FINAL

The 2022 Summer Meeting of the NEPOOL Participants Committee was held at The Samoset Resort, Rockport, Maine, on Tuesday, June 21, and Wednesday, June 22, pursuant to notice duly given, followed on Thursday, June 23, by meetings between modified Sector groups and ISO Board Members, state officials, and staff from the FERC's Office of Energy Market Regulation (OEMR) respectively. A quorum determined in accordance with the Second Restated NEPOOL Agreement was present and acting throughout the meeting. All motions acted on at the meeting were voted on Tuesday, June 21. Attachment 1 identifies the members, alternates and temporary alternates attending the meeting and voting that day.

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

JUNE 21, 2022 SESSION

The June 21, 2022 session began at 9:30 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. He invited Mr. Melvin Williams, recently elected to a first term as a Director on the ISO Board, to offer a few remarks to the Committee. Mr. Williams highlighted the impacts and lessons learned from his career in the U.S. Navy (where he rose to be an admiral), government (including time as Deputy Secretary of Energy), and academia. He noted, in particular, the times that he had spent in New England, including an important stretch as a child in Groton, CT, where he benefitted from a first class education and first developed his commitment to the service of others. He thanked the Participants for the opportunity to come home and to serve with all those around the table in supporting New England and looked forward to meeting with Participants in the future.

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 Technical Committees. Following motion duly made and seconded, the Consent Agenda was unanimously approved as circulated, with an abstention by Mr. Sam Mintz noted.

CONTINUOUS STORAGE FACILITY MARKET RULE REVISIONS

Ms. Mariah Winkler, Markets Committee (MC) Chair, referred the Committee to Tariff revisions, circulated and posted with the meeting materials in advance of the meeting, that would allow storage resources that inject energy into the grid but do not receive energy from the grid to register and operate as a Continuous Storage Facility. She reported that the MC recommended Participants Committee support for the revisions at its June 8, 2022 meeting and, but for the timing of the MC recommendation, this matter would have been on the Consent Agenda.

The following motion was duly made, seconded, and unanimously approved without discussion, with an abstention noted for Mr. Mintz:

> RESOLVED, that the Participants Committee supports the revisions to Section III.1.10.6 of the Tariff pertaining to storage resources operating as Continuous Storage Facilities, as recommended by the Markets Committee and as circulated in advance of this meeting, together with such further non-substantive changes as the Chair and Vice-Chair of the Markets Committee may approve.

ISO CEO REPORT

ISO Board and Board Committee Meeting Summaries

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), referred the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the May

5, 2022 meeting, which had been circulated and posted in advance of the meeting, and invited questions. There were no questions or comments on those summaries.

Winter 2022-23

Noting that the summaries identified a Board Markets Committee discussion on winter reliability issues, and in light of requests received at the NECPUC Symposium that the ISO consider options to mitigate risks to reliability for Winter 2022-23, Mr. van Welie, together with Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), provided context and a summary of preliminary thoughts regarding potential options for incremental actions for Winter 2022-23.

Mr. van Welie summarized ISO actions already taken to bolster reliability, including the actions in 2018 to retain the Mystic Generating Station (Mystic) and thereby the Everett liquefied natural gas (LNG) terminal. He then noted two significant variables beyond the ISO’s control – weather and the global fuels markets – and the fragility/uncertainty that those variables add to the re-supply chain specifically and reliability generally. Mr. van Welie reported that the ISO had not yet identified any cost-effective and impactful actions that could fully cover the risk presented by an unusually cold winter (like that experienced in 2013-14). However, in light of requests received during and following the NECPUC Symposium the month before, the ISO was gathering information and updating its data and cost information from recent, representative winters and programs to inform consideration of possible incremental actions that might mitigate reliability risks and/or costs. That consideration, which Mr. van Welie suggested needed to happen swiftly, would take place in July, and if and to the extent there would be any next steps (on which the ISO remained open to considering, but had not either taken a position or committed to), action on those steps would be taken in August.

In any case, Mr. van Welie said that the ISO would, as it had the year prior, forecast, report and evaluate the risk profile of the current winter period against three winter scenarios – an extreme (Winter 2013-14), a moderate but tight (Winter 2017-18), and a mild (Winter 2020-21) scenario. He hoped that the joint energy-security study on extreme winter weather being conducted with the Electric Power Research Institute (EPRI) would provide valuable input into further mitigating the region's winter reliability risk. He also noted the discussion that was planned for the FERC's September 8 technical conference to be held in Burlington, Vermont and the need to address the structural challenges that impede mitigating reliability risks, including possible exploration of cost-based, rather than market-based, development of fuel infrastructure, as is being done with wholesale electric transmission.

Dr. Chadalavada then provided highlights from the winter readiness and replenishment information gathered to that point from large generating and storage (oil and LNG) assets. He estimated that the likely starting point for fuel storage for Winter 2022-23, when compared to the prior winter, would be similar if not better (with less fuel oil, but with more LNG on hand). Replenishment plans from oil asset owners, evaluated in the context of a non-extreme winter, raised minimal concerns.

Turning to the Analysis Group's update on the costs of previous winter programs, Dr. Chadalavada expected that the ISO would have, by the end of June, the cost data necessary to inform possible next steps, and which would be shared with Participants after the Fourth of July holiday and in advance of the July Markets Committee summer meeting. By way of example, he expected that, given the price of oil futures, the costs of any potential Winter 2022-23 program would be materially more than the costs of the last winter reliability program (Winter 2017-18). The update would also permit evaluation of the cost of potential technology-specific contributions via a design based on the Inventoried Energy Program (IEP) (as limited by the DC Circuit Court's order on IEP the week before). He stated that Participants could expect benchmarking of winter readiness against a mild winter scenario.

The Committee then commented and asked questions. A member urged the ISO, should it decide to pursue a Winter 2022-23 reliability program, to distinguish between baseline and incremental fuel inventory compensation; Dr. Chadalavada noted the difficulty with that approach, but looked forward to further discussion on potential approaches to address those difficulties. Other members offered thoughts and asked clarifying questions on potential options and consequences for incremental actions for Winter 2022-23, with Dr. Chadalavada addressing how the ISO approaches and balances variables and considerations associated with those actions.

In response to questions on pricing and consumer conservation, Dr. Chadalavada indicated that, while the ISO had focused on wholesale supply-side issues and was operationally better prepared than previous winters, the ISO did not have tools for projecting prices, particularly given the challenges of the external global variables described earlier. Mr. van Welie elaborated on the advantages of, and need for, dynamic pricing at the retail level, as well as on wholesale market refinements implemented after Winter 2017-18 to enhance the early warnings that can be provided to the market when the system was facing potential adequacy shortfalls. Members again underscored some of the economic signals already available to the market and the difficult balancing between risk and reliability facing the ISO. Many expressed appreciation to the ISO for the information provided and their efforts in this area.

ISO COO REPORT

Operations Update

Dr. Chadalavada, whose June 2022 report had been circulated and posted earlier in the month, began by addressing a question on the Minimum Generation (Min Gen) Emergency declared by the ISO on May 21, 2022. He explained that the ISO went into May 21 with temperature forecasts for 90° F or above in all of New England's major load centers. However, due to an unusually cool weather front that moved through the region on the morning of the 21st, where actual morning temperatures did not exceed 75° F, loads were 1,800 MW lower than forecast. The lower loads left the ISO with more supply on the system than necessary, but without enough room to back down the unneeded generation, resulting in a three-hour Min Gen event, including negative LMPs (-$150/MWh) for a few hours during the early afternoon.

In response to a question on the hardware malfunction experienced by the ISO on May 18, Dr. Chadalavada reported that the outage lasted for nearly 6 hours. The outage, caused by a faulty manufacturer's setting in firewall software, did not impact the ISO's reliability functions, but did impact all of the ISO's market systems until the manufacturer was able to correct the setting defect. The ISO was working with the vendor to ensure better communications regarding defects discovered or needed patches going forward.

2022-2025 Roadmap to the Future Grid

Referring the Committee to materials circulated and posted in advance of the meeting, Dr. Chadalavada reviewed a projection of the major projects and associated timelines anticipated over the next four years to advance New England's grid transition. He identified and provided additional information on the projected projects, which were grouped generally into three categories – markets, transmission planning/operational, and IT initiatives.

With respect to the Markets initiatives, he noted projects underway, including the Future Grid Pathways process, Resource Capacity Accreditation, Day-Ahead Ancillary Services Improvements, and Storage Modeling Enhancements projects. He highlighted and described new projects, including an Energy Shortage Pricing Assessment, ongoing work to enhance the Forward Capacity Market (FCM), including Parameters for FCA21, Intertemporal Pricing and Optimization, and Replacement Reserve and Reserve Zone reforms.

Transmission Planning and operational initiatives included the 2050 Transmission Study, extended-term Transmission Planning, storage as Transmission-Only Asset (SATOA), the Future Grid Reliability Study (FGRS), and efforts related to the operational impacts of extreme weather, energy adequacy, and load, solar, and wind forecast improvements. IT initiatives identified in the report but not reviewed with the Committee included future grid models & simulators, next generation market (nGem) software implementation, cyber-security initiatives, Order 2222 implementation, and Energy Management System (EMS) modeling enhancements.

In response to comments and questions, Dr. Chadalavada provided additional detail related to the projects and explained how the project descriptions incorporate and might be refined to incorporate other various long-term efforts. He tied the initiatives to the 2023 budget presentation to follow. Members were also directed to the Appendices that identified work associated with known and anticipated FERC mandates, as well as a list of 2023 priority items that had been identified to date by the NEPOOL Sectors.

ISO CFO REPORT: 2023/2024 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 2023 and 2024 preliminary Operating and Capital Budgets (Budgets) included with the materials posted in advance of the meeting. He reported that he had also shared this information with New England state officials earlier in the month.

Mr. Ludlow discussed the following four key components that were driving changes to the 2023 and 2024 Operating Budget: (i) staffing additions (in markets development, information technology (IT), system planning, and participant support and external affairs and corporate communications); (ii) professional fees (including for studies supporting major market and reliability efforts); (iii) IT support (system maintenance, software licenses, data storage, and inflationary costs); and (iv) inflation impacting salaries and benefits. He projected that the 2023 Operating Budget would reflect an overall increase over 2022's Operating Budget of about 11%, to be largely offset, however, by a $15 million true-up from 2021 (a true-up resulting from a $3 million underspend and $12 million over-collection in 2021). The 2023 Capital Budget was projected to be $33.5 million, with increases being driven by upgrades to the core market software (nGEM), major market and reliability-related efforts, cyber security, and IT asset and infrastructure replacement.

In response to questions, Mr. Ludlow provided additional explanation regarding staffing increases and retention efforts, and the top-down estimates used to establish the preliminary budget numbers. He noted that the detailed budgets to be presented in August would include additional information supporting proposed headcount increases. He confirmed that the ISO had sufficient physical space to support the headcount increases. He also confirmed that the increase in the headcount for external affairs and corporate communications was designed to support enhanced regional educational and outreach efforts.

LITIGATION REPORT

Mr. Doot referred the Committee to the June 17 Litigation Report that had been circulated and posted in advance of the meeting. He highlighted the following developments: (i) FERC approval of regional plan for transforming the minimum offer price rule (MOPR), with requests for rehearing due on or before June 27, 2022; (ii) FERC extension to August 17 of the deadline for filing comments on the transmission Notice of Proposed Rulemaking (NOPR), with reply comments due by September 19; (iii) FERC Staff issuance of a deficiency letter in response to the proposal for addressing Order No. 2222, and the ISO's submission of a response to that letter on June 17; (iv) FERC notice of a forum to be held on September 8 in Burlington, Vermont to discuss winter operation plans; (v) the order of the U.S. Court of Appeals for the DC Circuit (the DC Circuit) vacating the FERC's approval of payments to nuclear, biomass, coal and hydro generators under the IEP; (vi) FERC's issuance of the interconnection NOPR, which NEPOOL counsel proceeded to summarize briefly, referring members to the Reliability Committee for more detailed information; and (vi) the dismissal by the DC Circuit of the appeal by NTE challenging FERC's approval the termination of Killingly's Capacity Supply Obligation (CSO). He noted that the September Participants Committee, originally scheduled for September 8, was being rescheduled to September 1 in light of the FERC's scheduled forum. He encouraged anyone with questions on the status of relevant proceedings to contact NEPOOL Counsel.

COMMITTEE REPORTS

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that the next regularly-scheduled RC meeting was scheduled for July 19. The RC would receive another report on the EPRI/ISO-NE study of the impact of extreme weather on reliability.

Transmission Committee (TC). Mr. José Rotger, the TC Vice-Chair, reported that the next TC meeting was scheduled for June 28 and would include a discussion of the Interconnection NOPR, input on whether NEPOOL should file comments on the Transmission NOPR, the ISO's SATOA Tariff changes, and changes to the Attachment K economic study process (to implement a repeatable study framework).

Markets Committee. Mr. William Fowler, the MC Vice-Chair, reported that the MC would hold its 2022 summer meeting at Mills Falls at the Lake (Winnipesaukee) in Meredith, New Hampshire from July 12-14. The summer MC meeting was projected to have a full agenda, to include discussion on the Resource Capacity Accreditation project and, as discussed earlier in this meeting, whether and what incremental changes might be proposed for the Winter 2022-23 period. Those still seeking accommodations for that meeting were encouraged to reach out to Mr. Fowler or Ms. Winkler for recommendations.

Budget & Finance (B&F) Subcommittee. Mr. Thomas Kaslow reported that the B&F Subcommittee was scheduled to meet on July 22 to review NESCOE's preliminary (fourth) 5-year pro forma budget, and then twice in August, first on August 11 to review the ISO's proposed 2023 Budgets and NESCOE's 2023 Annual Budget, and second on August 23 to receive its usual reports and address any proposed B&F-related Tariff issues.

Membership Subcommittee. Ms. Sarah Bresolin, Membership Subcommittee Chair, reported that the Subcommittee was next scheduled to meet on July 11 to consider any applications for membership that might be received.

ACKNOWLEDGEMENT - HERB HEALY

Mr. Doot announced that this would be Mr. Herb Healy's last Participants Committee meeting. Mr. Healy was retiring after more than a half century in the energy industry, nearly 40 years spent with United Technologies developing fuel cell projects, and another 15 supporting the demand response sector, including nearly 10 as a vice president for regulatory affairs for his son's company, EnerNOC. On behalf of the Committee, Mr. Doot acknowledged Mr. Healy's contributions to the region over the years (not the least of which was his penchant for probing questions at the Participants Committee) and the sentiment that he would be missed. Mr. Healy expressed his appreciation for those thoughts and for the long standing working and personal relationships developed over the years.

COMMENTS BY FERC OEMR STAFF

Mr. Cavanaugh welcomed, introduced and thanked Ms. Nicole Businelli and Mr. Noah Schlosser, co-leads for the ISO New England virtual team within the FERC's OEMR – East Division, for their attendance and participation. Ms. Businelli and Mr. Schlosser were focused on New England activities before the FERC, and grateful for the opportunity to put faces to New England's voices before the Commission.

Ms. Businelli began her comments by making clear that their remarks reflect their views and opinions, and not those of the Commission or any of the Commissioners. She provided a brief personal and professional background, describing OEMR's functions in general, their roles within OEMR specifically, and the relationship of OEMR to the other offices within the FERC.

Mr. Schlosser similarly provided a brief personal and professional background, noting his specialty in financial modeling (cost of capital and reactive power). He described the role of FERC's ISO New England virtual team (whose name pre-dated the pandemic), and acknowledged Eric Jacobi, a virtual team member based in the FERC's regional office in Massachusetts. He identified opportunities to interface with FERC staff, expanding on the role and purpose of the Commission's rules regarding *ex parte* communications.

In response to questions, Ms. Businelli identified pre-filing meetings as particularly helpful to getting their work done, both with filers and with parties who have specific positions on a future filing, either in support or opposition. Comments that develop a robust public record and make points substantiated by evidence in that record were also critically important. Mr. Schlosser acknowledged an appreciation for, and both agreed that there was little downside to, submissions with humor, resonance, or other features making the submission a bit livelier, though he emphasized that there was no substitute for substantiated record evidence given the review and necessary findings of the just and reasonableness of any proposal. In response to a question, Mr. Schlosser explained that the manner in which pleadings are reviewed and summarized by analysts was largely proceeding-specific, and varied from analyst to analyst. Ms. Businelli and Mr. Schlosser both encouraged all those communicating with the Commission to provide historic and contextual information relating to filings, and to present clearly their perspectives and perceived impacts of those filings on various regional groups.

EMM 2021 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 2021 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. He opined that the ISO's markets performed competitively in 2021 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 markets, noting that energy prices nearly doubled since 2020, driven largely by higher natural gas prices. In New England, as he explained, energy prices rose in large part due to a 140% increase in average natural gas prices, while average load in the region rose by 2%. In addition, carbon pricing (e.g., the Regional Greenhouse Gas Initiative) increased supply costs in New England, contributing to the higher prices. Although New England's energy prices were greater than in most other regions, Dr. Patton noted that New England's energy prices were in line or lower than in regions with high transmission congestion, which was not a material issue in New England.

Next, Dr. Patton addressed capacity prices. He explained that New England's capacity prices were generally higher than in other markets because, in part, the ISO's load forecast was too high. But as the ISO had adjusted the forecast downward, as shown in the most recent CELT (Capacity, Energy, Loads, and Transmission) Report (which showed a load forecast reduction of 5%), capacity prices had decreased to a $2 per kilowatt hour (kWh) range.

Dr. Patton then reviewed transmission congestion costs. With an average of less than $0.38 per megawatt hour (MWh), New England's transmission congestion costs were exceedingly small when compared to other regions. The EMM explained that New England's investment in transmission over the last decade mitigated congestion costs but had increased transmission rates to nearly $22 per MWh in 2021, which was higher than in any other market. He noted, however, that transmission rates in other markets were likely to increase due to upcoming and/or ongoing investment in transmission to incorporate intermittent resources. In response to comments and questions, Dr. Patton acknowledged that the region justified major transmission investment on the basis of reliability rather than congestion reduction and that the ISO was utilizing highly conservative assumptions in its calculation. He anticipated that other regions would likely see higher growth in transmission investments relative to New England as renewable resources increase. He also opined that allowing some transmission congestion to exist increased the incentives for wind developers to site those resources where they could minimize costs to consumers and that those incentives would be reduced if transmission costs were socialized.

Turning to virtual trading, Dr. Patton observed that virtual transactions (Increment Offers and/or Decrement Bids in the Day-Ahead Energy Market) in New England were much lower as a percentage of load than in other markets. He attributed this to the region's uplift cost allocation methodology. Dr. Patton again recommended that the ISO modify its methodology, noting that the upcoming Day-Ahead Ancillary Services improvements project could address his recommendation.

Out-of-Market Commitments and Operating Reserve Markets

Dr. Patton then discussed the Operating Reserve Markets, starting with the need for a Ten-Minute Spinning Reserve product. As he explained, the Day-Ahead Market's constraint to satisfy the Ten- and Thirty-Minute Reserve requirements without corresponding market products resulted in the commitment of more resources Day-Ahead but not in the scheduling of those resources to provide Reserves in Real-Time. Consequently, market prices were depressed and Net Commitment Period Compensation (NCPC) costs increased. The EMM noted that, in 2021, out-of-market commitments occurred in nearly 3,400 hours to satisfy New England's Ten-Minute Spinning Reserve requirement, which accounted for 35% of Day-Ahead NCPC. He also pointed out that the $2 per MWh average reserve value, as shown in his presentation, offered a sense of the magnitude that energy prices were depressed.

Dr. Patton then discussed Day-Ahead commitments for Local Second Contingency Protection. He highlighted that the NH-ME and NE West-to-East interfaces had seen the greatest number of out-of-market commitments for local needs in 2021, with the latter region creating the greatest distortion to the market. He explained that those regions 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 those local needs in the Day-Ahead market could produce between $6 and $15 per kW-year of additional revenue for resources in those local areas.

The EMM concluded this section of his presentation by recommending that the ISO introduce Operating Reserves in the Day-Ahead market and define local reserve zones when local second contingency issues appear, which would allow the ISO to dynamically introduce a local reserve requirement in the market.

Market Operations in January 2022

In the next section, Dr. Patton discussed the system's performance during January 2022. He presented a table showing the average daily amount of oil-capable units (in terms of MW) that would have been economic to produce energy based on Day-Ahead and Real-Time clearing prices. Dr. Patton observed that, as oil became more economic due to the increased natural gas prices, oil-capable units became more economic. Yet, only 41% of economic oil-capable units used oil to generate electricity, while 27% of the economic oil-capable units chose to burn natural gas for reasons not related to maintaining inventory. Ultimately, Dr. Patton concluded that the market operated as expected during cold January days and that generators seemed to respond to price signals. Members questioned the calculations and discussed with Dr. Patton a number of reasons for running at a higher cost, in particular during hours for which the EMM might not have fully accounted (e.g., minimum take requirements for LNG, efforts to manage inventories, environmental constraints, or incentive to avoid mitigation). Overall, the EMM noted that he did not see any behavior from oil-capable generators that was inconsistent with the market signals. Dr. Patton stressed that this conclusion was important as winter reliability concerns increase.

Assessment of the Forward Capacity Market

Dr. Patton then reviewed various slides assessing the FCM. He began by discussing capacity accreditation, noting that the principles and recommendations applied to all resources. One such principle was that the amount of accredited capacity should reflect the benefit resources provide, measured on the basis of Loss of Load Expectation or Expected Unserved Energy, to resource adequacy, with the most valuable resources being those that are available when the risk of losing load is the highest. The EMM also urged the use of marginal ratings for calculating accreditation rather than the average approach, describing potential inaccuracies in valuing capacity for (1) intermittent resources as penetrations increase, (2) older, less flexible resources as needs come with less notice, (3) large resources, such as nuclear that is available most hours, and (4) pipeline gas-dependent resources.

Next, Dr. Patton discussed a chart depicting the 30 winter days with the highest peak loads from December 2017 to February 2022. The EMM interpreted the chart to indicate that, without LNG injection on certain days, there was not enough natural gas available in New England for all the gas-fired resources in the region to generate electricity. Dr. Patton explained that, during times of constrained gas availability, most of the gas piped into New England was used by gas utilities for their firm customers.

Discussion about the formation of the chart and conclusions that could be drawn followed. The EMM noted that overall availability of pipeline gas for electric generation would be heavily impacted by temperature, noting that there was a high correlation between electric load and gas demand. He acknowledged that the chart in the presentation only included LNG injections from the larger LNG facilities such as Canaport and Everett, and it did not track LNG from satellite facilities located in the region. Members observed that gas-only generators enter hedging transactions to cover expected needs regardless of whether it is pipeline or LNG, that LNG also helps maintain pressures in the pipeline to the benefit of all, and that generators seek to manage inventories and optimize value of their transactions.

Dr. Patton went on to discuss his recommendation to apply a marginal reliability methodology by comparing a pipeline gas resource's accredited capacity rating using two approaches. Specifically he summarized the EMM's calculations of the marginal reliability improvement (MRI) and average effective load carrying capability (ELCC) metrics at system criteria (i.e., without the current surplus) for pipeline gas resources during different seasons. He explained that the calculation of MRI values for gas-only resources not backed by LNG or pipeline capacity commitments declines rapidly during the winter at system criteria. The EMM calculated a 0% MRI value at system criteria during a winter when there are about 8 gigawatts (GW) of gas-only resources on the system. By way of comparison, Dr. Patton added that the MRI for solar approaches zero in the winter, but both of these types of resources have much higher MRI values in the summer. The EMM further explained that, as the reliability risk shifts from summer to winter, it becomes much more important to have marginal seasonal ratings with a seasonal prompt market for resources, which would encourage availability when those resources are most needed. The EMM acknowledged that the region would need also to change how it establishes regional capacity requirements. He re-emphasized that, based on this information, the importance of accrediting resources with a marginal methodology rather than an average one.

Discussion concerning the EMM's accreditation recommendations and modeling followed. In response to a question seeking his opinion as to whether there was a need for a potential future winter reliability program, Dr. Patton indicated he did not believe such a program was needed for Winter 2022-23 because Mystic remained in operation. When Mystic ceases to operate, however, Dr. Patton urged adopting market solutions such as a resource accreditation to allow resources to respond to market signals, which could reduce costs to consumers. In response to the EMM's comments, a member questioned whether the much higher prices for oil and LNG might alter that recommendation. Another member suggested that the planning model used in the future should account for the factors that drive the availability of generators, such as their location along the natural gas pipeline. The EMM explained in response to questions that its analysis was intended to show that a mechanism needs to be put in place to provide market incentives for an appropriate amount of gas-only generators to firm up their fuel supply for the winter.

FCM Improvements

Dr. Patton next transitioned to a discussion of his recommendations for improving the FCM. He opined that the region's FCM had not met its objective to coordinate new entry, especially now that a price lock-in mechanism no longer exists. Dr. Patton stated that requiring a resource that clears the auction to take on a CSO that begins three years later creates uncertainty for the resource. To support his observation, Dr. Patton showed statistics on the timeliness of commercial operation for new CSOs of at least 50 MW for the Capacity Commitment Periods beginning June 2016 through June 2022. Those statistics showed that less than half the resources entered service on time, with the remaining resources either late or cancelled altogether. He added his views that the FCM requires older resources to assess the likelihood that the resource will be operational three and a half years later when the new capacity year begins. That assessment created significant risk and may result in early retirements of economic resources.

Another concern of the EMM with the FCM was the difficulty in accrediting resources in light of forecast errors. Because the expected resource mix is a key assumption when accrediting resources, Dr. Patton opined that resources' marginal accreditation three and a half years later creates inaccuracies. Further, forecasting loads three years in advance also introduces more inaccuracies. To address these concerns, Dr. Patton recommended the region shift from a forward market to a prompt market along with making it seasonal. He did not have specific recommendations on the precise timing of the capacity auction for each prompt market delivery period, opining that it could be worked out to provide sufficient lead time needed for generators to plan to participate in a capacity auction. Responding to questions about the current market, Dr. Patton opined that transitioning to a sealed bid-auction would work for both the current FCM and a prompt market. He expressed concern that a move to increase financial assurance for new resources that are delayed could be counterproductive

Dr. Patton concluded his presentation with a slide referring to his list of recommendations, emphasizing that some of the recommendations were from prior reports and identified the prior report in which the recommendation was first made without repeating the supporting information from that prior report.

JUNE 22 SESSION

The Summer Meeting reconvened at 9:10 a.m. on June 22, 2022.

WELCOME REMARKS BY PHIL BARTLETT

Mr. Cavanaugh welcomed members and guests back to the meeting and introduced Maine Public Utilities Commission Chair Philip Bartlett for welcoming remarks. Chair Bartlett welcomed all to Maine and expressed appreciation for the opportunity to meet in person with members and colleagues on the very challenging issues facing the region. He urged active participation in the meetings and encouraged attendees to enjoy Maine and support the Maine businesses in the area.

RESOLUTION OF APPRECIATION FOR FORMER CHAIR NANCY CHAFETZ

At the request of the Chair, Mr. Doot introduced the following resolution of appreciation, which was approved by acclamation, for the services of Nancy Chafetz during her two years as Chair of the Participants Committee:

RESOLUTION OF APPRECIATION

Nancy P. Chafetz

WHEREAS, Ms. Nancy P. Chafetz was elected Chair of the New England Power Pool (NEPOOL) Participants Committee for, and led NEPOOL during, 2019 and 2020, following five years serving as the elected Vice-Chair of the Supplier Sector and many more years (and questions to the ISO COO) as a NEPOOL representative and thought leader; and

WHEREAS, Nancy has been an unwavering advocate for NEPOOL's role in influencing and guiding the trajectory of New England's competitive wholesale power markets and its operations by working collaboratively and collegially with members, state and federal officials, and ISO colleagues; and

> WHEREAS, Nancy' guided the operation of the NEPOOL Participants Committee through the unprecedented COVID-19 pandemic, seamlessly maintaining NEPOOL work and priorities through virtual meetings; and
>
> WHEREAS, Nancy's leadership and her hallmark thoroughness, compassion, and warm and graceful style have deftly advanced NEPOOL's mission and the interests of the many Participants she has represented through the years; and
>
> WHEREAS, Nancy has left an indelible mark on the Pool, not only through her participation and leadership, but in the adoption of a newly-charged NEPOOL logo and website.
>
> NOW, THEREFORE, the Participants Committee of the New England Power Pool, on behalf of the NEPOOL Participants, hereby expresses its sincere appreciation to Nancy for her service as its Chair and for her leadership and dedication to moving New England forward, together, first and foremost through the NEPOOL stakeholder process.

REMARKS OF FERC COMMISSIONER MARK CHRISTIE

Mr. Cavanaugh welcomed and introduced FERC Commissioner Mark Christie, summarizing his background and service on the Commission. Commissioner Christie expressed his appreciation for the invitation to participate in the meeting, describing his time in and appreciation for this part of Maine.

Commissioner Christie concentrated his remarks on the Transmission NOPR that had recently been issued by the FERC. He emphasized that the NOPR did not apply to reliability or economic transmission projects. Rather, it applied specifically and narrowly to regional public policy projects, where the States have primacy in deciding on the projects and cost allocation. He emphasized his view that, while the projects are regional and subject to FERC jurisdiction, the NOPR requirements would be satisfied for public policy requirements if states agree on cost allocation. He sought comments from interested parties on how best to handle cost allocation for public power and cooperatives, encouraging state regulators to reach out to address cost allocation issues. He emphasized that, from his viewpoint, the NOPR was drafted with maximum flexibility for the states. He described his respect for and recognition of the states' knowledge of what works best for them and his inclination to defer to that knowledge and expertise. In response to questions, he expressed his preference for maximum flexibility in the final proposed rule for states to decide what works best for their region for public policy projects.

Pivoting slightly from discussion of the Transmission NOPR, he referred to the recent interconnection queue reform NOPR and underscored his respect for regional variation. He emphasized the number of times that he saw the role of regulators to first do no harm. Further, he re-emphasized his view that states should be the final arbiter on how planning for public policy projects are to be determined and handled. He looked to the states also as best equipped to ensure cost containment for transmission projects and opined that the states retain ultimate responsibility for assuring resource adequacy for their own states. He expressed his view that the FERC should ensure that states receive from the RTOs all of the information they need to perform their job in assessing need for and prudence of expenditures. He received a suggestion from a member to ensure competition for new projects.

Following further discussion, Mr. Cavanaugh thanked Commissioner Christie for his comments and time, and invited him to join NEPOOL at future meetings, either in person or virtually, if desired.

PANEL DISCUSSION WITH NEW ENGLAND STATE OFFICIALS ON FUTURE GRID PATHWAYS

Mr. Cavanaugh then introduced the following New England state (States) officials for a panel discussion of the various pathways being considered within the region to support New England's clean energy transition: Vermont (VT) Public Service Commissioner June Tierney; Massachusetts (MA) Department of Public Utilities (MA DPU) Chair Matthew Nelson; Maine

Public Utilities Commission Chair Philip Bartlett; MA Department of Energy Resources (MA DOER) Commissioner Patrick Woodcock; New Hampshire Department of Energy (NHDOE) staff member Dan Phelan; and Connecticut Public Utilities Regulatory Authority (CT PURA) staff member Eric Annes. Mr. Cavanaugh summarized the Future Grid Pathways process followed to date and then turned to each panelist to comment on the ISO-commissioned Analysis Group Study Report that had quantitatively assessed four potential pathways: status quo, a forward clean energy market (FCEM), net carbon pricing, and a hybrid approach.

The state officials generally agreed that while status quo was certainly implementable into the future, it was not the most desirable pathway forward as it would likely impose increased costs on consumers in the region. One of the state panelists opined that sticking with status quo also would take longer than acceptable to achieve desired outcomes and would endanger the current markets. While not necessarily expressing a clear preference for one pathway over the other, there was general support among the state panelists for further exploration and consideration of a form of FCEM. Certain of the state officials explained that a carbon pricing adder was not a politically feasible alternative at that time. The CT PURA representative, though, indicated support for further consideration of a hybrid approach, indicating that current higher fuel prices could conceivably result in a net-carbon price at or near zero. VT's Commissioner also agreed that she could conceptually support a hybrid approach if the governance issues could be worked out to the satisfaction of all the States.

On the subject of governance, the panelists spoke about a governance framework that would provide greater involvement and oversight by the States while protecting their sovereign roles. Some panelists opined that in order to promote and maintain the stability and sustainability of a new market construct, the governance structure/process utilized would benefit from a certain amount of insulation from political pressures at both the state and federal levels. That opinion was not uniform, with VT's Commissioner noting that politics necessarily must be respected and the MA DPU Chair noting that stability for investments, not necessarily political insulation, was the desired outcome in order to ensure least cost to consumers. Representatives from MA and VT both expressed the view that a priority for the States, through the NESCOE managers or NECPUC, was to arrive at a consensus on governance issues.

Focusing on next steps, the MA officials indicated that they planned to identify additional details that they would find acceptable and workable and to work to educate state and regional policy makers on the need for market reform. Other of the state officials expressed the need for more input from market participants on what they would find effective and help to communicate the expected benefits of an alternative market mechanism to the public.

In response to follow on questions, some of the state officials acknowledged the potential need to rely on certain existing generation for transition purposes, with markets that support directionally the goals of the states. They expressed the need to ensure transparent and honest discussions about what resources are required for reliability while moving toward increased carbon-free resources. One of the panelists also expressed the need for other active market improvement efforts, such as capacity accreditation and improved Ancillary Service Markets, to remain on track.

In response to questions as to whether there is any way to overcome the political impasse over carbon pricing, panelists explained that they were simply unable in their respective roles to change support for a carbon adder without far more efforts from the industry to build political support. Voters and elected officials needed to be educated and willing to support carbon pricing.

Although there remained strong political support within some of the States for advancing long-term contracting options, the panelists concluded generally in response to questions that alternative pathways/market reforms were preferable to help achieve State policy objectives/mandates over the longer term.

There being no other business, the June 22 session ended at 11:55 a.m., with the following day set for Sector meetings beginning at 8:00 a.m.

Respectfully submitted,

David T. Doot, Secretary

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN
JUNE 21-23, 2022 SUMMER MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Melissa Birchard (tel)		
Advanced Energy Economy (AEE)	Associate Non-Voting	Caitlin Marquis		
Ampersand Energy Partners	Supplier			Hannah Braun (tel)
AR Large Renewable Gen. (RG) Group Member	AR-RG	Alex Worsley		
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell (tel)		
AR Small Renew. Generation (RG) Group Member	AR-RG	Erik Abend (tel)		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matt Ide	
Associated Industries of Massachusetts (AIM)	End User			Mary Smith (tel)
AVANGRID: CMP/UI	Transmission	Alan Trotta	Jason Rauch	Zach Teti (tel)
Bath Iron Works Corporation	End User			Bill Short; Gus Fromuth
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		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		
Calpine Energy Services, LP	Supplier	Brett Kruse	Brett Howell	Bill Fowler; John Flumerfelt
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Central Rivers Power	AR-RG		Dan Allegretti	
Centrica Business Solutions Optimize, LLC	AR-LR		Aaron Breidenbaugh (tel)	
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	
Clearway Power Marketing LLC	Supplier		Dan Hendrick	Pete Fuller (tel)
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw (tel)		
Connecticut Office of Consumer Counsel	End User		Dave Thompson	
Conservation Law Foundation (CLF)	End User		Priya Gandbnir (tel)	
Constellation Energy Generation	Supplier	Steve Kirk (tel)	Bill Fowler	
CPV Towantic, LLC	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
Durgin and Crowell Lumber Co., Inc.	End User			Bill Short; Gus Fromuth
Dynegy Marketing and Trade, LLC	Supplier		Andy Weinstein	Arnie Quinn; Bill Fowler
Elektrisola, Inc.	End User		Gus Fromuth	Bill Short
Emera Energy Services	Supplier			Bill Fowler
Enel X North America, Inc.	AR-LR		Greg Geller	
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission		Dave Burnham	
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc.	Supplier	José Rotger		
Garland Manufacturing Company	End User			Bill Short
Generation Group Member	Generation		Abby Krich	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Granite Shore Power Companies	Generation			Bob Stein
Great River Hydro	AR-RG			Bill Fowler

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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)	Supplier	Louis Guilbault (tel)	Bob Stein	
Hammond Lumber Company	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		
Ipswich Municipal Light Department	Publicly Owned Entity		Matt Ide	
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths	Nancy Chafetz	
Jupiter Power	Provisional Member		Hans Detweiler	Ron Carrier
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 Kilgoar (tel)		
Maine Power LLC	Supplier	Jeff Jones		
Maine Public Advocate’s Office	End User	Drew Landry		
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	Tina Belew		
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide		
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	
Mintz, Samuel	End User	Sam Mintz		
Moore Company	End User			Bill Short; Gus Fromuth
Morgan Stanley Capital Group, Inc.	Supplier	Jennifer Harding		
Onward Energy (Blue Sky West LLC)	AR-RG		Katie Bellezza	
Narragansett Electric Company	Transmission		Brian Thomson	
National Grid	Transmission	Tim Brennan	Tim Martin	
Nautilus Power, LLC	Generation	Dan Pierpont	Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski (tel)		Brian Forshaw; Dave Cavanaugh
New Hampshire Office of Consumer Advocate	End User			Jason Frost
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson	Dan Dolan	
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	Supplier		Pete Fuller (tel)	
Nylon Corporation of America	End User			Bill Short; Gus Fromuth
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		Matt Ide	

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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	
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity		Matt Ide	
Saint Anselm	End User	Gus Fromuth		Bill Short
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
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	Chris Rauscher		Peter Fuller (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	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
Versant Power	Transmission	Lisa Martin	Dave Norman	
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide	
Walden Renewables Development LLC	Generation			Abby Krich
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.	AR-RG		Bill Fowler	Jim Ginnetti (tel)
Z-TECH LLC	End User		Gus Fromuth	Bill Short