported that he had also shared this information with state officials at the 2019 NECPUC Symposium.

Mr. Ludlow discussed the following key components that were driving changes to the 2020 and 2021 Budgets from 2019's Budgets: compensation and inflationary costs; Order 1000 implementation (including project management and legal activities); network modeling and Energy Management System (EMS) maintenance (reflecting significant increases in renewable resources and other new power system technologies and related complexities); cyber security (both compliance and operational costs); and energy security and other market improvements (including implementation costs for the Competitive Auctions with Sponsored Policy Resources (CASPR)). He summarized that the 2020 Operating Budget was projected to reflect an overall increase over 2019 of about 4.5%, and the 2020 Capital Budget was projected to be $28 million, which remained unchanged from the 2019 Capital Budget.

Beyond 2020, Mr. Ludlow explained that the ISO was not able to project a reliable 2021 "look ahead" forecast because of the significant, but as yet unspecified, scope of investments in software systems and settlement processes to be driven by the energy security market design. He indicated, though, that the changes would likely require an increase in the 2021 Capital Budget.

Focusing on process, Mr. Ludlow reported that the ISO planned to discuss the 2020 Budgets with state officials again on August 12, and with the NEPOOL Budget & Finance Subcommittee on August 9. The 2020 Budgets would then be submitted with any feedback received to the ISO Board's Audit & Finance Committee on August 22. The ISO would then review feedback received with its full Board on September 12. The Participants Committee was scheduled to vote on the final proposed Budgets at its October 4 meeting, and the final ISO Board vote would be taken following that Participants Committee meeting. The ISO plans to file the 2020 Budgets with the FERC later in October, with a requested effective date of January 1, 2020.

ISO IMM ANNUAL REPORT

Dr. Jeffrey McDonald, the ISO's Internal Market Monitor (IMM), presented highlights from the IMM's 2018 Markets Report (IMM Annual Report), which had been circulated and posted in advance of the meeting. Summarizing, he noted that total wholesale costs were 33% higher than 2017, attributed to the cost of electricity, driven by the cost of natural gas, which was also 33% higher than 2017. The uniformly higher capacity prices for Capacity Commitment Periods 8 and 9 also contributed to overall higher wholesale electricity costs.

He reported that there was a higher level of competitiveness in 2018, especially in the Energy Market, and reviewed the measures used by the IMM to gage that, including the use of price cost markups and the Residual Supply Index. Further, the IMM saw a much lower incidence of pivotal suppliers, driven by higher reserve margins (due to improved generator availability and presence of price-responsive demand in the energy and reserve markets) and a dilution of market share (due to a reduction in one major generation portfolio and relatively large new entrants and changes in control of other portfolios).

Dr. McDonald then referred the Committee to charts reflecting mitigation levels and fuel prices. Focusing on mitigation, he reviewed the system-wide Residual Supply Index duration curve and price cost mark-ups and frequency of mitigation events by type, noting the downward trend in mitigation levels over the past several years. Reviewing fuel prices, he reported an increase in prices for all major fuels, noting the increase in oil prices was primarily due to a reduction in oil production by the member countries of OPEC (Organization of the Petroleum Exporting Countries). He reported natural gas prices on average increased in 2018, largely attributed to the prolonged cold snap that ran from the end of December 2017 into the first weeks of January 2018. In response to a question, Dr. McDonald stated natural gas prices were based on the Algonquin pipeline prices, not delivered prices. He noted that the price increases in January were largely the result of transportation constraints into New England.

Turning to CO_2 prices, he reported that New England (RGGI) and Massachusetts (MA) CO_2 prices added to the cost of generation in New England. He stated the RGGI prices increased 25% in 2018 compared to 2017, from \$3.59 to \$4.50/short ton, which translated to approximately \$2/MWh. He attributed some of that price increase to an anticipated 30% reduction in the CO_2 cap by 2030. He reported that, in January 2018, MA began a new CO_2 cap-and-trade program (MA Program), in addition to RGGI, with prices starting at about \$20/short-ton and declining, with increased market certainty, to about \$10/short ton by the end of the year. He concluded that MA generators were reflecting their additional costs of the MA Program in their supply offers. In response to questions, he confirmed that affected MA resources saw a \$4-8/MWh increase in their costs over non-MA resources, but the IMM did not have enough data to assess what impact, if any, that had had on LMPs. He agreed that it was possible that, as a result of the MA Program, less efficient/higher heat rate units not subject to the MA Program might be dispatched ahead of cleaner MA generators, which could increase CO_2 emissions for the region.

Dr. McDonald then reviewed a chart reflecting annual load by quarter. He reported that, in the third quarter (Summer 2018), compared to the same period in 2017, there was an 8% increase in load, which subsequently contributed to an annual load increase of 2% in 2018. A member noted the considerable load variability reflected not just between years, but between quarters within a year, and asked whether this provided any insights for the IMM's assessment of Chapter 3. Dr. McDonald stated that the IMM would make a point of considering the impact of inter-seasonal variations on forward procurements and the potential price suppressive effects.

Dr. McDonald reviewed a 2014-2018 comparison of weather-normalized load over all hours that had been reconstituted to include the effects of energy efficiency (EE) and BTM solar. The vast majority of the reduction in load (over 2,000 MW in 2018) was attributable to EE, but the impact of BTM solar was growing year-over-year.

He turned to a chart addressing NCPC, which showed an increase in 2018 after four consecutive prior years of decline. He explained that the increase was largely driven by out-of-market posturing and higher fuel prices during the January 2018 cold snap, which saw an increase in both the quantity (given fuel uncertainty during that period) and the price of the make-whole payments. He explained that, among the lessons learned from the cold snap, was a recognition, particularly in light of the manual posturing undertaken, that the opportunity costs of fuel-limited resources must be appropriately valued in the market clearing and resulting market prices in both the Day-Ahead and Real-Time Energy Markets. He credited Dr. Chadalavada with instituting an expedited internal design and implementation process in response to those lessons learned to ensure that, going into Winter 2019/20, the region would have an appropriate valuation of opportunity costs for, and efficient allocation and dispatch of, fuel-limited resources.

Turning to a slide illustrating the costs of Ancillary Services over the prior five years, he noted that overall costs were relatively unchanged over the last three years. Addressing a question about the Net Forward Reserve component, he explained that the higher values in 2014 and 2015 resulted from the inability of generation to meet certain local requirements, which resulted in prices hitting the cap in those areas, driving up prices. Those circumstances had not occurred since.

Dr. McDonald concluded his presentation by reviewing charts that provided an overview of the FCM over the prior eight periods. He expressed his hope that the charts would provide useful context for the continued discussions assessing the FCM. He noted that the market response was largely consistent with expectations (i.e. higher prices and increased new entry when the system was short and, conversely, lower prices when the system was long). He noted, however, that despite lower prices over the prior few years, retirements had not increased and the system was long on capacity. He acknowledged that the retention of units for fuel security reasons had contributed to that outcome, but opined that the system would still have been long without those units being retained and expressed interest in how future FCM procurements would impact the system's return to equilibrium.

PARTICIPANTS-SPONSORED PROPOSAL: ADDITION OF AFFILIATE GUARANTEES AND SURETY BONDS TO ISO-NE FAP

Mr. Ken Dell Orto, Budget & Finance Subcommittee (Subcommittee) Chair, referred the Committee to the materials circulated and posted in advance of the meeting concerning a Participants-sponsored proposal (the Proposal) to change the ISO New England Financial Assurance Policy (FAP) (i) to permit Market Participants to rely on an affiliate guaranty as a means of obtaining an unsecured Market Credit Limit or Transmission Credit Limit and (ii) to add surety bonds as an acceptable form of financial assurance. He noted that the Proposal was sponsored by Calpine, Direct Energy, Dominion, Exelon, MMWEC, NextEra, and PSEG (the Sponsors). He summarized the process that had been followed to review the Proposal and the input provided at Subcommittee meetings.

The Committee discussed the Proposal. Advocating in favor of the Proposal, the Sponsors and others argued that the Proposal potentially would produce cost savings, which would benefit consumers and that similar financial instruments were available to market participants in other organized markets. A Publicly Owned Entity representative suggested that the changes would reduce the burden on small municipal entities without increasing risk to the region. Another Sponsor representative explained how the Proposal could improve competitiveness in standard service solicitations and other load-related contracts. Sponsors also noted that unsecured credit was already permitted in New England, with risks shared amongst those in the unsecured credit risk pool, rather than more broadly across all Participants.

Other Participants expressed concerns with the proposed changes. They argued that the limited financial instruments proposed would only be available to Participants with significant market capitalization or access to creditworthy entities. They also referred to points raised by the ISO in explaining its opposition to the Proposal.

The ISO then described its position, referring to its memorandum, which was circulated and posted with the meeting materials. The ISO highlighted the importance of the risk management role of the FAP in ensuring that all Market Participants would be paid on time and in full. The ISO was concerned that would not occur with guarantees and surety bonds. The ISO noted, in response to other questions, that it considered guarantees and surety bonds to present greater risk to the region if bankruptcies of the related Market Participants occur. The ISO added that it would not be in a position to independently verify or monitor the breadth or scope of parent guarantees that an entity might have in place in other regions or for other purposes.

At the conclusion of discussion, the following motion was then duly made, seconded and voted:

> RESOLVED, that the Participants Committee supports revisions to the ISO New England Financial Assurance Policy, as proposed by Calpine Energy Services, LP, Direct Energy Business, LLC, Dominion Energy Generation Marketing, Inc., Exelon Generation Company, LLC, Massachusetts Municipal Wholesale Electric Company, NextEra Energy Resources, LLC and PSEG Energy Resources & Trade LLC and as circulated to this Committee for its June 25, 2019 meeting, together with such non-substantive changes as the Chief Financial Officer of ISO New

> England and the Chairman of the Budget & Finance Subcommittee may approve.

The motion failed to pass with a 45.13% Vote in favor (Generation Sector – 16.79%; Transmission Sector – 0%; Supplier Sector – 11.55%; AR Sector – 9.44%; Publicly Owned Entity Sector – 7.35%; and End User Sector – 0%;). (See Vote 2 on Attachment 2).

FUELS INDUSTRY PARTICIPANT ARRANGEMENTS

Referring to the materials circulated and posted in advance of the meeting, Mr. Patrick Gerity, NEPOOL Counsel, summarized the reasons for, and substance of, the two actions being requested of the Participants Committee, both in response to the membership application of the American Petroleum Institute (API) and its consideration by the Membership Subcommittee (Subcommittee). First, at the recommendation of the Subcommittee, the Participants Committee was being asked to authorize and direct the Balloting Agent to circulate ballots for approval of limited amendments to the NEPOOL Agreement that would expand the definition of Gas Industry Participant (to be renamed "Fuels Industry Participant") by authorizing the Participants Committee to determine on a case-by-case basis whether applicants, such as API, not meeting the existing eligibility criteria for Gas Industry Participant, should be approved as a Fuels Industry Participant.

The following motion, on this first request, was duly made and seconded:

> RESOLVED that the Participants Committee authorizes and directs the Balloting Agent (as defined in the Second Restated NEPOOL Agreement) to circulate ballots for the approval of changes to the Second Restated NEPOOL Agreement (that define and address the arrangements for Fuels Industry Participants), but with such non-material changes therein as the Chair of the Membership Subcommittee may approve, to each Participant for execution by its voting member or alternate on this Committee or such Participant's duly authorized officer.

A member speaking on behalf of two Participants (VEIC and NH OCA) expressed their hesitation to support on a routine basis the participation by Fuels Industry Participants, but also their acknowledgement that such participation could provide perspectives and the benefits of expertise useful to the region's deliberations. Without further discussion, the Committee considered and approved by a show of hands the motion to authorize and direct the balloting of the limited amendments, with an opposition by VEIC[1] and an abstention by Michael Kuser noted.

Turning to the second requested action, Mr. Gerity explained that the Subcommittee recommended that the Participants Committee make the determination at this meeting that API is a Fuels Industry Participant if the amendments just approved for balloting are finally approved and become effective. He explained that approval of the recommendation now would avoid the need for further Participants Committee action on the API membership application.

The following motion was then duly made, seconded and, subject to the same comment on the prior motion, approved with an opposition by VEIC and an abstention by Michael Kuser noted:[2]

> RESOLVED, that, subject to Participants Committee approval in balloting and FERC acceptance of the amendments to the Second Restated NEPOOL Agreement regarding Fuels Industry Participants, American Petroleum Institute is determined as permitted by those amendments to be a "Fuels Industry Participant".

LITIGATION REPORT

Mr. Doot referred the Committee to the June 21 Litigation Report that had been circulated and posted in advance of the meeting. Noting the high level of activity, he highlighted

[1] The NH OCA was absent from the meeting but had expressed its opposition to the motion through another Participant representative.

[2] *See* prior note regarding NH OCA opposition.

developments in the following four proceedings: (i) the Regional Network Service/Local Network Service (RNS/LNS) Rates and Rate Protocols proceeding, EL16-19, where the FERC had rejected the proposed settlement and the proceeding was headed to hearings; (ii) the FCA13 results filing, ER19-1166, where the FERC had issued a deficiency letter with the ISO's response due July 8; (iii) the ISO's Interim Winter Energy Security (Chapter 2B) proposal proceeding, ER19-1428, where comments on the ISO's response to the FERC's May 8 deficiency letter were due June 27; and (iv) a proceeding addressing retroactive surcharges in PJM, EL08-14, where the FERC had reversed its prior position on the issue of ordering refunds in cost allocation and rate design cases, finding that it has the authority to order refunds to fix errors, even if refunds require surcredits or surcharges on other market participants. He requested that anyone with questions on the Report to contact NEPOOL Counsel.

COMMITTEE REPORTS

Budget & Finance Subcommittee. Mr. Dell Orto reported that the Subcommittee was scheduled to meet twice in August, first on August 9 to review the ISO's proposed 2020 Operating and Capital Budgets and NESCOE's proposed 2020 Annual Budget, and second on August 19 to continue discussion of the ISO's proposal to adjust the FAP to account for non-commercial resources.

Transmission Committee. Mr. José Rotger reported that the Transmission Committee was scheduled to meet next at its July 16-17 joint summer meeting with the Reliability Committee, with topics to include the annual review of the RNS formula rates, continued discussion of Attachment K changes to enable competitive solicitation for the Boston Needs Assessment, and clarification of Schedule 22 and the Interconnection process related to procedures for market exits (retirements and Permanent De-List Bids).

Markets Committee. Mr. Fowler reported that the next regularly-scheduled Markets Committee would be held July 8-10. He noted a special meeting was scheduled for July 30, which would include a first look at the ISO's impact assessment on the energy security program.

OTHER BUSINESS

Mr. Doot reminded members of the public, FERC staff-led meeting to be held July 15 at FERC headquarters. All those interested were encouraged to participate in-person or through the FERC's free webcast. Members were directed to the FERC calendar for details.

He also advised the Committee that the next Participants Committee meeting, scheduled to be held August 2, was likely to be a teleconference meeting.

REMARKS BY FERC COMMISSIONER CHERYL LAFLEUR

Ms. Chafetz welcomed and introduced Commissioner Cheryl LaFleur, noting that Commissioner LaFleur's nine-year tenure at the FERC was coming to an end in August. She thanked Commissioner LaFleur for the time and attention provided to the region.

Commissioner LaFleur noted FERC Staff in the audience and reminded the Committee that her remarks were hers and not the opinions of the Commission, and that she could not talk about any issues pending before the Commission, which would be considered *ex parte*. She outlined the three broad themes facing the electric industry in New England and elsewhere: (1) what resources would be on the system in the future; (2) how payment to those resources would be determined; and (3) how the industry would get the infrastructure built to deliver energy from those resources to market.

As to the first theme, she said that resource selection and who decides on that selection were critical issues everywhere, but especially so in the Eastern markets that rely on mandatory capacity markets. She said the markets in New England and the other Eastern regions reflected an underlying decision that resource selection be accomplished through competition and an auction structure, rather than administratively through integrated resource planning. She expressed her view that the markets had accomplished well what they were designed to do: they had provided reliability at least cost through regional dispatch, facilitated innovation in new technologies, and shifted investment risks from customers to shareholders. She reported that 54% of the New England resources, on a nameplate capacity basis, became operational after the introduction of the organized markets in 1999, which she said was a larger percentage than any other Eastern market. She noted that New England and PJM states increasingly were playing a more directive role in the transition to the resource mix of the future, either by encouraging distribution companies and their customers to procure energy from new resources that might not be selected in a competitive market, or by requiring retail customers to subsidize certain existing resources. She acknowledged that renewable portfolio standards (RPS) predated the market, but noted that the scope and scale of state involvement has been growing.

Commissioner LaFleur reminded the Committee of the FERC's two-day technical conference on state initiatives and how they would require changes in the markets. She identified three broad paths to effect the necessary markets changes: (1) litigation, which had been done to some extent in New York and Illinois; (2) negotiation; or (3) re-regulation, either in a planned way by handing resource adequacy entirely back to the states, or in an unplanned way through individual and limited state actions cannibalizing the markets. She noted her preference for negotiated solutions, reporting that New England was the only region to successfully do so, filing the CAPSR proposal that was approved by the FERC. She said New York was working with stakeholders on a carbon pricing proposal in that one-state ISO that mirrored the Governor's carbon policies, and she looked forward to seeing that proposal when filed with the FERC. PJM, she said, was unable to reach agreement and, instead, submitted two ideas for review by the FERC, which produced a decision that the PJM Capacity Market was unjust and unreasonable, over her dissent. She said that region was still working on next steps in response.

She noted three broad models that were currently being employed in the country. The first was organized markets with retail choice and merchant generation, like New England, PJM and New York. The second model was organized markets for energy and ancillary services and accomplishing transmission planning, but with state control over resource adequacy and, usually, vertical integration. She said that MISO, SPP and California fit this second model to some extent. The third model was entirely vertical integration with no organized market, which she said was the model in the Southeast and most of the West.

Continuing, she said that, across the country, these various models were converging. Places without organized markets were looking to meet their resource goals by dispatching resources over a broader footprint, citing as example the Bonneville Power Administration joining the Western Energy Imbalance Market. Organized markets in the East were seeing the states in their footprints taking over resource selection rather than relying on the markets. These developments suggested movement to some kind of hybrid model or menu of hybrid models where markets and state control combine.

Commissioner LaFleur then commented on the second topic of setting prices for payments to those resources. She noted that there was a fundamental shift occurring, in both organized and bilateral markets, in how electricity was being paid for. With persistently low gas prices and growing zero marginal cost renewables on the system, resources were not making money on volume and load curves were changing. More attention was being placed on pricing other services beyond volumetric payments for energy, such as for ramping, fuel security, different types of reserve products and essential reliability services. There was consideration being given to charging for carbon emissions and there was more focus on scarcity pricing.

On her third topic -- getting infrastructure built to serve customers -- she said that markets were designed to send signals to drive infrastructure decisions. Both New York and some New England states, though, had sent strong signals that they would not support new pipelines even though the markets would support those resources through reduced costs during times of constraints. She noted her conclusion that New England was planning on more renewables but needed a bridge to get there.

Commissioner LaFleur stated her concern about infrastructure went well beyond pipelines, noting that any new central station resources that are needed to keep the lights on would need to be sited and paid for to be built, especially if there is to be more reliance on location-constrained resources like Canadian hydro and big wind. She opined that it would take regional cooperation among the six New England States to get any resources built in New England in the future. She premised that New England has some important advantages over some of the other regions as it navigates these energy challenges, including: (1) it was an actual region that identifies and exists outside of its market structure, with a set of regional organizations that are geographically coterminous and aligned; (2) it was very tightly interconnected with a long history of operating as a power pool since the 1965 Blackout; (3) it had a demonstrated history of doing things together; (4) there was more policy alignment among the New England States; and (5) it had the advantage of having NEPOOL since 1971. She highlighted that she fielded questions about NEPOOL from the New England congressional delegation at the U.S. House of Representatives hearings two weeks earlier (from Congressman

Kennedy and Congresswoman Kuster) concerning NEPOOL governance, reflecting that the existence of NEPOOL seems to be an asset over the other regions. She stressed the ability to work together was at that point at a premium, was preferable to FERC- or court-imposed solutions, and was the best hope for the development of innovative solutions.

She concluded her remarks by responding to questions. Concerning resource adequacy, a member commented that the states had been picking their favored resources but not picking resources for reliability, and questioned how that might be fixed. Commissioner LaFleur stated that was a problem because, if the states choose to take back resource adequacy entirely, then you would have a capacity imbalanced market like they have in PJM, but if the states only choose some of the resources, the existing resources that were built without the benefit of state-supported subsidization would have to rely entirely on the market for their needed revenues. She stated that one solution was some kind of price correction for the resources that were not being subsidized. Another solution was to use some kind of market mechanism to buy out the resources that were not subsidized. The problem she perceived is that, if the resources that were not being subsidized by the states were not being chosen in an RFP and being paid by distribution customers when actually needed for reliability, then they must be compensated to continue to operate if they are needed. In follow up concerning her remarks about ancillary services and reserves, Commissioner LaFleur stated that, in looking at the shape of the supply curves, if you allow the markets to work and prices get low enough, resources will start to retire and then the prices will correspondingly increase. However, resources that you need at certain times of the day must be paid some way other than on a per megawatt hour basis.

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 2018 Markets Report (EMM Annual Report), which had been circulated and posted in advance of the meeting. He said that the Report focused on key market issues and comparisons of New England to other markets to highlight the differences and challenges in New England.

Referring to his presentation, Dr. Patton discussed the all-in price comparisons among ERCOT, MISO, NYISO and ISO-NE. He opined that the summary of costs provided a good comparison among the markets and for various services. He reported ISO-NE generally had the highest costs, driven in large measure by the relatively high capacity costs in 2018 and by significantly higher energy costs driven by higher natural gas prices in New England.

He then referenced the comparison of the markets' congestion costs. In this comparison, New England had much lower congestion costs, with congestion at about 10% of what the other markets experienced. He explained the small congestion costs impacted market performance and reduced market power, and he attributed New England's results to the large transmission investments in New England over the past five or so years. He noted that average transmission costs in New England were approaching $18/MWh of load, which was substantially higher than the other markets. In his view, New England had shifted its costs from the markets, reducing the value of transmission rights to below $1/MWh of congestion. He said efficient transmission investment occurs when the value of the congestion being reduced is greater than the cost of the transmission investment, so it would be much more difficult in New England than elsewhere to find efficient transmission investment.

In response to questions, Dr. Patton characterized as artificial any attempt to distinguish between reliability investments and economic investments unless markets were not pricing reliability. He said RTOs should be building transmission based primarily on economic criteria. He questioned whether the congestion experienced in parts of Connecticut and Boston before these transmission investments were sufficient to justify the extent of transmission investments to address that congestion. He opined that there were some differences in how conservative the various RTOs were in identifying transmission security needs, and that New England appeared to be more conservative than other RTOs. In response to a member challenging the suggestion that the RTO could ignore reliability standards and base its transmission expansion decisions solely on economics, Dr. Patton clarified that, in his view, reliability requirements should be fully captured in modeling the transmission system in the energy market, and in setting locational operating reserve requirements. Planning reliability requirements in local areas that are impacted by limited transmission should be reflected in the capacity market price differentials that, in turn should support economically efficient new transmission investment when those price differentials rise to appropriate levels.

Referring to the cost comparison and New England-only energy, Dr. Patton indicated in response to members' questions that some of the increase in average gas and energy prices might be attributed to specific cold snap events, but those costs are increasing even if one sought to back out such events.

Responding to member comments and questions on capacity revenues, Dr. Patton referred to a chart in his presentation capturing peaking capacity market revenues in the all-in prices. He noted the consistent decline in capacity prices as new resources entered the market and capacity needs did not increase. He explained that capacity revenues together with energy and ancillary service revenues were insufficient in the short-run to support new capacity resources. He referred to CASPR as a mechanism that should help to reduce supply/demand imbalance as subsidized public policy resources are added in the region.

In working to better understand the comparison of transmission costs, Dr. Patton noted in response to a member's comment that the EMM worked to isolate the components of the transmission rates solely to recovery of embedded costs and not to include variable transmission costs like marginal losses. He again advocated for market-based incentives for transmission investments as the best means to focus investors on finding incremental investments that can deliver net economic benefits to the region.

Dr. Patton was asked whether he had reviewed what capacity prices might have been had the Mystic Units been allowed to retire. He stated the EMM did not calculate theoretically alternative prices, but explained that capacity prices would certainly have been higher. He referred to the EMM's filings in the Mystic docket and in similar New York filings, where the EMM opined that it was not competitively inefficient to retain a resource to provide service for which it is demonstrably an efficient provider, but that it was inefficient not to reflect the pricing of the product being provided in the prices everyone else is paid for that same service. For that reason the EMM supported the Chapter 3 solution. He further opined that the EMM saw more value in prompt capacity markets as compared to a longer forward capacity market. He explained his view that running the capacity market three years ahead forces decisions based on incomplete or inaccurate projections of the future. That concern he said is eliminated by running the capacity market immediately prior to the planning year.

Turning back to the comparison of revenues, Dr. Patton observed that New England was the only market in 2018 that showed net revenues above the estimated annual costs of new entry for additional resources. That result, he said, was largely because of high capacity revenues. He noted that, like other RTOs, New England would not economically support new resources entering its market if the net revenues were limited to energy, ancillary services, and reserves.

He then referred to a chart summarizing the Coordinated Transaction Scheduling (CTS) process and highlighting the benefits he thought were achieved by adjusting the interchange between New York and New England through the CTS process. He attributed the relative success of CTS, when compared to trading between other regions, to the fact that ISO-NE and NYISO agreed to waive transaction fees and transmission fees. In other regions where such fees were not waived, the benefits of interregional trading were much reduced. The EMM continued to recommend that the RTOs work on improving their interface price forecasts so that the benefits of this process could be increased, citing examples of forecast model differences that may be making trades less efficient.

He went on to note that the New England market was very competitive, more so in 2018 than 2017, because of new generation, particularly in Boston where new combined cycle resources significantly reduced pivotal supplier frequency and market concentration. He referenced the higher import capability into Boston and Southwest Connecticut resulting from transmission system upgrades, which he explained was a powerful competitive force in disciplining the concentrated supply in those areas. Thus, he characterized mitigation as relatively infrequent, with mitigation of units most frequently for those that are committed for local reliability, which primarily impacted uplift. There were very few instances of mitigation having a potentially significant impact on prices.

Comparing uplift costs among the various markets over the last three years, he reported reductions in ISO-NE uplift costs, significantly in local reliability uplift costs, but noted that

ISO-NE still had higher market-wide uplift than the other markets. He attributed that primarily to the cold snap in January 2018, which accounted for roughly 25% of the market-wide uplift. Had those January costs been excluded, he explained, uplift costs in 2018 would have been comparable to those in 2017. He said that the primary remaining difference in costs between ISO-NE and the other markets was explained by higher fuel costs. He added that another explanation for the differences in uplift costs was the fact that New England did not have Day-Ahead ancillary services markets. Consequently, ISO-NE met its reserves requirements by committing resources outside the market. Those uplift costs would not be needed if ISO-NE had co-optimized Day-Ahead ancillary services markets. More specifically, the EMM determined that ISO-NE, in 4,000 hours during 2018, committed resources outside the market to supply its system-level Ten-Minute Spinning Reserve (TMSR) requirement. The EMM calculated those out-of-market commitments to have lowered energy prices by $1.00-$1.50/MWh. He clarified in response to questions that the EMM attributed approximately $8 million of NCPC to this cause, but the financial impact was much larger when the price impacts caused by departure from commitment and scheduling through the markets, rather than outside the markets, was factored in.

Turning to the portion of his presentation that reviewed virtual trading and Real-Time NCPC allocation, Dr. Patton repeated his conclusions from prior years that allocating Real-Time NCPC to virtual transactions was bad for the markets. 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. Other markets where virtual traders were not subject to uplift payments had many more trades with much lower profits per trade, further highlighting the relatively low liquidity of ISO-NE markets for virtual trades.

Next he discussed fuel security in New England. Summarizing his conclusions on Chapter 3, Dr. Patton explained his support for establishing requirements to be satisfied through the markets rather than out of market. He stressed his view that doing so with fuel security in mind would improve short-term incentives to procure fuel, optimize commitment and dispatch to account for limited fuel availability, and would provide longer-term incentives to secure firm fuel. He noted his agreement that changes should be made. He explained, though, that the EMM's analysis showed fewer instances of Thirty-Minute Operating Reserve (TMOR) and TMSR depletions and little or no load shedding compared to the results of ISO's Operational Fuel-Security Analysis (OFSA). The EMM's alternative analysis was based on modified dispatch of the marginal units, increased replenishment of oil inventory, and some batteries being added to replace steam turbines. The EMM alternative made reasonable assumptions about the impact of already implemented market design changes that the EMM expected would substantially and positively impact reliability. He noted that the actual reliability impact of the retirements of Mystic and Distrigas facilities would depend on how other sources of supply respond, including alternative sources for LNG imports and how quickly other supply resources enter or leave the market. He concluded by noting his belief that an effective Chapter 3 market mechanism would provide valuable incentives, and could reduce or eliminate the reliability impact of losing Mystic and Distrigas.

Discussion then turned more specifically to the Chapter 3 proposal currently under consideration. Dr. Patton confirmed his view that, in concept, Chapter 3 was a sound design. The EMM and the ISO market design folks had been discussing the Chapter 3 proposal and it had been evolving in ways that addressed earlier concerns of the EMM. He confirmed in response to a question from a New England State representative that the ISO should be applying a standard of reliability for winter energy security based on probabilistic analysis of potential fuel supply. He went on to note that, from an operational perspective, the ISO importantly must limit the quantities of the products it planned to satisfy through the markets to what is needed for reliability. He was still uncertain about a seasonal forward procurement product, in part because of uncertainty over what may be needed for the season. He acknowledged advantage to buying forward if the need was accurately assessed.

The group then discussed with Dr. Patton his views on how Chapter 3 products were being handled in the Day-Ahead Energy Market and not being carried through the Real-Time Energy Market. The Day-Ahead Markets for new reserve products were characterized as financial, and Dr. Patton confirmed his view that they would be very helpful in establishing and optimizing the scheduling of resources. He was undecided whether or not carrying those associated requirements into the Real-Time, physical market was necessary. The Chapter 2 changes were considered to be focused on physical markets and ISO-NE seemed focused for Chapter 3 on markets that were financial. Dr. Patton agreed that, in theory, purchasing an option seven days' out made sense since it would assist the ISO in optimizing the scheduling of the resources that have limited fuel. Dr. Patton stressed the importance of the proposal implementing the Day-Ahead Reserve Market so that it reflected more precisely what the ISO needed to operate the system. He was not sure that failing to follow the requirement through into Real-Time was essential since the objective of the market requirement was to optimize the commitment in dispatch of the resources that had limited fuel. The EMM's preliminary conclusion was that the Chapter 3 proposal should accomplish the design objective, but he needed to think through more carefully whether there could be problems if that requirement was not carried through into the Real-Time dispatch, particularly with committed resources deciding for financial reasons to expire their firm fuel ahead of Real-Time. He agreed to think this through more fully and report his evaluations at a Markets Committee meeting before NEPOOL votes on the proposal.

Dr. Patton then discussed the intersection of Pay-for-Performance (PFP) and Chapter 3. He stressed the financial incentives PFP provided for units to be available. He said that incentive would be even greater when a cold snap occurred if Chapter 3 alone was insufficient to satisfy the region's fuel security needs, since the result would be shortages of TMOR, which would provide large incentives for resources to be available. Members asked about the value of battery storage in those instances. Dr. Patton opined that batteries would not materially contribute to fuel security during a cold snap because the need would be for resources that could run for an extended period and the useful storage from current batteries would last only for hours, not days. He expressed his belief that batteries would be overcompensated under PFP, which would be a real problem if it discouraged necessary generation.

Members asked whether the EMM might provide some insight or confidence that Chapter 3 would eliminate the need for the ISO to take further actions outside the market, particularly given the fact that PFP was in place before the current reliability rejection for fuel security purposes. Dr. Patton responded that the EMM analysis was intended to show how the markets could impact fuel security results. He explained that analysis of whether to grant a RMR contract to a resource was heavily impacted by assumptions and the EMM modified some of the ISO's assumptions to provide a less concerning conclusion when looking out two to three years. Implementing market mechanisms designed to drive good decision-making regarding the trade-offs among different types of oil units, the procurement of LNG, and the replenishment of oil inventories in the winter would decrease the risk of pessimistic assumptions that drive decisions to enter into additional RMR agreements.

Responding to a question as to how big an impact changing the dispatch order would have had on the Mystic retention analysis, Dr. Patton opined that it would have had a significant impact, but not enough to change the conclusion that modified market mechanisms were needed to achieve fuel security. He referred to prior Markets Reports in which the EMM analyzed a variety of scenarios showing in a two-week cold snap the effects of having Mystic and Distrigas available and not available. He confirmed the very significant risk that arises without Distrigas. He clarified that his conclusions were driven in part by both the co-optimization of the reserves Day-Ahead under the Chapter 3 proposal and the proposed multi Day-Ahead Energy Market. He reinforced his view that Day-Ahead commitment would be the most important, but the optimization over the multi-day period looking forward was also important because the decisions of whether to run a higher cost steam unit the next day would be influenced by the desire to conserve fuel on cheaper units two, three and four days out. Dr. Patton agreed to report further to the Markets Committee the relative impacts of the multi Day-Ahead Energy Market versus just co-optimizing the reserves in the Day-Ahead or co-optimizing the reserves in the Day-Ahead Energy Market, with opportunity costs bidding that would include the ability to husband fuel based on future opportunities.

Dr. Patton then referred the Committee to the portion of his presentation concerning PFP. He referenced the first PFP event on September 3 and reviewed his chart of the price at the New England Hub in Real-Time that reflected the period of TMOR shortages when the $2,000/MWh PFP rate applied. He summarized, given PFP and the doubled shortage pricing values, that the Real-Time price during the event was $2,700 and the PFP energy settlement, which occurred outside of the Energy Market, resulted in total settlement of $4,700/MWh. He stated that units that were not committed in the Day-Ahead Energy Market and were not online, which was the case for many of the steam units that have longer start times, were substantially penalized and units that supplied above their obligation, including imports, received substantial payments. The steam turbine units were charged $22 million in PFP charges during that event, and imports received performance payments of nearly $15 million, roughly half of which was paid to imports with no capacity obligations.

He followed with discussion of the EMM's calculation of the expected $30,000 per MWh value of lost load. He explained that the PFP payments needed to be high enough to provide sufficient revenues during shortage events so that the overall energy settlements could support the addition of a new unit at the margin. The value of lost load decreases as the shortage of reserves decreases, since the probability of a loss of load goes down. Continuing, he opined that the fixed price for payments under PFP were set administratively low to start and would increase over time to a value of $5,455/MWh which, when added to the shortage price in the Energy Market would produce payments over $8,000/MWh.

Dr. Patton concluded his presentation responding to additional questions on his report and committing to continue discussions when he attended a future Markets Committee meeting.

There being no other business, the June 25 session ended at 5:00 p.m., with the Summer Meeting to reconvene the following day, on Wednesday, June 26 at 8:30 a.m.

JUNE 26, 2019 SESSION

The Summer Meeting reconvened at 8:30 a.m. on June 26, 2019.

OPENING AND WELCOMING REMARKS

After welcoming members and guests, Ms. Chafetz introduced Ms. Marissa Gillett, the newly appointed Chair of the Connecticut Public Utility Regulatory Authority (CT PURA), who shared comments on behalf of NECPUC President Michael Caron, who was unable to attend the meeting. Chair Gillette thanked NEPOOL for the invitation to participate and welcomed everyone to Newport. She told the group that the States find the discussions with stakeholders very helpful and welcomed the opportunity for continued constructive dialogue.

NEW ENGLAND ENERGY LEGISLATION SUMMARY

Mr. Doot referred the Committee to the 2019 New England State Energy Legislation Summary circulated at the meeting that morning. He stated that the Summary was current through June 19, 2019 and noted that there continued to be developments in some of the states. He welcomed comments and thoughts, particularly from those tracking some of the legislation more closely and in more detail and nuance. Mr. Doot indicated that NEPOOL Counsel would continue to update and would post any updated versions on the NEPOOL website.

ASSESSING CHALLENGES FACING NEW ENGLAND'S EVOLVING GRID

The UK Experiences

Ms. Chafetz introduced Mr. Michael Calviou, National Grid Senior Vice President for Strategy and Regulation. Mr. Calviou proceeded to review his presentation on the experiences of National Grid as the grid operator for the UK, which was circulated and posted in advance of the meeting. He described the UK bulk power system and how materially decreasing amounts of conventional generation were being used to satisfy load, with increasing amounts of renewable power being deployed. He showed graphically the impact of increased solar on the UK system. He described the substantial uncertainty created by the transition of resources, including uncertainty of demand with increased deployment of electric vehicles, uncertainty of supply with the very substantial growth in renewables, and uncertainty in the markets. He then summarized with some detail the system operator's efforts to produce financial energy scenarios, informed with substantial engagement of all stakeholders. He showed a short video that was designed to engage consumers in change that supports the grid evolution in the UK and increases flexibility for the operator. He identified the many different studies and reports produced by the grid operator for stakeholders and regulators.

Mr. Calviou completed his presentation observing that change was occurring at an ever-increasing pace and scenario planning was essential. He noted that the system was becoming far more complex and interdependent. There continued to be much more occurring on the distribution system that was impacting the bulk power system and there was more interaction between the gas and electricity markets. He said that the system operator in the UK played a strong role in facilitating change, removing barriers to new technology, identifying new markets to meet operational demands, and working more closely with the connected distribution systems that are supporting increased distributed generation.

Following his presentation, the Committee engaged in discussion of the similarities between the UK and New England and explored whether some of the UK experiences, particularly with an enhanced study process, might provide good lessons for the region.

Reliable Market Operations with Changing Technologies and Public Policies

Ms. Chafetz recognized Ms. Sharon Reishus, President, Reishus Consulting, and former Chair of the Maine Public Utilities Commission (MPUC), to moderate a more specific discussion of the impact of changing public policy and technology on markets and public policy in New England. Ms. Reishus reminded the Committee of the stated goals of electric restructuring, which included allowing competitive markets to set prices, to shift the risk of business decisions from customers to investors, and to meet consumer needs and preferences through lowest cost options, all without diminishing environmental quality, efficiency or reliability.

She then introduced two panelists who presented the following:

Ari Peskoe's Remarks

Mr. Ari Peskoe, Director of the Electricity Law Initiative at Harvard Law School, noted that the New England States have been leaders in environmental regulation, with changing regulations now affecting the ISO-administered markets. Mr. Peskoe said that fossil-fueled facilities have become difficult to site and the fuel security debate represented a recognition of that constraint. He observed that, within 10 years, about one-half of the region's electric energy would be generated by resources that entered the market through state-mandated, long-term contracts. With increased utility procurements, it was clear that States seeking low-carbon contracts would get them, but the current wholesale market design must change to reflect that fact.

Mr. Peskoe reviewed NEPOOL's historic goals to attain for New England the maximum practical economy, consistent with proper standards of reliability, in the generation and transmission of bulk power through joint planning, central dispatching, and coordinated operation and maintenance of generation and transmission facilities. He said those goals have endured, and were remarkably similar to NEPOOL's current mission: to create and sustain open, non-discriminatory, competitive, unbundled markets for energy, capacity, and ancillary services that are balanced between buyers and sellers. He observed that unbundled markets were now the vehicle for regional coordination to attain maximum practical economy and equitable sharing of costs and benefits evolved into balance between buyers and sellers, to reflect the transition from vertically integrated utilities to the current markets.

He noted that the New England region had the only regional market that had so extensively achieved that level of balance by separating buyers from sellers. MISO and SPP were both dominated by vertically integrated utilities, and about half of generation in PJM was owned by utility holding companies with distribution utilities in the footprint or vertically integrated utilities. He commented on the positive aspects of New England's regional markets with LMPs and open, non-discriminatory competition.

Mr. Peskoe urged the region as markets evolve to seek to accomplish its objectives as much as possible within a framework that maintains the underlying connection between economics and energy flows. The ultimate benchmark, he noted, would be fidelity to NEPOOL's mission. Each new product, market, or procurement should advance regional coordination that is balanced between buyers and sellers. He characterized the current efforts to decarbonize the regional power system as phase 2 of the regional markets, with phase 1 initiated 20 years ago when the markets opened. He said that carbon emissions in 2019 were approximately one-third lower than 1999, largely accomplished through the displacement of coal and oil by natural gas in the wholesale market. The region, he said, would not be able to achieve much more carbon reduction in that way.

Continuing with his summary, he observed that the policy framework for phase 3 of New England's markets was just starting to take shape. The parameters for phase 3 were being set by states' long-term carbon goals, with five New England states setting targets that required approximately 80 percent carbon emission reductions by 2050. If a regional mechanism for achieving decarbonization goal is not identified, phase 3 might be characterized by a combination of state procurements and escalating renewable portfolio or clean energy standards. That outcome would largely be a continuation of phase 2 and would be combined with inconsistent regulation of CO_2 emissions from the region's fossil generators. Mr. Peskoe expressed the view that this outcome for phase 3 would threaten the key principles of openness and non-discrimination and would mark a major step backward in the decades-long effort to improve regional coordination. He said, to avoid an outcome in which ISO markets don't drive investment and RMR agreements are needed to keep existing assets operational, the region needed a market-mechanism that reflects if not drives new entry of low-emission resources.

Summarizing, he said that phase 1 reduced emissions through natural gas plants entering the market relying on LMPs and capacity markets. Switching from coal and oil steam turbines to natural gas combined cycle plants was consistent with existing physical operations and market dynamics. In his phase 2, new entry is not based on market expectations but rather on long-term power purchase agreements (PPAs) because LMPs and the capacity markets are not providing an entry path for these resources. State-mandated RFPs were, nonetheless, a market mechanism. Like some ISO product markets, a state-directed mandate facilitates competition among suppliers while dictating to buyers the products they must to buy. But those RFPs isolate the state from the region, and therefore mark a departure from the decades-long regionalization trend.

Focusing on phase 3, Mr. Peskoe noted that regional carbon pricing was an unattractive option for States in Phase 2 in part because it did not facilitate the desired new entry, but it was worth reexamining whether a carbon price could play some role in phase 3. If carbon pricing was not politically viable, he suggested exploration of whether payments for reducing carbon emissions might be more attractive. According to Mr. Peskoe, if neither of these alternatives proved possible, a sub-optimal solution that uses the LMP framework was better than the alternative of more utility-mandates and inconsistent state CO_2 emission regulations. Mr. Peskoe suggested that the ultimate goal for the region should be based on regional coordination. Absent a regional alternative, states would continue with increasing utility mandates. If that happened, markets would need to adjust to be explicit about the role of state procurements. He noted that the region must also retain resources needed for reliability. The regional capacity construct as designed procures fungible megawatts, which is no longer sufficient to assure resource adequacy and reliability.

He questioned whether volatile energy prices that accompany high penetrations of low marginal cost resources could support the financing of new resources. He asked whether the ISO would oversee future financing mechanisms, or whether Market Participants and financial institutions would develop them without any new FERC-regulated products. He also wondered whether there would be a regional solution to long-duration storage. He noted that large additions of offshore wind would produce surplus renewable energy generation each spring and fall. He expressed uncertainty about whether financing was possible with such seasonal variations in LMPs.

Mr. Peskoe then returned to reviewing NEPOOL history, quoting the following passage from the 1972 Federal Power Commission (FPC) order approving NEPOOL's formation: "The participants to the Agreement have subordinated some of their own self-interest objectives in order to achieve a workable pooling arrangement for their own benefit and for the benefit of the whole geographical area involved." He followed with several questions: Would states be satisfied with a regional solution if a credible proposal is presented, or would they continue to insist on picking their resources? Could states subordinate some of their own self-interest? Pointing to RPS laws and RGGI, both of which are regional solutions that preceded current procurements, he concluded that there was reason to be optimistic. He observed that leadership in this space must come from those who plan to still be in the market in the future. He said that current opportunities to influence outcomes slip away as states continue passing additional procurement mandates. He acknowledged that politicians could pass laws that effectively dissolve the past 50 years of regionalization. He concluded by noting that New England had a unique cohesiveness that other markets lacked, and that might allow the region to overcome inertia and provide a path forward for a regional, low-carbon power system.

Travis Kavulla's Remarks

Mr. Travis Kavulla, Director of Energy and Environmental Policy at the R Street Institute and a former Chairman of the Montana Public Service Commission and former President of the National Association of Regulatory Utility Commissioners (NARUC), reminded the Committee that he last spoke in New England in March 2016. He predicted then that "vague and indirect environmental objectives" would likely drive state policymakers to continue a regime of long-term supply procurements, rather than rely on a marketplace that must have a clearly defined variable to solve for before it can work toward a cost-minimizing solution.

He then proceeded to review with the Committee a paper that he had circulated to the Committee. He reviewed numerous decisions by regulators across the country that appeared valid at the time but ultimately committed customers to support investments that proved later to be uneconomic. He explained that these examples all failed to require the businesses for whom these investments in generation were accretive to own the risk of the bets in which such planning resulted. He opined that competitive markets are more likely than government-mandated solutions to deliver economic resources, new technology and integrated, reliable solutions.

Mr. Kavulla agreed with Mr. Peskoe that power markets had solved for the public policy demands of affordability and reliability, but fell short where they adopted features resembling the paternalistic elements of regulation. He noted that regulations produce positive results when they provide risks and rewards to utilities for their investments, require competitive solicitations for PPAs, and rely on security-constrained economic dispatch to co-optimize the generation portfolio in the short run.

Mr. Kavulla also agreed with Mr. Peskoe that the power markets are not designed to and were not achieving environmental objectives. He said that power markets could advance environmental objectives by pricing carbon but that is not politically acceptable.

Mr. Kavulla summarized his views of outcomes of the politically driven solutions by the states. He opined that the current path, where legislators decree the construction of particular power projects by particular parties is even worse than "integrated resource planning."

Mr. Kavulla then posed a series of questions to the audience:

1. Was it possible to have the New England States agree, if not on a carbon price, then on some definition of the product that should be acquired to satisfy their clean energy standards?
2. Was there a way to ensure that those faced with a compliance obligation for this product have an economic incentive to engage in least-cost procurements?
3. Was there a way to avoid setting the duration of commitments in a way that allowed the markets to work toward continuing innovations and improvements in efficiency?

4. Was there a way to emphasize the basic framework of a market for electricity that had served us well, while also having a compatible feature to that market that hosts a trade in clean energy attributes?
5. Could the market incorporate sectors other than the power sector?

He concluded his remarks by referring to the history of prior decisions that proved uneconomic and led to the emergence of markets. He said that markets did not get everything right to begin with and there is clear potential in those markets for improvement from the status quo.

There being no further business, the meeting adjourned at 11:45 a.m.

Respectfully submitted,

David T. Doot, Secretary

ATTACHMENT 1

**PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
JUNE 25-27, 2019 SUMMER MEETING**

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
AR Small Load Response (LR) Group Member	AR-LR	Doug Hurley	Brad Swalwell (tel)	
AR Small Renewable Generation (RG) Group Member	AR-RG	Erik Abend (tel)		
American PowerNet Management	Supplier			Michael Macrae
Ashburnham Municipal Light Plant	Publicly Owned		Brian Thomson	Brian Forshaw
Associated Industries of Massachusetts	End User			Roger Borghesani
AVANGRID: CMP/UI	Transmission	Eric Stinneford	Alan Trotta	
Bath Iron Works Corporation	End User			Liz Delaney
Belmont Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Block Island Power Company	Supplier	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
BP Energy Company	Supplier			Nancy Chafetz
Braintree Electric Light Department	Publicly Owned			Dave Cavanaugh
Brookfield Energy Marketing	Supplier	Aleks Mitreski		
Calpine Energy Services, LP	Supplier	Brett Kruse	Rebecca Hunter	John Flumerfelt Bill Fowler
Chester Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned		Brian Thomson	Brian Forshaw
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield		
C.N. Brown Electricity, LLC	Supplier			William P. Short III
Covanta Energy Marketing, LLC	AR-RG		Sharon Abbott	
CPV Towantic, LLC	Generation	Daniel Pierpont		
Competitive Energy Services, LLC	Supplier			Glenn Poole
Concord Municipal Light Plant	Publicly Owned		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned	Brian Forshaw		
Connecticut Office of Consumer Counsel	End User			Dave Thompson
Conservation Law Foundation (CLF)	End User	David Ismay	Jerry Elmer	
Consolidated Edison Energy, Inc. (ConEd)	Supplier	Jeff Dannels		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned		Dave Cavanaugh	
Direct Energy Business, LLC	Supplier	Ron Carrier		Nancy Chafetz
Dominion Energy Generation Marketing, Inc.	Generation	Michael Purdie		
DTE Energy Trading, Inc.	Supplier			Nancy Chafetz
Durgin and Crowell Lumber Co., Inc.	End User			Liz Delaney
Dynegy Marketing and Trade, LLC	Supplier			Bill Fowler
Elektrisola, Inc.	End User		Gus Fromuth	
Emera Maine	Transmission	Lisa Martin		
Enel X North America, Inc.	AR-LR	Greg Geller	Herb Healy	
ENGIE Energy Marketing NA, Inc.	Generation	Sara Bresolin		
Entergy Nuclear Power Marketing, LLC	Generation	Ken Dell Orto		Bill Fowler
Environmental Defense Fund	End User	Liz Delaney		
Eversource Energy	Transmission	James Daly	Cal Bowie	Vandan Divatia
Exelon Generation Company	Supplier	Steve Kirk	Bill Fowler	
FirstLight Power Management, LLC	Generation	Tom Kaslow	Peter Rider	
Galt Power, Inc.	Supplier	Nancy Chafetz		
Generation Group Member	Generation	Dennis Duffy		Bob Stein Ron Coutu (tel)
Georgetown Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Great River Hydro	AR –RG	Shawn Keniston		Bill Fowler

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN JUNE 25-27, 2019 SUMMER MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Groton Electric Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Groveland Electric Light Department	Publicly Owned		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc.	Supplier	Louis Guilbault	Bob Stein	Ron Coutu (tel)
Hanover, NH (Town of)	End User			Liz Delaney
Harvard Dedicated Energy Limited	End User		Michael Macrae	Roger Borghesani
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Holyoke Gas & Electric Department	Publicly Owned		Brian Thomson	Brian Forshaw
Hull Municipal Lighting Plant	Publicly Owned		Brian Thomson	Brian Forshaw
Industrial Energy Consumer Group (IECG)	End User	Kevin Penders		
Ipswich Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Jericho Power, LLC	AR-RG	Mark Spencer		
King Forest Industries, Inc.	End User			Liz Delaney
Littleton (MA) Electric Light and Waster Department	Publicly Owned		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned		Craig Kieny	
Long Island Lighting Company (LIPA)	Supplier		William Killgoar	
Maine Power LLC	Supplier			Glenn Poole
Maine Public Advocate Office	End User		Barry Hobbins	
Maine Skiing, Inc.	End User	Kevin Penders		Liz Delaney
Mansfield Municipal Electric Department	Publicly Owned		Brian Thomson	Brian Forshaw
Maple Energy LLC	AR-LR	Angela Fox		
Marblehead Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Mass. Attorney General's Office	End User	Christina Belew		
Mass. Bay Transportation Authority	Publicly Owned		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company (MMWEC)	Publicly Owned	Brian Thomson		Brian Forshaw
Mercuria Energy America, Inc.	Supplier			Nancy Chafetz
Merrimac Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Michael Kuser	End User	Michael Kuser		
Middleborough Gas & Electric Department	Publicly Owned		Dave Cavanaugh	Brian Forshaw
Middleton Municipal Electric Department	Publicly Owned		Dave Cavanaugh	
The Moore Company	End User			Liz Delaney
National Grid	Transmission	Tim Brennan	Tim Martin	
Natural Resources Defense Council	End User	Bruce Ho		
Nautilus Power, LLC	Generation	Chris Sherman	Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned	Steve Kaminski		Brian Forshaw
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned		Dave Cavanaugh	
Novatus Energy (Blue Sky West, LLC)	AR-RG		Katie Bellezza	
NRG Power Marketing LLC	Generation		Pete Fuller	
Nylon Corporation of America	End User			Liz Delaney
Pascoag Utility District	Publicly Owned		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Peabody Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
PNE Energy Supply	Supplier			Gus Fromuth
PowerOptions, Inc.	End User	Cindy Arcate		
Princeton Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
JUNE 25-27, 2019 SUMMER MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Reading Municipal Light Department	Publicly Owned			
Rowley Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned		Brian Thomson	Brian Forshaw
Saint Anselm College	End User	Gus Fromuth		
Salem (Footprint Power Salem Harbor Development LP)	Generation			Nancy Chafetz Bob Stein
Shrewsbury Electric & Cable Operations	Publicly Owned		Brian Thomson	Brian Forshaw
South Hadley Electric Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Sterling Municipal Electric Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Stowe Electric Department	Publicly Owned		Dave Cavanaugh	
Sunrun Inc.	AR-DG	Chris Rauscher		
Taunton Municipal Lighting Plant	Publicly Owned		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned		Brian Thomson	Brian Forshaw
Texas Retail, LLC	Supplier		Alonzo Williams	
The Energy Consortium	End User	Roger Borghesani		Doug Hurley
Union of Concerned Scientists	End User	Michael Jacobs		
Vermont Electric Cooperative	Publicly Owned	Craig Kieny		
Vermont Electric Power Company	Transmission		Mark Sciarrotta	
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned			Brian Forshaw
Verso Energy Services LLC	Generation	Glenn Poole		
Village of Hyde Park (VT) Electric Department	Publicly Owned	Dave Cavanaugh		
Wakefield Municipal Gas & Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Wallingford DPU Electric Division	Publicly Owned		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned		Brian Thomson	Brian Forshaw
Westfield Gas & Electric Department	Publicly Owned		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	
Z-TECH, LLC	End User		Gus Fromuth	

VOTES TAKEN AT
JUNE 25-27, 2019 PARTICIPANTS COMMITTEE MEETING

TOTAL

Sector/Group	Vote 1	Vote 2
GENERATION	11.19	16.79
TRANSMISSION	16.79	0.00
SUPPLIER	13.59	11.55
ALTERNATIVE RESOURCES	16.04	9.44
PUBLICLY OWNED ENTITY	16.46	7.35
END USER	2.81	0.00
% IN FAVOR	**76.88**	**45.13**

GENERATION SECTOR

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

TRANSMISSION SECTOR

Participant Name	Vote 1	Vote 2
AVANGRID (CMP/UI)	F	O
Emera Maine	S[3]	S
Emera Maine	F	O
Emera Energy Services Subsidiaries	--	--
Eversource Energy	F	O
National Grid	F	O
Vermont Electric Power Co.	F	A
IN FAVOR (F)	4.5	0.0
OPPOSED (O)	0.0	3.5
TOTAL VOTES	4.5	3.5
ABSTENTIONS (A)	0.0	1.0

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote 1	Vote 2
Renewable Generation Sub-Sector		
Covanta Energy Marketing	A	F
Great River Hydro	F	F
Jericho Power	--	F
Wheelabrator North Andover	F	F
Small RG Group Member	A	O
Distributed Generation Sub-Sector		
Sunrun Inc.	F	F
Load Response Sub-Sector		
Enel X North America, Inc.	F	A
VT Energy Investment Corp.	F	A
Small LR Group Member	F	A
IN FAVOR (F)	6	5
OPPOSED (O)	0	1
TOTAL VOTES	6	6
ABSTENTIONS (A)	2	3

SUPPLIER SECTOR

Participant Name	Vote 1	Vote 2
American PowerNet Management	--	O
Block Island Power Company	F	O
BP Energy Company	F	F
Brookfield Energy Marketing Inc.	O	F
C.N. Brown Electricity, LLC	O	O
Calpine Energy Services, LP	F	F
Competitive Energy Services	F	F
Consolidated Edison Energy, Inc.	F	F
Cross-Sound Cable Company	F	A
Direct Energy Business, LLC	F	F
DTE Energy Trading, Inc.	F	A
Dynegy Marketing and Trade, LLC	F	F
Entergy Nuclear Power Marketing	F	A
Exelon Generation Company	O	F
Galt Power	F	F
H.Q. Energy Services (U.S.) Inc.	F	A
Long Island Power Authority (LIPA)	F	A
Maine Power, LLC	F	O
Mercuria Energy America, Inc.	F	A
PNE Energy Supply LLC	O	O
PSEG Energy Resources & Trade	F	F
Texas Retail, LLC	F	F
IN FAVOR (F)	17	11
OPPOSED (O)	4	5
TOTAL VOTES	21	16
ABSTENTIONS (A)	0	6

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[3] Pursuant to Section 6.2 of the NEPOOL Agreement, Participants and their Related Persons are for voting purposes together permitted to join only one Sector to which any of them is eligible to join, but are permitted to split the vote in that Sector as they see fit. Emera Maine and the Emera Energy Services Subsidiaries, as Related Persons, are collectively members of the Transmission Sector, but sometimes split their vote evenly between the companies' transmission (Emera Maine) and generation (Emera Energy) interests.

VOTES TAKEN AT
JUNE 25-27, 2019 PARTICIPANTS COMMITTEE MEETING

END USER SECTOR

Participant Name	Vote 1	Vote 2
Associated Industries of Mass.	F	A
Bath Iron Works Corporation	O	O
Conn. Office of Consumer Counsel	A	O
Conservation Law Foundation	O	O
Environmental Defense Fund	O	O
Hanover, NH (Town of)	O	O
Harvard Dedicated Energy Limited	O	O
High Liner Foods (USA) Inc.	O	O
Industrial Energy Consumer Group	A	A
King Forest Industries	O	O
Michael Kuser	A	A
Maine Public Advocate Office	--	O
Maine Skiing, Inc.	A	A
Mass. Attorney General's Office	O	O
Moore Company	O	O
Natural Res. Defense Council	O	O
PowerOptions, Inc.	F	O
The Energy Consortium	F	O
IN FAVOR (F)	3	0
OPPOSED (O)	15	19
TOTAL VOTES	18	19
ABSTENTIONS (A)	4	4

PUBLICLY OWNED ENTITY SECTOR

Participant Name	Vote 1	Vote 2
Ashburnham Municipal Light Plant	F	F
Belmont Municipal Light Dep't	F	O
Boylston Municipal Light Dep't	F	F
Braintree Electric Light Dept.	F	O
Chester Municipal Light Dep't	F	O
Chicopee Municipal Lighting Plant	F	F
Concord Municipal Light Plant	F	O
Conn. Mun. Electric Energy Coop.	F	O
Danvers Electric Division	F	O
Georgetown Municipal Light Dep't	F	O
Groton Electric Light Department	F	F
Groveland Electric Light Dep't	F	O
Hingham Municipal Lighting Plant	O	O
Holden Municipal Light Dep't	F	F
Holyoke Gas & Electric Dep't	F	F
Hull Municipal Lighting Plant	F	F
Ipswich Municipal Light Dep't	F	F
Littleton (MA) Electric Light Dep't	F	O
Littleton (NH) Water & Light Dep't	F	A

PUBLICLY OWNED ENTITY SECTOR (cont.)

Participant Name	Vote 1	Vote 2
Mansfield Municipal Electric Dep't	F	F
Marblehead Municipal Light Dep't	F	F
Mass. Bay Transportation Authority	F	O
Mass. Mun. Wholesale Electric Co.	F	F
Merrimac Municipal Light Dep't	F	O
Middleborough Gas & Elec. Dep't	F	O
Middleton Municipal Electric Dep't	F	O
New Hampshire Electric Coop.	F	O
North Attleborough Electric Dep't	F	O
Norwood Municipal Light Dep't	F	O
Pascoag Utility District	F	O
Paxton Municipal Light Dep't	F	F
Peabody Municipal Light Plant	F	F
Princeton Municipal Light Dep't	F	F
Reading Municipal Light Dept.	F	O
Rowley Municipal Lighting Plant	F	O
Russell Municipal Light Dep't	F	F
Shrewsbury's Elec. & Cable Ops.	F	F
South Hadley Electric Light Dep't	F	F
Sterling Mun. Elec. Light Dep't	F	F
Stowe (VT) Electric Department	F	O
Taunton Municipal Lighting Plant	F	O
Templeton Mun. Lighting Plant	F	F
Vermont Electric Cooperative	F	A
VT Public Power Supply Authority	F	O
Village of Hyde Park Electric Dep't	F	O
Wakefield Mun. Gas & Light Dep't	F	F
Wallingford, Town of	F	O
Wellesley Municipal Light Plant	F	O
West Boylston Mun. Lighting Plant	F	F
Westfield Gas & Elec. Light Dep't	F	O
IN FAVOR (F)	49	21
OPPOSED (O)	1	27
TOTAL VOTES	50	48
ABSTENTIONS (A)	0	2