FINAL

The 2018 Summer Meeting of the NEPOOL Participants Committee was held at The Water's Edge Resort, Westbrook, Connecticut, on Tuesday, June 26, and Wednesday, June 27, pursuant to notice duly given, followed on Thursday, June 28, by meetings between modified Sector groups and ISO Board Members, state regulators and officials, and FERC representatives, 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 26. Attachment 1 identifies the members, alternates and temporary alternates attending the meeting and voting that day.

Mr. Thomas Kaslow, Chair, presided and Mr. David Doot, Secretary, recorded for the meeting.

JUNE 26, 2018 SESSION

The June 26, 2018 session began at 9:30 a.m. with Mr. Kaslow offering welcoming remarks.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), reported that the ISO updated the "ISO To Go" software application based on feedback received over the past several years. He encouraged feedback on the updated application and suggestions for future upgrades. He then reported that the Board met earlier in June with VT Governor Scott, CT Governor Malloy and MA Governor Baker, and their staffs, at the request of Governor Scott who is the head of the Coalition of Northeastern Governors (CONEG). He said that the attendees discussed the CONEG task force on regional energy affordability and concerns with the economic competitiveness of the region. Each Governor provided his state's perspectives on electricity costs and actions that they are taking to address climate change and reliability. The Board discussed the current concerns with winter reliability and the potential retirement of fuel security resources and committed the ISO to continue working with the CONEG task force in its preparation for the annual conference in August of the New England Governors and Eastern Canadian Premiers.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), explained to members that the monthly report reflecting data for June operations would be finalized, circulated, and posted in early July. He reported that the Price Responsive Demand (PRD) project went live on June 1. He said that, of the approximately 325 MW of dispatchable Capacity Supply Obligations (CSO) in the market, the PRD offers in the first two and one-half weeks resulted in about 800 MWh of energy clearing Day-Ahead and about 500 MWh dispatched in Real-Time. He reported on the reasons for the negative energy clearing prices that were experienced between 4:00-6:00 a.m. on June 18. He explained that the ISO had expected a warm front to come into the region earlier in the afternoon than it did. As a result, there were almost 1,200 MW more resources committed Day-Ahead for the early morning than were needed in Real-Time. He said there were also substantially more self-schedules and renewable production in Real-Time than were reflected in the Day-Ahead Energy Market. All of these factors together resulted in energy clearing prices as low as negative $1.50 per KWh, with wind and hydro resources the marginal units during that time. Energy clearing prices did not turn positive until the load picked up later in the day.

Referring to a question from the June 1 Participants Committee meeting concerning Massachusetts emissions limits, he reported that there were about six million metric tons of remaining permitted emissions for all the units, with three million used during the winter. He explained that, at an aggregate level, the ISO was comfortable that there should be sufficient emissions allowances for the remainder of the year, but some units had less available allowances than others, so dispatch could be impacted later in the fall depending on how allowance trading evolved.

ISO CFO REPORT

Mr. Robert Ludlow, ISO Vice President, Chief Financial Officer (CFO) and Chief Compliance Officer, referred the Committee to the ISO 2019/20 preliminary operating and capital budget presentation included with the materials posted in advance of the meeting. He reported he had also shared this information with state officials at the 2018 New England Conference of Public Utilities Commissioners (NECPUC) Symposium. He discussed the following key components that were driving changes to the 2019/20 Budgets from 2018's budgets: no new headcount but a higher forecasted vacancy rate; increases for consulting and systems support for cyber security and compliance with North American Electric Reliability Corporation (NERC) critical infrastructure protection (CIP) standards, with the need to prepare a three-year cyber security plan to be presented to the ISO Board at its September meeting; an increase for Forward Capacity Market (FCM) work related to Net Cost of New Entry (CONE) and other FERC orders; additional funding for addressing concerns with fuel security; additional funding for load forecasting; increased costs for compensation/medical and defined contribution pension plans; increased costs to comply with new regulations, including increased NERC compliance costs and increased NERC and Northeast Power Coordinating Council (NPCC) fees; increased computer services and systems support costs; and reduced funding requirements to reflect efficiencies and other cost reductions. He summarized that the 2019 and 2020 Operating Budgets were projected overall to increase by about 3.5% each year, while the 2019 Capital Budget was projected to be the same as the 2018 Capital Budget.

Focusing on the budget review process, Mr. Ludlow reported that the ISO would review the 2019/20 Budgets with state officials again on August 9, and with NEPOOL again at the August 10 Budget & Finance Subcommittee meeting. The Budgets would then be submitted to the ISO Board's Audit & Finance Committee on August 16 with any feedback received. The ISO would then review feedback received with its full Board on September 13. The Participants Committee was scheduled to vote on the proposed budgets at its October meeting, and the final ISO Board vote would be taken following that Participants Committee meeting. The ISO planned to file the 2019 Budgets with the FERC later in October, with a requested effective date of January 1, 2019.

Members then asked questions on the report. In response to concerns with the ISO's ability to perform required tasks without increasing the head count, Mr. Ludlow explained that the ISO was planning to reassign existing resources to areas of need.

Mr. van Welie explained in response to a question that the Governors had not raised with him any issues with the ISO budget, but rather had focused on concerns with wholesale bulk power costs. In response to the Governors' questions, he had explained that costs for capacity were trending up while costs for energy were trending down, and the ISO could not confidently predict the future net effect. He further explained that transmission costs were increasing so, at least in the near-term, he did not expect all-in prices to be lower than they were in 2016/17. Given fuel security concerns during the winter, he did expect to see a near-term increase in wholesale power costs. Following up on questions concerning head count, Mr. van Welie noted that the ISO's vacancy rate was increasing because, with the strong job market, the ISO was losing people more quickly in the IT and engineering side of the business. He explained that the ISO was addressing that decreasing head count through an increased use of outside professionals.

ISO IMM ANNUAL REPORT

Dr. Jeffrey McDonald, the ISO's Internal Market Monitor (IMM), presented highlights from the IMM's 2017 Markets Report (IMM Annual Report), which had been circulated and posted in advance of the meeting. Summarizing, he noted wholesale electricity costs 20% higher than 2016, with the following contributing factors: FCA8 capacity market prices 93% higher than FCA7 prices; a 9% increase in energy market costs; a 19% increase in fuel costs for natural gas-fired resources, with much of that increase attributable to the very cold weather at the end of December;

and a 2% decrease in electricity demand. Explaining why a 19% increase in natural gas prices produced only a 9% increase in energy prices, Dr. McDonald noted that natural gas is generally on the margin but not 100% of the time, so that natural gas and energy prices do not always precisely track each other. He reported the energy, capacity and ancillary service markets all exhibited competitive outcomes in 2017, with an increase in system-level competitiveness for both the Forward Reserve Market (FRM) and the FCM. He then reviewed his new recommendation for enhancing Coordinated Transaction Scheduling (CTS) and adjusting rules for how multi-configuration generators are treated in the markets.

Responding to comments and questions, Dr. McDonald was uncertain of the reasons for discrepancies between structural market power observations by the IMM and the External Market Monitor (EMM), and committed to follow up with the EMM. He noted in response to a question that the IMM sees improved competitiveness in Greater Boston resulting from the Greater Boston Reliability Project and Footprint coming into service.

Focusing on mitigation, Dr. McDonald opined that it was the IMM's job to anticipate the potential for market power being unfairly exercised, even if the risk was remote or infrequent, and to design and implement mitigation measures to address those risks. He acknowledged the need to examine the system-wide energy mitigation threshold in order to ensure an outcome one would expect if all competitive offers were based on the applicable resources' variable costs.

Turning to the EMM recommendation for elimination of FRM, Dr. McDonald reported that the IMM had worked to estimate what a competitive offer would be for an FRM bid, and acknowledged that a cost basis for FRM bids was probably more complex than originally formulated. He identified the following two key drivers: (1) the likelihood of penalties for non- or under-performance; and (2) estimates of the opportunity costs for the delivery period for being a reserve resource instead of selling electricity. He acknowledged other motivating factors, but reported that the drivers identified produced a very wide range of offers that would be considered competitive, making adequate mitigation measures particularly challenging and leaving more attractive the alternative of getting rid of FRM in favor of procuring reserves in the Day-Ahead Energy Market. Mr. van Welie confirmed that ISO management had planned to replace FRM once Day-Ahead Energy Market reserves were implemented.

Proceeding to discussion, a member argued that price formation was being undermined by a number of factors that included lack of adequate buyer-side mitigation and the ISO's out-of-market posturing of resources. He urged the ISO instead to improve FRM price (through adequate buyer-side mitigation) and reduce out-of-market actions in the Day-Ahead Energy Market. Dr. McDonald agreed to review ways to improve Real-Time price signals. He observed that the IMM did monitor markets on a day-to-day and week-to-week basis, and followed up on any aspects that appear to be abnormal. Such follow up included a review of daily operator logs to better understand the types of challenges/issues facing operators.

Dr. McDonald was also asked for the IMM's position on the EMM recommendation for changes to allow generators to better reflect opportunity costs in their energy offers in times of increasing fuel supply scarcity. He reminded members that he observed this concern in the Winter Period Quarterly Report and that the ISO was working on an approach to estimate opportunity costs for fuel-limited resources in the winter. He acknowledged that he and the EMM had discussed this last winter but had not identified at that point a reasonable way to calculate those opportunity costs. He said the IMM planned to have something addressing this issue in place for winter 2018/19. He noted one particular challenge was that the ISO's software was programmed only to look ahead 24 hours, but economic opportunities stretch beyond 24 hours. He said that the Tariff currently allowed the IMM to include an opportunity cost adder in the reference prices for limited-fuel resources, but the IMM intended to review its proposed plan for capturing this change and to review that plan for comments by affected entities.

Transitioning to his report on fuel mix, he noted very little change from the prior year. He flagged that energy from wind resources was greater than the energy from oil and coal resources combined. Noting that Towantic and Footprint were to come on line in 2018, he projected that there would likely be relatively more energy produced by natural gas-fired resources in 2018 than in 2017. He clarified the percentage of gas could increase without a corresponding increase in the quantity of gas used for the electric sector. He agreed in future reports to include information on imports, exports and energy efficiency resources in his charts.

Reviewing the impact of energy efficiency on loads in 2017, Dr. McDonald reported that such resources were primarily the reason that load decreased by 2.4% overall. He explained that the ISO-measured loads did not reflect energy efficiency or behind-the-meter photovoltaic (BTM PV) resources. Thus, load was reconstituted to take those variables into account. He reported energy efficiency had the largest impact, reducing annual load by approximately 1,900 MWh, and BTM PV reduced annual load by approximately 200 MWh.

Referencing the chart of wholesale costs from 2013-2017, Dr. McDonald noted a 30% reduction in Net Commitment Period Compensation (NCPC) during 2017. He acknowledged that the charts were not supporting earlier ISO predictions that capacity prices must increase as energy market revenues decrease. Dr. McDonald agreed that structurally the predictions were appropriate. The underlying bid structure was designed so each generator should calculate its net revenues in Real-Time from actual operations during the delivery year, and submit a capacity offer price that covers the balance of its risk-adjusted going forward costs. As additional wind and solar resources come onto the system, they will reduce energy prices overall and capacity resources will be required to recover a growing share of the going-forward fixed costs. He said there were other things at play as well, noting that capacity oversupply would push prices down to the point that marginal resources retire.

There was discussion of whether the shrinking amounts of price-sensitive supply suggested the need for changes in the Market Rules. Dr. McDonald stated this would not be a concern unless the price-sensitive resources in the dispatch range fell below 20% of the energy offers, and the current New England fleet did not suggest concerns. Resources were offering in a way designed to establish their preserved schedule Day-Ahead, and to preserve that schedule in Real-Time. For some resources, negative energy prices did not persist long enough to change their preferred dispatch. A member requested that the IMM look at the depth and duration of oversupply, noting concern that uneconomic transactions could result during periods of very low oversupply. Dr. McDonald committed to include focus on this issue in the IMM's 2018 report.

Dr. McDonald finished his presentation referencing the reduction in uplift from $73 million in 2016 to $52 million in 2017. He said this reduction was principally because the Greater Boston Transmission Upgrade increased import capability into Boston, which reduced the amount of resources needed to be committed out-of-merit order for local reliability purposes, and due to the implementation of fast-start pricing, which allowed fast-start resources to be made whole with Real-Time prices rather than requiring additional out-of-market compensation. He calculated fast-start pricing to have increased Real-Time prices by about $2.70/MWh on average, which he said agreed with the EMM study on the topic. Dr. McDonald was not able to provide a breakdown between the uplift reduction resulting from the transmission upgrades versus the fast-start pricing. He said a rough approximation could be made by looking at the reduction in unit commitments that has resulted from the Boston Upgrade and the estimated price impact from the IMM's analysis of how over-commitments of multi-stage generators could impact market outcomes (which was provided in the IMM's Fall 2017 Quarterly Report).

APPROVAL OF JUNE 1, 2018 MEETING MINUTES

Mr. Doot referred the Committee to the preliminary minutes of the June 1, 2018 teleconference meeting that had been circulated in advance of the meeting. Following motion duly made and seconded, those preliminary minutes were unanimously approved without change.

CONSENT AGENDA

Mr. Kaslow referred the Committee to the Consent Agenda that was circulated in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved, with abstentions noting objections to Consent Agenda Item 1 (Revisions to Tariff and Market Rule 1 -- Zonal Demand Curves: FCM Cost Allocation project) by Cross- Sound Cable and the following members of the Publicly Owned Entity Sector: Belmont Municipal Light Department, Braintree Electric Light Department, Concord Municipal Light Department, Danvers Electric Division, Energy New England, Georgetown Municipal Light Department, Groveland Municipal Light Department, Hingham Municipal Light Department, Jericho, Littleton Electric Light and Water, MMWEC and all the Participants it represented, Merrimac Municipal Light Department, Middleton Municipal Department, Pascoag Utility District, Rowley Municipal Lighting Plant, and Taunton Municipal Lighting Plant.

ISO FINANCIAL ASSURANCE POLICY CONFORMING CHANGES

Mr. Ken Dell Orto, Budget & Finance Subcommittee Chair, referred the Committee to the materials circulated in advance of the meeting concerning conforming changes to the ISO Financial Assurance Policy (FAP) reflecting the changes to the ISO Tariff just approved by the Committee by way of the Consent Agenda (Item 1). He explained that the changes to the definition of "Estimated Capacity Load Obligation" impacted the calculation of FCM Capacity Charge in Section VII.C of the FAP (which was based on the product of the Estimated Capacity Load Obligation and the FCM Capacity Charge), requiring conforming FAP changes. The B&F Subcommittee reviewed the conforming changes at its May 10, 2018 teleconference with no objection raised. Mr. Dell Orto noted further that, consistent with the implementation schedule incorporated into the Market Rule 1 changes, the ISO would request that the changes to the FAP also reflect a delay in the implementation date until June 1, 2022, a delay identified only after the B&F Subcommittee discussion.

The following motion was then duly made, seconded, and unanimously approved:

> RESOLVED, that the Participants Committee supports the conforming changes to the ISO Financial Assurance Policy, as circulated to the Committee and discussed at this meeting, together with such further non-substantive changes as the Chief Financial Officer of ISO New England and the Chairman of the Budget & Finance Subcommittee may approve.

PARTICIPANT-SPONSORED WINTER RELIABILITY PROGRAM PROPOSAL

Mr. Alex Kuznecow, Markets Committee Chair, referred the Committee to the materials circulated in advance of the meeting concerning Participant-proposed revisions to Market Rule 1, Appendix K to re-establish a winter reliability program for future winter periods, beginning with the 2018/19 winter period. He explained that the proposed program would be similar to that in effect for the last three winters and was sponsored and advocated by Energy New England (ENE). He reported that the Markets Committee vote on whether to recommend the revisions to the Participants Committee failed. He said that, since the Markets Committee vote, sponsors proposed to provide that the changes only remain in effect for the next three winters.

The ENE representative then summarized the proposal. He explained that conforming changes to Appendix K were proposed to the prior winter program to reflect the full integration of PRD. He said that Publicly Owned Entities represented by ENE retain the obligations locally to serve their constituents reliably at reasonable costs. ENE was concerned that reliability would be compromised without a winter reliability program in effect in part because of concern that new pay-for-performance (PFP) provisions in effect for the next three winters would not provide adequate incentive for maintaining fuel inventories. A short continuation of a winter program, he suggested, was a small price to pay for some added insurance for reliability.

The following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports revisions to Market Rule 1, Appendix K, as proposed by Energy New England and circulated to this Committee in advance of this meeting, together with such non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

Members then commented on the proposal. Repeating concerns voiced at the Markets Committee, some members opposed the program because they argued it was discriminatory, targeting only select resources. An argument was made that it contributed to incorrect price formation in the Energy Market. Another member expressed opposition because it failed adequately to value resources that have storage that can contribute to winter reliability. Opposers urged that the region give PFP a chance to work. The NESCOE representative reported that the New England States were unanimous in their opposition to the motion and supported the ISO's proposal to give PFP a chance. Members speaking in support of the proposal emphasized that the program was a reasonably low cost insurance policy to increase reliability.

Following further discussion, the Committee considered and voted on the motion. The motion failed to pass with a 50.37% Vote in favor (Generation Sector – 11.4%; Transmission Sector – 0%; Supplier Sector – 7.04%; Alternative Resources Sector – 11.41%; Publicly Owned Entity Sector – 8.55%; End User Sector – 11.97%; and Provisional Member Group Seat - 0%). See "ENE Winter Rel. Prgm." vote on Attachment 2.

PARTICIPATION BY PRESS IN NEPOOL MEETINGS

Mr. Kaslow indicated to the Committee that he had actively participated in this matter and wished to advocate, so asked that the Secretary chair this portion of the meeting. In the absence of the Chair of the Membership Subcommittee, Mr. Doot asked Mr. Gerity to present the matter for discussion. He explained ahead of Mr. Gerity's presentation that background materials had been circulated confidentially, respecting that they reflected preliminary discussions with and from NEPOOL counsel on positions NEPOOL might take in response to potential litigation. There was no request to cover the discussion of this matter in executive session.

Mr. Gerity referred the Committee to the confidential materials and summarized the history of the deliberations of the Membership Subcommittee since the earlier guidance provided by the Participants Committee. He explained that the package of changes proposed by the Subcommittee was intended to capture the Committee's earlier guidance. He noted some streamlining of the drafting in ways that were not material but removed repetition. He identified the fact that there were three set of changes for Committee review: amendments to the Second Restated NEPOOL Agreement (2d RNA); changes to the Participants Committee and Technical Committee Bylaws; and revisions to the Standard Membership Conditions, Waivers and Reminders (SCWRs) whose acceptance is a condition to NEPOOL membership for all applicants. He explained that the 2d RNA changes, which would be submitted to the FERC for review, would define Press and make clear that Press could not become a Participant or representative of any Participant. He explained that the Bylaws additions included, in addition to provisions reflecting the 2d RNA changes, a new provision addressing the principles, protocols, and revocation of privileges of attendance. The SCWRs were updated to reflect for new members the long-recognized understandings about reporting on NEPOOL meetings and the consequences for violating those understandings. He then finished his introduction by explaining that the Participants Committee was likely to be asked to consider a proposal that differed from the earlier guidance by the Participants Committee, which was referred to it the confidential materials as the Dissenting Proposal. He said the Dissenting Proposal, if offered, would be explained and voted in the form of a motion to amend the main motion at the appropriate time.

The following motion was then duly made and seconded:

> RESOLVED that the Participants Committee (i) 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 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; (ii) approves the changes to the Standard Membership Conditions, Waivers and Reminders as circulated to this Committee in advance of this meeting; (iii) approves the changes to the Participants Committee Bylaws as circulated to this Committee in advance of this meeting; and (iv) approves the changes to the Technical Committee Bylaws as circulated to this Committee in advance of this meeting, each together with such non-material changes as the Participants Committee Chair and Vice-Chairs may approve.

The Committee then began discussions with clarifying questions on the proposal. In response to questions about the definition of Press in the proposed amendments to the Restated NEPOOL Agreement, Mr. Gerity explained that the definition was worded to permit participation by press organizations so long as the representatives were not individuals with those responsibilities covered in the definition. He referenced the previous participation as a member of the New Hampshire Union Leader as an example of a press organization that participated through a third-party representative to represent its electric consumer interests.

Following further discussion, the acting Chair invited proponents of the Dissenting Proposal to offer that proposal and a motion to amend if they wished. Responding, proponents of the Dissenting Proposal referred to the circulated materials and described their proposal to create a new non-voting class of membership for Press with a $5,000 application fee and $5,000 annual fee. They explained that any such members would be excluded from executive sessions of NEPOOL meetings and from the semi-annual Sector meetings with the ISO Board, would be subject to a code of conduct governing their publications, and would be permitted to photograph meetings but not record them. They then duly made a motion to amend the main motion to reflect the Dissenting Proposal, which was seconded.

The Committee then discussed the two proposals. Beginning with the discussion of the Dissenting Proposal, proponents argued that the treatment of Press under their proposal was similar to how press was treated in other RTOs. They expressed concern that litigation over this matter could be distracting and costly with unpredictable results. They asserted that they would not behave any differently with press in the room, and those who would might best modify their behavior so that it was suitable for public view. They argued that the press should have the opportunity to report on what is happening in NEPOOL meetings and that, in their view, the Dissenting Proposal would impose conditions on membership that should minimize or reduce concerns that had been raised during prior discussions. Consumer advocates noted their support for the Dissenting Proposal and commended the proponents for their efforts to identify an alternative to the approach proposed by the main motion.

Proponents of the main motion explained their reasons for not supporting a change to the long-standing understanding that discussions in NEPOOL meetings are considered preliminary and are not for public attribution, either to members or the entities they represent, and the related policy concerning press attendance at NEPOOL meetings. Some explained that they would not behave the same with Press in the room, whether or not the conditions outlined in the Dissenting Proposal were in effect and approved as enforceable. Some referred to experiences here and elsewhere addressing Press coverage of comments they had made outside of NEPOOL meetings, and described those experiences as very time-consuming and difficult in ensuring accurate reporting. They explained their concerns that the obligation of enforcing any code of conduct imposed on Press could reduce the willingness of members to serve as officers, and the distractions any violations would impose on NEPOOL. They expressed the view that NEPOOL business meetings have been successful over time because they establish a setting that is designed to support collaborative negotiations and problem solving. They expressed concern that changing the dynamic so that anything they say could be reported in the press would drive them to conduct their negotiations outside of the meetings, and they feared from what they have seen and heard that others would do the same. In their view, that would reduce the chances for others to hear concerns and proposals, and to test those concerns and proposals together. The result, they argued, would be that NEPOOL meetings would be far less helpful, meaningful or productive in understanding and resolving or narrowing issues.

Following further discussion, the motion to amend to adopt the Dissenting Proposal was then voted and failed with a 27.29% Vote in favor (Generation Sector – 2.44%; Transmission Sector – 0%; Supplier Sector – 5.34%; Alternative Resources Sector – 6.31%; Publicly Owned Entity Sector – 0%; End User Sector – 12.98%; and Provisional Member Group Seat – 0.22%). See “Press Dissntg. Proposal” vote on Attachment 2

The unamended main motion was then voted and passed with a 79.23% Vote in favor (Generation Sector – 17.1%; Transmission Sector – 17.1%; Supplier Sector – 13.44%; Alternative Resources Sector – 12.15%; Publicly Owned Entity Sector – 17.1%; End User Sector – 2.33%; and Provisional Member Group Seat - 0%). See “Press Provs.” vote on Attachment 2.

Mr. Doot explained that the 2d RNA changes would be balloted and urged members to return their ballots promptly. He said that, if the 2d RNA amendments were approved in balloting, NEPOOL counsel expected to submit the amendments to the Commission late in July.

REMARKS BY FERC COMMISSIONER RICHARD GLICK

Mr. Kaslow welcomed and introduced the Honorable Richard Glick, Commissioner of the FERC. After thanking the Committee for the invitation, Commissioner Glick noted that he began his tenure as a FERC Commissioner about 6 months earlier. Since that time, he had appreciated the opportunities to meet with stakeholders from New England and across the nation to hear and better understand perspectives, without violating the FERC’s *ex parte* rules, on what the FERC should or should not be doing.

Commissioner Glick talked about the FERC's focus on grid resilience, noting that almost all FERC orders since he began referenced it. He even observed that a resilience panel was added to the FERC's three-day technical conference on increasing Real-Time and Day-Ahead Market efficiency and enhancing resilience through software taking place that same day. He summarized the history leading up to the FERC's order on resilience. He noted the reference by the Department of Energy (DOE) to its authorities under Section 202(c) of the Federal Power Act (FPA) and the Defense Production Act. He said that he had prior experience with both statutes during the Western energy crisis, when the DOE issued a number of orders under Section 202(c) that required energy to be sold into California. He reported that all five Commissioners testified at a recent hearing before the Senate Committee on Energy and Natural Resources, and when asked by members of that Senate Committee, none of the Commissioners agreed that resilience presented an emergency at that time. He said that Chairman McIntyre recently announced the resilience proceeding would continue no matter what the DOE did, and the FERC would review comments that it had received.

He also expressed the view that some comments from other regions of the country seemed primarily driven by certain parties' frustrations that they had been unable to achieve certain results through the various RTO stakeholder processes, and sought instead to propose solutions directly to the FERC through the resilience docket. He said circumstances were evolving, and the FERC needed to review how competitive markets were compensating electric generators in the energy and capacity markets, whether other services were needed, how to provide greater flexibility in some of the regions and to compensate for that flexibility, and whether there may be a need for a new market outside the current energy, capacity and ancillary service markets.

Commissioner Glick acknowledged New England's focus on natural gas pipeline capacity constraints and the need to utilize existing pipeline capacity more effectively and efficiently. He referenced the FERC's on-going gas/electric coordination efforts, noting that reforms so far had been limited to changes on which the gas pipelines and electric generators had agreed. Other potential solutions for New England might include the following, which he acknowledged could be a partial list: a change in the rules for the inclusion of natural gas prices in electric bids; expansion of electric transmission capacity to import power from other regions; adoption of new technologies; use of off-shore wind; expansion of gas storage; and adjustment of capacity performance expectations and related revenues. He urged interested parties and the Committee to provide feedback to the FERC on how best to proceed.

The Commissioner then opened the floor for questions. Chair Angie O'Connor, MA Department of Public Utilities, thanked Commissioner Glick for his remarks on gas pipelines and the encouragement of a more aggressive approach on gas/electric coordination. She noted that, nationally, NARUC is beginning Joint Electric & Gas Committee meetings and would have a panel discussion on the topic at a July NARUC Conference. Commissioner Glick was asked whether anything could be done at the federal level to help in the financing of natural gas pipeline expansions through New York and into New England. He discussed the limited jurisdiction FERC has over state decisions on such matters but expressed the view that new laws might be needed for the FERC to be able to do more. He noted that there was some interest in the Senate Energy Committee and the House Energy & Commerce Committee on the topic.

He was then asked about how the FERC might react to a range of solutions to address changing state laws to reduce emissions. He expressed his view that the FERC had more latitude to accept proposals from the RTOs where there was some kind of consensus, such as in New York, a single state market considering a carbon pricing proposal in its wholesale energy market. He reported that the FERC was facing requests to respond with market changes to state policies that were adversely affecting markets, with those state policies aimed at dealing with externalities that the markets do not address, such as climate change. He expressed the view that the FERC should allow states to pursue policies to address externalities, the authority over which he explained the FPA leaves to the states. He said that, while a carbon pricing mechanism in a region or RTO may not completely solve the problem, as states would continue to pursue other policies for other reasons, applying a price on carbon in the markets could address some of the larger concerns that people had been raising. He acknowledged that, in New England, there were different states and governors with quite different views on environmental issues, climate change and renewable energy, so he was focused in the shorter-term on New York's efforts.

Commissioner Glick went on to encourage the region to address fuel security concerns that must be addressed absent additional pipeline capacity. He explained that the FERC Chairman sets the schedule for discussing such issues. He was not aware of any further scheduled technical conferences to address the issue. However, he stated that the FERC could most likely include cost recovery in any future actions addressing resilience.

LITIGATION REPORT

Mr. Doot referred the Committee to the Litigation Report circulated and posted in advance of the meeting. He highlighted the numerous pleadings relating to the Mystic situation and flagged for the group the Footprint Power show cause order. He requested 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 on August 10 to review the ISO's proposed 2019 Operating and Capital Budgets and NESCOE's proposed 2019 Annual Budget.

Reliability Committee. Mr. Robert Stein reported that the Reliability Committee met on June 20 to begin reviewing fuel security, the problem definition and plans for Chapter 3. He noted that a Joint RC/MC meeting was scheduled for July 31 on the same topics. Ms. Mariah Winkler reported that the Joint RC/TC Summer Meeting was scheduled for August 7-8 at the OceanEdge Resort in Brewster, MA. She also reported the ISO circulated a memorandum addressing fuel security Chapter 2 that outlined the proposed stakeholder process ending with NEPOOL votes in September.

Markets Committee. Mr. Kuznecow reported that the Markets Committee Summer Meeting was to take place July 17-19 at the Stowe Mountain Resort in Stowe, VT, with key items including the discussion of fuel security Chapter 2 and voting on enhanced electric storage participation in the New England Markets.

Transmission Committee. Mr. José Rotger reported that the Transmission Committee was scheduled to meet on July 24 in Westborough, MA, immediately following a special Participants Committee meeting to vote on Dynamic De-List Bid Rationing. He stated key items on the agenda for the July 24 TC meeting include continued discussion of the interconnection reforms to comply with Order 845 (generator interconnection reforms) and discussion of blackstart provisions.

NEW ENGLAND ENERGY LEGISLATION SUMMARY

Mr. Harold Blinderman, NEPOOL counsel, referred the Committee to the 2018 New England Energy Legislation Summary circulated at the meeting. He stated that the Summary was current through June 19, noting there had been continuing developments in some of the states. He reported, in particular, that NH Governor Sununu vetoed NH SB365 regarding renewable generation and SB446 regarding net metering. He said RI adjourned its legislative session the prior evening and NEPOOL counsel was sorting through bills that were passed over the previous 24 hours. NEPOOL counsel planned to update the Summary to reflect the NH and RI developments to date and any additional developments in MA and NH as they conclude their sessions. He said NEPOOL counsel would post updates to the Legislation Summary as appropriate.

OTHER BUSINESS

Mr. Kaslow advised the Committee that the next Participants Committee meeting, scheduled to be held August 3 in Boston, would likely be re-scheduled as a teleconference meeting or cancelled given the relatively few items expected to be ready for Participants Committee consideration at that time. He urged Participants to pay close attention to notices for that meeting.

ISO EMM REPORT

Dr. David Patton, Ph.D., President, Potomac Economics, the ISO's EMM, presented highlights from the EMM's 2017 Markets Report (EMM Annual Report), which had been circulated and posted in advance of the meeting. He reported that the New England markets performed competitively in 2017. He noted the fuel security issue in New England.

Dr. Patton highlighted concerns with resilience, most notably that it was not well defined. He stated the biggest challenges to reliability had been with transmission and distribution, with much work having already been completed to improve reliability. He expressed his view that resilience was not related to the energy and ancillary service markets and generation. With PFP, New England implemented something that comes closer to an energy-only market. The contingencies that need to be addressed would all translate into huge energy settlements, so Market Participants should be provided strong incentive to anticipate resilience contingencies and make investment decisions based on the expected value of those occurrences. That theory would not work, though, for very low probability, high impact events. He opined that the best means of addressing those circumstances was the adoption of some form of planning standard for resilience. For shorter term and repetitive challenges, such as those resulting from high penetration of intermittent resources, energy and ancillary service markets work well to motivate flexibility and controllability. He expressed his view that New England did not need a ramping product or flexibility product. Rather, it needed good energy pricing that motivates people to ramp, to perform well, and to build resources that are highly controllable and can start quickly. He highlighted the success of New England's just-implemented fast-start pricing mechanism.

In summarizing 2017 market outcomes in New England, Dr. Patton reported that, as in other regions, natural gas prices were up (19%), load was down (2%), peak load was down (7%), energy prices were up (12-17% depending on location), and NCPC was down (29% because of some improvements made over time which resulted in lower uplift, including fast-start pricing). He reviewed a chart of New England FCM prices over the past six years.

He then referred to a chart reflecting market power mitigation in New England, summarizing that mitigation had been very effective at addressing concerns with structural market power issues. He said that conduct had been very competitive so there had been very little mitigation, primarily because there had been so little congestion and local market power in New England. He said the largest source of mitigation had been for resources called out of merit for local reliability, which he explained impacted the magnitude of uplift payments rather than clearing prices. He committed in response to a question to review the mitigation that occurs for Retirement De-List Bids, Permanent De-List Bids and Static De-List Bids.

He explained that his recommendations focused on those areas in which the markets were not supporting how the ISO operates the system, which resulted in operator actions that produce uplift and depress prices. He was seeking solutions in which the markets provide operators the resources they need to maintain reliability and produce applicable clearing prices that reflect shortage pricing. He referenced the fast-start pricing mechanism as a mechanism that calls on fast-start resources when they are needed with the resulting prices reflecting shortage prices and avoiding the price-depressing effects of an emergency action taken by the operator.

Dr. Patton committed in response to a question to work to provide some data concerning how De-List Bids are mitigated. He noted his expectation that the capacity market would be less competitive than other markets because capacity was being procured against the peak need. For that reason, potential market power concerns in the capacity market were greater than in the energy market, driving the need for mitigation in the capacity market. He acknowledged that mitigation was getting more difficult under PFP because of the potential impact of revenues and risks associated with future performance based on the actual energy and reserves provided in Real-Time during scarcity conditions.

Dr. Patton then proceeded to discuss NCPC uplift. He noted that New England had almost three times more uplift per MWh of load than MISO and just under twice as much as NYISO. He said that fast-start pricing and other market improvements implemented in 2017 were reducing NCPC, but the region needed to continue work on improving energy pricing so that the marginal units on the system increasingly set Real-Time prices. Providing more detail on NCPC in 2017, he referred the Committee to a chart in his presentation of the proportionate contributors. He highlighted the following:

- 42% of Day-Ahead NCPC was for second contingency protection in local areas. On this he said that 77% of those Day-Ahead commitments for Boston and would not have been needed if energy and reserves were co-optimized in the Day-Ahead Energy Market.

- 37% was for the system-level 10-Minute Spinning Reserve requirement. He said that this occurred in 4,900 hours of the year and estimated that such commitments reduced Day-Ahead Energy Market prices by an average of $0.82/MWh.

He opined that improving the Day-Ahead Energy Market and adding a Day-Ahead ancillary service market would better match Real-Time pricing with market operations. A Day-Ahead reserve market would also provide better information to the operators about fuel availability for the next day.

Dr. Patton then talked about the EMM's recommendation to change the allocation of uplift costs to virtual trades. He noted that better allocation of uplift to Real-Time deviations, similar to MISO's allocation methods, would improve liquidity in the virtual trading market, which was very important to well-functioning markets. He said that the reduction in NCPC in the Day-Ahead Energy Market from fast-start pricing had a very positive impact on the virtual traders. He referenced comments to the FERC suggesting that the ISO favors eliminating the allocation of costs to Real-Time deviations. He said that would be much better than *status quo* but is not the best solution. He encouraged changes to increase virtual trading in the region, which he noted currently was undertaken primarily to arbitrage congestion, which was low in New England. He suggested that members review the EMM's detailed evaluation of virtual trading in MISO, which was in the 2017 MISO State of the Market Report.

He explained in response to a question the potential for operator action in the Real-Time market to impact virtual trading. He explained that a mismatch between Day-Ahead and Real-Time prices might be arbitraged if predictable, but operator actions make Real-Time prices less predictable. As a result, virtual trading over time will be far less effective in better matching the Day-Ahead commitments to Real-Time operations.

He then reviewed external interface scheduling, reporting that New England and New York have the best CTS system in the country. He estimated that CTS produced about $5 million of production cost savings for New England in 2017. He applauded New England and New York for not imposing charges on CTS transactions. He opined that further improvement would depend on reducing forecast errors, and he referred to a chart of contributing factors that lead to forecast errors. He explained the difference between CTS and RTO tie optimization, which he estimated could have saved an additional $400,000 for the region given the current forecast errors.

In response to questions, he noted his view that the RTOs/ISOs might marginally improve co-optimization at the border if they included predictive safety factors. He talked about the impact carbon pricing in New York might have on this topic. He did not think carbon pricing would have a big impact. If done correctly, New York could address leakage at the borders to ensure prices are comparable factoring in carbon intensity.

Dr. Patton then focused on market operations during the extreme cold weather from December 28, 2017 through January 8, 2018. He estimated that oil production was 48% lower than what economic dispatch would predict, primarily because of concerns with fuel inventory limitations and forced outages and de-ratings. The EMM expressed concerns with the ISO's ability to manage fuel inventory and opined that, operator action, such as posturing resources, may have made the problem worse, not better. He explained his view that Market Participants must be able to reflect opportunity costs in their offers. He referenced a figure in his Annual Report that, in his opinion, showed that reduced production attributed to fuel limitations because of the offers submitted by the owners of oil resources. He noted that several gas-fired generators purchased more gas during this cold period in anticipation of higher LMPs, but that their market expectations were not realized, due in part to operator actions taken to preserve oil inventories. He opined that scheduled 30-Minute Reserves greatly exceeded requirements, with clearing prices at $0/MWh throughout the period. Had the ISO actually procured reserves consistent with its fuel limitation concerns, he estimated over 400 MW of additional reserves to assure adequate levels. He urged all to consider in the fuel security discussion how to assure that Energy and Operating Reserve Markets fully reflect actual operating limits of available resources on the system. Continuing discussion of fuel security improvements, he said in response to questions that co-optimization of Energy and Reserves in the Day-Ahead Energy Market is in his view a medium to high priority issue. He said that it was a good time for New England to address the matter because the region was collaborating with GE, PJM and MISO on revamping the market software.

Dr. Chadalavada clarified some of Dr. Patton's observations. He noted that the average commitment of 400 MW for posturing was only during the last three days of the cold weather and not the first nine days. He noted the ISO's earlier report that they were posturing units only after inventory levels had been drawn to an average of 19% across the oil tanks. He reported that later in the year, the ISO planned to submit its proposal for addressing Day-Ahead Reserves, including co-optimization. Dr. Patton acknowledged in response to questions that the Energy Market needed to better reflect the opportunity costs of fuel limitation, which could be accomplished in the Day-Ahead Energy Market, but that it would be very challenging to allow that while ensuring prices were mitigated, if and as needed, to avoid market power issues.

Dr. Patton went on to discuss the EMM's consideration of fuel security concerns that he agreed would become more pronounced as non-gas resources serving New England continued to retire. He noted that determination in a Baseline Scenario that more than two-thirds of all potential liquefied natural gas (LNG) and oil storage capacity would be needed if Distrigas retired. In the Pipeline Contingency Scenario, he projected that, in 2023/24, the market would be slightly short with Distrigas, and short by almost 2,500 MW without Distrigas. The EMM recommended evaluating the need to augment PFP to ensure fuel security under severe winter conditions.

Dr. Patton then talked about the region's handling of new resources whose commercial operation date had been delayed. Overall, he opined that there needed to be stronger consequences on resources whose start-up dates were delayed, such that they bear any additional system costs associated with that delay. He explained that this issue might be addressed if there was a buy-out of the late resource's CSO. He acknowledged that stronger penalties could create additional risk and increase the leverage of those seeking to stop or delay the resources. He encouraged the ISO to reconsider the potential benefits of a prompt market relative to the current FCM, which he thought better addressed the problems. He concluded his presentation by responding to a number of questions on the EMM's recommendations.

There being no other business, the June 26, 2018 session ended at 5:00 p.m., with the Summer Meeting to reconvene on Wednesday, June 27, 2018 at 8:30 a.m.

JUNE 27, 2018 SESSION

The Summer Meeting reconvened at 8:30 a.m. on June 27, 2018.

OPENING AND WELCOMING REMARKS

After welcoming members and guests, Mr. Kaslow introduced NECPUC Vice President Katie Scharf Dykes, who also is Chair of the Connecticut Public Utility Regulatory Authority (CT PURA). Chair Dykes thanked NEPOOL for the invitation to participate and welcomed everyone to Connecticut. She told the group that the States find the discussions with stakeholders very helpful and welcomed the opportunity for continued constructive dialogue.

FERC REGIONAL UPDATE

Mr. Kaslow welcomed, introduced and thanked FERC Staff for their attendance and participation. Mr. Deepak Ramlatchan, Office of Energy Market Regulation (OEMR), Senior Policy Advisor, then provided remarks. He began by making clear that anything that was said by him or other FERC Staff were the views and opinions of those making the remarks, not those of the Commission.

Mr. Ramlatchan said he and his colleagues were looking forward to meeting with the Sectors the next day. He summarized the FERC's initiative on grid resilience, referencing the initial proposed rule from the DOE that would have required RTOs/ISOs to purchase energy from "reliability and resilience resources" under terms that would ensure recovery of costs and return on equity for those resources. He went on to summarize the January 2018 order by the FERC rejecting that proposed rule and initiating the Grid Resilience Docket (AD18-7), which was supported by all five Commissioners. He explained that the FERC intended to review resilience holistically, and had set forth three basic goals for the proceeding: (1) to reach a common understanding on the definition of "resilience"; (2) to identify how the RTOs and transmission planners should assess resilience; and (3) to define potential action that the FERC could take to help ensure resilience of the grid.

After reviewing a proposed definition of resilience as offered in the FERC's January 28 order, Mr. Ramlatchan reported that, to date, over 200 entities had filed comments in the proceeding, with many different proposed definitions of resilience. He said Staff was working through those comments, and planned to suggest a definition that the Commission could adopt that was not overly restrictive, and that would potentially take into account regional differences.

On the second objective, Mr. Ramlatchan referenced the order's questions about anticipating and addressing, as appropriate, high impact and low frequency events. He explained that the Commission was seeking an understanding of how regions assess risks, what policies and procedures were in place that advance resilience, what obstacles might interfere with assurance of resilience, and what current market mechanisms were available to advance resilience. He noted the order suggested resilience was a broad concept and may well encompass fuel security. In working to understand and assess resilience, the FERC would review transmission planning, reliability standards, wholesale electric market rules, and action plan development in general. He explained the challenge in differentiating between resilience and reliability.

Focusing next on process, Mr. Ramlatchan reported that, based on the information provided, FERC Staff was preparing a memorandum that would explore options as they relate to resilience that the Commission could potentially use in defining future action, if any. He reported in response to questions that NERC has been participating in the proceeding, and had provided helpful comments reflecting that organization's expertise and focus on reliability and related standards.

Ms. Christy Walsh, Director, Office of Energy Policy and Innovation (OEPI), Division of Policy Development also provided remarks, beginning with a reminder to members of Staff's *ex* *parte* limitations. She highlighted Dr. Patton's observations in his annual report about how gas infrastructure limits might also be addressed by expanded transmission into the region, and noted that the FERC was actively exploring transmission issues. She also talked about the FERC's focus on Distributed Energy Resources (DER) issues, referencing the DER aggregation notice of proposed rulemaking issued in November 2016, and the FERC's final energy storage rule (Order 841). She summarized the FERC's favorable emphasis in Order 841 on DER aggregations. She referred to the FERC's two-day technical conference on DER issues, highlighting the discussion about communication and coordination among DER aggregators, the ISO/RTO and the distribution utility. She reported on the additional questions asked by the FERC following the technical conference, with many comments filed before the just-passed deadline.

Ms. Becky Robinson, OEPI, Deputy Director, Division of Economic and Technical Analysis, discussed with the group the growing need for highly flexible resources. She said the FERC considered this an important issue for the markets, and that a number of regions were actively exploring how to provide appropriate market compensation to encourage adequate flexibility on the system. FERC Staff was following those conversations closely and was considering the issues. She noted the broad scope of possible solutions being discussed, and encouraged stakeholders in New England to share their perspectives.

The group then proceeded to ask questions of Staff. Mr. Ramlatchan acknowledged that resilience needs might be impacted by resources across the entire energy industry, potentially including products or resources where FERC jurisdiction might be unclear or limited. FERC Staff was receiving comments and looking very broadly at all potential solutions. The Commission would work to provide direction, guidance or assistance in any areas where it perceived the need, working cooperatively with other regulators, as needed, or as appropriate. In response to observations that DERs and resilience can be impacted heavily at the local level, Ms. Walsh reported the FERC was working on two efforts in the DER aggregation docket: (1) the participation of DER aggregations in the wholesale market; and (2) the identification of issues at the interface between the effects of DER on local distribution systems and the DER that affects the bulk power system. She said the FERC received numerous comments concerning the line between distribution and transmission and the possibility for technologies connected at the distribution-level to participate in the wholesale market. Ms. Walsh also responded to questions concerning the FERC's focus on the interplay between the gas and electric markets. She reported that there continued to be a focus on gas/electric coordination beyond the communications issues previously addressed. She noted that, with the benefit of ongoing industry input on the issues, the FERC may well consider whether more is needed than was originally done in response to the prior rulemaking on the topic.

FUEL SECURITY PANEL DISCUSSION

Mr. Kaslow recognized Mr. Paul Hibbard, Principal of the Analysis Group, as the moderator of a panel to discuss assessing fuel security challenges for the Wholesale Power Markets in New England. Mr. Hibbard introduced the two panelists: Dr. Anji Seth, Professor and Director of Applied Research, Connecticut Institute for Resilience & Climate Adaptation, Department of Geography, and Chair of the Atmospheric Sciences Group, University of Connecticut; and Dr. Phyllis Yoshida, Senior Fellow for Energy and Technology, Sasakawa Peace Foundation USA and former Deputy Assistant Secretary for Asia and the Americas, in DOE's Office of International Affairs.

Framing the Fuel Security Challenge for New England

Referring to a PowerPoint, Mr. Hibbard summarized from his perspective the fuel security risks the region faces for future winters and his desire for the panel presentations and subsequent discussions to identify the questions that should be asked in deciding how best to address those challenges. He identified some available options for the region to help ensure reliability and resilience, including expanding gas infrastructure into the region, modifying market incentives to drive desired market responses, requiring fuel contracts, and/or entering into out-of-market arrangements to support desired actions, investments and fuel contracts. He referred to existing and recently past arrangements such as PFP in the FCM, the winter reliability programs, and numerous Energy and Ancillary Services Market changes. He characterized the challenges facing the New England region to include little incremental gas supply infrastructure, uncertainty in seasonal delivery resources, sustained depressed energy market revenues pushing retirements, continued susceptibility to severe winters (though demand is in decline), and a lack of faith in PFP to address the challenge. He then reviewed current efforts to adjust the markets to account for fuel security separate from transmission security.

Mr. Hibbard stated his view that fuel security risks are being driven by carbon policy and market response. He identified numerous state policies that were reducing wholesale load and increasing renewable generation to the point that it could contribute as much as 1/3 – 1/2 of energy needs over the next 10+ years. He saw no respite from state policies to reduce carbon emissions, referencing Regional Greenhouse Gas Initiative (RGGI) reductions required by 2030 and increasing mandates from the states for carbon-free generation over the next few decades. He opined that states were seeking to affect climate change in the absence of federal action and he was seeing unprecedented efforts to prevent the development of any infrastructure that could lead to an increased carbon emissions.

He projected a future where aging nuclear generators and coal-, gas- and oil-fired generators would receive insufficient market revenues to operate. He opined that PFP was unlikely to drive generators to invest in incremental pipeline capacity.

Future Climate Risk Assumptions

Dr. Seth referred to her presentation “Understanding Changes in New England Weather Extremes,” as circulated and posted with the meeting materials in advance of the meeting. She highlighted the January 2018 “bomb cyclone” and the impact it had on the daily generation mix in New England. While acknowledging the extreme cold in December and January, she said that average winter temperatures in much of the United States, as they were in New England, had been increasing and she expected that average temperature increase to continue. She explained the many atmospheric variables that have a substantial impact on weather and the challenges that causes in making longer-term weather predictions.

She described the differences between weather forecasts and climate forecasts, saying she thought existing climate and weather models provided reasonably good short-term weather forecasts and long-term climate projections, but figuring out what would happen between those time frames was less predictable. High-level observations based on factors such as El Niño help, but generally predictive capabilities deteriorate for weather predictions out a year or two.

Dr. Seth made broad observations about uncertainties and then referred to slides showing global warming trends, observing that increasing CO_2 in the atmosphere had been the largest driver of temperature change since about 1970. She referred more specifically to a map of North America reflecting annual temperature changes, noting that the Northeast is warming at, or above, the average rate for all of North America and winter was warming at a faster rate than summer. She said that scientists predict both average temperatures and extreme temperatures (both high and low) will rise by at least 5°F (2.8°C) in most areas by mid-century and 10°F (5.5°C) or more by late century.

She said it was more difficult both to see trends in precipitation and to simulate those trends in the future. At highest level, she expected more extreme rainfall because, as temperatures increase, there is more water vapor in the atmosphere (atmospheric water vapor had increased by 4%), and water vapor fuels stronger storms.

Dr. Seth then noted the expected increases in the following types of storms with the warming climate:

- Tropical Cyclones – with increases both in maximum wind speeds and frequencies.
- Winter Storms – the frequency of large snow storms in the Northeast.
- Tornadoes – the frequency both of days with a large numbers of tornadoes and days with severe thunderstorms.
- Droughts.

She referred to charts showing sea level rise, with expected increased flood frequency in New England due to nor'easters and hurricanes. She cautioned that sea level depends in large measure on the stability and size of the Antarctic ice-sheet, which made projections of sea level rise less predictable.

Returning to the impact on climate from CO_2 emissions, she referenced a chart of data going back to 1870 that showed an almost linear relationship between CO_2 and temperature. She referenced the efforts from the Paris Agreement designed to keep new CO_2 in the atmosphere at levels below what were calculated to result in a temperature increases of 2°C. Calculations she referenced suggest that, even if the committed efforts at reducing CO_2 emissions were successful, by 2030 global CO_2 in the atmosphere would be approaching 80% of the CO_2 that would result in a 2°C temperature rise.

Summarizing her views in response to questions, Dr. Seth predicted that temperature increases in the Northeast would be largest in winter and at night, and precipitation increases would be largest in winter. She expected that there still could be periods of prolonged winter-time cold events, but those would be less frequent over time, with heat waves becoming more frequent.

Japan's Energy Transition and Lessons Learned for New England

Dr. Yoshida introduced her presentation entitled , "Japan's Energy Conundrum – A Discussion of Japan's Energy Circumstances and U.S.-Japan Energy Relations", as circulated and posted with the meeting materials in advance of the meeting, by noting for over a century Japan's energy policy has sought to compensate for geographic size and lack of fossil fuel resources while supporting economic growth. In the wake of the Great Eastern Japan Earthquake and Tsunami in 2011 and its aftermath, which she described as a singular extraordinary event, Japan continued to face and deal with an energy conundrum familiar to New England: How to provide an affordable and environmentally friendly energy supply which is resilient to unexpected weather events in a country with inadequate domestic energy resources.

Prior to 2011, Dr. Yoshida observed, Japan's overall energy policy emphasized nuclear power, LNG imports, energy efficiency, and, to a lesser degree, renewable energy. Subsequent to the events of March 2011, which resulted in the shutdown of Japan's entire fleet of 54 nuclear power plants, Japan faced an immediate 30 percent shortfall in electricity production. Without nuclear power, Japan relied almost completely on imports of coal, oil and natural gas to meet its primary energy demand. Meanwhile, the country's greenhouse gas emissions quickly increased, its trade deficit grew, and its economy slowed due to higher LNG prices, which doubled in large part because Japan's demand for the fuel increased 30 percent. High fuel prices drove up electricity rates, which had already been among the highest in the world. Collectively, Dr. Yoshida termed these issues -- decreased energy self-sufficiency, a deteriorating trade balance, high electricity costs, and increased air emissions -- a "quadlemna" for Japan's energy policymakers.

Following the 2011 energy crisis, an activist international policy ensued to encourage the supply of LNG. Coal imports increased and Japan sought to expand the export market for the advanced, highly-efficient, low emission coal technologies that Japan increasingly needed for itself. Policies to constrain energy demand continued although, Dr. Yoshida noted, aggressive efforts in this regard were already in place pre-2011. Opposition to renewables virtually disappeared and the pace of development of renewables post-2011 significantly increased.

Dr. Yoshida told the Committee that Japan's energy mix post-2011 continues to evolve. With only eight nuclear power plants currently operational, she believed that Japan needed to continue to develop new domestic energy sources including renewables and to continue its efforts to make its energy markets more competitive. Further diversification of types and sources of imported fossil fuels could support Japan's energy security, she added.

In the midst of this change, the future of nuclear energy in Japan remained clouded. According to Dr. Yoshida, while nuclear energy could be part of the solution to Japan's energy conundrum and climate needs, strong public opposition needed to be overcome. For instance, she stated that Japan's nuclear industry believed that over 45 nuclear units that were shut down in 2011 could be brought back on line but she doubted there was support for restarting more than a few of them. In response to questions, Dr. Yoshida stated that there was considerable interest in Japan in advanced fast reactors and small modular reactors that could be more efficient, safe and socially acceptable.

Along with changes in the energy mix, she discussed efforts to deregulate the electricity and natural gas markets. While some of changes had already been under consideration or started, Japan greatly sped them up after March 2011 and opened up a number of electric and gas markets to competition. Transmission and distribution markets were slated to be deregulated in the future.

Dr. Yoshida supported her remarks with numerous charts and graphs. For a more in-depth discussion of Japan's energy conundrum and relatively recent initiatives, she referred the Committee to a new book published by Sasakawa USA (*Japan's Energy Conundrum – A Discussion of Japan's Energy Circumstances and U.S.-Japan Energy Relations*), which she edited and to which she contributed two chapters. Dr. Yoshida concluded her remarks with a number of recommendations specific to Japan which may have application for the New England energy markets, including:

- Policymakers must ensure electricity and natural gas market deregulation and reform are transparent, increase competition, and create opportunities for new technologies and practices.
- Japan must reverse its underinvestment in and underutilization of renewables as a major source of domestic supply to enhance energy security and environmental sustainability.
- Japan must actively explore the next generation of advanced nuclear reactors to determine how they can play a role in Japan's energy future and energy security.
- Adequate system flexibility, especially the expansion of transmission interconnections, must play a role in lowering energy demand and achieving Japan's goal of cutting greenhouse gas emissions from 2013 levels by 80 percent by 2050.
- Japan must limit investment in the fossil fuel power plants to generators with the highest operational efficiency to support environmental and climate goals for security, health, and resiliency.
- Advances in energy storage systems, digital technologies and hydrogen technologies have been numerous but Japan must push these technologies considerably harder and faster.
- Japan must maintain momentum in energy demand reduction by continuously expanding coverage of products, sectors, and parts of sectors, such as recent expansion of energy efficiency standards for new buildings. Practices like demand supply management should be widely implemented.

The June 27 Session then recessed at 12:00 p.m., with Mr. Kaslow reminding members of the modified Sector breakout meetings scheduled for the following morning with the ISO Board, state regulators and officials, and FERC representatives.

RECOGNITION OF RAYMOND HEPPER

During the banquet that evening, the Committee endorsed by acclimation the following resolution of appreciation for the ISO Vice President, General Counsel and Corporate Secretary, Mr. Raymond Hepper:

RESOLUTION OF APPRECIATION

Raymond W. Hepper

WHEREAS, Raymond W. Hepper has decided he has had enough -- for now -- having retired after an oh-so-brief fourteen year stint with ISO New England, most recently as Vice President, General Counsel and Corporate Secretary; and

WHEREAS**,** Ray may have thought he was prepared for his position with ISO New England, having spent more than a decade with Central Maine Power (including time as that Company's General Counsel), preceded by a decade with the Department of Justice, and a four-year interlude as a Partner with Pierce Atwood in Portland, Maine; and

WHEREAS, NEPOOL members have worked individually and collectively throughout Ray's time with ISO New England to test his skills and his preparation; and

WHEREAS**,** Ray has risen to the challenge, serving as the ever-present consigliore, adviser, guardian, and gladiator for ISO New England, helping with steady hand and clear thought to navigate his client and the region through challenging times and major evolution of New England's bulk power market.

NOW, THEREFORE, the Participants Committee of the New England Power Pool, on behalf of the NEPOOL Participants, hereby expresses its sincere appreciation to Ray for his years of dedicated and determined service in the region, and wish him Godspeed in the next chapter of his life.

JUNE 28, 2018 SESSION

The June 28 session of the Summer Meeting convened at 8:00 a.m., in modified Sector breakout meetings with the ISO Board, state regulators and officials, and FERC representatives, which continued until 12:15 p.m. With no further Committee business thereafter, the Summer Meeting adjourned.

Respectfully submitted,

David T. Doot, Secretary

ATTACHMENT 1

**MEMBERS AND ALTERNATES PARTICIPATING IN
THE PARTICIPANTS COMMITTEE
JUNE 26-28, 2018 SUMMER MEETING**

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
American Power Net Management	Supplier			Mary Smith (tell)
An baric Development Partners LLC	Provisional Group	Steve Conant		
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			Gus Fromuth William P. Short III
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	Alek's MITRE ski		
Chester Municipal Electric Light Department	Publicly Owned		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned		Brian Thomson	Brian Forshaw
Clearest Consulting, Inc.	AR	Doug Hurley		
C.N. Brown Electricity, LLC	Supplier	Jeff Jones (tell)		William P. Short III
Competitive Energy Services, LLC	Supplier			Glenn Poole
Concord Municipal Light Plant	Publicly Owned		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop. (CMEEC)	Publicly Owned	Brian Forshaw		
Connecticut, State of, Office of Consumer Counsel	End User			Dave Thompson
Conservation Law Foundation (CLF)	End User	David Ismay (tell)		
Consolidated Edison Energy, Inc.	Supplier	Jeff Dannels		
CPV Towantic, LLC	Generation	Daniel Pierpont		
Cross-Sound Cable (CSC)	Supplier		Jose Rotger	
Danvers Electric Division	Publicly Owned		Dave Cavanaugh	
DC Energy, LLC	Supplier	Bruce Bleiweis		
Direct Energy Business, LLC	Supplier	Ron Carrier		Nancy Chafetz
Dominion Energy Generation Marketing, Inc.	Generation	Michael Purdie		
DTE Energy Trading, Inc. (DTE)	Supplier			Nancy Chafetz
Dynegy Marketing and Trade, LLC	Supplier		Sean Allen	Bill Fowler
Elektrisola, Inc.	End User		Gus Fromuth	William P. Short III
Emera Energy Services Subsidiaries	Transmission	Sandi Hennequin		Bill Fowler
Emera Maine	Transmission	Lisa Martin		
EnerNOC, Inc.	AR		Herb Healy	
Enerwise Global Technologies Inc./ d/b/a CPower Corp	AR		Herb Healy	
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	
Fairchild Semiconductor Corporation	End User	Gus Fromuth		William P. Short III
FirstLight Power Resources Management, LLC	Generation	Tom Kaslow	Peter Rider	
Food City, Inc.	End User			Christina Belew Sarah Bresolin Silver
Galt Power, Inc. (Galt)	Supplier	Nancy Chafetz		
Garland Manufacturing Company	End User			Christina Belew Sarah Bresolin Silver
Generation Group Member	Generation	Dennis Duffy	Abby Krich	Bob Stein
Georgetown Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Great River Hydro	AR		Shawn Keniston	Bill Fowler
Groton Electric Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Groveland Electric Light Department	Publicly Owned		Dave Cavanaugh	

ATTACHMENT 1

MEMBERS AND ALTERNATES PARTICIPATING IN
THE PARTICIPANTS COMMITTEE
JUNE 26-28, 2018 SUMMER MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
H.Q. Energy Services (U.S.) Inc.	Supplier	Louis Guilbault	Bob Stein	Abby Krich
Hammond Lumber Company	End User			Christina Belew Sarah Bresolin Silver
Harvard Dedicated Energy Limited	End User	Mary Smith (tel)		Paul Peterson Doug Hurley
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			Jim D'Andrea
Just Energy (U.S.) Corp.	Supplier	Gretchen Fuhr		
Long Island Lighting Company (LIPA)	Supplier		Bill Killgoar	
Littleton (MA) Electric Light & Water Department	Publicly Owned		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned		Craig Kieny	
Maine Power LLC	Provisional Group	Jeff Jones (tel)		
Maine Public Advocate Office	End User		Barry Hobbins	Paul Peterson
Maine Skiing, Inc.	End User	Kevin Penders		
Mansfield Municipal Electric Department	Publicly Owned		Brian Thomson	Brian Forshaw
Marblehead Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Massachusetts Attorney General's Office (MA AG)	End User	Christina Belew	Sarah Bresolin Silver	
Mass. Development Finance Agency	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	
Middleborough Gas and Electric Department	Publicly Owned		Brian Thomson	Brian Forshaw
Middleton Municipal Electric Department	Publicly Owned		Dave Cavanaugh	
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 (NHEC)	Publicly Owned	Steve Kaminski		Brian Forshaw
New Hampshire Office of Consumer Advocate (NH OCA)	End User	Paul Peterson		
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
NRG Power Marketing, Inc.	Generation		Pete Fuller	
Nylon Corporation of America	End User			William P. Short III
Pascoag Utility District	Publicly Owned		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
Peabody Municipal Light Plant	Publicly Owned		Brian Thomson	Brian Forshaw
PNE Energy Supply	Supplier			Gus Fromuth William P. Short III
PowerOptions	End User			Paul Peterson
Princeton Municipal Light Department	Publicly Owned		Brian Thomson	Brian Forshaw
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
Reading Municipal Light Department	Publicly Owned			Brian Forshaw
Repsol Energy North America Company	Gas Industry Participant			Nancy Chafetz
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		William P. Short III
Shipyard Brewing LLC	End User	Gus Fromuth		William P. Short III
Shrewsbury Electric & Cable Operations	Publicly Owned		Brian Thomson	Brian Forshaw

.

ATTACHMENT 1

MEMBERS AND ALTERNATES PARTICIPATING IN
THE PARTICIPANTS COMMITTEE
JUNE 26-28, 2018 SUMMER MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Small Load Response Group Member	AR	Doug Hurley	Brad Swalwell	
Small Renewable Generation Group Member	AR	Erik Abend (tel)		
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	
Taunton Municipal Light Department	Publicly Owned		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned		Brian Thomson	Brian Forshaw
Texas Retail, LLC	Supplier	Chris Hendrix		
The Energy Consortium (TEC)	End User		Mary Smith (tel)	Paul Peterson Doug Hurley
Union of Concerned Scientists (UCS)	End User		Francis Pullaro	
Utility Services, Inc.	End User			Paul Peterson
Vermont Electric Cooperative	Publicly Owned	Craig Kieny		
Vermont Electric Power Company, Inc.	Transmission	Frank Ettori	Mark Sciarrotta	
Vermont Energy Investment Corporation (VEIC)	AR		Doug Hurley	
Vermont Public Power Supply Authority (VPPSA)	Publicly Owned			Brian Forshaw
Verso Energy Services LLC	Generation	Glenn Poole		
Vitol Inc.	Supplier	Joe Wadsworth		
Wakefield Municipal Gas and 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	
Westfield Gas & Electric Light Department	Publicly Owned		Dave Cavanaugh	
Wheelabrator/Calpine	AR		Brett Kruse	Bill Fowler
Z-TECH, LLC	End User		Gus Fromuth	William P. Short III

VOTES TAKEN AT
THE PARTICIPANTS COMMITTEE
JUNE 26, 2018 SUMMER MEETING

TOTAL

Sector/Group	ENE Winter Rel. Prgm.	Press Dissntg. Proposal	Press Provs.
GENERATION	11.40	2.44	17.10
TRANSMISSION	0.00	0.00	17.10
SUPPLIER	7.04	5.34	13.44
ALTERNATIVE RESOURCES	11.41	6.31	12.15
PUBLICLY OWNED ENTITY	8.55	0.00	17.10
END USER	11.97	13.14	2.23
PROVISIONAL GROUP MEMBER	0.00	0.22	0.00
% IN FAVOR	50.37	27.45	79.12

GENERATION SECTOR

Participant Name	ENE Winter Rel. Prgm.	Press Dissntg. Proposal	Press Provs.
CPV Towantic	A	O	F
Dominion Energy Marketing	A	O	F
Entergy Nuclear Power Marketing	A	O	F
FirstLight Power Resources Mgmt.	O	O	F
Generation Group Member	O	O	F
Nautilus Power	F	O	F
NextEra Energy Resources	F	A	A
NRG Power Marketing	F	A	A
Verso Maine Energy LLC	F	F	A
IN FAVOR (F)	4	1	6
OPPOSED (O)	2	6	0
TOTAL VOTES	6	7	6
ABSTENTIONS (A)	3	2	2

TRANSMISSION SECTOR

Participant Name	ENE Winter Rel. Prgm.	Press Dissntg. Proposal	Press Provs.
AVANGRID (CMP/UI)	O	O	F
Emera	Split[1]	Split[1]	Split[1]
Emera Maine	O	O	F
Emera Energy Services Subs.	O	O	F
Eversource Energy	O	O	F
National Grid	O	A	A
Vermont Electric Power Co.	O	O	F
IN FAVOR (F)	0	0	4
OPPOSED	5	4	0
TOTAL VOTES	5	4	4
ABSTENTIONS (A)	0	1	1

[1] 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 split their vote evenly.

ALTERNATIVE RESOURCES SECTOR

Participant Name	ENE Winter Rel. Prgm.	Press Dissntg. Proposal	Press Provs.
Renewable Generation Sub-Sector			
Great River Hydro	O	O	F
Jericho Power	F	F	A
Calpine/Wheelabrator	O	A	A
Small RG Group Member	A	F	O
Distributed Generation Sub-Sector			
CLEAResult Consulting	F	O	F
Load Response Sub-Sector			
Enerwise Global Technologies	F	F	A
EnerNOC	F	F	A
VT Energy Investment Corp.	F	O	F
Small LR Group Member	A	O	F
IN FAVOR (F)	5	4	4
OPPOSED	2	4	1
TOTAL VOTES	7	8	5
ABSTENTIONS (A)	2	1	4

SUPPLIER SECTOR

Participant Name	ENE Winter Rel. Prgm.	Press Dissntg. Proposal	Press Provs.
American PowerNet Mgmt.	F	A	A
Block Island Power Co.	F	A	A
BP Energy Company	O	O	F
Brookfield Energy Marketing	O	O	F
C.N. Brown Electricity	F	F	O
Competitive Energy Services	F	F	A
Consolidated Edison Energy	O	O	F
Cross-Sound Cable	A	O	F
Direct Energy Business	O	F	A
DTE Energy Trading	O	O	F
Dynegy Marketing and Trade	F	O	F
Exelon Generation Company	A	O	F
Galt Power, Inc.	O	O	F
H.Q. Energy Services (U.S.)	O	O	F
Just Energy (U.S.)	O	A	A
LIPA	A	O	F
Mercuria Energy America	A	A	A
PNE Energy Supply	F	F	O
PSEG Energy Resources & Trade	F	O	F
Texas Retail, LLC	O	F	O
Vitol Inc.	O	A	A
IN FAVOR (F)	7	5	11
OPPOSED	10	11	3
TOTAL VOTES	17	16	14
ABSTENTIONS (A)	4	5	7

ATTACHMENT 2

VOTES TAKEN AT
THE PARTICIPANTS COMMITTEE
JUNE 26, 2018 SUMMER MEETING

END USER SECTOR

Participant Name	ENE Winter Rel. Prgm.	Press Dissntg. Proposal	Press Provs.
Associated Industries of Mass.	F	O	F
Bath Iron Works	F	F	O
Conn. Office of Consumer Counsel	F	O	A
Conservation Law Foundation	O	F	O
Elektrisola, Inc.	F	F	O
Environmental Defense Fund	A	F	O
Fairchild Semiconductor Corp.	F	F	O
Food City	-	F	O
Garland Manufacturing	-	F	O
Hammond Lumber Company	-	F	O
Harvard Dedicated Energy Limited	F	F	O
High Liner Foods (USA)	F	F	O
Industrial Energy Consumer Group	F	O	A
Maine Public Advocate Office	O	F	O
Maine Skiing, Inc.	F	O	A
Mass. Attorney General's Office	O	F	O
Natural Resources Defense Council	A	F	O
NH Office of Consumer Advocate	O	F	O
Nylon Corporation of America	F	F	O
PowerOptions	O	O	F
St. Anselm College	F	F	O
Shipyard Brewing Co., LLC	F	F	O
The Energy Consortium	F	A	O
Union of Concerned Scientists	O	F	A
Utility Services	A	O	F
Z-TECH, LLC	F	F	O
IN FAVOR (F)	14	19	3
OPPOSED	6	6	19
TOTAL VOTES	20	25	22
ABSTENTIONS (A)	3	1	4

PUBLICLY OWNED ENTITY SECTOR

Participant Name	ENE Winter Rel. Prgm.	Press Dissntg. Proposal	Press Provs.
Ashburnham Municipal Light Plant	O	A	A
Belmont Municipal Light Dep't	F	A	A
Boylston Municipal Light Dep't	O	A	A
Braintree Electric Light Dep't	F	A	A
Chester Municipal Light Dep't	F	A	A
Chicopee Municipal Lighting Plant	O	A	A
Concord Municipal Light Plant	F	A	A
Conn. Mun. Electric Energy Coop.	F	O	F
Danvers Electric Division	F	A	A
Georgetown Municipal Light Dep't	F	A	A
Groton Electric Light Department	O	A	A
Groveland Electric Light Dep't	F	A	A

PUBLICLY OWNED ENTITY SECTOR (cont.)

Participant Name	ENE Winter Rel. Prgm.	Press Dissntg. Proposal	Press Provs.
Hingham Municipal Lighting Plant	F	A	A
Holden Municipal Light Dep't	O	A	A
Holyoke Gas & Electric Dep't	O	A	A
Hull Municipal Lighting Plant	O	A	A
Ipswich Municipal Light Dep't	O	A	A
Littleton (MA) Electric Light Dep't	F	A	A
Mansfield Municipal Electric Dep't	O	A	A
Marblehead Municipal Light Dep't	O	A	A
Mass. Mun. Wholesale. Elec. Co.	O	A	A
Merrimac Municipal Light Dep't	F	A	A
Middleborough Gas & Elec. Dep't	O	A	A
Middleton Municipal Electric Dep't	F	A	A
New Hampshire Electric Coop.	F	O	F
Pascoag Utility District	F	A	A
Paxton Municipal Light Dep't	O	A	A
Peabody Municipal Light Plant	O	A	A
Princeton Municipal Light Dep't	O	A	A
Reading Municipal Light Dep't	F	O	F
Rowley Municipal Lighting Plant	F	A	A
Russell Municipal Light Dep't	O	A	A
Shrewsbury's Elec. & Cable Ops.	O	A	A
South Hadley Electric Light Dep't	O	A	A
Sterling Mun. Elec. Light Dep't	O	A	A
Stowe (VT) Electric Department	F	A	A
Taunton Municipal Lighting Plant	F	A	A
Templeton Mun. Lighting Plant	O	A	A
VT Public Power Supply Authority	F	O	F
Wakefield Mun. Gas & Light Dep't	O	A	A
Wallingford (CT) Div. Pub. Utils.	F	A	A
Wellesley Municipal Light Plant	F	A	A
West Boylston Mun. Lighting Plant	O	A	A
Westfield Gas & Elec. Light Dep't	F	A	A
IN FAVOR (F)	22	0	4
OPPOSED	22	4	0
TOTAL VOTES	44	4	4
ABSTENTIONS (A)	0	40	40

PROVISIONAL GROUP MEMBER

Participant Name	ENE Winter Rel. Prgm.	Press Dissntg. Proposal	Press Provs.
Anbaric Development Partners	A	F	A
Maine Power	O	F	O
IN FAVOR (F)	0	2	0
OPPOSED	1	0	1
TOTAL VOTES	1	2	1
ABSTENTIONS (A)	1	0	1