FINAL

The 2016 Summer Meeting of the NEPOOL Participants Committee was held at The Omni Mount Washington Resort, Bretton Woods, New Hampshire, on Tuesday, June 21, Wednesday, June 22, and Thursday, June 23, 2016, pursuant to notice duly given. 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 Thursday, June 23. Attachment 1 identifies the members, alternates and temporary alternates attending the meeting and voting that day.

Mr. Joel Gordon, Chair, presided and Mr. David Doot, Secretary, recorded for all three days.

JUNE 21, 2016 SESSION

The June 21, 2016 session began at 1:15 p.m., following morning meetings among the Sectors, ISO Board, New England State Officials, and FERC representatives. Mr. Gordon welcomed the members, alternates and guests who were present, and extended a special welcome to the representatives of the New England State Commissions and other State Officials, NECPUC and NESCOE (collectively, the States), the FERC, and members of the ISO Board.

OPENING AND WELCOMING REMARKS

Mr. Gordon referred the Committee to the Legislative Report that NEPOOL Counsel prepared and circulated at the meeting, stating the Report would be helpful given the theme of the meeting *Considering Potential Solutions to Achieve State Public Policy that are Compatible with New England's Competitive Markets* and discussions by the States on Wednesday, June 22. He commented on the record State attendance at the Summer Meeting, for which he was grateful given the efforts and commitment to find ways to advance public policies of the States through the markets. He expressed optimism for that effort, noting the history of NEPOOL, ISO-NE and

States working together on industry restructuring over the last two decades to support efforts to achieve just and reasonable rates through competitive wholesale markets.

Mr. Gordon invited NECPUC President Angela O'Connor, Chairman of the Massachusetts Department of Public Utilities (MA DPU) to provide opening remarks. Speaking on behalf of the six New England States, Chairman O'Connor expressed appreciation for the efforts started at the NECPUC Symposium a few weeks earlier to integrate power markets with the States' policy initiatives. She reminded the group that the States had an obligation to advance their respective public policy objectives and wanted to do that in a way that is consistent with competitive markets and achieves the goals of affordable, reliable and sustainable energy. She expressed appreciation for NEPOOL's leadership and indicated that the States were encouraged based on the Sector meetings earlier that day that market participants recognize the challenges facing the States.

Next, the Honorable Martin Honigberg, Chairman of the New Hampshire Public Utilities Commission (NHPUC), welcomed those attending the NEPOOL meeting to New Hampshire. He read a letter to NEPOOL from New Hampshire Governor Margaret Wood Hassan, which was posted on NEPOOL's website, that welcomed everyone to NH, expressed her regret for not being able to attend the meeting in person, and encouraged continued productive conversations on regional energy policy and wholesale markets. He thanked NEPOOL for including him and other State Officials in the Summer Meeting and encouraged attendees to take advantage of all that the historic Mount Washington Hotel and region had to offer. He concluded explaining his and his colleagues anticipation of productive discussions on the challenges of accommodating state public policies into the wholesale electric market, especially given the region's history of working together.

EXTERNAL MARKET MONITOR (EMM) REPORT

Dr. David Patton, Ph.D., President, Potomac Economics, the ISO's EMM, presented highlights from the EMM's 2015 Markets Report (EMM Annual Report), which had been circulated and posted in advance of the meeting. Reviewing highlights from that Report, he said the EMM concluded that New England's Energy and Ancillary Services Markets performed competitively in 2015. He referenced positively the adoption of hourly energy offer flexibility, which improved the market's Real-Time price signals and fast start deployments. He also cited with approval the increase in Reserve Constraint Penalty Factor (RCPF) values, which allowed prices to better reflect the value of lost load during Operating Reserve shortages.

Dr. Patton turned to a series of graphs comparing energy and natural gas prices in 2014 and 2015, summarizing the trending of natural gas prices, oil and LNG prices over the past year. He said that the strong relationship between energy and natural gas prices indicated a well-functioning, competitive market.

Focusing in more detail on natural gas and other fuel prices in New England (NE) relative to New York (NY), Dr. Patton observed that the Algonquin and Iroquois pipelines serve most of the gas generators in New England, and the Transco Zone 6 Line serves much of Eastern New York. He noted the occasional price separation between NY and New England, which he attributed to pipeline constraints, and showed that when the gas system becomes constrained, electricity imports from New York to New England increase with electric prices separating once the limits were reached on the NY/NE interface. He stated those experiences confirmed the value to customers of better coordination between the NY/NE markets in allowing generators in both regions with the lowest gas cost to be run. He noted the frequent cost advantages between the Iroquois pipeline compared to Algonquin pipeline, which affected intra-New England prices and provided incentives to site generators near Iroquois. He then showed how LNG and oil prices had helped to limit price spikes during times of pipeline congestion and capacity limits. He observed also that, from time-to-time, the natural gas pipelines are not fully utilized, which might be attributed to (1) the scheduling process for procuring gas, nominating it, and consuming it, that is not as efficient as the RTO electric market, or (2) competitive issues on the gas side, which are not monitored by the EMM.

Dr. Patton then compared Real-Time price volatility in 2014/15 between the New England Markets and other RTO markets. He stated price volatility provides useful incentives for increased compensation to flexible fast start resources. He referenced the chart in the Annual Report that showed that New England's volatility was slightly higher in 2015 than in 2014, when there was the Polar Vortex. He noted that New England over time had been one of the least volatile markets, in part because ISO-NE runs dispatch effectively every 15 minutes, looking further ahead and with more ramp than NYISO or MISO, who run dispatch every 5 minutes. He observed also that New England had extremely low congestion, relative to other RTO markets, which he attributed to: (1) transmission upgrades in New England that eliminated chronic congestion into Boston and Connecticut; (2) the absence of congestion causing loop flow as in MISO; and (3) larger volatility in other regions' pricing models.

Dr. Patton went on to review the portions of the Annual Report concerning Coordinated Transaction Scheduling (CTS) that was implemented between New York and New England in December 2015. He opined that CTS was doing a much better job at merging prices between NE and NY than the cross-border arrangements between NY and PJM. He attributed this difference, in part, to lower administrative costs for NE/NY transactions. He noted performance would improve further if price forecasting improved. He estimated production cost savings for the four month period to be about $600,000 with even larger total savings because more efficient transfers between the two Control Areas improved prices within each area. Dr. Patton was asked whether the EMM could translate the production costs savings into savings for consumers. He explained that calculation would require some speculation about how Market Participants would have behaved in the absence of CTS. He stated the consumer savings are biggest during times of shortages in one area but not the other. He reminded members that the EMM had estimated large consumer savings when it was advocating in favor of CTS. A member suggested as a solution that the two ISO's work together in dispatch almost as if they were one Control Area. Dr. Patton stated that the EMM is obligated after about two years of CTS operation to produce a study of what portion of the projected savings were captured and there is a presumption that New England will turn to tie optimization or some other change if a sufficient percentage of the savings is not being captured.

Changing focus to uplift, Dr. Patton explained that New England had relatively high uplift costs. He reported that, in 2015, New England experienced the transitory impact of an NCPC rule change designed to create an incentive for resources scheduled in the Day-Ahead Energy Market to not have an incentive to be shut off before Real-Time. He explained that, although that change sounded like a good incentive from a reliability standpoint, it was economically inefficient in some cases because it could, in fact, be efficient for high cost units to go off-line if they were not needed for reliability in Real-Time, obviating Real-Time make-whole payments that would otherwise be paid. He reported that $47 million of the $107 million paid in uplift was attributable to this class of uplift (i.e. Real-Time make-whole payments to units that were needed for Day-Ahead but not Real-Time reliability and had not gone off-line before Real-Time). He said that the ISO agreed with the EMM's recommendation to make changes to effectively eliminate that class of uplift, and those changes were vetted through the stakeholder process and ultimately made effective in February 2016. He opined that, had such uplift not occurred, total uplift in New England would have only been slightly higher than in the other eastern RTOs. He explained that improved Day-Ahead modeling had also reduced uplift and noted changes underway that were designed to further reduce NCPC.

Dr. Patton commented briefly on the comparison of Operating Reserves across the RTOs. He observed that New England's Operating Reserve prices are slightly lower than other regions because of its relatively large percentage of spinning reserves. He noted the EMM's recommendation to introduce a Day-Ahead Reserve Market in New England and the reasons for that recommendation. He indicated regulation prices are significantly higher in New England than in NYISO and MISO because in New England regulation is not co-optimized with Energy and Operating Reserves. He stated that co-optimization will do a better job of pricing the trade-offs between regulation activity and producing energy.

Dr. Patton then referred to charts reflecting long-term price signals measured by net revenues, which he defined for the Committee. He reported that net revenues in 2015 for suppliers were significantly below the Cost of New Entry for combined cycle units because of a capacity surplus and infrequent shortage pricing.

Dr. Patton concluded his presentation by reviewing the following recommendations with respect to the Energy, Reserves and Capacity Markets, and addressing numerous follow-up questions:

- Allow the costs of fast start resources, operator actions, and demand response deployments to be reflected in Real-Time prices;
- Modify allocation of "Economic" NCPC charges to make it more consistent with "cost-causation" principles;
- Utilize the lowest cost configuration for multi-unit generators when committing resources for local reliability;
- Introduce Day-Ahead Operating Reserve Markets that are co-optimized with the Day-Ahead Energy Market;
- Eliminate the Forward Reserve Market;
- Evaluate changes in the availability or timing of information about qualified supply before the auction to improve competition in the FCA;
- Replace the descending clock auction with a sealed bid auction;
- Allow the FCA to select between projects that are interdependent, rather than designating a priority; and

- Assess changes in the Minimum Offer Price Rule (MOPR) provisions to ensure MOPR will be effective under the pay-for-performance framework.

FERC REGIONAL UPDATE

Mr. Gordon introduced Mr. Jesse Hensley, Senior Energy Industry Analyst, FERC Office of Energy Policy and Innovation (OEPI). Mr. Hensley explained the role of OEPI. He highlighted several FERC initiatives, noting he was the coordinator for the FERC's price formation efforts. He summarized the FERC's recent rule on settlement and shortage pricing (Order 825), and noted the recent changes jointly filed by the ISO and NEPOOL to change to five minutes the settlement interval in the Real-Time Energy and Reserves Markets. He summarized the November 2015 Order Directing RTOs and ISOs to report on identified price-formation topics. Mr. Hensley also highlighted the FERC's January 2016 Notice of Proposed Rulemaking on Offer Caps (RM16-3) relating to RTO/ISO caps on incremental energy offer.

Mr. Hensley then summarized FERC's generator interconnection and energy storage efforts, referring to the May 13, 2016 technical conference, a rulemaking proceeding (RM16-12) proposing changes to the *pro forma* Large Generation Interconnection Agreement and Procedures, and the notice of inquiry (AD16-20) regarding electric storage rules in the organized markets.

Mr. Hensley concluded his update by noting upcoming technical conferences and workshops including: competitive transmission development rates (AD16-18); reactive supply compensation in RTO/ISO markets (AD16-17); Public Utility Regulatory Policies Act (PURPA) implementation (AD16-16); and increasing Real-Time and Day-Ahead Market efficiency through improved software (AD10-12).

Mr. Gordon thanked Mr. Hensley for his report and the June 21 session then adjourned at 4:00 p.m., with the meeting to be reconvened at 8:30 a.m. on June 22.

JUNE 22, 2016 SESSION

The Summer Meeting reconvened at 8:30 a.m. on June 22, 2016. Opening the session, Mr. Gordon reviewed the meeting process for the day.

PANEL DISCUSSIONS: "CONSIDERING POTENTIAL SOLUTIONS TO ACHIEVE STATE PUBLIC POLICY THAT ARE COMPATIBLE WITH NEW ENGLAND'S COMPETITIVE MARKETS"

Mr. Gordon referred the Committee to presentations circulated and posted with the June 22 meeting materials in advance of the meeting concerning potential solutions to achieve state public policy that are compatible with New England's competitive markets. He introduced the following panelists: Mr. Ben D'Antonio, Counsel & Analyst, NESCOE; Mr. Vincent Duane, Sr. Vice President, General Counsel & Secretary, PJM; and Mr. Paul Hibbard, Principal, Analysis Group.

To help set the stage for the following presentations and discussion, Mr. D'Antonio summarized, at a high level, some of the public policies and mechanisms to support such policies that have affected the wholesale power markets. He clarified that his presentation was not an exhaustive list of every requirement of every States' energy and environmental laws and was intended to provide generally indicative information about *current* energy and environmental laws that influence the regional power system. He provided an overview of the States' legal authority relating to energy efficiency, renewable resources and carbon dioxide emission reduction and indicated that States' public policy objectives vary across the region. Mr. D'Antonio added that a general discussion about States' public policies should not be assumed to apply uniformly across the New England States. He then referred the Committee to his detailed presentation which included citations for legal authorities and economic information related to the mechanisms. He described the energy efficiency efforts. Referring to renewable standards, he noted they were generally motivated by public policies to achieve environmental objectives, to enhance energy security, to encourage economic development, and to promote fuel diversity. He explained that the States' collective objective of reducing carbon dioxide emissions included a desire to avoid and/or mitigate the impact of greenhouse gases and climate change. He then summarized the following mechanisms the States use to support public policies:

- System Benefits Charge - A non-bypassable surcharge on an electricity customer's bill that is widely used to support energy efficiency policies.
- Renewable Portfolio Standard - A mandate the States place on their load serving entities to support renewable production for a defined portion of their retail loads.
- Net Metering - Enables customers to offset their energy consumption from the grid with customer-sided generation.
- Long Term Contracts - Provides legally enforceable revenue streams for terms commonly 10-15 years to help facilitate financing of eligible resources.
- Regional Greenhouse Gas Initiative (RGGI) – Caps greenhouse gasses regionally and auctions carbon dioxide emission allowances which generators, subject to program regulation, can purchase in the primary and secondary marketplace.
- Green Banks - Provides favorable financing terms for eligible resources.
- Grid Modernization – Through strategic investments in the grid, better utilizes existing infrastructure and increases customers' ability to modulate energy consumption in response to prices and/or system conditions.
- Storage – Expands the use of energy storage with advance technology (batteries, thermal applications, etc.).
- Electric Vehicles - Some States are addressing carbon dioxide emissions from the transportation sector through mechanisms to support electricity vehicles.

Mr. Duane began by referring to the question of whether PJM's markets were efficiently and reliably managing the entry and exit of supply resources in the face of growing external forces and industry transformation. He said that, in response to criticism of the PJM markets on this question, the PJM Board initiated a review and issued a paper on the topic the month before. Noting that PJM operated in a collection of markets with different objectives, he said that the PJM paper drew the distinction between the markets in providing operational efficiencies and investment efficiencies. He summarized the paper's observations that PJM's markets were favorably attracting emerging technologies compared to other regions, in part because of the open access environments of these organized markets, coupled with the focus on providing revenue streams to support attributes of certain resource types, notably in the ancillary service markets, paying for flexibility, paying for fast responsive frequency resources, and operational reserves.

Another observation from the PJM report was that the organized markets were disciplined and PJM had not experienced many regulatory misadventures relative to markets in other parts of the country. Mr. Duane noted that the revenue requirements out of the Capacity, Energy and Ancillary Services Markets were approximately $151,000 MW/year, with lower revenue requirements in Virginia, which remained cost-of-service regulated. He said the difference in revenue requirements related to the risk profile of the investment and who was managing the risk. In an organized market, market participants must manage the operational investment given the tremendous current and future uncertainty. In a regulated market, that risk was underwritten by the ratepayer. To compare the two environments, one must price that risk. When the risks are properly priced, merchant investment proves to be a good deal for consumers.

Mr. Duane reported that, since PJM started its capacity market, it had overcome concerns that it would not attract new entry or, if it did, the new entry would be too expensive. The concern now was that the capacity market would not attract the right kind of investment or provide sufficient revenues to support desired legacy investments. He explained that, when PJM looked at exits from the markets, there appeared to be no material difference between organized markets and regulated markets in moving uneconomic resources out of service. He concluded that the organized markets and PJM's market seem to be doing a pretty good job of maintaining reliability. With respect to markets managing retirements, he noted the following concerns: short-sighted pricing, rising gas prices, price/reliability delivery concerns, reliability operational attributes, and long-term adequacy. Turning to the environmental policy and zero emissions, he concluded that the markets could implement well-designed environmental policies and markets could be changed to permit subsidized projects while protecting market price integrity.

Mr. Hibbard then reviewed his presentation highlighting the challenges that New England was facing with conflicting public policy goals in competition and climate. He reviewed the public policies from the 1990s to transition to competitive markets that were designed to decrease long-run cost to meet customer demand, to remove risk from captive ratepayers, to reduce contentious state resource planning adjudications, and to open the door to technical innovation. He noted the next major policy over the decades had been to progressively reduce the carbon intensity of the electric sector. He said that those two policies were increasingly at odds, not by definition, but in practice.

He summarized that public policy on competition had been a bumpy road for the New England region, but competition was working from the standpoint of fleet turnover to efficient capacity, increased generation efficiency, reliable operation, prices driven by marginal costs, dramatic reduction in ratepayer risks, and constructive evolution of market rules with lessons learned. He stated that ISO-implemented Energy, Reserves and Capacity Market Rule changes over the past several years had been geared to make sure that resources were available when needed in times of scarcity and shortage, which was a major evolution of markets in the direction of achieving the fundamental need of the region at the lowest possible price.

Focusing on the efforts of the New England States to mitigate carbon emissions from the electric sector, Mr. Hibbard identified the renewable portfolio standards, long-term contracts for eligible resources, net metering, energy efficiency, credits/contracts to maintain existing nuclear generating capacity, pay for transmission to access distant renewable resources, and capping emissions of carbon across/beyond the market region. He stated the challenge was that the wholesale markets did not face a strong enough carbon price signal. RGGI worked, but the price signal was not sufficient enough to influence resource outcomes and to achieve the level of mitigation of climate risks desired by the New England States. Other public policy programs had grown to the point that they were degrading the efficiency of wholesale market operations.

He restated the goals for the region were to achieve state policy objectives while maintaining a competitive market, to provide efficient incentives for low carbon resources, and to harmonize the goals of competition and carbon reduction through seamless market approaches. He reviewed four principles to harmonize environmental and other public policy goals, including:

1. Getting the price/cap correct.
2. Eliminating multiple duplicative policies.
3. Consistency with efficient market outcomes.
4. Location, fuel and connection neutrality.

Mr. Hibbard concluded his presentation by identifying alternatives being discussed, including a carbon tax, RGGI with a more stringent cap, carbon intensity dispatch, a tiered capacity market, and clean energy standards. Summarizing, he said that generally the markets were working well, but were failing to meet state policy objectives. State policies were spurring investment but may be harming market efficiency and increasing costs without necessarily achieving the stated objectives, and the region needed to explore ways to align competition policy with climate policy.

STATE OFFICIALS' PRELIMINARY OBSERVATIONS ON THE POLICY AND MARKETS CHALLENGE

With Mr. Raymond Hill, ISO Board Member, facilitating, the following State Officials then provided their observations about the policy and markets challenges: Ms. Katie Scharf Dykes, Deputy Commissioner for Energy, Connecticut (CT) Department of Energy & Environmental Protection (CT DEEP), Mr. Patrick Woodcock, Director, Maine Governor's Energy Office, Mr. Matthew Beaton, Secretary, the Commonwealth of Massachusetts' Executive

Office of Energy & Environmental Affairs (MA OEE), Ms. Margaret Curran, Chairperson, Rhode Island Public Utilities Commission (RI PUC), Mr. Robert Scott, Commissioner, NH PUC, and Mr. Edward McNamara, Regional Policy Director, Vermont (VT) Department of Public Service (VT DPS). All of the speakers were interested in active involvement in the August 11 meeting and encouraged broad participation by others. They individually provided the following additional remarks:

On behalf of Maine, Mr. Woodcock highlighted that state's commitment to environmental policies and the inefficiencies experienced achieving them. He identified as a problem the continued misalignment between natural gas and electric markets and the continued exposure to the price of oil and worldwide LNG prices. He expressed concern about the impacts of the region's loss of nuclear assets, which had been an important to achieving environmental policies. He suggested that added costs associated with environmental policies passed by states within the region should be supported by those states.

Addressing Vermont policies, Mr. McNamara noted that, in 2015, VT's legislature passed a renewable energy standard, with distributed generation its primary focus. He summarized the VT targets, explaining that much of VT's needs were satisfied by long-term contracts with Hydro-Québec and other resources. Indeed, he reported that 65% of VT load was hedged through long-term contracts, with some individual utilities approaching 100%. He stated VT's policies worked less with wholesale market mechanisms and concentrated more on contracts and solar and other behind-the-meter resources.

RI PUC Chairperson Curran addressed the Rhode Island Governor's priority to reduce greenhouse gasses. She stated the Governor was also concerned with economic impacts, jobs, the need for infrastructure, more reasonably priced energy, new capacity in light of retirements, and energy efficiency. Like VT, Rhode Island was also pushing for the development of more distributed generation. She acknowledged that those priorities, goals and objectives outlined created inherent conflicts that needed to be addressed.

On behalf of Massachusetts, Secretary Beaton expressed enthusiasm for the efforts to address together the issues arising from pressures of legislatures in 6 different states which shared generally the same perspective but had 6 different ways of conducting business. He said that legislators know the outcome they seek, but need help defining the best solutions. The challenged, therefore, was to identify a collaborative approach to help implement public policy in the smartest, most economical way possible. The MA Global Warming Solutions Act had largely established MA's current goals (25% by 2020 and 85% by 2050). MA was seeking solutions to best integrate those policy requirements into sound market changes that would minimize detrimental effects on the MA economy. He reported that MA would be hosting the New England Governors and Eastern Canadian Premiers at the end of August, and hoped that the August 11 meeting would identify concepts and next steps that could also be discussed at that conference.

NH Commissioner Scott observed that state policies have impacts on the wholesale market even if intended to be out-of-market mechanisms. He stated solutions might be much easier to identify if the States were unified with the same goals and legal authorities, but that was not generally the case. He noted that New England had a unified policy with RGGI, but state RPSs, with each states' RPS slightly different from the next, were much less so. By way of example, he cited NH alternative compliance price payments that cap the price of RECs in NH. NH also had different legal authorities and different levels of stringencies in its state policies than other New England States. It would be critically important to informed decision making, he opined, for the region to understand comprehensively the price and other impacts of alternative solutions.

Deputy Commissioner Dykes explained that Connecticut's energy policy priorities were focused on being cheaper, cleaner, and more reliable. She stated climate change was one of the biggest threats to reliability of CT's electric system. She stated CT policy was to support fuel diversity, with concern that, should low natural gas prices drive the retirement of base load nuclear resources, the New England generation fuel mix could be 70-80% fired by natural gas, thereby increasing regional carbon emissions by 27%. Accordingly, retention of existing nuclear resources was a strong policy priority for CT. She reported that the RGGI states had reduced carbon emissions by 45% since 2005, with a 50% expected reduction by 2020, largely through the wholesale market and markets the states have been influencing. New England States also had RPSs supported by a renewable energy certificate (REC) market. She said that CT concluded that, to secure investment for new renewable generation, CT needed to competitively procure those resources through long-term contracts.

Mr. Hill then facilitated comments from others. From the panelists, Mr. Hibbard noted that harmonizing state policy goals and competitive markets would be complicated and challenging but it was critical that both objectives be met. Mr. Duane noted remarkable optimism from the six New England States in a shared policy objective even with the challenge of different ways of accomplishing those objectives

One member noted that RPS were intended and designed to enable states to meet clean energy objectives over time in restructured markets, and questioned whether more focus should be placed on improving RPS. Commissioner Dykes responded that CT was evaluating RPS changes to address policy needs, but CT was looking more broadly at how revenues were assured and environmental attributes were rewarded in order to support necessary financings. Commissioner Scott noted that modifying RPSs would be a real challenge but might produce a positive effect similar to RGGI.

A member commented that there needed to be an honest acknowledgement of the added costs these initiatives might impose on customers, and asked whether and how NEPOOL can help educate the States' legislatures, governors and consumers to that fact. Secretary Beaton responded that, on varying levels, the States have all expressed concern with costs of these state policies. Articulating the added costs to consumers would be a significant challenge. Mr. Woodcock noted that the NEPOOL and NESCOE analyses are intended to identify public policy costs. A member challenged the assertion that the path forward had to be more costly and suggested that adapting to a cleaner future could be achieved without additional cost.

Another member challenged the statement that the markets are working, particularly in light of the fact that they are constantly changing. Mr. Hibbard responded that the PJM, NYISO, and ISO-NE markets were attracting new investments, and it was entirely appropriate to learn from our experiences with these relatively new markets and adjust them to reflect lessons learned. Mr. Duane expressed surprise at the level of new entry in PJM's most recent capacity auction. He acknowledged the complexity and pace of changes to the markets, and the chilling effect that could have on investment, but noted that those challenges notwithstanding, capital continued to be invested in the markets. Mr. McNamara added that the markets were not ends unto themselves. Rather, markets were administrative constructs that would have evolving rules. He stated his view that New England markets had produced economically efficient outcomes, but had not encouraged fuel diversity.

A member questioned how States were addressing carbon dioxide emissions from the transportation sector, which were double those of the energy sector. Mr. McNamara responded that VT is required every four to five years to come up with a comprehensive energy plan, including electricity, but also transportation and heating (which in VT produced more overall carbon emissions than electricity), and was even looking at increasing the electrification of the transportation and heating sectors. The focus on electrification and electricity emissions, he surmised, may largely be attributable to the fact that it is easiest, politically, to address. Deputy Commissioner Dykes added that States need to be transparent with stakeholders and stakeholders need to be informed as to the progress of electrification of heating and transportation, which would themselves be contingent on electricity sector emission reductions and would also drive increased regional demand. Chairperson Curran echoed statements describing the difficulty in achieving substantial change in the transportation and heating areas. Commissioner Scott stated that emission from other sectors is under constant discussion among the States, but barring a unified approach, different responses from different State legislatures could be expected and would contribute to the ongoing tension he had described earlier. Commissioner Dykes added that all the States were thinking about the cost implications and highlighted the importance to come up with a harmonized solution to promote efficient investment that is supportive of the state policy goals.

Discussion turned to whether the current RGGI goals could help States achieve their carbon reduction targets by 2030-2040. Mr. Hibbard stated he did not believe RGGI would get the States where they wanted to be, but RGGI could favorably influence that outcome in the electric sector. Mr. Woodcock agreed, and noted that States must focus on the more comprehensive emissions picture. He wondered whether in retrospect the focus on, and investment in, PV deployment and distributed generation would be view favorably. He noted the disconnect between petroleum consumption and electrical greenhouse gas emissions, with policies largely focused just on the electric sector. He suggested that, to be successful like RGGI, a regional transportation sector emission reduction program design would require additional partners and public awareness. He challenged those in the environmental community to raise that awareness and focus on the sources from which the majority of New England's actual greenhouse gas emissions emanate.

Following further discussion and comment, Mr. Gordon thanked the panelists, the State Officials and all who participated.

INTERNAL MARKET MONITOR (IMM) REPORT

Dr. Jeffrey McDonald, the ISO's IMM, presented highlights from the IMM's 2015 Markets Report (IMM Annual Report), which had been circulated and posted in advance of the meeting. Summarizing, he noted the lower wholesale power costs and uplift due to lower fuel prices. He highlighted New England's growing reliance on natural gas resources.

Dr. McDonald then reviewed the different types of resources that were marginal during the year, including virtual demand and supply, imports and exports, and price-sensitive demand. He stated the diversity of resources setting the price in the Day-Ahead Markets was good and reflected a fairly liquid group of demand and supply resources in the price stack. He noted that the marginal units in Real-Time Markets were more commonly natural gas-fueled and vary slightly from season to season.

He commented on the impact of NCPC charges on virtual transactions. He explained that preliminary results from CTS were promising, and committed to provide more analysis of CTS in his next report.

He summarized from his presentation the net imports and exports from Canada and NY. He noted from his presentation the reduction in Forward Reserve Prices in 2015 from prior years.

Dr. McDonald expressed his view that the Day-Ahead Energy Market was operating competitively and producing competitive outcomes. He reviewed a chart reflecting the residual supply index for the Real-Time market which indicated high frequency of pivotal suppliers. He then reviewed a chart of the offer conduct and impact tests applied prior to mitigation, with most often the market impact passing and no mitigation applied.

Dr. McDonald concluded his report reviewing the IMM's recommendations, including the ISO developing a database of corporate relationships and asset control that allows for accurate portfolio construction, enhancing the Real-Time Energy Market mitigation pivotal supplier test to include ramp-based accounting of supply recognizing the differences between energy and reserve products and participant affiliations, and developing and implementing processes and mechanisms to resolve the market power concerns associated with exempting all or a portion of a Forward Reserve resource's energy supply offer from energy market mitigation.

On behalf of NEPOOL, Mr. Gordon thanked Dr. McDonald for his report. The June 22 session then adjourned at 11:45 a.m., with the meeting to be reconvened at 9:30 a.m. on June 23.

JUNE 23, 2016 SESSION

The Summer Meeting reconvened at 9:30 a.m. on June 23, 2016, following reports on the prior day's activities. Mr. Gordon expressed appreciation to Day Pitney for the efforts in planning a successful Summer Meeting.

REPORT OF THE ISO CHIEF EXECUTIVE OFFICER

Mr. Gordon van Welie, ISO Chief Executive Officer, echoed Mr. Gordon's sentiments regarding the Summer Meeting and thanked the Sectors for their engagement in the earlier Sector meetings. He reported positive feedback received from Board members and Participants alike, indicating that the discussions, particularly on the topics of integrating wholesale markets and public policy and continuing concerns over regional fuel issues, had been constructive and engaging.

REPORT OF THE ISO CHIEF FINANCIAL OFFICER

Mr. Robert Ludlow, ISO Chief Financial Officer, referred the Committee to the ISO 2017/18 Preliminary Operating and Capital Budget presentation included with the materials posted in advance of the meeting, which he indicated had also been shared and discussed with the States at the 2016 NECPUC Symposium. He described key components of the 2017/18 Budgets, including: steady headcount (no increase); increased cyber security costs; increased compensation and employee benefits costs; increased regulatorily-mandated costs, including NERC/NPCC fees; increased computer services and systems support cost; efficiencies mitigating and reducing costs, and other cost reductions.

He stated the 2017/18 Budgets reflect the ISO's balancing of cost containment with the need for continued high-level of service. He reported that the 2017/18 Operating Budget was projected to increase by 4%, while the 2017 Capital Budget was projected to increase by $1 million from the 2016 Capital Budget.

Turning to the next steps in the 2017/18 Budget process, Mr. Ludlow reported that the Budget & Finance Subcommittee meeting to discuss the 2017/18 Budgets would take place on August 12. The ISO would review the 2017/18 Budgets with the States on August 15 and with the Participants Committee on September 9. Feedback received from those three meetings would be reviewed with the ISO Board at its September 15 meeting. The Participants Committee would then be asked to vote on the proposed budgets at its October 14 meeting, with the final ISO Board vote taken following the October Participants Committee meeting. Mr. Ludlow indicated that the ISO planned to file the 2017 Budgets with the FERC on October 17.

APPROVAL OF JUNE 3, 2016 MEETING MINUTES

Mr. Doot referred the Committee to the preliminary minutes of the June 3, 2016 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. Gordon 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 without discussion or comment.

FORWARD CAPACITY MARKET (FCM) ENHANCEMENTS PROJECT (PHASE I)

Mr. Gordon referred the Committee to, and summarized, the materials circulated and posted in advance of the meeting related to, Markets Committee-recommended revisions to Market Rule 1 to implement Phase I of the FCM enhancements project relating to FCM qualification process and participation in Capacity Supply Obligation (CSO) Bilaterals. He reported that the Markets Committee had recommended unanimously Participants Committee support for the package of FCM enhancements at its June 14 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:

> RESOLVED, that the Participants Committee supports the revisions to Market Rule 1 to implement enhancements to the Forward Capacity Market (FCM) rules relating to the FCM and Annual Reconfiguration Auction (ARA) qualification processes and CSO Bilaterals, as circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

FCM COMPOSITE OFFERS & PRICE LOCK MECHANISMS (FERC COMPLIANCE)

Mr. Alex Kuznecow, Markets Committee Chairman, referred the Committee to the materials circulated and posted in advance of the meeting regarding ISO-proposed and Markets Committee-recommended changes to the FCM rules, in response to the FERC's May 2, 2016 order (Docket No. EL16-38). He summarized the history of the proceeding and the concerns raised by Dominion Resources. He noted the FERC directive that ISO submit a compliance filing specifically addressing whether new incremental and existing capacity at the same resource must submit a composite offer and either allow an existing generating resource to lock-in the price for the new incremental capacity or show cause for why the lock-in should not be permitted. He proceeded to describe the ISO's recommendation that was recommended by the Markets Committee and two amendments to the proposed changes, one by Dominion and the other by NRG, that were presented to the Markets Committee. He explained that the Dominion amendment would have allowed either new summer or new winter incremental capacity to be paired with any existing excess qualified capacity and would also have allowed the multi-year rate lock to be applied. The NRG amendment would have permitted a resource to apply the multi-year rate lock-in election to new incremental capacity for the entire Capacity Commitment Period, but would not have permitted incremental winter capacity to be used to increase the Qualified Capacity of the resource. He explained that the Markets Committee, in each case with a 47.61% Vote in favor, did not recommend Participants Committee support for either amendment. The Markets Committee did, however, recommend support for the ISO-proposed changes, with two oppositions and one abstention in the Generation Sector, and four abstentions in the Supplier Sector.

Mr. Kuznecow then reported that, following the Markets Committee votes, on June 16, the FERC had issued an order in response to a pending NextEra Complaint that involved a different aspect of the same Market Rule, here relating to significant increase in capacity. In response to that order, the ISO had circulated additional Tariff language for Participants Committee review and consideration at the Summer Meeting. Mr. Gordon asked whether there was any objection to including the additional Tariff language as part of the main motion. Mr. William Fowler, Markets Committee Vice-Chairman, offered his view that the additional changes were a good response to the NextEra Complaint order and supported including the additional changes as part of the main motion. No objection was raised.

Mr. Doot clarified that there was no need for proponents to re-raise proposals considered but not recommended by the Markets Committee. No process issues would be raised over a failure to vote the same changes at the Participants Committee.

Accordingly, the following main motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the revisions to Sections III.13.1.1.1.3.A and III.13.1.1.2.2.4 to Market Rule 1, as proposed by ISO-NE in response to FERC's May 2 order in Docket No. ER16-38-000 and recommended by the Markets Committee at its June 14, 2016 meeting, and revisions to Section III.13.1.2.2.5 as proposed by ISO-NE, all as circulated to this Committee in advance of this meeting, together with such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

In response to clarifying questions of the ISO, Mr. Mark Karl confirmed that the changes, if accepted, would be effective for the FCA11 qualification process and confirmed that discussion as to how the IMM would treat capacity revenue in its calculation of the auction floor price would begin at the Markets Committee Summer Meeting in July. The NextEra representative expressed appreciation to the ISO for proposing to include the additional language in the Tariff.

The NRG representative then offered a motion to amend the main motion to include the following revised language to Section III.13.1.1.2.2.4, that was duly made and seconded (NRG Amendment):

> If an incremental amount of new capacity that meets the requirements of Section III.13.1.1.1.3 is matched to winter existing excess Qualified Capacity at the same generating resource pursuant to Section III.13.1.1.1.3.A, then this election shall ~~only~~ apply to the new incremental ~~amount of capacity~~ FCA Qualified Capacity that clears, including~~. The election shall not apply to~~ the winter existing excess Qualified Capacity matched to the new incremental capacity at the same generating resource.

Mr. Karl stated the ISO continued to oppose the NRG Amendment out of a concern that the NRG Amendment would go beyond the FERC's compliance directives.

The Dominion representative expressed appreciation to the ISO for coming around on the composite offer pairing of new incremental capacity with existing excess winter capacity. He stated, however, that Dominion will support the NRG Amendment since it addresses gaps in the ISO's compliance proposal. He also noted Dominion's concern with how the multi-year price lock-in mechanism is applied. He explained that, since a resource is taking on a CSO for an entire year, the 7-year or multi-year lock rate should apply to those incremental megawatts for the entire Capacity Commitment Period. He further expressed the need for ISO to add language clarifying how payments will be made if a multi-year rate lock is awarded just for new incremental summer capacity.

In opposition to the NRG Amendment, members restated comments raised at the Markets Committee that there would be circumstances where the proposed changes might make sense but also other circumstances where they might not. Accordingly, they advocated for this matter to be considered at a future date when it could be considered more deliberately, and not as part of this compliance obligation.

Following final comments by NRG, the NRG Amendment was considered and failed to pass with a 47.20% Vote in favor (Generation Sector - 14.98%; Transmission Sector - 2.45%; Supplier Sector - 15.22%; Alternative Resources Sector - 9.66; Publicly Owned Entity Sector - 0%; and End User Sector - 4.89%). (See Vote 1 on Attachment 2).

The unamended main motion was then voted and passed with one opposition noted by Dominion, and abstentions noted by Anbaric, Calpine, NRG, and SunEdison.

ADDITIONAL CHANGES TO NEPOOL GIS APPLICATION PROGRAMMING INTERFACE (API)

Mr. Paul Belval, NEPOOL Counsel, referred the Committee to the materials circulated in advance of the meeting regarding changes to technical details for the NEPOOL Generation Information System (GIS) API architecture. He said that the Participants Committee on May 6 approved changes to the GIS Operating Rules to extend the API. He explained that the previously approved changes were requested by SRECTrade, and had been circulated to the GIS Operating Rules Working Group. Following the May 6 Participants Committee approval of the changes, SRECTrade circulated a revised set of technical details, which APX confirmed would add no additional cost to NEPOOL but may delay the implementation of the API-related changes to the GIS from September 30, 2016 to not later than October 15, which is the start of the second quarter Trading Period in the GIS. Neither the Vice-Chairman of the Markets Committee nor the Chairman of the Budget & Finance Subcommittee were comfortable concluding that the additional technical changes were non-material changes that they could approve without Participants Committee input, and accordingly the matter is back to the Participants Committee for further consideration of the additional changes.

The following motion was duly made and seconded:

> RESOLVED, that the Participants Committee approves the changes to the technical details related to the extension of the application programming interface for the NEPOOL Generation Information System, with such non-material changes thereto as the Vice-Chair of the Markets Committee or the Chair of the Budget & Finance Subcommittee may approve.

In response to a request by Mr. Gordon, Mr. Kenneth Dell Orto, Budget & Finance Subcommittee Chairman, expressed his view that the proposed changes are consistent with the spirit and intent of the original proposal by SRECTrade that was approved by the Participants Committee. He reiterated that the revised changes do provide some additional functionality in the GIS, at a minimal schedule delay with no additional cost. He considered the changes to be non-controversial, and he supported and would vote in favor of them. Mr. Fowler, Markets Committee Vice-Chairman, expressed similar views. He added, though, that he was not comfortable accepting the changes as non-material in light of the controversy raised when the original changes were presented to the Markets and Participants Committees, and the technical nature of the changes. Accordingly, both he and the Budget & Finance Subcommittee Chairman agreed that the additional changes were best brought back to the Participants Committee for consideration.

A member who opposed the earlier approved changes offered a motion to defer consideration of this motion until after January 1, 2017, and that motion was seconded. Mr. Doot clarified in response to a member's question that the deferral would only preclude completion of the additional proposed changes and APX would be required to proceed with the changes approved at the May 6 meeting, without the beneficial, no-cost additional functionality proposed by the latest changes. In response, the member offering the motion to defer further explained that the Working Group considering the expiration of the contract with APX has met and may seek major changes both to the GIS and the cost allocation. He repeated arguments from the May 6 Participants Committee meeting that it would be better to incorporate prior and the pending changes into a new GIS agreement rather than by amending the current agreement.

The motion to defer consideration of this matter until January 1, 2017 was voted and failed to pass with AIM, Emera Maine, Harvard, High Liner Foods, and TEC voting in favor and all others opposed.

The main motion was then voted and passed with an opposition by High Liner Foods.

NEPOOL AUDIT MANAGEMENT SUBCOMMITTEE (NAMS) REPORT

Mr. Steven Kirk, NAMS Chairman, referred the Committee to the June 10 Interim Report to NAMS on the operational audit of the ISO (Interim Report), circulated and posted in advance of the meeting. He explained that, following the Participants Committee-approved hiring of Mr. Bill Dunn to conduct the audit for NAMS, activities began in earnest in late 2015 to coincide with the ISO's rolling 18-month audit. Mr. Dunn had been directed to focus on mitigation in the Energy and Capacity Markets, NCPC, and Control Room operator actions. The Interim Report covered activities and observations through May 2016. After a brief hiatus, Mr. Dunn's efforts would start back up in September when the ISO's auditors from KPMG were expected to resume their work on (and Mr. Dunn could resume shadowing) their Service Organization Control (SOC) 1 Type 2 engagement. He reported that NAMS expected a second Interim Report to be issued before the end of 2016.

LITIGATION REPORT

Mr. Patrick Gerity, NEPOOL Counsel, noted that there had been no Litigation Report since the one circulated earlier in the month. He directed those who were interested in the more current updates since the last report to the Litigation Updates page on the NEPOOL website. He said that the following activities had occurred since the issuance of the last Report: a request by the ISO on June 9 for a Tariff waiver to allow Real-Time Emergency Generation Resources either to change their resource type to Real-Time Demand Response Resources or to de-list; a June 16 FERC order accepting the results of FCA10; a June 16 order denying NextEra Complaint's regarding ISO actions disallowing the proposed capacity increase at the Bellingham Energy Center; and the scheduling of oral argument on September 6 in the proceeding before the DC Circuit Court of Appeal challenging the orders accepting the FCA8 results filing. He reminded the Committee of the technical conferences and workshops scheduled for the following week at FERC headquarters, as summarized by Mr. Hensley earlier in the meeting.

In response to a question regarding expected timing of FERC action on the Marginal Reliability Impact (MRI)-based demand curves, Mr. Raymond Hepper, ISO Counsel, explained that, because the April 15 filing was in part a compliance filing, the FERC was under no obligation to issue an order by a specific date, including by the June 16 date requested by the ISO. Mr. Doot added that, although the requested June 16 date had passed, and the FERC was under no specific deadlines, there was no reason to expect substantial delay in the issuance of a FERC order on the filing.

COMMITTEE REPORTS

Mr. Fowler reported that the Markets Committee Summer Meeting was scheduled for July 18-20 at the Stowe Mountain Lodge in Stowe, VT, with anticipated agenda items to include a vote on resource dispatchability changes, a first look at the reset for Cost of New Entry, Offer Review Trigger Prices for FCA12, and the ISO's look at CSO liquidation in a third ARA. Mr. Robert Stein, Reliability Committee Vice-Chairman, reported that the Reliability Committee was scheduled at its July 12 meeting to consider and vote on the I.3.9 application for the 1,000 MW Clear River project located in Burrillville, Rhode Island. Mr. José Rotger, Transmission Committee Vice-Chairman, reported that the Transmission Committee was scheduled to meet on June 28 for an update on FERC Order 827 (which changed the reactive power requirements for nonsynchronous generation), the ISO's annual presentation on the Schedule II Capacity Cost Compensation rate, and a presentation by the PTOs of the RNS rate that took effect on June 1. Extended discussion of the 2016/17 RNS rate would take place at the Transmission Committee's August Summer Meeting. Mr. Dell Orto reported that the Budget & Finance Subcommittee would meet twice in August -- August 12 to review the proposed ISO and NESCOE 2017 Budgets and the ISO's third quarter Capital Funding Tariff filing, and August 24 to review proposed Financial Assurance and Billing Policy changes.

Mr. Gordon reminded the Committee of the August 11 meeting on integrating wholesale markets and public policy, noting that the agenda for that meeting and next steps were being developed. The August 11 meeting would be held at the Colonnade Hotel in Boston and Mr. Gordon urged those interested to be on the lookout for notices, an agenda and further materials and information for that meeting.

OTHER BUSINESS

Mr. Doot indicated that the next Participants Committee meeting, scheduled to be held August 5 in Boston, was likely to be re-scheduled as a teleconference meeting given the relatively few items expected to be ready for Participants Committee discussion at that time.

There being no further business, the June 23 session and the 2016 Summer Meeting adjourned at 11:15 a.m.

Respectfully submitted,

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David T. Doot, Secretary

ATTACHMENT 1

MEMBERS AND ALTERNATES PARTICIPATING IN THE PARTICIPANTS COMMITTEE JUNE 21-23, 2016 SUMMER MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Anbaric Management LLC	Provisional Group	Steve Conant		
Ashburnham Municipal Light Plant	Publicly Owned			Brian Forshaw
Associated Industries of Massachusetts	End User			Roger Borghesani
AVANGRID (CMP/UI)	Transmission	Eric Stinneford (tel)	Christian Bilcheck	Alan Trotta (tel)
Belmont Municipal Light Department	Publicly Owned			Tim Hebert
Boylston Municipal Light Department	Publicly Owned			Brian Forshaw
BP Energy Company	Supplier			Nancy Chafetz
Brookfield Energy Marketing	Supplier	Aleks Mitreski		
Calpine Energy Services, L.P.	Supplier		Brett Kruse	Bill Fowler
Central Maine Power Company	Transmission	Eric Stinneford		
Chester Municipal Electric Light Department	Publicly Owned			Tim Hebert
Chicopee Municipal Lighting Plant	Publicly Owned			Brian Forshaw
CLEAResult Consulting, Inc.	AR	Doug Hurley		
Competitive Energy Services, LLC	Supplier			Glenn Poole
Concord Municipal Light Plant	Publicly Owned			Tim Hebert
Connecticut Municipal Electric Energy Coop.	Publicly Owned	Brian Forshaw		
Connecticut, State of, Office of Consumer Counsel	End User			Dave Thompson
Conservation Law Foundation	End User	Jerry Elmer		
Conservation Services Group (CSG)	AR		Doug Hurley	
Consolidated Edison Energy, Inc. (ConEd)	Supplier	Jeff Dannels		
CPV Towantic, LLC	Generation	Daniel Pierpont		
Danvers Electric Division	Publicly Owned			Tim Hebert
Dominion Energy Marketing, Inc.	Generation	Jim Davis		
DTE Energy Trading, Inc.	Supplier			Nancy Chafetz
Dynegy Marketing and Trade, LLC	Supplier			Bill Fowler
Emera Maine	Transmission		Jose Rotger	Stacy Dimou Sandi Hennequin Andrew McCullough
Energy America, LLC	Supplier	Ron Carrier	Marji Phillips	Nancy Chafetz
EnerNOC, Inc.	AR	Herb Healy	Sarah Griffiths	
Entergy Nuclear Power Marketing, LLC	Generation		Ken Dell Orto	Bill Fowler
Essential Power, LLC	Generation	M.Q. Riding	Bill Fowler	
Eversource Energy	Transmission	James Daly	Calvin Bowie	
Exelon Generation Company	Supplier	Steve Kirk	Bill Fowler	
FirstLight Power Resources Management, LLC	Generation	Thomas Kaslow		
Galt Power, Inc.	Supplier	Nancy Chafetz		
GDF SUEZ Energy Marketing NA, Inc.	Generation	Joe Dalton		
Generation Group Member	Generation	Dennis Duffy	Abby Krich	Bob Stein
Georgetown Municipal Light Department	Publicly Owned			Tim Hebert
Granite Ridge/Merrill Lynch	Supplier		Bill Fowler	
Groton Electric Light Department	Publicly Owned			Brian Forshaw
Groveland Electric Light Department	Publicly Owned			Tim Hebert
H.Q. Energy Services (U.S.) Inc.	Supplier	Louis Guilbault (tel)	Bob Stein	Abby Krich
Harvard Dedicated Energy Limited	End User			Roger Borghesani
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned			Tim Hebert
Holden Municipal Light Department	Publicly Owned			Brian Forshaw
Holyoke Gas & Electric Department	Publicly Owned			Brian Forshaw
Hull Municipal Lighting Plant	Publicly Owned			Brian Forshaw
Industrial Energy Consumer Group	End User	Don Sipe		
Ipswich Municipal Light Department	Publicly Owned			Brian Forshaw

ATTACHMENT 1

MEMBERS AND ALTERNATES PARTICIPATING IN THE PARTICIPANTS COMMITTEE JUNE 21-23, 2016 SUMMER MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Jeffrey A. Jones P.E.	End User	Jeff Jones		
Jericho Power, LLC	AR			Tim Hebert
Long Island Lighting Company (LIPA)	Supplier	William Killgoar		
Littleton (MA) Electric Light & Water Department	Publicly Owned			Tim Hebert
Littleton (NH) Water & Light Department	Publicly Owned		Craig Kieny	
Maine Public Advocate Office	End User		Tim Schneider	
Maine Skiing, Inc.	End User	Don Sipe		
Mansfield Municipal Electric Department	Publicly Owned			Brian Forshaw
Marblehead Municipal Light Department	Publicly Owned			Brian Forshaw
Massachusetts Attorney General’s Office (MA AG)	End User	Fred Plett		
Mass. Development Finance Agency	Publicly Owned			Tim Hebert
Mass. Municipal Wholesale Electric Company (MMWEC)	Publicly Owned			Brian Forshaw
Merrimac Municipal Light Department	Publicly Owned			Tim Hebert
Middleborough Gas and Electric Department	Publicly Owned			Brian Forshaw
Middleton Municipal Electric Department	Publicly Owned			Tim Hebert
National Grid	Transmission	Timothy Brennan	Timothy Martin	
New Hampshire Electric Cooperative (NHEC)	Publicly Owned		Steve Kaminski	Brian Forshaw
New Hampshire Office of Consumer Advocate (NH OCA)	End User	Paul Peterson	Sarah Jackson	
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
Noble Americas Gas & Power Corp.	Supplier		Becky Merola	
NRG Power Marketing, Inc.	Generation	Dave Cavanaugh	Pete Fuller	
Pascoag Utility District	Publicly Owned			Tim Hebert
Paxton Municipal Light Department	Publicly Owned			Brian Forshaw
Peabody Municipal Light Plant	Publicly Owned			Brian Forshaw
PowerOptions	End User	Cynthia Arcate (tel)		
Princeton Municipal Light Department	Publicly Owned			Brian Forshaw
PSEG Energy Resources & Trade LLC	Supplier	Joel Gordon		
Repsol Energy North America Company	Supplier			Nancy Chafetz
Rowley Municipal Lighting Plant	Publicly Owned			Tim Hebert
Russell Municipal Light Dept	Publicly Owned			Brian Forshaw
Shrewsbury Electric & Cable Operations	Publicly Owned			Brian Forshaw
Small Load Response Group Member	AR	Doug Hurley		
Small Renewable Generation Group Member	AR	Erik Abend (tel)		
South Hadley Electric Light Department	Publicly Owned			Brian Forshaw
South Jersey Energy Company	Supplier			Nancy Chafetz
SRECTrade, Inc.	GIS-Only	Steve Eisenberg (tel)		
Sterling Municipal Electric Light Department	Publicly Owned			Brian Forshaw
Stowe Electric Department	Publicly Owned			Tim Hebert
Sun Edison (First Wind Energy Marketing, Inc.)	AR	John Keene		Bob Stein
Talen Energy Marketing, LLC	Supplier	Tom Hyzinski		
Tangent Energy Solutions	AR	Brad Swalwell (tel)		
Taunton Municipal Light Department	Publicly Owned			Tim Hebert
Templeton Municipal Lighting Plant	Publicly Owned			Brian Forshaw
Texas Retail, LLC	Supplier	Chris Hendrix		
The Energy Consortium	End User	Roger Borghesani		
TransCanada Power Marketing Ltd.	Generation	Daniel Congel		
Union of Concerned Scientists (UCS)	End User		Francis Pullaro	
Utility Services, Inc.	End User			Paul Peterson
Vermont Electric Cooperative	Publicly Owned	Craig Kieny		David Mullett
Vermont Electric Power Company, Inc.	Transmission	Francis Ettori		

ATTACHMENT 1

**MEMBERS AND ALTERNATES PARTICIPATING IN
THE PARTICIPANTS COMMITTEE
JUNE 21-23, 2016 SUMMER MEETING**

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Vermont Energy Investment Corporation	AR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned	David Mullett		
Verso Maine Energy LLC	Generation	Glenn Poole		
Wakefield Municipal Gas and Light Department	Publicly Owned			Brian Forshaw
Wallingford DPU Electric Division	Publicly Owned			Tim Hebert
Wellesley Municipal Light Plant	Publicly Owned			Tim Hebert
West Boylston Municipal Lighting Plant	Publicly Owned			Brian Forshaw
Westfield Gas & Electric Light Department	Publicly Owned			Tim Hebert
Wheelabrator North Andover Inc.	AR	Bill Fowler		

ATTACHMENT 2

VOTE TAKEN AT
JUNE 21-23, 2016 PARTICIPANTS COMMITTEE SUMMER MEETING

TOTAL

Sector/Group	Vote 1
GENERATION	14.98
TRANSMISSION	2.45
SUPPLIER	15.22
ALTERNATIVE RESOURCES	9.66
PUBLICLY OWNED ENTITY	0.00
END USER	4.89
PROVISIONAL MEMBERS	0.00
% IN FAVOR	**47.20**

GENERATION SECTOR

Participant Name	Vote 1
CPV Towantic, LLC	F
Dominion Energy Marketing, Inc.	F
Entergy Nuclear Power Marketing	A
Essential Power, LLC	F
FirstLight Power Resources Mgmt. LLC	O
GDF SUEZ Energy Marketing NA	F
Generation Group Member	F
NextEra Energy Resources, LLC	F
NRG Power Marketing, LLC	F
IN FAVOR (F)	7
OPPOSED (O)	1
TOTAL VOTES	8
ABSTENTIONS (A)	1

TRANSMISSION SECTOR

Participant Name	Vote 1
AVANGRID (CMP/UI)	O
Emera Maine	S
Emera Maine	A
Emera Energy Services Subsidiaries	F
Eversource Energy	O
National Grid	O
Vermont Electric Power Company	A
IN FAVOR (F)	0.5
OPPOSED	3.0
TOTAL VOTES	3.5
ABSTENTIONS (A)	1.5

ALTERNATIVE RESOURCES SECTOR

Participant Name	Vote 1
Renewable Generation Sub-Sector	
SunEdison (First Wind)	F
Small RG Group Member	F
Wheelabrator North Andover Inc.	A
Distributed Generation Sub-Sector	
CLEAResult Consulting Inc.	F
Load Response Sub-Sector	
EnerNOC, Inc.	F
Vermont Energy Investment Corp.	O
Small LR Group Member	S
Energy Federation Inc.	O
Tangent Energy Solutions Inc.	O
IN FAVOR (F)	4
OPPOSED	2
TOTAL VOTES	6
ABSTENTIONS (A)	1

SUPPLIER SECTOR

Participant Name	Vote 1
BP Energy Company	A
Brookfield Energy Marketing Inc.	F
Calpine Energy Services	F
Consolidated Edison Energy, Inc.	F
DTE Energy Trading, Inc.	A
Dynegy Marketing and Trade, LLC	F
Energy America, LLC	O
Exelon Generation Company	A
Galt Power, Inc.	A
H.Q. Energy Services (U.S.) Inc.	F
LIPA (Long Island Power Authority)	A
PSEG Energy Resources & Trade	F
Repsol Energy North America	F
Talen Energy Marketing, LLC	A
Texas Retail, LLC	F
IN FAVOR (F)	8
OPPOSED	1
TOTAL VOTES	9
ABSTENTIONS (A)	6

ATTACHMENT 2

VOTE TAKEN AT
JUNE 21-23, 2016 PARTICIPANTS COMMITTEE SUMMER MEETING

END USER SECTOR

Participant Name	Vote 1
Associated Industries of Massachusetts	A
Conn. Office of Consumer Counsel	O
Harvard Dedicated Energy Limited	A
High Liner Foods (USA) Inc.	F
Mass. Attorney General's Office	F
NH Office of Consumer Advocate	O
PowerOptions, Inc.	O
The Energy Consortium	O
Utility Services Inc.	O
IN FAVOR (F)	2
OPPOSED	5
TOTAL VOTES	7
ABSTENTIONS (A)	2

PUBLICLY OWNED ENTITY SECTOR

Participant Name	Vote 1
Ashburnham Municipal Light Plant	O
Boylston Municipal Light Department	O
Belmont Municipal Light Department	O
Chester Municipal Light Department	O
Chicopee Municipal Lighting Plant	O
Concord Municipal Light Plant	O
Conn. Municipal Electric Energy Coop.	O
Danvers Electric Division	O
Georgetown Municipal Light Department	O
Groton Electric Light Department	O
Groveland Electric Light Department	O
Hingham Municipal Lighting Plant	O
Holden Municipal Light Department	O
Holyoke Gas & Electric Department	O
Hull Municipal Lighting Plant	O
Ipswich Municipal Light Department	O
Littleton (MA) Electric Light Department	O
Littleton (NH) Water & Light Department	O
Mansfield Municipal Electric Department	O
Marblehead Municipal Light Department	O
Mass. Development Finance Agency	O
Mass. Municipal Wholesale Electric Co.	O
Merrimac Municipal Light Department	O
Middleborough Gas & Electric Dept.	O
Middleton Municipal Electric Department	O

PUBLICLY OWNED ENTITY SECTOR (cont.)

Participant Name	Vote 1
New Hampshire Electric Cooperative	O
Pascoag Utility District	O
Paxton Municipal Light Department	O
Peabody Municipal Light Plant	O
Princeton Municipal Light Department	O
Rowley Municipal Lighting Plant	O
Russell Municipal Light Department	O
Shrewsbury's Elec. & Cable Ops.	O
South Hadley Electric Light Department	O
Sterling Mun. Elec. Light Department	O
Stowe (VT) Electric Department	O
Taunton Municipal Lighting Plant	O
Templeton Mun. Lighting Plant	O
Vermont Electric Cooperative	O
Vermont Public Power Supply Authority	O
Wakefield Municipal Gas & Light Department	O
Wallingford (CT) Division Public Utilities	O
Wellesley Municipal Light Plant	O
West Boylston Mun. Lighting Plant	O
Westfield Gas & Electric Light Department	O
IN FAVOR (F)	0
OPPOSED	45
TOTAL VOTES	45
ABSTENTIONS (A)	0

PROVISIONAL MEMBERS

Participant Name	Vote 1
Anbaric Management LLC	A
IN FAVOR (F)	0
OPPOSED	0
TOTAL VOTES	0
ABSTENTIONS (A)	1

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