FINAL

The 2023 Summer Meeting of the NEPOOL Participants Committee was held at The Equinox, Manchester Village, Vermont, on Tuesday, June 27, and Wednesday, June 28, pursuant to notice duly given, followed on Thursday, June 29, by meetings between modified Sector groups and ISO Board Members, state officials, and FERC staff, respectively. 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 attending the meeting.

Mr. David Cavanaugh, Chair, presided and Mr. Sebastian Lombardi, Secretary, recorded for the meeting.

JUNE 27, 2023 SESSION

The June 27, 2023 session began at 10:00 a.m., with Mr. Cavanaugh welcoming the members, alternates, federal and state officials, ISO colleagues, including members of the ISO Board, and guests who were present.

CONSENT AGENDA

Mr. Cavanaugh referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting, which included four items unanimously recommended for Participants Committee support by the respective Technical Committees. Following motion duly made and seconded, the Consent Agenda was unanimously approved as circulated, with an abstention by Mr. Jon Lamson noted.

ISO CEO REPORT

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

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer, noting that his June 2023 report (with May data) had been circulated and posted earlier in the month and his July 2023 report (with June data) would be circulated early the following month, highlighted a few operations-related items. First, he stated that, although seasonal forecasts had called for above-average temperatures, June had been mild; July and August, however, were expected to be warmer. The ISO had assessed the impact of an upcoming scheduled pipeline outage and had concluded that the outage would not have an adverse impact on reliability. He confirmed that, as reported, there had been and continued to be an outage at Seabrook Station, with no indication as to when the unit would come back on line.

Turning to the impact of the wildfires in Québec, he reported that the resulting smoke had caused the Phase II HVDC-TF Intertie with Hydro-Québec (Phase II) to trip three times, on June 22, 24 and 26, but some relief was expected given the rain forecasted for the remainder of the week. In response to questions, he said that Phase II had not been operating at full capacity on any of those days. Looking ahead, and based on discussions with the Hydro-Québec control room, the ISO did not expect there to be any specific adverse reliability impacts from the drought conditions being experienced in Canada, with the 12-month supply from Hydro-Québec appearing to be secure and no drought-related reductions or curtailments impacting power delivery over Phase II expected during the winter.

Concluding his report, Dr. Chadalavada referred to his June 14 memorandum circulated to the Committee that outlined potential approaches for proceeding with the Resource Capacity Accreditation (RCA) project (RCA Memo). He explained that the options identified were not exhaustive nor was the final course set. He looked forward to discussing the potential options and receiving feedback during the Wednesday session.

ISO CFO REPORT: 2024/2025 ISO PRELIMINARY BUDGETS

Mr. Robert Ludlow, the ISO's Chief Financial Officer and Compliance Officer (CFO), referred the Committee to the presentation of the ISO's 2024 and 2025 preliminary "top down" Operating and Capital Budgets (Budgets) included with the materials posted in advance of the meeting. He stated that the preliminary budget presentation provided an opportunity for stakeholder review and feedback prior to presentation in August of the proposed detailed budget reflecting that feedback. He reported that he had also shared the preliminary budget information with New England state officials earlier in the month.

Mr. Ludlow discussed the following key drivers causing the proposed increase over the 2023 budget: (i) the net change in Revenue Requirement true-up; (ii) inflationary and continued operational increases, including inflationary increases to salaries and benefits; and (iii) additional investments in information technology (IT) infrastructure and licensing, cybersecurity, and the transition to cloud-based infrastructure. He projected that the proposed 2024 Operating Budget would reflect an overall increase, before true-up, of 15.4% over 2023.

Mr. Ludlow explained further that the 2024 proposed Capital Budget was $35 million, a $1.5 million increase over the 2023 Capital Budget. Areas driving capital costs included spending to replace the current market system (nGem platform), major reliability-related efforts, cyber security, and IT asset and infrastructure replacement. He noted further that, to support the future capital program, the ISO would have to secure roughly $75 - $90 million in private placement notes, and may have to secure short-term financing to fund the increases in the 2023 and 2024 programs(at least until the private placement notes are in place).

In response to questions, Mr. Ludlow provided additional explanation as to how the change in the application of the Revenue Requirement true-up operated to increase the overall budget amount by roughly 5.1%. He committed to provide in mid- to late-September, once the ISO's proposed budget numbers were closer to final, the increases in rates that would take effect under Schedules 1, 2 and 3 of the Tariff. He also provided additional context regarding employee turnover experienced by the ISO, with much of the turnover related directly to compensation, which was driving the reevaluation of the ISO's compensation program.

FAP CHANGES - ELIGIBLE LETTER OF CREDIT ISSUERS

Mr. Thomas Kaslow, Chairman of the Budget & Finance Subcommittee (Subcommittee), referred members to the materials circulated in advance of the meeting. He reviewed the changes to the Financial Assurance Policy (FAP) proposed by the ISO in response to the recent deterioration in financial condition of some of the banks on the ISO's List of Eligible Credit Issuers (List) (the Eligible LOC Issuer Changes). The Eligible LOC Issuer Changes would permit the ISO to disqualify a letter of credit (LOC) bank if the ISO determined in its sole discretion that accepting a LOC from that bank would present an unacceptable risk that the bank will fail to honor the LOC. Further, the Eligible LOC Issuer Changes expanded the circumstances in which the ISO could extend the period to replace a LOC to 20 Business Days, established requirements for notice to the Subcommittee when a bank is removed from its List, and established how a disqualified LOC bank could be reinstated to the List. He reported that the Proposal was reviewed at the Subcommittee's May 12 meeting, without any objections to the Proposal expressed by any Subcommittee member in attendance.

The following motion was duly made and seconded:

> RESOLVED, that the Participants Committee supports the revisions to the letter of credit bank eligibility standards in the ISO New England Financial Assurance Policy, as proposed by the ISO and as circulated to this Committee with the June 20, 2023 supplemental notice, together with such non-substantive changes as may be approved by the Chair of the Budget & Finance Subcommittee.

The Committee then asked questions regarding the Eligible LOC Issuer Changes. In response, Mr. Chris Nolan, ISO Director, Market and Credit Risk, reported that there were no banks currently in a position to be dropped from the List if the Changes were implemented, though there had been at least one bank (since acquired by another bank) that would have met the criteria for being dropped from the List during the time in which the Proposal was being developed and vetted. Mr. Ludlow confirmed that there was no specific linkage between the Eligible LOC Issuer Changes and the proposed increase in employees for market and credit risk functions in the ISO's proposed 2024 Operating Budget. In addition, while Mr. Ludlow opined that the Eligible LOC Issuer Changes provided the ISO adequate flexibility to remove from, and reinstate banks to, the List, he acknowledged the potential burden and concerns for Market Participants that, in accordance with the deadlines identified in the FAP, would be required to replace their LOC provided by a bank removed from the List.

Without further discussion, the motion to support the Eligible LOC Issuer Changes was voted and approved unanimously, with abstentions noted by CPV, Jericho Power, Nautilus, Wheelabrator, and Mr. Lamson.

GIS OPERATING RULES AND GIS AGREEMENT WAIVER REQUEST – 777 MAIN STREET

Mr. Paul Belval, NEPOOL Counsel, introduced the request of 777 Residential LLC (Account Holder) for Committee action to waive certain Generation Information System (GIS) Operating Rules and portions of the GIS Agreement between APX and NEPOOL to allow for changes to the renewable energy certificates for Account Holder's Hartford, Connecticut fuel cell facility (777 Main Street). He explained that Account Holder was seeking the waiver so that its 2022 fourth quarter (Q4) certificates for 777 Main Street could be changed to be GIS eligible. Account Holder asserted that it was unable to have emissions data for 777 Main Street inputted before the requisite deadline due to IT/password complications accessing the GIS System on the day of the Q4 deadline. Efforts by Account Holder to separately have the Connecticut Public Utilities Regulatory Authority (CT PURA) recognize 777 Main Street's GIS Certificates as Connecticut Class I eligible had not, to date, been successful.

Members asked clarifying questions. In response, representatives for Account Holder and APX, Inc. (GIS Administrator) provided additional information from their perspectives regarding the circumstances surrounding the password complications and the pending request by Account Holder for access to any APX records regarding the password reset, which required NEPOOL authorization. Mr. Belval described the experience with the two most recent GIS waiver requests and the response by CT PURA to treat certificates differently than as registered in the GIS.

In discussion, members expressed both willingness and reluctance to support the requested waiver. Those supporting the waiver suggested that a softening of the hard line historically taken by the Participants Committee with respect to GIS waiver requests, given the ubiquitous nature of administrative snafus and human mistake, was warranted and encouraged others to support the waiver. Those inclined not to support the waiver focused on the role of the GIS as a tool to support state renewable energy requirements and were hesitant to participate in or unduly influence the ultimate determination by a state of the qualification of a renewable energy certificate.

Mr. Cavanaugh, informed the Committee that, on behalf of NEPOOL, he had directed APX to share with Account Holder, to the extent possible, the requested information related to the password re-set. Under these circumstances, he then suggested to the Committee that the matter move to the GIS Operating Rules Working Group (GIS WG) for a discussion and potential recommendation on the requested waiver once all the requested information had been provided to Account Holder. Consideration of, and action by, the Participants Committee on the 777 Main Waiver Request could be scheduled thereafter. He added that any changes or enhancements to the GIS system/processes identified as part of the consideration of the 777 Main Street request could be taken up separately in follow-up by the GIS WG using the established GIS rule change processes. Mr. Cavanaugh asked whether there was any objection or opposition to moving the matter to the GIS WG. No objection or opposition to that course of action was ultimately expressed.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the June 24 Litigation Report that had been circulated and posted in advance of the meeting. He highlighted the following developments:

(i) *ISO Deficiency Letter Responses* **-** *Storage As Transmission-Only Assets (SATOA) (ER23-739/743) and IEP Parameters Updates (ER23-1588).* Responses to the deficiency letters issued in the SATOA and IEP Parameters Updates proceedings, respectively, had been submitted by the ISO, each restarting the FERC's 60-day clock for action. The comment periods on those responses were about to end, with FERC actions anticipated thereafter;

(ii) *FERC-Initiated Section 206 Proceeding re Market Power Mitigation Rules (EL23-62).* The FERC instituted a Section 206 proceeding on May 5, 2023, finding that some of the mechanics of the ISO's current market power mitigation rules, including consideration of any proposed fuel price adjustment(s), may be unjust and unreasonable. FERC had directed the ISO to show cause as to why the Tariff provisions remain just and reasonable or to identify changes to remedy the concerns identified in FERC's order; and

(iii) *FERC Order 895 (ISO/RTO Credit-Related Information Sharing).* Closely adhering to its earlier Notice of Proposed Rulemaking, the FERC issued a final order requiring ISO/RTOs to amend their tariffs to permit the sharing of credit-related market participant information with other ISO/RTOs.

Mr. Lombardi encouraged anyone with questions on these highlights or on the full Report to reach out to him or any of NEPOOL counsel.

COMMITTEE REPORTS

Markets Committee. Mr. William Fowler, the MC Vice-Chair, reported that the MC would hold its next meeting on July 11. It had been rescheduled as a single day meeting, rather than the three-day meeting as originally noticed. A full meeting day agenda was projected, with votes to be taken on the Day-Ahead Ancillary Services Initiative (DASI) project, and a discussion on the RCA.

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that the RC would meet jointly with the Transmission Committee (TC) for a Summer Meeting in Newport, RI on July 18-19.

Transmission Committee. Mr. David Burnham, the TC Vice-Chair, reported that the TC would also meet next at the joint RC/TC Summer Meeting, with topics for consideration to include presentations on the ISO's response to the FERC's order conditionally accepting the region's Order 881 compliance filing and on the Participating Transmission Owners' annual update to the Regional Network Service rates. The TC was also schedule to take action on its pieces of the DASI project.

Membership Subcommittee. Ms. Sarah Bresolin, Membership Subcommittee Chair, reported that the Subcommittee was next scheduled to meet on July 10.

Budget & Finance (B&F) Subcommittee. Mr. Thomas Kaslow reported that the B&F Subcommittee had no meeting scheduled in July, but two in August.

HOST STATE WELCOME REMARKS (TONY ROISMAN)

After a recess for lunch, Mr. Cavanaugh introduced Vermont Public Utility Commission Chairman Anthony Roisman for welcoming remarks on behalf of the host state. Chairman Roisman reflected on the remarkable time of transition facing the region generally, and NEPOOL particularly. He noted the opportunity for NEPOOL, in its role as the region's stakeholder body, to bring together, as it had so successfully done in the past, diverging views to work together towards a common goal. He poignantly suggested that the region, at that particular moment in time (Point A), knew where it wanted to go, and knew when it wanted to get there (Point B) – it just had to work through the demanding task of getting from Point A to Point B. He suggested that the transition would require navigating the journey with considerations of equity, affordability and reliability. He thanked all those in attendance for their commitment to making the transition a successful one. He looked forward not only to the remainder of the meeting, but to a future of increased electrification, reduced climate change impacts and bountiful days for New England.

EMM 2022 ANNUAL MARKETS REPORT

Overview

Dr. David Patton, President of Potomac Economics and the ISO's External Market Monitor (EMM), presented highlights from the EMM's 2022 Markets Report (EMM Annual Report), which had been circulated and posted in advance of the meeting. Dr. Patton introduced his presentation by noting that the EMM Annual Report complimented the report published by the ISO's Internal Market Monitor (IMM). He opined that the ISO's markets performed competitively in 2022 and that the EMM Annual Report included recommendations to improve the markets' performance.

Cross-Market Comparison

Referring to his presentation, Dr. Patton started by comparing the "all-in" energy prices across various organized markets (RTOs), noting the consistently highest energy prices for New England, mainly driven by higher natural gas prices. He also noted that New England's capacity costs were much higher than those in other RTOs.

In contrast, Dr. Patton explained that New England's transmission congestion costs were much lower than other RTOs, even after accounting for the difference in the size of the RTO markets, due to prior transmission investments in New England. Although costs were low, New England's 2022 transmission rates were the country's highest at $22/MWh. Dr. Patton also noted that, in the future, it would be essential for New England to conduct transmission planning that is compatible with market incentives in order to facilitate the addition of technology, such as storage devices, that lower transmission congestion costs.

Dr. Patton then addressed virtual transactions. He observed that, in New England as compared to other markets, virtual transactions (Increment Offers (INCs) and/or Decrement Bids (DECs) in the Day-Ahead Energy Market) had historically been lower, and profit volatility higher, each an indication of lower liquidity in the Day-Ahead Market. Day-Ahead and Real-Time price convergence in New England was also more volatile than that experienced in MISO or NYISO. Dr. Patton opined that New England's uplift cost allocation methodology, particularly the quantity of costs allocated, contributed to higher costs for virtual transactions, discouraging market participation. He believed that DASI could help address this issue.

In response to further comments and questions, Dr. Patton answered additional DASI-related questions. Among other points, he noted that he was not too concerned with the ISO's forecasting of Day-Ahead prices. He suggested that higher strike prices tended, from his perspective, to be better than lower strike prices, and could help mitigate both risk for generators that might otherwise be passed along in offer prices as well as ISO price forecast errors.

Although not part of his presentation, but included in the EMM Annual Report, Dr. Patton observed that Coordinated Transaction Scheduling (CTS) would perform much better if the CTS process operated every five minutes based on the most recent Real-Time prices rather than forecasted prices.

Competitive Assessment of the Energy Market

Dr. Patton opined that the Energy Market performed very competitively. His analysis found no significant issues. He highlighted, as the sole example of concern in the competitive performance area, a mitigation event from December 24, 2022, which had illustrated several deficiencies in the market power mitigation process and had led to the 206 proceeding described earlier in the meeting. After providing a brief background, Dr. Patton presented three recommendations to address, in as surgical a way as possible, the mitigation issues highlighted by the December 24 event. In response to a question, Dr. Patton explained that the mitigation had raised costs to others in the market by reducing the dispatch from the mitigated generator, but opined that the mitigation did not create a reliability problem.

Out-of-Market (OOM) Commitments and Operating Reserve Prices

Dr. Patton began by discussing Day-Ahead commitments for Ten-Minute Spinning Reserve (TMSR). He explained why he characterized the commitments as out-of-market (due to the requirement to fulfill physical reserve constraints, but with no corresponding product procurement). With no product procurement, no price was being set to reflect the reserve requirement, needed commitments would not be covered by prices, and uplift in the Day-Ahead market would be generated as a result. He noted that 2022 OOM commitments occurred in nearly 2,450 hours to satisfy New England's TMSR requirement. He pointed out that the nearly $2/MWh average reserve value, as shown in his presentation, illustrated the magnitude of energy price depression and that pricing TMSR could raise revenues by up to $15/kW-year for resources providing energy and/or spinning reserves. Dr. Patton opined that these results underscored the value of DASI.

Dr. Patton then turned his attention to Day-Ahead commitments for Local Second Contingency Protection. Although the reserve needs for local areas in 2022 were quite a bit less than in previous years, he highlighted that the NH-ME and NE West-to-East interfaces had seen the most significant number of OOM commitments for local needs. He explained that those areas were not defined in the Real-Time markets and that the Reserve requirements were not priced in the Day-Ahead markets. Dr. Patton noted that pricing the local needs in the Day-Ahead market from 2020 to 2022 would have raised between $4/kW-year and $10/kW-year of additional revenue for resources in the local areas. Ultimately, the EMM recommended the adoption of a more dynamic regime for defining local reserve zones.

Dr. Patton concluded this section by presenting an issue identified through the annual assessment process concerning the fast-start pricing logic to price Operating Reserves, an essential aspect of the New England Market. After providing a high-level explanation of the fast-start pricing logic (explained further in the EMM Annual Report), he illustrated how the identified issues result in raising Reserve and Energy prices inefficiently under tight conditions. Although the inefficient result did not occur frequently in 2022, Dr. Patton noted that, as the region moves towards less surplus and additional intermittent resource integration and, thus, increased reliance on peaking resources, the fast-start pricing logic issue was likely to be magnified. Accordingly, he recommended that the ISO address this issue by modifying the fast-start pricing logic.

Assessment of the December 24 OP-4 and Capacity Scarcity Condition Event

In the next section, Dr. Patton discussed the December 24 shortage event that triggered the Pay-For-Performance (PFP) Reserve Constraint Penalty Factors (the "December PFP Event"). He began by reviewing external transactions during the December PFP Event. He noted that in hour 16, New England cut exports to New York. In turn, New York cut more than 700 MW of exports to New England. Dr. Patton noted that this type of curtailment, i.e., cutting exports to a neighboring Balancing Area in an emergency, occurs in every RTO. Thus, based on his experience, Dr. Patton expressed astonishment that New York and New England did not have amongst themselves an agreement to promote coordinated reliability-maximizing interchanges when one or both of the regions were in an emergency.

The EMM turned to a broader discussion on PFP incentives. One of his concerns was the increased PFP rate for 2025, i.e., approximately $9,300/MWh. In his opinion, that high rate would distort incentives for some resources to remain in the market. Dr. Patton concluded that over-penalizing certain resources could result in premature retirements. He also discussed the PFP incentives for importers. As he explained, PFP creates a significant incentive to transfer power into New England, even when it is demonstrably non-economic, as shown during the December PFP Event. Dr. Patton expressed concern that the current PFP incentives could create undesirable opportunities to schedule equal imports and exports at the New England/New York interchange.

Assessment of the Forward Capacity Market

Before presenting his assessment of winter reliability, Dr. Patton provided that he viewed energy adequacy and resource adequacy as sharing the same goal, i.e., to produce enough energy to keep the lights on when needed. Turning to a chart in his presentation showing several critical points regarding New England's generation supply during prolonged cold weather periods between December 2017 and January 2018, Dr. Patton pointed out that some units obtained natural gas through liquefied natural gas (LNG) injections and that oil-fired resources continuously produced large amounts of energy. The key takeaways from the chart were that generators with only pipeline gas supply had limited value, especially on the margins, and New England relies on oil and LNG during conditions presented during the studied winter period. Thus, Dr. Patton added that the accreditation method becomes very important, particularly for oil resources.

Next, Dr. Patton presented a chart showing the total Seasonal Claimed Capacity of resources with Capacity Supply Obligations for January 2027 and the capacity of dual-fuel and oil resources based on the maximum days of output in MW. He pointed out that a fair number of oil units could run for 14 days or more. Dr. Patton also noted that about half of the units would run out of oil in less than seven days, with a good number of units running out in about two days. With this in mind, oil replenishment becomes a key modeling assumption when accrediting resources. Dr. Patton stated that he disagreed with the ISO's modeling assumption that oil units with 40 hours of fuel are assumed with unlimited availability.

Dr. Patton reviewed several slides detailed in the EMM Annual Report to support his conclusions. He concluded this section by addressing several members' questions/comments concerning accreditation (including the ISO's ongoing approach) and offering three points: (1) the oil replenishment assumption was critical in resource accreditation; (2) expressing a concern with the ISO's current average accreditation approach as opposed to the marginal approach; and (3) based on technological capabilities and the ability to procure fuel, noting that appropriate accreditation is one mechanism to send the appropriate entry and exit signals to the market.

The EMM turned its attention to the Forward Capacity Market (FCM). Dr. Patton expressed two concerns with the FCM. First, he opined that the FCM did not have a good record of facilitating the entry of new resources. Second, Dr. Patton stated that the FCM created financial risks for existing older retirements, which could result in premature retirements. Thus, he recommended that the region move to a prompt seasonal market. Anticipating a question concerning the four options the ISO laid out in the RCA Memo, Dr. Patton stated that he preferred Option C. Under this option, the ISO would delay the nineteenth Forward Capacity Auction (FCA19). With the additional time, the ISO could implement a new RCA construct and transition to a prompt and seasonal market for FCA19 running in 2028 rather than 2025. In responding to a member's question, Dr. Patton stated that moving to a prompt market was more critical than a seasonal market.

JUNE 28 SESSION

The Summer Meeting reconvened at 9:00 a.m. on June 28, 2023.

FERC STAFF INTRODUCTIONS & COMMENTS

Mr. Cavanaugh welcomed members and guests back to the meeting. He also welcomed, introduced and thanked the following representatives from the Federal Energy Regulatory Commission for their attendance and participation: Ms. Nicole Businelli, Mr. Zach Harris, Mr. Noah Schlosser, and Mr. Eric Jacobi. Ms. Businelli, who had since the last Summer Meeting joined Chairman Phillips' staff, spoke briefly about her focus on New England matters for the Chairman's office and her wish to stay engaged with NEPOOL. She looked forward to discussions with members during Thursday's Sector meetings. Messrs. Schlosser and Harris, each members of the FERC's Office of Energy Market Regulation (OEMR) ISO New England virtual team, provided similar overviews of their roles and experiences related to New England. They encouraged members, subject to the Commission's rules regarding *ex parte* communications, to share their perspectives on regional issues with any of them during the meeting's activities or in the Sector meetings to be held the following day.

DEBRIEF & DISCUSSION ON JUNE 20 FERC NEW ENGLAND WINTER GAS-ELECTRIC FORUM

Mr. Lombardi recapped highlights from the June 20, 2023 New England Winter Gas-Electric Forum (June Forum). He summarized the June Forum's presentations, panels, and round table discussions. He noted the keen interest expressed in the completion of the 2032 portion of the study effort being jointly undertaken by the ISO and the Electric Power Research Institute (EPRI) to conduct a probabilistic assessment of the operational energy adequacy risks in New England under extreme weather events (ISO/EPRI Study). He concluded by sharing his overall sense that, compared to and since the FERC's first forum in September 2022, some foundational progress had been made, and there appeared to be, at least at the highest-level, broader consensus among those participating and in the room. Mr. Cavanaugh then invited those participating in the Summer Meeting to share their reactions and feedback on, and any takeaways from, the June Forum.

A number of Participants commended the ISO on both the analysis and framework presented by way of the Study, including the review of the history preceding the ISO/EPRI Study, which many found to be informative and understandable. Some stressed the importance of prompt completion of the 2023 Study results, which they believed would be key to informing critical decisions and continued progress in addressing the long-term challenges facing the region as it endeavors to ensure electric system reliability at a reasonable cost to customers. Other Participants thought it helpful that the FERC heard regional commitment to market-based solutions, and proposed various concepts for further consideration, including new and different reserve products (beyond the DASI proposal to be voted the following month), other market-rule-based enhancements, as well as the value and potential use of resource types not traditionally noted or used for their winter reliability benefits. With respect to consideration of potential longer-term reserve products, a member suggested that a short thought piece, incorporating the efforts from the previous Energy Security Initiative (ESI), could be used to better frame and facilitate concrete discussion on that topic. There were conflicting views on whether any such solutions should be exclusively market-based or should also include potential out-of-market mechanisms/elements. Some cautioned that solutions centered just in the capacity market may not be sufficient to ensure that the necessary resources are procured. More generally, and looking ahead, some, expressing a desire to build on the progress being made, asked for additional clarity as soon as practicable on proposed next steps in the consideration of solutions that ensure that region benefits from appropriate long-term market signals, including possible capacity, energy and reserve market changes.

On the topic of Everett as it related to the reliable operation of New England's electric and/or natural gas systems, some stakeholders noted the nuances of the ISO's positions regarding Everett's contribution to electric system and broader regional winter reliability, and the challenges communicating those nuances effectively to the public. Some viewed the June Forum as a success because of the additional clarity provided with respect to roles and responsibilities in addressing Everett and its attendant issues, and urged that, whether or not Everett is retained, that new products or market rule changes be considered to ensure the availability of the levels of LNG assumed in the ISO/EPRI Study. The ISO was complimented for its continued commitment and efforts to better understand the natural gas system, which would be increasingly important going forward.

Officials from multiple New England States expressed their appreciation for the FERC's outreach ahead of the Forum, and the recognition of the importance of the States' collective and distinct role in identifying paths forward. They also highlighted their appreciation for the opportunity for the dialogue at the Participants Committee table, described as both essential and timely. They noted the caution expressed by those charged with maintaining bulk power system reliability of winter risks going forward and emphasized the need for robust, rigorous analysis.

Consistent with their mandate, they urged that the welfare of the citizens of New England be a central component of all constructs considered, such that ratepayers would neither be cold nor sitting in the dark during a New England winter. They implored the ISO and NEPOOL to approach the consideration of solutions with a sense of urgency, and to commit early in the process to market-type solutions, rather than be left with a round of out-of-market solutions. One suggested that any solutions be presented in way that every day citizens could understand, in order to enhance support for those solutions and to inspire confidence.

More specifically, some of the State Officials suggested that, when considering solutions to tightening winter conditions, additional uses or roles for Demand Response (DR) and other technologies be explored, and that any such consideration not be limited to fuel-related solutions. They urged the ISO to continue its commitment to better understanding the natural gas system, and to comprehensively consider and assess how that system will hold up from a reliability stand-point under the assumptions and solutions to be proposed on the electric side.

On behalf of the ISO, Dr. Chadalavada thanked everyone for the additional and helpful feedback as well as the support provided by many. He highlighted the achievement of developing a platform that would provide advanced notice and signals regarding future contingencies, which he believed distinguished New England from the rest of the county's organized markets, and would serve the region well into the future.

In response to questions regarding next steps, he stated that the ISO planned to publish the 2032 Study results in August, which would provide the region an opportunity to discuss those results in September. From there, in late 2023 and into 2024, he expected discussion on the "Regional Energy Shortfall Metric" described at the June Forum. He explained that the Metric would provide a necessary and predicate baseline to the development of potential market and/or infrastructure solutions and the evaluation of their feasibility and cost effectiveness. He noted the ISO's preference to design market-based solutions, but next steps would be informed and determined by evaluation using that Metric.

For his part, Mr. van Welie identified a couple of takeaways from the Forum. The first was his sense that the oft-used 1-in-10 resource adequacy standard (that presumed the probability or risk of demand exceeding generation capacity was less than one day in 10 years) was, on its own, likely obsolete, particularly given the rapidly evolving circumstances facing the region. He noted his satisfaction with the work that had already been completed to address this changing situation, which he believed positioned the region to move from the conceptual to the tangible in quantifying the energy adequacy risks that it faced. He stated that, among the next steps to be taken by the region, would be to supplement the 1-in-10 standard with an energy shortfall metric that would, in turn, inform the development of solutions to hedge against resource adequacy risk.

The other high-level takeaway Mr. van Welie identified was the importance of the role that DR could and should play going forward. He agreed with the view expressed that DR was not being fully reflected in proposed solutions, and explained why, at least to him, managing increasing demand for electricity without the participation of a large quantity of responsive demand in the marketplace didn't make much sense. He explained how anticipated system build-out and ramp up in demand was likely to present constraints on the wires (both transmission and distribution), as demonstrated in the 2050 transmission-related study. He viewed increased integration of DR as a potential tool to mitigate that risk, noting the positive impact/reduction in costs to consumers if DR is able to reduce the amount of energy that the system is required to solve for. He opined that the increased use of DR would require action by the States, noting that, while DR had been incorporated into the wholesale arrangements, there remained much to do to unleash the benefits of DR at the retail level, including deployment of automation into people's homes and electric charging facilities.

Mr. Cavanaugh concluded this discussion by thanking all for their feedback, takeaways and views on possible actions to be taken, noting that there was much work ahead for the region. Echoing sentiments expressed by a State Official, he expressed confidence that the regional stakeholders best suited to accomplish the critical tasks were around the NEPOOL table, that NEPOOL could and should provide a forum for future discussions, and that discussion and efforts would continue.

RESOURCE CAPACITY ACCREDITATION UPDATE & OPTIONS

Dr. Chadalavada referred the Committee to the memo that had been circulated in advance of the meeting providing an update on and potential options for proceeding with the Resource Capacity Accreditation (RCA) project (Memo). He emphasized that the Memo was intended to facilitate conversation at this meeting regarding the RCA project, which had been delayed as a result of a GE Multi-Area Reliability Simulation (GE MARS) software error identified by the ISO. He reviewed both the broad objectives that the ISO sought to balance and potential options for proceeding with the project, noting that the list of options was neither exhaustive nor final. He asked for Participant feedback as to (i) whether the ISO had gotten the objectives right; (ii) what should be the scope of work (including capacity accreditation reforms and/or prompt/seasonal capacity market designs) and timing in connection with the Forward Capacity Auction for Capacity Commitment Period 19 (FCA19); and (iii) what should be the scope of the end state.

Turning to process, he reported that the ISO was planning for a discussion at the July Markets Committee meeting on its thoughts on the trade-offs between a prompt and forward capacity market design and looking forward to further feedback at that time.

Participants proceeded to provide their views, both in response to the three topics that Dr. Chadalavada had identified, as well as on several additional but related topics. Participants were appreciative of the opportunity to provide feedback on the Memo and urged the ISO to minimize, to the maximum extent possible, regulatory uncertainty and implementation risk.

Addressing the need for additional time to improve and rerun the winter risk model, members sought additional clarity on the modeling error identified, as well as its impact on the RCA schedule. Dr. Chadalavada confirmed that the current pause was attributable to modeling errors identified, primarily related to LNG resources, but also to deficiencies revealed with respect to the modeling of other resources (e.g. gas-fired units), rather than any fundamental flaws with the RCA methodology itself. He was unequivocal that the modeling error had to be corrected and, while not prejudging the outcomes that would follow after those corrections were completed, was certain that there would be some level of winter risk identified, though the scope of that risk was yet to be determined and addressed.

A number of members offered their preliminary thoughts on what might be incorporated into FCA19 and/or the RCA efforts as a result of the pause, and whether, and if so, how, the pause or further additional time could or should impact the schedule and conduct of FCA19. Some explained why they would entertain proposals to delay, or would support, even insist, that the conduct of FCA19 be delayed, so that the RCA project, at least in some form, could be incorporated into FCA19 (rather than in a future auction). Many opined that there were likely to be efficiencies to be had by coupling FCA19 with RCA reforms, and wished to maximize those efficiencies and avoid incremental implementation. The opportunity to discuss the feasibility of, and trade-offs associated with, that approach, with the benefit of as much information and analysis as possible, would be appreciated.

Others expressed concerns with delaying, and/or incorporating RCA reforms into, FCA19. Those actively developing new resources explained the impacts and challenges that would follow from a delay. Some were hesitant, if at all able, to commit to a delay prior to a full discussion on the pros and cons of proposed changes to the market. Still others suggested that, absent impact analysis showing that there was heightened winter risk to be accounted for in the FCA19 Capacity Commitment Period, they could support conducting FCA19 under the existing rules, with or without RCA. Notwithstanding some suggestion that an auction delay would not be viewed as undesirably as it might have been in the past, there were members who favored proceeding with FCA19 as planned in the interest of certainty and optics, at least until any changes to the market structure going forward had been decided upon.

An End User Sector representative, noting the importance of assumptions made in the modeling, questioned whether the additional time might permit consideration of alternatives or further changes to GE MARS, which was being contorted beyond its intended uses to support the winter risk modeling. A Generation Sector member hoped that the pause would allow for concerns with gas resource accreditation to also be addressed.

More broadly, members offered feedback on suggestions that the region should consider a move from a forward to a prompt and seasonal capacity market construct. Some members from the supply side cautioned that any change in approach would have to ensure that market revenues would be sufficient for them to cover their total costs (thereby ensuring appropriate financial incentives for capacity investment), and requested further analysis illustrating how those principles would be satisfied.

Seasonality, Dr. Chadalavada suggested, was less about resource adequacy and more about New England's overall needs going into the future, e.g. how winter and summer demand may shape future annual load curves. Designing a seasonal market would, given the challenges and timing involved, likely be a multi-year effort and, in a forward construct, implementation would take the region into the early to mid years of the next decade. For that reason, focus had turned to the prospect of a prompt capacity market construct, which might offer better options to more nimbly and quickly incorporate seasonality into the region's market structure.

Various perspectives on seasonality were expressed. There was an acknowledgement of the momentum around seasonal capacity market design efforts, and the need for much work ahead to determine its feasibility, periodic basis, and resolution to its many perceived challenges. Many favored undertaking the required efforts sooner rather than later (and before it was too late) to fully consider the design and facilitate implementation if that design was ultimately supported or adopted. In any such efforts, members were urged to also view the direction to be pursued holistically, carefully considering whether and how State objectives for a clean energy resource mix and visions for the future system could be incorporated in the design.

Members expressed some interest in further exploring how changes in the capacity market might impact basic service procurements and retail customers. A Transmission Owner representative expressed confidence that, given planning assumptions and processes, the transmission system could absorb any impacts from market changes (e.g., generation retirements) without perceivable disruption. Raising the determination of tie benefits, a couple of members encouraged, with the benefit of the extra time contemplated, a full analysis of tie benefits, including HQICCs.

Dr. Chadalavada acknowledged the breadth and complexity of the work to be completed, as well as the need for discussion and feedback on each of the components to be pursued. He looked forward to the collaborative efforts and shared commitment to resolving the challenges ahead. There being no other business, the June 28 session ended at 11:35 a.m., with the following day set for modified Sector meetings beginning at 8:00 a.m.

Respectfully submitted,

Sebastian Lombardi, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN JUNE 27-29, 2023 SUMMER MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Advanced Energy United	Associate Non-Voting	Caitlin Marquis		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matt Ide	
Associated Industries of Massachusetts (AIM)	End User	Robert Ruddock		Mary Smith (tel)
AVANGRID: CMP/UI	Transmission	Alan Trotta	Jason Rauch	Alex Noviki Zach Teti
Bath Iron Works Corporation	End User			Gus Fromuth; Bill Short
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
Boylston Municipal Light Department	Publicly Owned Entity	Matt Ide		
BP Energy Company	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield (tel)		
Clearway Power Marketing LLC	Supplier	John Miller		Pete Fuller
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw	Dave Meisenger	
Connecticut Office of Consumer Counsel	End User	Claire Coleman	J.R. Viglione	
Conservation Law Foundation (CLF)	End User	Phelps Turner (tel)		
Constellation Energy Generation	Supplier	Gretchen Fuhr	Bill Fowler	
CPV Towantic, LLC	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
DC Energy, LLC	Supplier	Bruce Bleiweis (tel)		
Deepwater Wind Block Island, LLC	Generation	Eric Wilkerson		
Dominion Energy Generation Marketing, Inc.	Generation	Wes Walker (tel)		
DTE Energy Trading, Inc.	Supplier			José Rotger
Durgin and Crowell Lumber Co., Inc.	End User			Bill Short
Dynegy Marketing and Trade, Inc.	Supplier	Andy Weinstein		Bill Fowler
ECP Companies Calpine Energy Services, LP New Leaf Energy	Generation	 Brett Kruse Liz Delaney		 Bill Fowler Alex Chaplin (tel)
EDF Trading North America, LLC	Supplier	Eric Osborn		
Elektrisola, Inc.	End User		Gus Fromuth	Bill Short
Emera Energy Services	Supplier			Bill Fowler
Enel X North America, Inc.	AR-LR	Alex Worsley		
Engie Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Environmental Defense Fund	End User	Jolette Westbrook (tel)		
Eversource Energy	Transmission		Dave Burnham	Vandan Divatia
FirstLight Power Management, LLC	Generation	Tom Kaslow	Peter Rider	
First Point Power, LLC	Supplier	Peter Schieffelin (tel)	Bryan Amaral	
Galt Power, Inc.	Supplier	José Rotger	Jeff Iafrati (tel)	
Garland Manufacturing Company	End User	Gus Fromuth		Bill Short
Generation Bridge Companies	Generation	Bill Fowler		
Generation Group Member	Generation	Dennis Duffy	Abby Krich	

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PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Granite Shore Companies	Generation			Bob Stein
Groton Electric Light Department	Publicly Owned Entity		Matt Ide	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	AR-RG	Louis Guilbault	Bob Stein	
Hammond Lumber Company	End User	Gus Fromuth		Bill Short
Hanover, NH (Town of)	End User			Bill Short
Harvard Dedicated Energy Limited	End User			Jason Frost
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		Matt Ide	
Holyoke Gas & Electric Department	Publicly Owned Entity		Matt Ide	
Hull Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
Icetec Energy Services, Inc.	AR-LR	Doug Hurley		
Industrial Energy Consumer Group	End User	Dan Collins		
Industrial Wind Action Corp.	End User		Annette Smith	
Ipswich Municipal Light Department	Publicly Owned Entity		Matt Ide	
Jericho Power LLC (Jericho Power)	AR-RG	Ben Griffiths		
Jupiter Power	AR-RG			Ron Carrier (tel)
KCE Companies	AR-DG		Paul Williamson	
Lamson, Jon	End User	Jon Lamson		
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Long Island Power Authority (LIPA)	Supplier	Bill Kilgoar		José Rotger
Maine Power LLC	Supplier	Jeff Jones (tel)		
Maine Skiing, Inc.	End User	Dan Collins		
Mansfield Municipal Electric Department	Publicly Owned Entity		Matt Ide	
Maple Energy LLC	AR-LR			Doug Hurley
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide	
Mass. Attorney General's Office (MA AG)	End User	Ashley Gagnon	Jaimie Donovan	Tina Belew (tel)
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Climate Action Network				
Mass. Dept. Capital Asset Management	End User		Paul Lopes (tel)	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide		Dan Murphy
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Moore Company	End User			Gus Fromuth; Bill Short
Narragansett Electric Co. (d/b/a RI Energy)	Transmission	Brian Thomson	Amanda Rumsey	Lindsay Orphanides
Nautilus Power, LLC (Nautilus)	Generation		Bill Fowler	
New Brunswick Energy Marketing Corp.	Supplier	Rob Gillies		
New England Power (d/b/a National Grid)	Transmission	Tim Brennan	Tim Martin	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson	Dan Dolan	Molly Connors
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw
New Hampshire Office of Consumer Advocate	End User		Jason Frost	
NextEra Energy Resources, LLC	Generation	Michelle Gardner	Nick Hutchings	
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	

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NRG Power Marketing LLC	Supplier		Pete Fuller	
Nylon Corporation of America	End User			Bill Short
Onward Energy (Blue Sky West LLC)	AR-RG	Emily Chapin	Katie Belleza	
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Pawtucket Power Holding Company	Generation	Dan Allegretti	Kevin Telford	
Paxton Municipal Light Department	Publicly Owned Entity		Matt Ide	
Peabody Municipal Light Department	Publicly Owned Entity		Matt Ide	
Princeton Municipal Light Department	Publicly Owned Entity	Matt Ide		
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Repsol Energy North America	Associate Non-Voting		Karen Iampen	
RI Division of Public Utilities Carriers	End User	Paul Roberti	Linda George	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Matt Ide	
Saint Anselm College	End User	Gus Fromuth		Bill Short
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User	Gus Fromuth		Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matt Ide	
South Hadley Electric Light Department	Publicly Owned Entity		Matt Ide	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Matt Ide	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Peter Fuller
Tangent Energy	AR-LR	Brad Swalwell (tel)		
Taunton Municipal Lighting Plant	Publicly Owned Entity	Devon Tremont	Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
Tenaska Power Services Co.	Supplier		Eric Stallings	
The Energy Consortium	End User		Mary Smith (tel)	
Union of Concerned Scientists	End User		Francis Pullaro	
Vermont Electric Cooperative	Publicly Owned Entity		Dan Potter	
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Energy Investment Corporation	AR-LR	David Westman	Jason Frost	
Vermont Public Power Supply Authority	Publicly Owned Entity	Ken Nolan		Brian Forshaw
Versant Power	Transmission	Lisa Martin (tel)	Dave Norman	
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide	
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		Matt Ide	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc. (Wheelabrator)	AR-RG		Bill Fowler	
ZTECH, LLC	End User		Gus Fromuth	Bill Short