FINAL

Pursuant to notice duly given, a meeting of the NEPOOL Participants Committee was held via teleconference beginning at 10:00 a.m. on Thursday, June 24, 2021. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the teleconference meeting.

Mr. David Cavanaugh, Chair, presided and Mr. David Doot, Secretary, recorded.

APPROVAL OF JUNE 3, 2021 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the June 3, 2021 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of that meeting were unanimously approved as circulated, with an abstention by Mr. Michael Kuser's alternate noted.

ISO CFO REPORT: 2022 ISO BUDGETS

Mr. Robert Ludlow, the ISO's Chief Financial Officer (CFO), referred the Committee to a presentation of the ISO's 2022 Preliminary Operating and Capital Budgets included with the materials posted in advance of the meeting. He reported that he had also shared this information with state officials in early June and had answered clarifying questions and committed to provide further detail/information in future meetings.

He began by noting that the 2022 preliminary operating budget supported the ISO's vision to harness the power of competition and advanced technologies to reliably plan and operate the grid as the region transitions to clean energy. He indicated that, to achieve this vision, the ISO anticipated the need for approximately 21 full-time equivalent (FTE) additions between 2022 and 2023. To meet that anticipated need, the 2022 preliminary budget included funding for 9 FTE additions. Those 2022 additions would be primarily to address the growing volume and workload for the integration of clean energy and distributed resources, which had impacted the market development, transmission planning, power system modeling, and legal areas, and for cyber security and information technology (IT) support. The 2023 preliminary budget included funding for 12 more FTE additions which, similarly, would be primarily to address the growing volume and workload for the integration of clean energy and distributed resources. The increased resources represented projected year-over-year increases, before depreciation, of $10,605,000 or 5.9% for 2022 and $9,161,900 or 4.8% for 2023. The projected increases, including depreciation, would be $9,057,100 or 4.4% and $7,181,900 or 3.4%, in 2022 and 2023, respectively.

Turning to the capital budget, Mr. Ludlow reported that the ISO anticipated that the annual capital budget would need to increase by up to $7 million over the next 5 years, from $28 million to $35 million. The ISO proposed, preliminarily, to have $4 million of that increase to occur in 2022, which would reflect a $32 million annual capital budget. Four primary drivers necessitated the projected increase: (i) nGEM platform replacement; (ii) cyber security; (iii) major capital projects to enable the clean energy transition and improve reliability; and (iv) IT asset and infrastructure replacement. Mr. Ludlow reported that the ISO planned to discuss the 2022 and 2023 budgets with the NEPOOL Budget & Finance Subcommittee in August.

In response to a question about the projected 2021 year-end actuals, Mr. Ludlow noted that the ISO anticipated being on budget at year's end.

ISO COO UPDATE

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by addressing the concerns raised about Minimum Offer Price Rule (MOPR) reform plans. He noted that the current work plan had changed substantially from the 2021 work plan that was shared with stakeholders eight months before, primarily due to intervening FERC orders and new priorities. He then highlighted that the ISO prioritized the project to eliminate MOPR in response to the strong message sent from the FERC Chair and the preference for a FERC proceeding initiated by a Federal Power Act (FPA) section 205 filing rather than an order from the FERC pursuant to FPA section 206.

He noted the ISO's operational concerns with a complete elimination of MOPR. He reported that the ISO had asked Dr. David Patton, Ph.D., President of Potomac Economics, the ISO's External Market Monitor (EMM), for assistance in quantifying the uncertainty of the market without MOPR. He explained that the ISO already had a standing contract in place with Potomac Economics so it did not separately document a statement of work. The ISO expected to receive more guidance from the FERC in late July or early August and would continue to engage with stakeholders to understand, discuss and refine what could be included in the MOPR filing (expected in early 2022). He noted the intent to provide early reports on status for feedback but noted possible limitation on the ability to do so with the need to think through implementation ahead of finalizing the analysis. He acknowledged work on resource electric load carrying capabilities (ELCC) was a critical companion to the elimination of MOPR. He said that the ISO planned to advance that project as soon as possible. He reiterated the ISO's objective to balance many competing factors that help to achieve reliability through the markets, rather than outside the markets, while maintaining a priority on elimination of MOPR. He expected that the stakeholder process would help to ensure informed and robust discussions amongst stakeholders.

Dr. Chadalavada responded to a number of questions about the scope of Dr. Patton's review to provide an assessment and quantification of a market without MOPR. He said the plans were for the EMM to share its core recommendations with stakeholders in late July or August, and to provide later a sequence of additional recommendations relative to ELCC and the Energy Security Initiative (ESI). When pressed with numerous additional questions about the work required by the ISO to support the filing, Ms. Maria Gulluni, the ISO's General Counsel, noted that the ISO would ensure that it completes the work it believes will be required for the ISO filing to include all the information necessary to demonstrate that the filed changes are just, reasonable and supportable.

EMM 2020 ANNUAL MARKETS REPORT

MOPR Reform

Following Dr. Chadalavada's presentation, the Chair introduced Dr. Patton to present his annual report on the state of the markets. Having listened to the earlier discussions about the EMM's scope of work in response to ISO's request relating to the elimination of MOPR, he volunteered to address some of those questions from the EMM's perspective and the Chair agreed.

Dr. Patton began by acknowledging the concerns with MOPR and the need for the Forward Capacity Market (FCM), as well as the markets holistically, to continue to work and serve their purpose. He shared two priorities the EMM had identified relating to this topic. The first priority he discussed was the need to improve resource capacity accreditation. Dr. Patton opined that resources, particularly newer technologies, were often given too much capacity credit and that their contribution to resource adequacy was dependent on the penetration of that type of resource in the resource mix. Thus, he stressed the importance of getting a resource's accreditation correct to prevent collateral issues in the market. Dr. Patton noted that, while accreditation was a high priority, the immediate scope of work did not encompass that issue but Potomac Economics would offer feedback.

The EMM considered the second priority to be ensuring that markets support resources' investment decisions were reasonably based on the expectation of market revenues over the life of the resource. Dr. Patton explained that eliminating MOPR would likely increase revenue risk and would reduce the expected future revenues for non-sponsored resources. The scope of work, as viewed by the EMM, was to quantify the adjustments to the demand curve that would be necessary to account for the increased price uncertainty in the market so that the expectation of future revenues in light of the elimination of MOPR would continue to support investments by non-sponsored resources.

After describing the EMM's plans for the work to be performed, numerous members sought further understanding on how those efforts might unfold. One line of questions sought Dr. Patton's views on whether the EMM in its scope of work would take into account the possibility that FCA17 would not have a new method to accredit resources. A colleague of Dr. Patton, who was on the team planning and performing the work, responded that the EMM was working to construct an analysis of multiple scenarios with and without MOPR to determine a range of outcomes. The EMM was planning to focus on a variety of inputs that would change if MOPR was eliminated. The analysis, he continued, was still being designed with the intention of answering the basic question of what impacts could reasonably be expected with the elimination of the MOPR. The next line of questions sought Dr. Patton's opinion on whether adjusting the inputs into the FCM would produce competitively determined auction prices. Dr. Patton responded that EMM intended to analyze whether and how the region might offset the detrimental effects of eliminating the MOPR and prevent out-of-market actions, with the desire that the markets would result in efficient decision making by Market Participants to satisfy resource adequacy.

Following approximately 30 minutes of the Committee's time with Dr. Patton on this topic, and while there remained other Market Participants that had expressed an interest in continuing to question the EMM as to its expectations and predictions of where its future work might take it in response to the ISO's request relating to elimination of MOPR, the Chair halted further questions. He expressed concern with the extended time discussion on this topic, which had not been noticed, was taking. He suggested that the Markets Committee would be a better forum for addressing such questions and that a Markets Committee meeting for that discussion was planned. He requested that Dr. Patton, in the remaining time he was available for the Committee during this meeting, move to the presentation of the highlights of the EMM's assessment of the markets in 2020, which was the topic that had been noticed for the meeting.

2020 EMM Annual Report Overview

In response to the Chair's request, Dr. Patton referred to the EMM's 2020 Markets Report (EMM Annual Report) and a presentation with highlights from that report, each of which had been circulated and posted in advance of the meeting. He explained that the role of the EMM was (i) to evaluate and report on the competitive performance and operation of New England's wholesale markets, (ii) to identify and recommend necessary changes to improve existing and proposed market rules, tariff provisions and market design elements, and (iii) to evaluate the mitigation by the ISO's Internal Market Monitor (IMM). He stated that the EMM Annual Report focused on and summarized the following key market areas: cross-market comparison of several key market outcomes and metrics; competitive performance of the markets; market issues related to reliability commitments and uplift costs; long-term investment signals; energy efficiency participation in the FCM; and capacity accreditation in the FCM. He then highlighted three high priority recommendations that he expected would improve the performance of the markets and facilitate large-scale entry of intermittent resources. The first was a recommendation to introduce co-optimized Operating Reserves in the Day-Ahead Energy Market to account for and price all system needs, such as had been proposed in ESI. The second recommendation was to ensure that the FCM accreditation of resources be based on the resources' marginal reliability value. The third recommendation was to modify the pay-for-performance rate to vary with the size of the Operating Reserve shortage.

Cross-Market Comparisons

Next, Dr. Patton reviewed the portion of the presentation that showed cross-market comparisons and highlighted key differences between the New England and other markets. Comparatively, New England generally had the highest all-in prices, driven largely by high capacity costs and higher natural gas prices than other regions of the country. Focusing next on congestion costs, Dr. Patton noted that New England had congestion costs that were only 10-20% of the relative congestion costs of other ISO/RTOs. He attributed the results to the large transmission investments made in New England. He observed that the resulting transmission rates in New England, however, were more than double the average rates in other ISO/RTO markets. When comparing uplift as a percent of load in different markets, he noted that New England appeared to be in line with other markets, but had much lower uplift per megawatt hours (MWh) of load than other markets. He attributed this uplift difference from the other markets to the absence of Day-Ahead reserve markets and low levels of virtual trading.

Discussing Coordinated Transaction Scheduling (CTS), Dr. Patton highlighted that the ISO was more accurate in its load forecasts than other ISO/RTOs and that CTS' positive performance was partly due to the decision not to impose administrative charges on CTS transactions. In other regions where such fees were not waived, the benefits of interregional trading were reduced. He noted the forecast errors, and encouraged that the impact of those errors be reduced through Real-Time price quotes rather than the current process of future estimating.

Market Competitiveness

Transitioning to discussion of market competitiveness, Dr. Patton opined that the New England Market had been performing competitively. He said market competitiveness had improved because of 1.5 gigawatts of new combined cycle units (CCs) in import-constrained areas, transmission upgrades in Boston, and falling load levels because of mild weather, continued growth of energy efficiency and behind-the-meter solar resources, and the effects of COVID-19.

Reliability Commitments and NCPC Charges

He then talked about the impacts of Day-Ahead commitments for local second contingency protection and system level reserve requirements, including on overall Net Commitment Period Compensation (NCPC) costs. With respect to local second contingency protection, he highlighted that Maine was seeing more frequent commitments and higher costs to address local transmission constraints, which would be mitigated if the EMM's recommendation to allow firm imports to satisfy local reserve requirements were to be implemented. He estimated that local second contingency protection commitments accounted for roughly 41% of Day-Ahead NCPC. With respect to system-level operating reserve requirements, Dr. Patton explained that additional generating capacity was being committed Day-Ahead to satisfy expected Real-Time system-level Ten-Minute Spinning Reserve requirements in roughly 45% of all hours. Without those reserve requirements being reflected in the Day-Ahead market dispatch or pricing software, clearing prices for energy (and reserves) were understated and incentives for resources to be made available at the lowest cost were being undermined. He estimated that the commitments for system-level operating reserve requirements accounted for roughly 41% of Day-Ahead NCPC.

He observed that the ISO satisfies a large share of the region's operating reserve requirements using resources that receive no Day-Ahead schedules or compensation (latent reserves), citing many days where the actual reserve requirements exceeded what had been procured. Latent reserves were protecting the region from reliability issues but increasing amounts of resources were being required to manage uncertainty. Dr. Patton opined that the issue of latent resources would become a more pressing issue with higher renewable penetration, reaffirming the need for additional reserve products in the Day-Ahead markets.

Following a short recess for lunch, Dr. Patton shared and explained his reasoning for the EMM's recommendation to reduce inflated costs associated with supplemental commitments by having the ISO use the lowest-cost fuel and/or configuration model for multi-unit generators committed for local reliability and by permitting firm imports to satisfy local reserve requirements.

Long-Term Investment Signals

Turning to the EMM's assessment of the ability of the New England Markets to support long-term investments, Dr. Patton presented a table showing the net revenue comparison across markets. He noted a new combustion turbine was not economic in most markets. He also noted the impact of COVID-19 on the change in load. He observed that 2020 revenues were high enough to motivate development of new resources other than wind. He referred to a table in his presentation that provided the following three recommendations to improve long-term investment signals: (i) improve accreditation rules; (ii) procure operating reserves in a co-optimized Day-Ahead market; and (iii) improve the pay-for-performance penalty rate. He explained that these recommendations would increase compensation for flexible resources, especially batteries.

Reviewing slides illustrating average prices in 2030 offshore wind scenarios, Dr. Patton explained that the impact of various technologies on energy prices depended on the level of penetration of each technology. High penetration of offshore wind, for example, could negatively affect renewable developers and land-based wind. He opined that implementation of technology-neutral strategies to advance State policy goals would lessen the effects of revenue erosion from excess penetration.

Members raised a number of questions about the EMM modeling assumptions for estimating long-term investment signals. Dr. Patton acknowledged that power purchase agreements (PPAs) with fixed prices insulate a supplier from market changes over time, and that the economic life of such resources under long-term PPAs might be equal to the term of the contract. He explained that reliability requires that the system be able to respond to both short-lived, transitory events and longer-duration events. Transitory events produce temporarily high prices that resources such as two-hour batteries would receive for a short time only. He indicated planning models needed to reflect both shorter and longer duration events to produce more accurate economic projections for each type of technology. He explained why the Report encouraged States to compensate public policy resources based on their contribution to the State's policy goal, regardless of entry date or technology. He opined that changes in State policies affect future contracts through additional entry and more attractive terms, which may push down prices to levels below those that earlier resources were relying on for their economic viability. He noted that the resource mix used in each of the EMM cases studied was the mix reflected the 2019 ISO Economic Studies. He explained that supporting certain technologies through contracting schemes, like bundled PPAs, make some Market Participants less sensitive to the efficiency of the investments and can shift investment risks to other Market Participants who may not have the same contractual protections.

Capacity Accreditation

Dr. Patton noted that resource adequacy accreditation should be designed to reflect how each type of resource impacts the loss-of-load expectation. He noted the following concerns with over-accreditation for certain resources: (i) intermittent resources were accredited based on median output in certain hours each day, defined seasonally, which effectively measures intermittent resources' average contribution to reliability; (ii) the marginal reliability value of intermittent resources falls as penetration grows because output is correlated; and (iii) by ignoring the correlation in output, the current approach could over-value the reliability provided by intermittent resources. He then shared a table reflecting average intermittent output during the top five annual net load hours as the penetration of those resources rise. He expressed the importance of tracking diminishing contribution of those resources to reliability. Applying this concept to the value of batteries, as the penetration of storage on the system increases, the marginal value of those resources falls. Batteries with longer duration of potential discharge, though, have a larger contribution to reliability than shorter duration batteries. The market should incentivize longer duration batteries. The marginal accreditation approach would compensate each resource based on its incremental reliability value to the system at each point in time. This would recognize correlations/synergies as the resource mix changes, would provide efficient incentives to invest in diverse resources and would reduce the risk of oversaturated technologies. It would also help defining efficient pairing of storage with intermittent resources, selecting the most advantageous storage durations and/or augment duration over time, and maintaining flexible conventional resources while they are needed. He recommended to improve capacity accreditation rules through the accreditation of all resources based their marginal reliability value. He commented on the shortcomings of the current resource adequacy modeling used because it failed to reflect the more dynamic output potentials and availabilities of specific technologies such as intermittent resources, resources that all depend on the availability of a particular pipeline, and resources with different flexibilities in responding to changes on the system.

There was considerable discussion about the EMM's accreditation suggestions and modeling. Some members suggested that the scenarios driving the EMM analysis should reflect more storage coupled with intermittent resources. Others suggested that accreditation changes should be more urgently pursued and potentially addressed as part of the MOPR reforms. The EMM acknowledged the importance of instituting many of the changes as soon as possible. There was also discussion of the importance of updating modeling for resource adequacy in connection with implementing the accreditation reforms. There was discussion of moving from an audit-based system for assessing capacity credits to one based on historical performance during times of the lowest Operating Reserve margin on the system. The EMM noted a key takeaway from the report was that the current process for translating the megawatts of a non-conventional resource into a generic qualified capacity number, assuming it had the same reliability value as other megawatts of qualified capacity, was not correct and leads to inaccurate compensation and inefficient investment. He encouraged future discussions of changes to accreditation in order to correct the overstatement in supply contribution of individual technology and changes to installed capacity modeling to avoid the underestimate in demand.

Energy Efficiency in the FCM

The EMM expressed concern with the treatment of energy efficiency as supply side rather than demand side. Doing so, he noted, would artificially increase demand, which would in turn inflate capacity prices. The EMM recommended that changes be made to account for energy efficiency as a reduction in load instead of as supply, which would lower administrative costs, address manipulation concerns and would not prevent load serving entities from benefiting from energy efficiency.

EMM Recommendations

The discussion ended with a review of the complete list of the EMM's recommendations, and highlighted the following four as recommendations of particular importance: (i) introduce co-optimized Operating Reserves in the Day-Ahead Energy Market reflecting all system needs, such as the proposed ESI products; (ii) incorporate a comprehensive set of local Operating Reserve requirements into the Day-Ahead and Real-Time markets; (iii) improve capacity accreditation by accrediting all resources consistent with their marginal reliability value and modifying the planning model to accurately estimate marginal reliability values; and (iv) modify the Payment Performance Rate (PPR) to rise with the reserve shortage level rather than implementing the remaining planned step increases in the payment rate.

COMMITTEE REPORTS

Markets Committee (MC). Mr. William Fowler, the MC Vice-Chair, reported that a two-day meeting would be held July 7-8. Discussion would focus on the region's response to Order 2222 and MOPR reform issues. The committee was working through stakeholder ideas and alternatives. He encouraged those seeking time on the agenda for the next meeting to contact the Chair and Secretary of the Markets Committee. A special meeting was scheduled for July 26 for a presentation by the EMM concerning MOPR reform issues discussed earlier in the meeting.

Transmission Committee (TC). Mr. José Rotger, the TC Vice-Chair, reported that the scheduled July 14 TC meeting would include (i) continued discussions on a stakeholder proposal to eliminate from Schedule 11 of the Tariff operating and maintenance (O&M) charges for network upgrades associated with generation interconnections, (ii) Order 2222 compliance including ISO and stakeholder feedback, (iii) information on ISO-proposed changes to Attachment K, which would include changes to the regional system planning process and changes relative to lessons learned from the Order 1000 transmission request for proposals (RFP) discussed at the Planning Advisory Committee, and (iv) an annual review by the Transmission Owners of the components of the regional network service transmission rate.

Reliability Committee (RC). Ms. Emily Laine, the RC Chair, reported that the RC continued to review changes to Planning Procedures and Operating Procedures.

Budget & Finance Subcommittee. Mr. Thomas Kaslow, the Subcommittee Chair, announced that the next meeting of the Subcommittee was scheduled for August 9.

Membership Subcommittee. Ms. Sarah Bresolin, the Subcommittee Chair, announced that the next meeting of the Subcommittee, which was scheduled for July 12, would include a discussion on potential changes to Fuels Industry Participant category and encouraged all those interested to attend.

Joint Nominating Committee (JNC). Mr. Cavanaugh noted the JNC had concluded its process by unanimously recommending a proposed slate of directors. He said that members would have time to consider that slate before being asked to vote. He noted that a confidential communication would be distributed to members the following week that would identify the proposed the slate, review the process for developing the slate, and discuss the challenges to the ISO Board during times of high turnover of directors. Additionally, he explained that the confidential distribution would describe actions that the members and alternates would be asked to consider at the July 21 meeting, to be held in executive session. He reported that the executive session would take place in the morning, and the Pathways working session would take place in the afternoon. He encouraged members to direct any questions, comments or concerns to their respective JNC members.

ADMINISTRATIVE MATTERS

Mr. Lombardi indicated that the July COO and litigation reports would be circulated the week of July 4. He noted two separate compliance filings related to the FCM parameters for FCA16 -- one addressing the Cost of New Entry (CONE), Net CONE and PPR values, and a second to comply with the recent Offer Review Trigger Price (ORTP) order. He noted that any requests for rehearing of the CONE and ORTP orders would need to be filed by June 28 and July 7, respectively. He further reported that post-conference replies to comments relating to the FERC's technical conference on principles and best practices for managing credit risk in organized markets were due by July 7.

Mr. Lombardi said that the next Participants Committee meeting following the July 21 meetings would take place on August 5. He reported that there was a tentative hold for a Pathways Study meeting on August 19, which would be confirmed in July. Sector meetings with the Board were planned over the following two Business Days, and the remaining Sector meetings with state officials were scheduled for June 28 and the second week in July.

There being no other business, the meeting adjourned at 3:22 p.m.

Respectfully submitted,

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David Doot, Secretary
Sebastian Lombardi, Acting Secretary

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN JUNE 24, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Advanced Energy Economy	Fuels Industry Participant	Caitlin Marquis		
Ampersand Energy Partners LLC	Supplier			Julia Frayer
AR Large Renewable Generation (RG) Group Member	AR-RG	Alex Worsley		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Brian Thomson	
Associated Industries of Massachusetts (AIM)	End User			Mary Smith
AVANGRID: CMP/UI	Transmission		Alan Trotta	
AVANGRID: Avangrid Renewables	Transmission	Kevin Kilgallen		
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Borrego Solar Systems Inc.	AR-DG	Liz Delaney		
Boylston Municipal Light Department	Publicly Owned Entity		Brian Thomson	
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity			Dave Cavanaugh
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Calpine Energy Services, LP	Supplier	Brett Kruse		Bill Fowler
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield		
Clearway Power Marketing LLC	Supplier			Pete Fuller
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw		
Conservation Law Foundation (CLF)	End User	Phelps Turner		
Consolidated Edison Energy, Inc.	Supplier	Norman Mah		
CPV Towantic, LLC (CPV)	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dominion Energy Generation Marketing	Generation	Mike Purdie		
DTE Energy Trading, Inc.	Supplier			José Rotger
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		Bill Fowler
Emera Energy Services	Supplier			Bill Fowler
Enel X North America Inc.	AR-LR	Michael Macrae		
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Environmental Defense Fund	End User	Jolette Westbrook		
Eversource Energy	Transmission	James Daly	Dave Burnham	
Excelerate Energy LP	Fuels Industry Participant	Gary Ritter		
Exelon Generation Company	Supplier		Bill Fowler	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger		
Generation Group Member	Generation	Dennis Duffy	Abby Krich	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Great River Hydro	AR-RG			Bill Fowler
Groton Electric Light Department	Publicly Owned Entity		Brian Thomson	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier		Bob Stein	
High Liner Foods (USA) Incorporated	End User		William P. Short III	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Holyoke Gas & Electric Department	Publicly Owned Entity		Brian Thomson	
Hull Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Industrial Energy Consumer Group	End User	Alan Topalian		

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN JUNE 24, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Ipswich Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Jericho Power LLC (Jericho)	AR-RG	Mark Spencer	Nancy Chafetz	Marji Philips
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned Entity		Craig Kieny	
Long Island Power Authority (LIPA)	Supplier		Bill Killgoar	
Maine Power LLC	Supplier	Jeff Jones		
Maine Public Advocate's Office	End User	Drew Landry		
Maine Skiing, Inc.	End User	Alan Topalian		
Mansfield Municipal Electric Department	Publicly Owned Entity		Brian Thomson	
Maple Energy LLC	AR-LR		Luke Fishback	Doug Hurley
Marblehead Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Mass. Attorney General's Office (MA AG)	End User	Tina Belew		
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Brian Thomson		
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Michael Kuser	End User		Jason York	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
National Grid	Transmission	Tim Brennan	Tim Martin	
Natural Resources Defense Council	End User	Bruce Ho		
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski		Brian. Forshaw; Dave Cavanaugh; Brian Thomson
New Hampshire Office of Consumer Advocate (NHOCA)	End User		Erin Camp	
NextEra Energy Resources, LLC	Generation	Michelle Gardner		
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
NRG Power Marketing LLC	Generation		Pete Fuller	
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Peabody Municipal Light Department	Publicly Owned Entity		Brian Thomson	
Princeton Municipal Light Department	Publicly Owned Entity		Brian Thomson	
PSEG Energy Resources & Trade LLC (PSEG)	Supplier		Eric Stallings	
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Brian Thomson	
Shell Energy North America (US), L.P.	Supplier	Matt Picardi		
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Brian Thomson	
Small RG Group Member	AR-RG	Erik Abend		
South Hadley Electric Light Department	Publicly Owned Entity		Brian Thomson	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Brian Thomson	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Pete Fuller
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
The Energy Consortium	End User		Mary Smith	
Union of Concerned Scientists	End User		Francis Pullaro	
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny		
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corp (VEIC)	AR-LR		Doug Hurley	
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN JUNE 24, 2021 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Versant Power	Transmission	Lisa Martin	David Norman	
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Brian Thomson	
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Brian Thomson	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	