David T. Doot
Secretary

September 29, 2022

VIA ELECTRONIC MAIL

TO: PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES

RE: Supplemental Notice of October 6, 2022 NEPOOL Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the October meeting of the Participants Committee will be held **in person on *Thursday*, October 6, 2022, at 10:00 a.m. at the Renaissance - Providence Downtown Hotel, 5 Ave of the Arts, Providence, RI, in the Symphony Ballroom** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/.

For your information, the October 6 meeting will be recorded. NEPOOL meetings, while not public, are open to all NEPOOL Participants, their authorized representatives and, except as otherwise limited for discussions in executive session, consumer advocates that are not members, federal and state officials and guests whose attendance has been cleared with the Committee Chair. All those in attendance or participating, either in person or by phone, are required to identify themselves and their affiliation at the meeting. Official records and minutes of meetings are posted publicly. No statements made in NEPOOL meetings are to be quoted or published publicly.

For those who otherwise attend NEPOOL meetings but plan to participate in the October 6 meeting virtually, please use the following dial-in information: **866-803-2146; Passcode: 7169224.** To join using WebEx, click this link and enter the event password **nepool**.

In addition, please note two items requiring your attention at this time:

- **Wednesday, November 2 Sector Meetings with ISO Board Panels** – The next Sector meetings with the ISO Board are scheduled to be held in person on Wednesday, November 2 at the Renaissance - Providence. The ISO has requested that proposed agendas and supporting materials for those meetings be provided on or before ***Friday, October 14***. Materials can be sent directly to Maria Gulluni at mgulluni@iso-ne.com and Pat Gerity at pmgerity@daypitney.com.

- **2023 NEPOOL Officers** – Each Sector needs to identify for us no later than ***Monday, October 31*** the voting member chosen by that Sector to serve as its 2023 Participants Committee officer. The Participants Committee will then select the Chair from among those Sector-selected officers, using the required voting process for that selection. We have included with this notice a memorandum that provides more information about the selection process.

Respectfully yours,

/s/
David T. Doot, Secretary

FINAL AGENDA

1. To approve the draft minutes of the September 1, 2022 Participants Committee teleconference meeting. Copies of the draft minutes, marked to show the changes from the version circulated with the initial notice, are included with this supplemental notice and posted with the meeting materials.

2. To adopt and approve the actions recommended by the Technical Committees set forth on the Consent Agenda included with this supplemental notice and posted with the meeting materials.

3. To receive an ISO Chief Executive Officer (CEO) report. The October CEO report will be circulated and posted in advance of the meeting. A letter to the ISO CEO and ISO Chief Operating Officer (COO) from the 'LSE Group' addressing the Mystic Cost-of-Service Agreement rates is included with this supplemental notice and posted with the meeting materials for your information.

4. To receive a report from the ISO Chief Operating Officer on the following:
    a. Operations Report Highlights; and
    b. Annual Work Plan.

   The Operations Report highlights will be circulated and posted in advance of the meeting. Materials related to the Annual Work Plan are being circulated and posted with this supplemental notice

5. To consider, and take action, as appropriate, on the following proposed budgets:
    a. 2023 ISO-NE Operating and Capital Budgets; and
    b. 2023 NESCOE Budget.

   Background materials and draft resolutions are included and posted with this supplemental notice.

6. To consider and take action, as appropriate, on the following for the 2026/2027 Capacity Commitment Period (FCA17):
    a. Hydro-Quebec Interconnection Capability Credits (HQICCs); and
    b. Installed Capacity Requirements (ICR) and ICR-Related Values.

   Background materials and draft resolutions are included and posted with this supplemental notice.

[continued on next page]

7. To consider and take action, as appropriate, on the following changes to incorporate treatment of Storage as a Transmission-Only Asset (SATOA):

    a. Changes to Sections I and II of the Tariff, as recommended by the Transmission Committee at its Aug 16 & 17 meeting; and

    b. Changes to Sections I.2.2 of the Tariff and Sections III.1.7.21, III.3.2.1(b)(iv), III.3.2.1(b)(vi), and III.3.2.2(a) of Market Rule 1, as recommended by the Markets Committee at its Sep 13-14 meeting.

    This matter has been placed on the Discussion Agenda at the request of representatives of Calpine and Shell. Background materials and a draft resolution(s) are included and posted with this supplemental notice.

8. To consider, and take action, as appropriate, on a referral to the NEPOOL GIS Operating Rules Working Group of a request for a waiver of the NEPOOL Generation Information System (GIS) Operating Rules by NuPower Cherry Street. Background materials and a draft resolution are included and posted with this supplemental notice.

9. To receive a report on current contested matters before the FERC and the Federal Courts. The litigation report will be circulated and posted in advance of the meeting.

10. To receive reports from Committees, Subcommittees and other working groups:
    - Markets Committee
    - Reliability Committee
    - Transmission Committee
    - Budget & Finance Subcommittee
    - Membership Subcommittee
    - Joint Nominating Committee
    - Others

11. Administrative matters.

12. To transact such other business as may properly come before the meeting.

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Pat Gerity, NEPOOL Counsel

DATE: September 22, 2022

RE: 2023 Participants Committee Officer Elections

In order to ensure that the selection process requirements in the Participants Committee Bylaws for 2023's Participants Committee officers can be timely completed, we need each Sector to indicate, no later than **Monday, October 31, 2022,** who the Sector has selected to serve as the Sector's Participants Committee officer. A description of the qualifications, responsibilities, and expectations of the Sector officers selected has been included with this memorandum. We urge each of you to work within your Sectors to select your Sector's 2023 Participants Committee officer.

By way of reminder, the Bylaws require that one voting member from each Sector be selected by a majority of all the voting members in its Sector (i) to serve as a nominee for Chair of the Participants Committee and (ii) if not elected Chair, to serve as a Committee Vice-Chair. A secret written balloting process will then be conducted to elect the 2023 Chair from among the Participants Committee officers selected by each of the Sectors. To allow time for that balloting process ahead of the December 1 Annual Meeting, as required by the Bylaws, we need the officers to be identified by October 31, 2022.

If any Sector needs assistance in conducting the vote for its Sector officer, please let us know (preferably no later than October 20). We would be pleased to help however we can. Also, if you have any questions, please contact me at pmgerity@daypitney.com or (860) 275-0533.

NEPOOL
NEW ENGLAND POWER POOL

Participants Committee Sector Officer
Qualifications, Responsibilities and Expectations

Qualifications: A Participants Committee Chair or Vice-Chair must be a voting member of the Participants Committee. Per the Participants Committee Bylaws, one voting member from each active Sector of the Participants Committee is to be selected to serve as the Vice-Chair of the Sector "by a majority of all the voting members in its Sector." The Chair is selected from among the nominated Vice-Chairs using the balloting procedures in the Bylaws.

Responsibilities and Expectations of Participants Committee Sector Vice-Chairs:

1. Help to build and maintain a collegial and productive working relationship with other Committee officers and members, ISO management, and state officials participating in Committee activities.

2. Communicate routinely and effectively with other members of the Sector:

    a. To help ensure that members have the information needed to support informed and active Committee participation;

    b. To ensure that the officer has sufficient information to provide to the other officers, ISO management and staff, and state and federal officials a fair and objective report of Sector members' positions and sensitivities on regional matters; and

    c. To report objectively to Sector members information, questions, positions, perspectives, and sensitivities of or from the other Sectors, the ISO, and state officials that are provided to the Officer to be shared with the Sector.

3. Attend and lead or support planning for and participation in Participants Committee meetings, including (a) participation in pre-planning conference calls and in-person meetings to identify and confirm discussion and consent agenda topics and materials, meeting logistics and orderly flow of business at Committee meetings, and (b) serving as Chair if and as needed for a meeting or portions of a meeting at which the Chair is not able to preside.

4. Coordinate and organize Sector members when appropriate, including for meaningful participation by the Sector members in the semi-annual meetings with the ISO Board of Directors, state officials and FERC representatives.

5. Ensure that the Sector is fairly and objectively represented at other committee and working group meetings and meetings among Officers, ISO management and state officials, and that the Officer or representative is reasonably informed as to the perspectives and sensitivities of the Sector members.

6. With the other NPC Officers, review and comment on NEPOOL filings or pleadings, raising awareness of any Sector-specific sensitivities.

7. Serve, or designate an appropriate Sector member to serve, on the Joint Nominating Committee that recommends to the Participants Committee for endorsement a slate of candidates for membership on the ISO Board of Directors.

9/22/2022

PRELIMINARY

Pursuant to notice duly given, a teleconference meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Thursday, September 1, 2022. A quorum, determined in accordance with the Second Restated NEPOOL Agreement, was present and acting throughout the meeting. Attachment 1 identifies the members, alternates and temporary alternates who participated in the meeting.

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

APPROVAL OF AUGUST 4, 2022 MEETING MINUTES

Mr. Cavanaugh referred the Committee to the preliminary minutes of the August 4, 2022 meeting, as circulated and posted in advance of the meeting. Following motion duly made and seconded, the preliminary minutes of that meeting were unanimously approved as circulated, with an abstention by Mr. Sam Mintz.

CONSENT AGENDA

Mr. Cavanaugh referred the Committee to the Consent Agenda that was circulated and posted in advance of the meeting. Following motion duly made and seconded, the Consent Agenda was unanimously approved as circulated, with abstentions by Cross-Sound Cable and Mr. Mintz.

ISO CEO REPORT

Mr. Gordon van Welie, ISO Chief Executive Officer (CEO), began his report by referring the Committee to the summaries of the ISO Board and Board Committee meetings that had occurred since the August 4, 2022 Participants Committee meeting, which had been circulated and posted in advance of the meeting, and invited any questions on those summaries. There were no questions or comments on those summaries. He then provided context and considerations that underlied the ISO's Problem Statement and Call to Action on LNG and Energy Adequacy (Problem Statement), which had been released and circulated in advance of the meeting, for the Federal Energy Regulatory Commission (FERC) New England Gas-Electric Forum on September 8, 2022.

First, Mr. van Welie noted that there were jurisdictional and regulatory issues that limit potential solutions to electric and gas system challenges in New England. Given those issues, Mr. van Welie stated that New England needed clear guidance from, and cooperation between, FERC and the state agencies, to solve the region's fuel security challenges. He noted that the ISO opposed FERC proceeding under a Section 206 order on this matter unless the FERC's guidance was very clear. He explained that an unclear Section 206 order would only impede communication among all parties -- particularly between the FERC and the state regulators -- on crafting a solution to address system challenges.

Then, Mr. van Welie noted differences between resource adequacy and energy adequacy. New England is long in capacity but short on energy. He opined that improving resource capacity accreditation, while a desired improvement, ~~will~~ would not alone be sufficient to ensure energy adequacy. He said the ISO supported and fully endorsed the New England governors' proposal in their letter to Department of Energy Secretary Granholm for a regional energy reserve. He noted that European countries had done so in response to Europe's energy crisis, explicitly mandating energy reserves in the inputs to their electric systems or their gas delivery systems.

Next, Mr. van Welie expressed the view that there were flaws in some assumptions underpinning competitive wholesale electricity markets. Specifically, he explained his view that the markets assume that supply-side frictions would be minimal, or at least manageable, and that investors would be able to develop new infrastructure in a timely fashion, ~~which~~ allowing~~s~~ for a smooth transition between retiring resources and new resources. In fact, however, at least in New England, there had~~s~~ been significant resistance to building any new energy infrastructure while there had~~s~~ been significant pressure to retire all of the region’s fossil-fueled resources. Thus, retirements were occurring before new infrastructure ~~h~~was been built to support/replace those retirements. For the~~o~~se reasons, the ISO maintained that it must preserve enough existing infrastructure to maintain reliability until the siting and permitting issues that impede the development of new infrastructure had~~ve~~ been resolved.

Mr. van Welie opined that competitive markets also assumed that society would be tolerant of short-run volatility and energy shortages in part because there would be healthy long-term bilateral contracting between load and supply to hedge long-term risks and significant price responsive load in the market. In actuality, he believed that the marketplace and society generally was largely unprepared for extreme shortages, while policymakers and consumers expected bounds on the risks of outages and extreme price volatility. Those expectations called into question the one day in 10 years ~~ahead~~ reliability standard, developed decades earlier in the context of a vertically-integrated, state-regulated industry that assured fuel supplies, ~~which could result in outages and volatility~~ and did not fully account for the depth and duration of outages, price volatility or extreme low probability events. Mr. van Welie questioned whether a new or supplemented reliability standard was needed for an unbundled, federally-regulated power system that would support the clean energy transition and would cope with more extreme weather due to climate change as well as geopolitical risks to fuel supply chains. Adopting changes to that standard would take significant time and analysis, research, debate, and support from state and federal officials. A decision on any changes to the reliability standard for New England must, in his view, be preceded by guidance from policymakers on how they want to manage the risks that have emerged and the regulatory means for that management.

The final flawed assumption, in Mr. van Welie's view, was that scarcity pricing in the energy and ancillary services markets would drive healthy bilateral contracting between load and supply, and thus, drive investment in sufficient fuel infrastructure. That simply had not been happening in New England.

He ended his summary of the Problem Statement noting that the high costs of imported energy, supply constraints caused by the Jones Act, and European demand for energy resulting from the war in Ukraine, all pointed to the need for the region to wean itself off its dependency on imported liquefied natural gas (LNG). Given the region's existing resource mix, the ISO calculated that New England required approximately 50 billion cubic feet (Bcf) to cover winter operations until planned investments in infrastructure ~~a~~were completed, which would~~will~~ take some time. Until then, reliability in New England would depend on the region retaining key energy facilities and stabilizing the fuel supply chain.

Committee members were then invited to comment and ask questions. Ahead of those comments and questions, the Chairman summarized generally the current and expected NEPOOL future grid efforts and remarked that dedicated discussions would be needed to reach a clearer and more common understanding on a problem statement and the underlying issues causing the identified problem(s). A number of members questioned why the Everett LNG Facility (Everett) was highlighted by the ISO in its Problem Statement without recognition of the contributions to LNG supply from the other two regional LNG terminals -- Northeast Gateway and Saint John. A member observed that LNG imports from those facilities accounted for 83% of the LNG storage capacity and 74% of the daily send-out capabilities in the region. In response, Mr. van Welie indicated that the ISO's concern was with the potential loss of Everett when the Mystic Cost-of-Service Agreement ends in 2024. The ISO had concluded that the region must preserve Everett to ensure adequate gas supply until new energy sources are in place to maintain reliability.

Mr. van Welie was advised in comments that that there was still an opportunity using the Excelerate Energy Floating Storage Regasification Units (FSRU), to source LNG from the United States (US), but only if there were a waiver of the Jones Act provisions prohibiting such deliveries. LNG providers viewed the challenges not as shipping issues but rather pricing challenges. The US produces a lot of LNG and New England could access reliable LNG from the Atlantic Basin LNG for the right price and terms.

A number of representatives of wholesale suppliers sought greater understanding and clarity around the ISO's questioning of whether the competitive markets could~~an~~ be adjusted to deliver fuel security for the region or whether the ISO had concluded that an out-of-market solution ~~i~~was needed. Mr. van Welie responded that the focus of his consideration was not whether energy adequacy could be addressed theoretically through wholesale market incentives and structure but rather whether the FERC and the ~~s~~tSates could support market changes to achieve such an outcome. He concluded that the first priority needed to be to stabilize the regional energy supply. Only then did he think adjustments to the markets could be implemented to achieve longer-term sustainability. Concern was expressed that an effort to stabilize one aspect of the regional energy supply would risk~~s~~ de-stabilizing other aspects of that supply.

Commenters also urged the ISO to share data supporting its conclusion in order to continue the dialogue on potential market solutions. Some member representatives reminded the ISO that achieving reliability through the markets was a long-standing NEPOOL priority.

Other members sought from Mr. van Welie clarity on a proposal for regional energy reserve in the short-, medium-~~,~~ and long-term, and whether the ISO had considered potential alternative solutions to its assessment of the problem. Mr. van Welie noted the complexities of the energy adequacy issues facing the region. In defining a feasible path forward for New England, the Problem Statement focused on solutions that those who submitted that Statement believed could be approved by the FERC and supported by the ~~s~~States. He concluded his remarks reiterating the importance of continued dialogue and collaboration to address energy reliability issues.

The Chairman noted the very high level of interest in the topic and thanked Mr. van Welie and the members for the discussion. He explained that further dialogue would continue both at the September 8 FERC Winter Forum and in subsequent NEPOOL committee meetings.

ISO COO REPORT

Dr. Vamsi Chadalavada, ISO Chief Operating Officer (COO), began by referring the Committee to the August COO report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through August 24, 2022, unless otherwise noted. The report highlighted: (i) Energy Market value for August 2022 was $1.1 billion, down $184 million from July 2022 and up $418 million from August 2021; (ii) August 2022 average natural gas prices were 17% higher than July average prices; (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for August ($97.33/MWh) were 7.3% higher than

July averages; (iv) average August 2022 natural gas prices and Real-Time Hub LMPs were up 109% and 99%, respectively, from August 2021 average prices; (v) average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 102.8% during August (up from the 99.1% reported for July), with the minimum value for August of 97.7% on August 6; and (vi) Daily Net Commitment Period Compensation (NCPC) payments for August totaled $5.4 million, which were down $3.7 million from July 2022 and up $2 million from August 2021. August NCPC payments, were 0.5% of total Energy Market value and were comprised of: (a) $4.9 million in first contingency payments (down $3.3 million from July 2022, and three-quarters of which were for the August 4-9 period); (b) $0 in second contingency payments; and (c) $402,000 in distribution payments (down $192,000 from July 2022). Dr. Chadalavada committed, once the full set of August data was available post-Labor Day, to have circulated a brief update on the total costs for the month and any other notable operational data.

In response to questions and requests both ahead of and during the meeting, Dr. Chadalavada reported that, for 2022, the system peak through the date of the meeting, as recorded through revenue quality meters, was 24,775 MW, and occurred on August 4 at hour ending 18:00. He confirmed that the peak load number did not account for settlement-only generators, so that the peak load for FCM purposes, also set at the same day and hour, would be lower. He committed to include in his post-Labor Day update the peak load information for FCM purposes. Dr. Chadalavada did not expect the August 4 peak to be exceeded during the remainder of the year.

Discussing upcoming regional transmission outages, Dr. Chadalavada noted that, from September 19-30, the Hydro-Quebec/NEPOOL Phase II tie (Phase II) would be out for its annual fall maintenance, reducing the total transfer capability for that tie (otherwise 2,000 MW) to 0 MW for that period.

Members, noting that billing for the costs of the Mystic Cost-of-Service Agreement had recently begun, expressed appreciation for the worksheets and information provided thus far with respect to those charges, but requested that the ISO provide as much additional information and visibility as possible into the inputs and components driving the monthly costs of the Agreement. The members suggested that the additional information could help mitigate the uncertainty and resulting risk premiums likely to follow in the absence of such information. Dr. Chadalavada committed to look into and report back on what additional information might be permissible and possible to be provided.

NESCOE BUDGET FRAMEWORK FOR 2023-2027

Mr. Tom Kaslow, Budget & Finance Subcommittee (B&F) Chair, referred the Committee to the materials circulated in advance of the meeting concerning NESCOE's fourth five-year budget framework covering NESCOE operations for years 16-20 (the 2023-2027 period) (the ~~Fourth~~ Budget Framework). He noted that the Budget Framework was required by the November 21, 2007 Memorandum of Understanding (MOU) among the ISO, NEPOOL and NESCOE. He reported that the ~~Fourth~~ Budget Framework was considered at the B&F's July 22 and August 11, 2022 meetings, and no objections or concerns were raised with respect to the Framework.

The following motion was then duly made, seconded, and unanimously approved, with an abstention noted by Mr. Mintz:

> RESOLVED, that the Participants Committee supports NESCOE's fourth five-year budget framework, for years 16 through 20 of its

operations (2023-2027), as circulated for and presented at this meeting.

2023 ISO AND NESCOE BUDGETS

Mr. Kaslow then referred the Committee to the materials circulated and posted in advance of the meeting related to the proposed 2023 ISO Operating and Capital Budgets. He reported that the 2023 ISO Budgets had been reviewed and considered at the B&F's August 11 meeting and no objections or concerns had been raised with respect to the 2023 ISO Budgets. Mr. Cavanaugh added that Mr. Robert Ludlow, ISO Vice President and Chief Financial & Compliance Officer, was prepared to receive any comments or answer any questions on the 2023 ISO Budgets or on the Budgets presentation included with the meeting materials. Those materials presented a refined, "bottom-up" detailed budget and resulted in a slight increase from the "top-down" preliminary budget presented to Participants and State Officials in June. Action on the 2023 ISO Budgets was scheduled for the Committee's October 6 meeting. There were no questions or comments on the Budgets.

Turning to the 2023 NESCOE Budget, Mr. Cavanaugh referred the Committee to the NESCOE Budget materials posted in advance of the meeting. He noted that Ms. Heather Hunt, NESCOE Executive Director, was available for questions or comments. There were no questions or comments. He asked that members reach out to Ms. Hunt directly prior to the October 6 vote if any questions or comments arose.

LITIGATION REPORT

Mr. Doot referred the Committee to the August 31 Litigation Report that had been circulated and posted before the meeting. He highlighted the following litigation-related developments included in the August 31 Report:

(i) The continuing submission of pleadings with respect to New England's pending *Order 2222* compliance filing.

(ii) The decision by the Maine Supreme Judicial Court related to the New England Clean Energy Connect (NECEC) transmission project, which concluded that elements of recent Maine legislation, which had effectively halted construction of the NECEC project, were unconstitutional to the extent the legislation required retroactive application to the Project (if NECEC had acquired vested rights to proceed with Project construction). A number of issues were remanded to and would be addressed by a lower court, particularly the issue of whether and to what extent NECEC's rights to proceed with the construction of the Project had vested.

(iii) The numerous proceedings pending before the FERC and appeals pending before the U.S. Court of Appeals for the D.C. Circuit (DC Circuit) related to the Mystic Cost-of-Service Agreement, particularly a recent DC Circuit decision remanding to the FERC for further consideration cost allocation, clawback~~,~~ and revenue crediting issues.

(iv) The ISO's response to the FERC's FTR Collateral Show Cause Order, which was due October 26, 2022, and would be reviewed with B&F Subcommittee on September 22.

(v) Comments on the FERC's proposed changes to ISO/RTO credit information sharing discretion, which would be reviewed with the Markets Committee (MC) at the MC's September 13-14 meeting.

(vi) The request for rehearing by the Northern Maine Independent System Administrator (NMISA) of the FERC's order denying NMISA's request for a reciprocal discount for Through and Out charges for transactions between the New England and Northern Maine regions, with FERC action on that request required by September 23 or the NMISA request would be deemed denied by operation of law.

COMMITTEE REPORTS

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that there were two RC meetings scheduled in September: a teleconference meeting on September 7 to introduce the HQICCs and ICR and ICR Related-Values for the 2026-27 Capacity Commitment Period (FCA17); and an in-person meeting on September 20 at the Marriott Courtyard in Marlborough, to act on the ISO proposed FCA17 HQICCs and ICR and ICR-Related Values.

Markets Committee. Ms. Mariah Winkler, the MC Chair, reported that the MC would meet in person on September 13-14 at the DoubleTree Hotel in Westborough. She indicated that key topics would include the following: voting on Tariff changes to incorporate the treatment of Storage as a Transmission-Only Asset (SATOA); continued discussion on Resource Capacity Accreditation (RCA); presentation and discussion of ISO perspectives on the performance of capacity resources and the Pay-for-Performance (PFP) design under current system conditions; and a presentation and discussion concerning the FERC NOPR on the sharing of credit information among ISO/RTOs and potential NEPOOL comments on the same. She encouraged those who had not yet registered on-line but were planning to attend in person to do so as soon as possible.

Transmission Committee (TC). Mr. José Rotger, the TC Vice-Chair, reported that the next TC meeting would be September 28. He highlighted planned discussion of the Interconnection NOPR and possible comments by NEPOOL and the ISO on that NOPR.

B&F Subcommittee. Mr. Thomas Kaslow, Subcommittee Chair, reported that the next regularly-scheduled B&F Subcommittee meeting would be held on October 11. Further, as mentioned earlier in the meeting, the B&F Subcommittee was also scheduled to hold a special, single-topic meeting on September 22 to consider the ISO's intended response to the FERC's *FTR Collateral Show Cause Order*.

Membership Subcommittee. Ms. Sarah Bresolin, Subcommittee Chair, reported that the next Membership Subcommittee meeting was scheduled for September 12 and encouraged all those interested to join.

ADMINISTRATIVE MATTERS

Mr. Doot noted that the next Participants Committee would be in Providence, RI. He encouraged members seeking accommodations for the night before that meeting to contact Mr. Patrick Gerity for more information. Looking further ahead, he said that the November meeting would be held on *Wednesday*, November 2 and would include the second of the semi-annual opportunities for modified Sector meetings with the ISO Board. Materials for those Sector meetings would be due in early October, and he encouraged all to consider topics for discussion and to work with their respective Vice-Chair in preparation of materials for those meetings. He also noted that the 2022 Annual Meeting, to be held on Thursday, December 1, would be at the Colonnade Hotel in Boston.

Mr. Cavanaugh reminded members of the FERC's New England Winter Gas-Electric Forum in Burlington, VT the following week. He again thanked members for their engagement and feedback on the Problem Statement and looked forwarded to the further work to come on that topic.

There being no further business, the meeting adjourned at 12:10 p.m.

Respectfully submitted,

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David Doot, Secretary

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN SEPTEMBER 1, 2022 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Acadia Center	End User	Melissa Birchard		
Accelerate Renewables, LLC	Supplier	Liz Delaney		
Advanced Energy Economy (AEE)	Associate Non-Voting	Caitlin Marquis		
American Petroleum Institute	Associate Non-Voting			Mike Giamo
AR Small Load Response (LR) Group Member	AR-LR	Brad Swalwell		
AR Small Renewable Generation (RG) Group Memb	AR-RG	Alex Worsley		
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matthew Ide	
Associated Industries of Massachusetts (AIM)	End User			Mary Smith
AVANGRID: CMP/UI	Transmission	Alan Trotta	Jason Rauch	Zach Teti
Bath Iron Works Corporation	End User			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		Matthew 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		
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Central Rivers Power	AR-RG		Dan Allegretti	
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Matthew Ide	
Clearway Power Marketing LLC	Supplier			Pete Fuller
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw		
Connecticut Office of Consumer Counsel	End User	Claire Coleman		Victor Owusu-Nantwi
Conservation Law Foundation (CLF)	End User		Priya Gandbnir	
Constellation Energy Generation	Supplier	Steve Kirk		
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		
Dominion Energy Generation Marketing, Inc.	Generation	Wes Walker	Weezie Nuara	
DTE Energy Trading, Inc.	Supplier			José Rotger
Durgin and Crowell Lumber Co.	End User			Bill Short
Dynegy Marketing and Trade, LLC	Supplier		Andy Weinstein	
Elektrisola, Inc.	End User			Bill Short
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin		
Eversource Energy	Transmission	James Daly	Dave Burnham	Vandan Divatia
Excelerate Energy LP	Associate Non-Voting	Gary Ritter		
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	Alex Worsley
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Granite Shore Power Companies	Generation			Bob Stein
Groton Electric Light Department	Publicly Owned Entity		Matthew Ide	
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQUS)	Supplier	Louis Guilbault	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	

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN SEPTEMBER 1, 2022 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Matthew Ide	
Holyoke Gas & Electric Department	Publicly Owned Entity		Matthew Ide	
Hull Municipal Lighting Plant	Publicly Owned Entity		Matthew Ide	
Icetec Energy Services, Inc.	AR-LR	Doug Hurley		
Ipswich Municipal Light Department	Publicly Owned Entity		Matthew Ide	
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths	Nancy Chafetz	
Jupiter Power	Provisional Member			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 Lighting Company (LIPA)	Supplier		Bill Kilgoar	
Maine Power LLC	Supplier	Jeff Jones		
Maine Public Advocate’s Office	End User	Drew Landry		
Mansfield Municipal Electric Department	Publicly Owned Entity		Matthew Ide	
Maple Energy LLC	AR-LR			Doug Hurley
Marblehead Municipal Light Department	Publicly Owned Entity		Matthew Ide	
Mass. Attorney General’s Office (MA AG)	End User	Tina Belew	Jamie Donovan	
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Dept. Capital Asset Management	End User		Paul Lopes	Nancy Chafetz
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matthew 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, Sam	End User	Sam Mintz		
Moore Company	End User			Bill Short
Narragansett Elec. Co. (d/b/a Rhode Island Energy)	Transmission	Brian Thomson		Lindsay Orphanides
National Grid	Transmission	Tim Brennan	Tim Martin	
Nautilus Power, LLC	Generation	Dan Pierpont		
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson	Dan Dolan	Molly Connors
New Hampshire Electric Cooperative	Publicly Owned Entity	Steve Kaminski		Brian Forshaw
New Hampshire Office of Consumer Advocate	End User		Jason Frost	
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	
Nylon Corporation of America	End User			Bill Short
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Paxton Municipal Light Department	Publicly Owned Entity		Matthew Ide	
Peabody Municipal Light Plant	Publicly Owned Entity		Matthew Ide	
Princeton Municipal Light Department	Publicly Owned Entity		Matthew 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		Matthew Ide	
Saint Anselm College	End User			Bill Short
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matthew Ide	
South Hadley Electric Light Department	Publicly Owned Entity		Matthew Ide	
Sterling Municipal Electric Light Department	Publicly Owned Entity		Matthew Ide	
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Peter Fuller
Taunton Municipal Lighting Plant	Publicly Owned Entity	Devon Tremont	Dave Cavanaugh	

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PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN SEPTEMBER 1, 2022 TELECONFERENCE MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Templeton Municipal Lighting Plant	Publicly Owned Entity		Matthew Ide	
Tenaska Power Services Co.	Supplier		Eric Stallings	
The Energy Consortium	End User		Mary Smith	
Union of Concerned Scientists	End User		Francis Pullaro	
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieny		
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori	Karin Stamy	
Vermont Energy Investment Corp. (VEIC)	AR-LR		Jason Frost	
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw
Versant Power	Transmission	Lisa Martin	David Norman	
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Wakefield Municipal Gas and Light Department	Publicly Owned Entity		Matthew 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		Matthew Ide	
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG			Jim Ginnetti
Z-TECH, LLC	End User			Bill Short

CONSENT AGENDA

Markets Committee (MC)

From the previously-circulated notice of actions of the MC's September 13-14, 2022 meeting, dated September 15, 2022.[1]

1. **Changes to Tariff §§ III.13.7.5.4.5 & III.13.1.1.2.3 (CTRs Calculation Clarification)**

   Support the revisions to Market Rule 1 Sections III.13.7.5.4.5 and III.13.1.1.2.3 of Market Rule 1 to further clarify the settlement calculation and reflect de-listed capacity for specifically allocated Capacity Transfer Rights (CTRs) for Pool-Planned Units, as recommended by the MC at its September 13-14, 2022 meeting, together with such further non-material changes as the Chair and Vice-Chair of the MC may approve.

   The motion to recommend Participants Committee support was unanimously approved.

2. **Changes to Tariff § III.13.8 (Additional FCA18 Schedule Modifications)**

   Support the additional revisions to Market Rule 1 Section III.13.8 to modify the FCA18 schedule to maintain the FCA18 start date given the changes made to the schedule for FCA17, as recommended by the MC at its September 13-14, 2022 meeting, together with such further non-material changes as the Chair and Vice-Chair of the MC may approve.

   The motion to recommend Participants Committee support was unanimously approved.

[1] MC Notices of Actions are posted on the ISO-NE website: https://www.iso-ne.com/committees/markets/markets-committee/?document-type=Committee%20Actions.

September 29, 2022

Gordon van Welie, President and Chief Executive Officer
Vamsi Chadalavada, Executive Vice President and Chief Operating Officer
ISO New England
One Sullivan Road
Holyoke, MA 01040

Dear Mr. van Welie and Mr. Chadalavada,

RE: Joint Information Request Relating to the Mystic Cost-of-Service Agreement

As a group of load-serving entities ("LSE Group"), we have significant concerns relating to the administration of the fuel security cost-of-service agreement for the Mystic Generation Station (Mystic COS Agreement) and its arrangements with the Everett Marine Terminal (EMT) and what that means for consumers this winter and for the duration of the agreement through 2024. The costs of this agreement, like past winter reliability programs, are allocated to the market through real-time load obligations (RTLO). The size of this agreement, however, dwarfs any past winter reliability program and the variable fuel supply costs are difficult to predict, if not impossible. To be clear, the LSE Group does not take issue here with ISO-NE's filing of or administration of the Mystic COS Agreement to ensure reliable operation of the grid this winter and next winter. Our goal is to concomitantly make this winter as economically efficient as possible for consumers by providing information to the market that is managing load obligations.

The Mystic COS Agreement is significant in size, difficult to manage, and virtually impossible to hedge. That was a true statement when this was first presented to NEPOOL and is even more so today given volatility in the global LNG and gas markets. Managing load this winter requires the forecasting of multiple volatile market costs, such as LNG costs and shipping, all the varied third-party sales and profits from the EMT, as well as the market costs earned by Mystic and its self-scheduling to burn off excess LNG. That does not include additional forecasting on capacity payments and/or risks of payments or penalties under PFP as modified by the agreement. Competitive LSEs provide valuable hedging services, but they cannot provide this value on the cost of the Mystic COS Agreement given the difficulty of predicting these variables.

Despite objections by suppliers and other stakeholders, including NESCOE, Maine and New Hampshire, the FERC approved continued allocation to RTLO rather than regional network load in an order issued in December 2018. FERC agreed with ISO-NE that the goal of a fuel security agreement is like that of past winter programs and therefore it should have a similar allocation of costs. The Mystic COS Agreement is vastly different, however, from other winter programs with capped costs. Past winter reliability program costs have ranged from approximately \$30M to \$70M per year. In 2018, stakeholders argued that the Mystic COS Agreement costs could be more than \$400M per year. Yet, for the single month of July, the Mystic COS Agreement costs were \$48 million, approximately 4 times higher than the forecasted costs for that month. Given this disparity, we have grave concerns regarding the winter months, when gas prices will be at their highest, and the costs that we could face under the Agreement. No one in 2018 could have predicted how much more volatile and unmanageable hedging these costs would become considering world events. When the program and its mechanics were contemplated, the gas market was in the \$3-\$4/MMBtu range with daily volatility +/- \$0.10 for Henry Hub while LNG prices were \$5-\$10/MMBtu. During this time, fuel cost estimates and scenarios were pinned on reasonable price moves and the Algonquin city-gate and LNG relationships at the time. The region is now facing a gas market that is $7-$9/MMBtu with daily volatility +/- $0.90 for Henry Hub while LNG prices are $20-$75/MMBtu. The global LNG crisis driven by the war in Ukraine has created a situation in the LNG and gas markets that was not contemplated.

Given present market conditions and bills received by suppliers to date - $13M for June 2022 and $48M for July 2022 market-wide - costs could balloon to levels not contemplated in 2018. Although estimates at present for LNG fall around $45/MMBtu in New England and $75/MMBtu globally, it is not entirely inconceivable that prices could spike higher given the instability in the global LNG market. Just to put this into context, if the price reached $120/MMBtu, the implied Mystic market offer could be greater than $900/MWh. Given the need to secure cargos in advance, there will be enormous price movement risk due both to global conditions and weather. In addition, the market could clear lower due to relatively less expensive fuel oil on the margin, absent a material event, including the weather. If at the time of delivery, there was downward pressure on global LNG price, Mystic's "least" cost option could be to self-schedule and burn the fuel at the LMP clearing price. All market losses here flow to RTLO. Given that Mystic can run at about 1MM MWh a month, it is possible that a $1B charge to load could occur over the 3 months of winter. These scenarios and the magnitude of this risk certainly were not contemplated at the agreement's inception.

The LSE Group is continuing to explore its options regarding how to mitigate the impacts of the Mystic COS Agreement. **To help manage these risks and minimize the impacts on consumers, the LSE Group respectfully requests additional information relating to the Mystic COS Agreement**. The LSE Group understands that ISO-NE will be addressing this topic at the NEPOOL Participants Committee in October and is planning to present on this at the NEPOOL Markets Committee, also in October. To the extent there are confidentiality or other concerns, the LSE Group is prepared to work with ISO-NE counsel, the EMM/IMM, and/or FERC counsel as appropriate to develop a workable solution. At a minimum, information shared with the market will help to minimize any risk premiums as suppliers process the realities of this agreement. Given the amount of default service winter load pending procurement in New England, any reduction of premiums will directly result in savings to consumers.

<u>First</u>, it would be beneficial for ISO-NE to complete the cost estimation spreadsheet posted on its website for the June and July 2022 settlements and share such results with the market. LSEs use that spreadsheet to estimate costs going forward. The ability of the market to see costs presented in that document and in that format will be of great value in predicting future costs. In addition to the data on the spreadsheet, any insight ISO-NE can share related to key drivers of cost, including related to the scheduling over the summer would be helpful, e.g., whether the LNG was scheduled to anticipate summer needs or as a reaction to the weather and/or system conditions.

<u>Second</u>, the LSE Group would like to request a cost estimate of the Mystic COS Agreement from ISO-NE. It would be extremely valuable for an entity like ISO-NE to post an estimate or estimates publicly for the market. We recognize that to date the fuel supply plan has not been made publicly available, which can make compiling an estimate difficult. However, proxy amounts or high/low/medium scenarios can be used to provide a range of probable outcomes. Further, to the extent ISO-NE can shed light on the current rules around the fuel rates paid for by Mystic and/or when such rates are fixed, that would be valuable, as well as whether there are any third-party sale expectations.

In addition to the two data requests above, the LSE Group has compiled additional points for which clarification from ISO-NE would be helpful to the competitive market. They are as follows:

1. If the plant enters a forced outage and a tanker is scheduled to arrive, we assume 3rd party sales (potentially at a loss) or diversion are the only options that can be exercised of which costs will be passed along to the system. We also assume capacity revenue would be lost. Please confirm.

2. Supplemental payment could be interpreted as double dipping. We assume the monthly fuel costs are net of any fuel costs already recovered via LMP. Please confirm.

3. Please confirm that ISO-NE has not directed Mystic to procure LNG that is not intended to be burned by Mystic for purposes of operating the generation facility.

In sum, the LSE Group recognizes the challenges ISO-NE has faced that lead to the Mystic COS Agreement and the hard work that ISO-NE is doing to prepare for this winter. The primary goal here is not to thwart those efforts but instead to work together to mitigate the costs associated with the Mystic COS Agreement as much as possible. We look forward to having a robust discussion on this topic at future NEPOOL meetings.

Sincerely,

Brookfield Renewable Trading and Marketing

ENGIE Energy Marketing NA

NextEra Energy Marketing, LLC

Shell Energy North America (US), L.P

Vistra Corp.

Vitol Inc.

SEPTEMBER 29, 2022

ISO New England's 2023 Annual Work Plan (AWP)

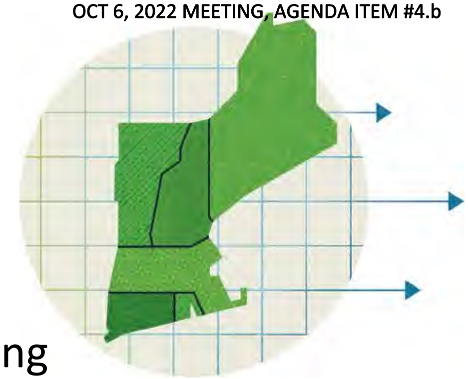
For Discussion at the October 6, 2022, NEPOOL Participants Committee Meeting

Vamsi Chadalavada

EXECUTIVE VICE PRESIDENT AND CHIEF OPERATING OFFICER

2023 Objectives and Highlights

Advancing a reliable clean-energy transition through innovation and collaboration



- **Anchor projects** require dedicated focus and a regional commitment to securing power system reliability while facilitating the integration of clean-energy and distributed-energy resources
  - **Resource Capacity Accreditation** to update the approach for reflecting individual resource contributions to resource adequacy in the capacity market as the resource mix evolves
  - **Day-Ahead Ancillary Services** to create pricing incentives for specific energy and reserve capabilities needed for reliability as regional supply and demand transform
  - **Extended-Term Transmission Planning Phase 2** to develop Tariff changes allowing a process for states to move policy-related transmission investments forward and allocate the costs
  - **2050 Transmission Study** to inform region of possible transmission infrastructure and associated cost estimates needed to reliably serve peak loads in 2035, 2040, and 2050 using scenarios that reflect state decarbonization policies
  - **Operational Impacts of Extreme Weather Events** to model and assess energy-security risks from future low-probability, high-impact weather events under a changing power system
  - **Energy Adequacy Considerations and Actions** to more precisely define the region’s energy adequacy challenges and begin to consider options and directions
  - **nGem Market Clearing Engine** to continue development and implementation of a new platform that is foundational to supporting an exponentially complex, future system
- **Notable initiatives** target innovation, advance efficiency, and help manage risks across markets, planning, operations, and software structures

Effects of Shifting Priorities

The ISO strives to support regional reliability and decarbonization goals in a coordinated manner

- Plans may need to adjust over time to reflect emerging requests, regulations, trends, and risks
  - Increased or expanded stakeholder requests, regional policy interests, and new issues can affect project schedules of planned efforts
  - Upfront agreement on priority work, including NEPOOL and state priorities, are intended to keep listed projects and schedules on track
  - A number of Federal Energy Regulatory Commission (FERC) actions (orders, notices of proposed rulemaking) are expected by or in 2023 and may shift priorities (e.g., NOPR RM21-17; Docket No. AD22-8)
  - Major changes that arise will be reflected in the Spring 2023 AWP Update
- Note that the AWP identifies key initiatives and not the full ISO workload; the ISO's annual budget incorporates the full volume of ISO work, including initiatives in the AWP as well as:
  - Work on smaller projects or projects nearing completion
  - Work to implement projects already through design, stakeholder, and regulatory phases
  - Work representing the ISO's extensive day-to-day operations related to running the grid, markets, IT infrastructure, and its organization

ANCHOR PROJECTS

Enhancements for the Current and Future Grid

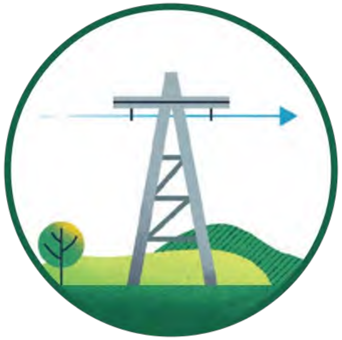
Markets Anchor Projects

Improving pricing and resource valuation to promote reliability and manage resource uncertainty as grid evolves

- **Resource Capacity Accreditation (RCA) in the Forward Capacity Market (FCM)**
  - This effort already underway seeks to implement new methodologies to quantify/accredit resources' capacity contributions to regional resource adequacy, which will be critical to reliability and market efficiency as the resource mix transforms
  - In 2023, the ISO and stakeholders will discuss the detailed framework design; the ISO plans to file with FERC by Q4 2023 and implement changes for Forward Capacity Auction 19 (FCA 19)
- **Day-Ahead Ancillary Services**
  - This initiative seeks to develop market constructs for procuring and transparently pricing ancillary service capabilities needed for a reliable, next-day operating plan with an evolving resource mix
    - **Energy Imbalance Reserve** would cover the "gap" when the day-ahead market's physical energy supply awards are below the ISO's forecast real-time load
    - **Day-Ahead Flexible Response Services** would procure day-ahead 10- and 30-minute response services to enable the system to recover from sudden source-loss contingencies and respond quickly to fluctuations in net load during the operating day
  - Market mitigation and other conforming rule changes will be addressed, including elimination of the Forward Reserve Market
  - In Q4 2022 and throughout 2023, the ISO and stakeholders will discuss the detailed designs; the ISO plans to file with FERC by the end of 2023

Planning Anchor Projects

Providing longer-term transmission planning that assesses a reliable, clean-energy future grid in response to the New England States' Energy Vision



- **Extended-Term/Longer-Term Transmission Planning Phase 2**
  - In 2022, FERC approved a first phase of changes to Attachment K of the OATT, creating a process that allows the New England States to request the ISO to perform planning analyses that may extend beyond the 10-year planning horizon that would provide visibility into the transmission investment needed to further state energy policy objectives
  - The second phase of changes would provide the process for the states to move public policy-related transmission investments forward along with the associated cost-allocation method; the process should permit conversion of longer-term transmission studies into developable projects
  - Stakeholder discussions on Phase 2 to begin in late 2022/early 2023, with a potential FERC filing in Q3 2023; ongoing processes at FERC may further inform this effort
- **2050 Transmission Study**
  - As per the Phase 1 changes above, the ISO has been conducting a transmission study that informs the region of possible transmission infrastructure and associated cost estimates needed to reliably serve peak loads in 2035, 2040, and 2050 using scenarios/assumptions that reflect state decarbonization policies
  - The ISO presented study results in spring and summer of 2022 and began developing possible transmission solutions; further development of solutions and associated cost estimates will extend into 2023

Operations Anchor Project

Energy adequacy study of reliability risks from severe events as grid supply and demand transform

- **Energy-Security Study: Operational Impacts of Extreme Weather Events**
  - The ISO is working with the Electric Power Research Institute (EPRI) to build an innovative framework for conducting a probabilistic energy-security study that assesses the operational impact of future extreme weather events
    - Step 1 Weather Modeling: Identify weather events of interest using statistical analysis and develop hourly profiles of weather variables for the periods of study in the future
    - Step 2 Risk Model Development and Scenario Generation: Identify events of interest and develop the inputs to the 21-day energy assessment in Step 3
    - Step 3 Energy-Security Assessments: Using the enhanced 21-day Energy Assessment tool, assess operational impacts by studying scenarios generated in Step 2
  - Steps 1 and 2 are expected to be completed in 2022; step 3 analysis and discussions to continue through Q1 2023

Energy Adequacy Anchor Project

Addressing winter reliability challenges

- NEPOOL, the New England States, FERC, and the ISO agree that energy adequacy discussions and actions are a top priority
- Upcoming work is outlined on the next slide
- To guide discussions, the following time horizons are considered:
  - **Immediate-term**: Winter 2022/23
  - **Short-term**: Winters 2023/2024 and 2024/2025
  - **Medium-term**: The subsequent seven winters–2025/2026 through 2032/2033
  - **Longer-term**: Beyond 2033 (roughly a decade from now)
- Defining timelines in terms of calendar years may offer clarity to the marketplace

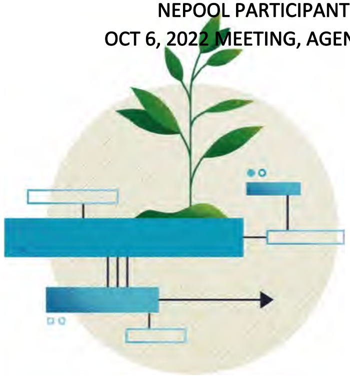
Energy Adequacy Anchor Project, cont'd

Addressing winter reliability challenges

- **Q4 2022**
  - Immediate-term: Confirm protocols to work with the DOE on emissions restrictions; maintain lines of communication for Jones Act waivers
  - Short-term: Update the Inventoried Energy Program for Winters 2023/2024, 2024/2025 (as indicated on slide 13)
  - Short/medium-term: Continue regional dialogue with respect to the Everett LNG Facility
  - Medium/longer-term: Present and gather feedback on the EPRI energy security study's risk model and scenario generation (Step 2 as indicated on slide 7)
- **Q1 2023**
  - Short-term: Review past winter and confirm readiness plans for winter 2023/2024
  - Medium/longer-term: Present preliminary results of the EPRI study energy-security assessments (Step 3 as indicated on slide 7)
    - Run additional Step 3 scenarios based on stakeholder feedback
  - Medium/longer-term: Finalize problem statement
- **Q2 2023**
  - Medium/longer-term: Discuss scope and viability of energy adequacy solutions and define the list of options to pursue, which could include:
    - A modernized strategic energy reserve, market enhancements, infrastructure options such as transmission
  - Reflect energy adequacy plans in the *2023 AWP Update* published in the spring

Technology Anchor Project

Overhauling the market software system to manage an exponentially complex future grid



- **nGEM Market Clearing Engine**
  - This major initiative replaces the ISO's 20+ year old Market Management System (MMS) with the next Generation Electricity Management (nGEM) platform that is foundational to supporting a system with a growing number and type of grid assets, new and more complex market features, ever multiplying security threats, and advancing IT technologies
    - GE Solutions is developing nGEM in collaboration with ISO-NE, MISO, and PJM
    - This effort spans 2020-2027/2028
  - The ISO has been working on the complex processes for customizing and implementing the day-ahead version of the new market clearing engine (MCE) software and infrastructure, which is expected to be in service in Q2 2023
  - Once the day-ahead MCE goes in service, the ISO expects to go onto the next phase, which includes real-time MCE

NOTABLE INITIATIVES

Other Major Initiatives Identified for 2023

New England's Future Grid Initiative

Continuing two-part initiative to help prepare for and support the transition to a future grid that meets state energy policies

- **Future Grid Reliability Study (FGRS) Phase 2**
  - In Phase 2, modeling tools and assumptions from the Pathways and FGRS Phase 1 studies will be used to solve for the set of clean-energy resources that are revenue sufficient and meet the 1-in-10 resource adequacy standard, including for a "preferred pathway" if established
  - Reliability attributes/capabilities of this revenue-sufficient resource mix and any potential reliability "gaps" that remain will be identified
- **Preferred Pathway to the Future Grid Assessment**
  - The ISO, states, and stakeholders have been working to define a preferred market pathway for facilitating the evolution of New England's power grid that reflects state energy policies (forward clean energy market, net carbon pricing, or hybrid)
  - In 2023, this will require a threshold determination of jurisdiction and governance frameworks for the path, which will largely involve policymakers and regulators, as well as identifying details needed to develop the market design

Notable Markets Initiatives, cont'd

Efficient pricing and updating the IEP

- **Updates to Interim Energy Program (IEP) for Winters 2023/2024, 2024/2025**
  - The IEP was approved by FERC in June 2020; eligibility terms need to be updated to comply with a recent court order, and the rate needs to be updated to reflect the current fuel-price environment
  - Stakeholder discussions to begin in 2022; the ISO plans to file changes with FERC in early 2023 so that updates can be implemented in time for winter 2023/2024
- **Energy Shortage Pricing Assessment**
  - The ISO plans to evaluate treatment of load-shed events in the energy and ancillary services market pricing software and discuss with stakeholders enhancements that may be needed to signal appropriate day-ahead and real-time prices during an event
  - Some day-ahead pricing changes will be discussed with stakeholders beginning in Q4 2022; evaluation and discussion with stakeholders regarding real-time changes will extend through 2023
- **Alternative FCM Commitment Horizons (Prompt/Seasonal)**
  - In 2023, the ISO plans to begin its evaluation of changes to the FCM commitment horizon under a construct that would replace the FCA with a prompt capacity auction and would structure the capacity product as a seasonal product
  - Stakeholder discussions would take place in 2024

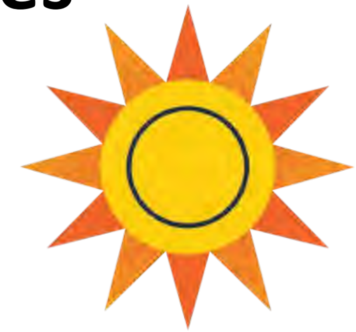
Notable Markets Initiatives

Adjusting the FCM to better balance incentives for resources

- **FCM Retirement Reforms: Bid Flexibility**
  - Beginning in Q4 2022 and extending into 2023, the ISO will discuss with stakeholders the ISO's assessment of the proposal, and possible market rule changes regarding bid flexibly associated with Retirement and Permanent De-list Bids, with a potential FERC filing by end of 2023 targeting FCA 19 implementation
  - Project stems from NEPOOL Proposal/2022 AWP Update
- **FCM Retirement Reforms: Return to Service**
  - Beginning in Q4 2022 and extending into 2023, the ISO will discuss with stakeholders the ISO's assessment of the proposal, as last presented to the Markets Committee in January and February 2022, with a potential FERC filing of any market rule changes by end of 2023 targeting FCA 19
  - Project stems from NEPOOL Proposal/2022 AWP Update
- **FCM Financial Assurance Policy/Entry-Related Improvement**
  - In 2023, the ISO plans to assess whether and why new capacity resources are clearing in the FCA when they may not be commercial by the associated Capacity Commitment Period and discuss possible reforms with stakeholders, with a potential FERC filing by end of 2023 targeting FCA 18 implementation
  - Project stems from NEPOOL Proposal/2023 Priorities

Notable Planning & Operations Initiatives

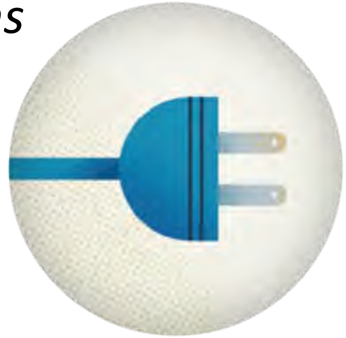
Continuously improving operations and processes



- **FCM Three-Year Capacity Time Out**
  - As new generation shifts largely from gas-fired generation to renewable energy, resource development approaches and timelines have changed significantly since the three-year time-out rules were first designed
    - The rules aligned with pre-existing queue-discipline time-out rules and designed to protect against "queue-blocking" in the FCM by resources not ready for development
  - As a priority item for NEPOOL, the ISO will discuss with stakeholders in 2023 possible elimination of the time-out rules, with a potential FERC filing by end of year
- **Expanded Weather Analytics for 21-Day to Intra-Day Load Forecasting**
  - This initiative will expand the number of weather forecasts from 8 to 23 cities and add two additional weather attributes to improve the forecast accuracy of the zonal and regional operational load forecast models
  - The project will also implement a behind-the-meter photovoltaic (BTM PV) forecasting blending process, which will eliminate reliance on a single vendor forecast for BTM PV forecasting data to increase accuracy
  - The ISO plans to present to stakeholders in Q2-3 and implement in Q3 2023
    - This initiative is one of the "Load, Solar, Wind Forecast Improvements" listed in the ISO's 2022-2025 Roadmap to the Future Grid

Notable Technology & Security Initiatives

Implementing sophisticated technologies and security applications to support the clean-energy transition and mitigate risks

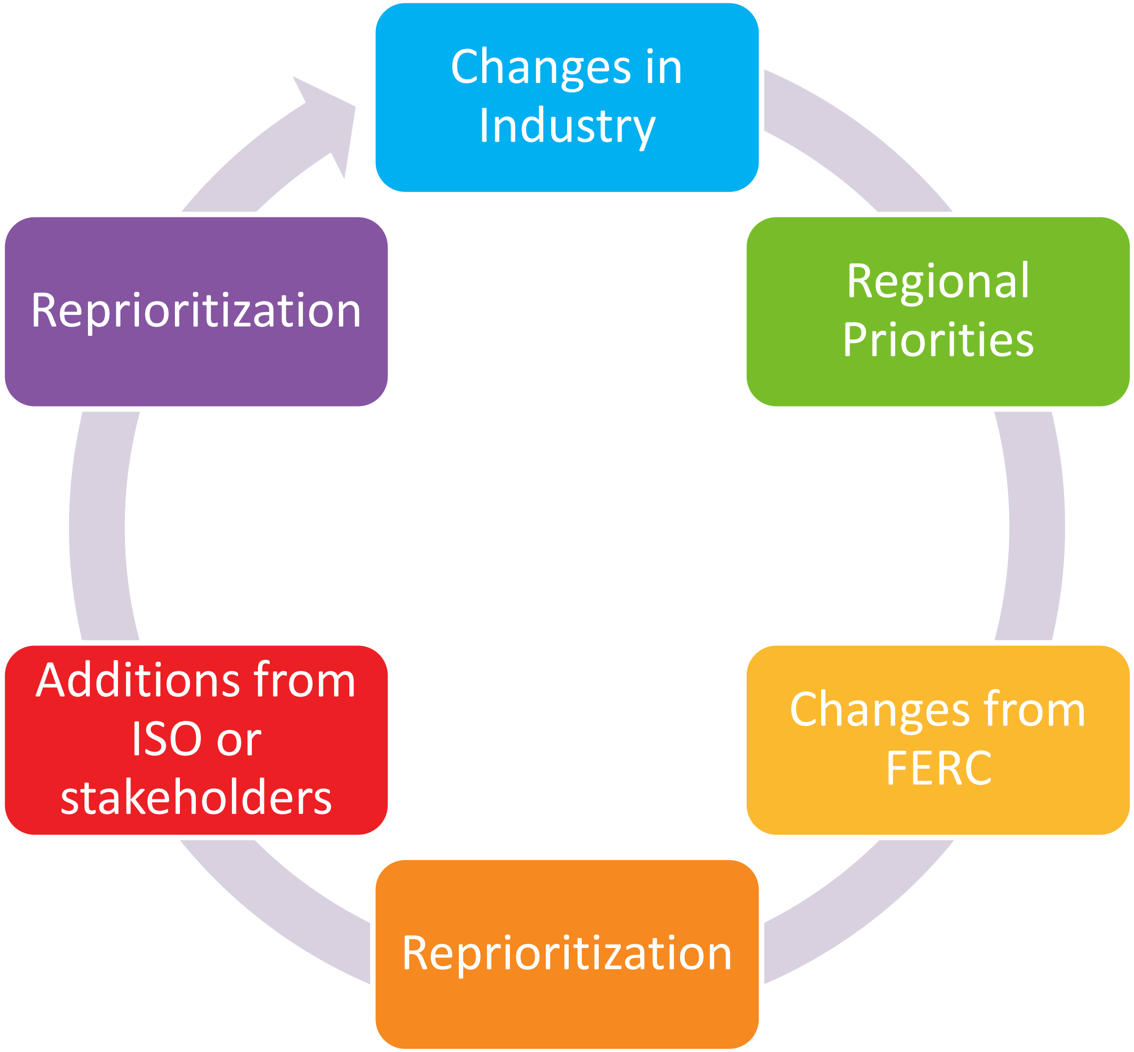


- **Models and Simulators to Support Future Grid:** The ISO is continuing development of models and tools for both reliability and planning study purposes that allows the ISO to more accurately and efficiently simulate potential market design changes and a future grid with rapidly evolving and increasing levels of DERs and inverter-based resources
  - **Inverter-Based Resource Integration and Modeling**: In 2023, the ISO will work to integrate new hybrid-simulation processes and multi-core parallel capability into large-scale system studies and standardize the Electromagnetic Transient simulation workflow
  - **Integrated Market Simulator:** Work continues on the day-ahead simulator; in 2023, the ISO will improve the performance of sub-hourly simulation and start developing network analysis capability
- **Cloud Computing:** Reliably operating a modern system comprised of renewable and storage resources requires the processing, transfer, and storing of vast amounts of data; in multiple phases, the ISO will be implementing cloud-computing infrastructure and virtualization technology to reduce reliance on energy-heavy data centers and enable more dynamic expansion of computing capability, while maintaining reliability
- **Cyber Security:** The ISO is implementing a portfolio of projects to address increasingly complex and frequent cyber-security threats plus new attack vectors, including Identity and Access Management improvements, Security Event Monitoring Infrastructure, updates to the CIP Electronic Security Perimeter, a new Security Operations Center, and other improved detection and response capabilities

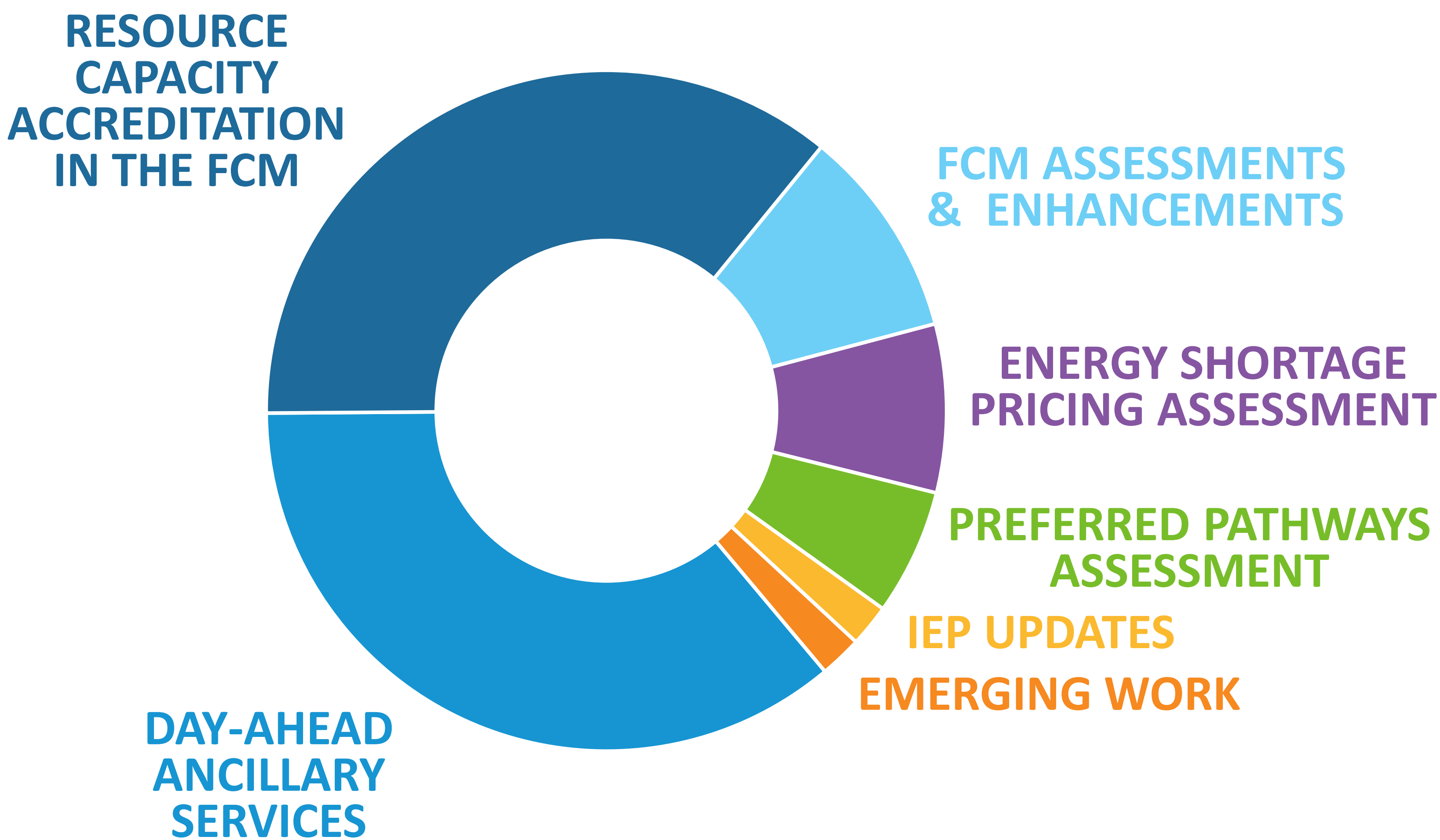
WORK PLAN PRIORITIZATION

Prioritization Process

- The ISO adjusts its priorities as needed to best maintain reliable operations, robustly plan for a changing grid, and ensure competitive wholesale markets
- Planned projects are impacted as scopes shift or new projects emerge



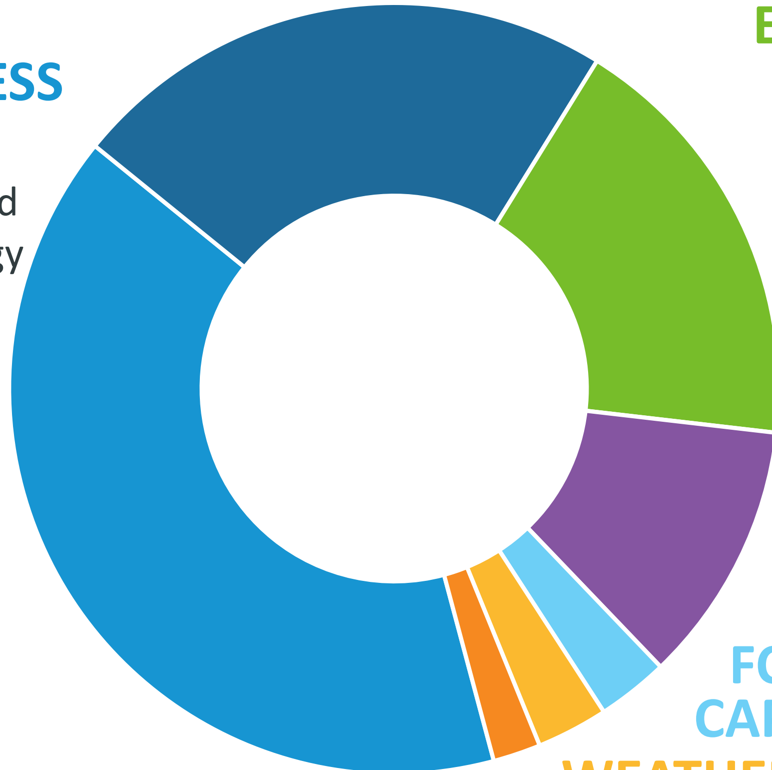
Markets-Related Priorities Include:



Planning/Operations Priorities Include:

CONTINUING BUSINESS

- Support qualification and interconnection of increased volume of distributed energy resources
- Administer FCA #17 and FCM-related modeling
- Economic Planning for the Clean Energy Transition Pilot Study
- NERC/FERC Compliance
- Implement lessons learned from the Controlled Outage Tabletop Exercise with TOs

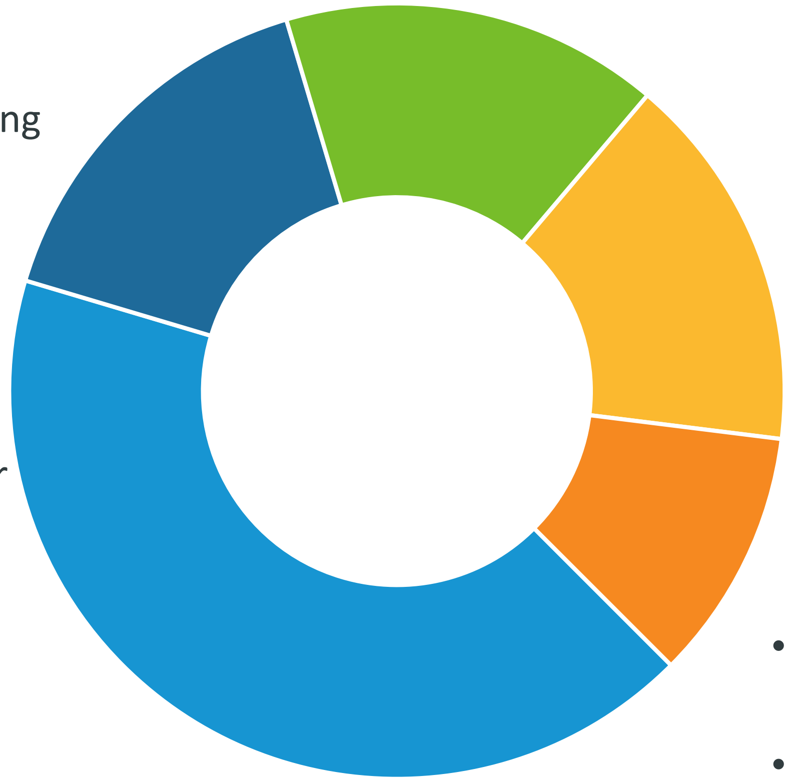


Capital Project Priorities Include:

APPLICATION AND DATABASE ENHANCEMENTS

- Support for systems managing increased quantity and complexity of grid assets
- FCTS Infrastructure Conversion Part III
- MIS Sub Accounts
- Integrated Market Simulator
- Windows Server 2019R2 Deployment
- IT Asset Workflow
- PMU Data Repository
- Order 2222 Software Development

CLOUD COMPUTING

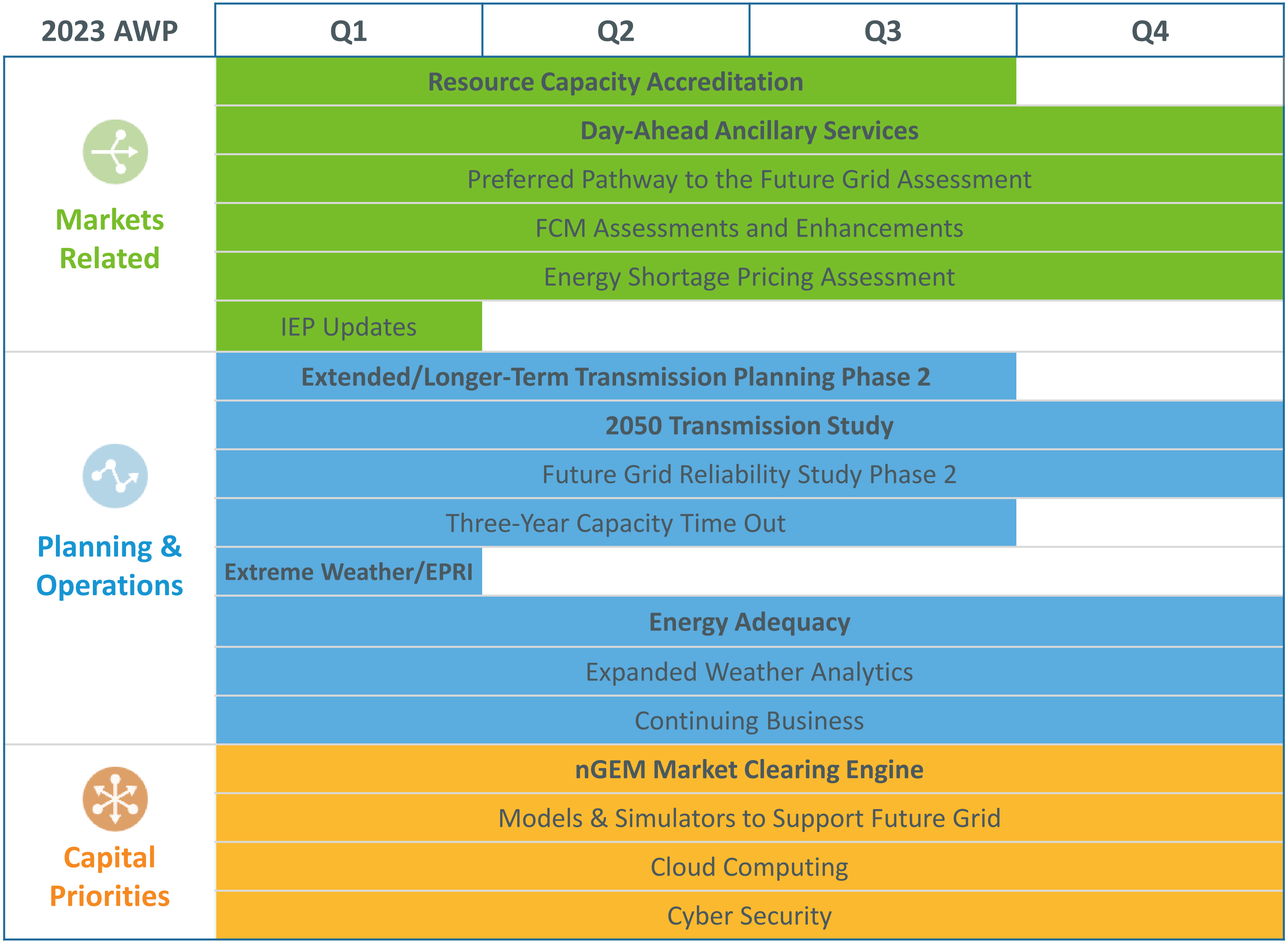


CYBER SECURITY

IT INFRASTRUCTURE ENHANCEMENTS

- Control Room Voice Recorder Modernization
- Hardware replacements
- Amazon Web Services Pilot
- Website Migration to Cloud

nGEM MARKET CLEARING ENGINE


2023 AWP
Q1
Q2
Q3
Q4
Markets Related
Resource Capacity Accreditation
Day-Ahead Ancillary Services
Preferred Pathway to the Future Grid Assessment
FCM Assessments and Enhancements
Energy Shortage Pricing Assessment
IEP Updates
Planning & Operations
Extended/Longer-Term Transmission Planning Phase 2
2050 Transmission Study
Future Grid Reliability Study Phase 2
Three-Year Capacity Time Out
Extreme Weather/EPRI
Energy Adequacy
Expanded Weather Analytics
Continuing Business
Capital Priorities
nGEM Market Clearing Engine
Models & Simulators to Support Future Grid
Cloud Computing
Cyber Security

NESCOE

New England States Committee on Electricity

To:	**ISO-NE**
From:	**NESCOE**
Date:	**September 22, 2022**
Subject:	**Comments on ISO-NE's Draft 2023 Work Plan**

The New England States Committee on Electricity (NESCOE) appreciates the opportunity to have reviewed ISO New England's (ISO-NE) draft 2023 Work Plan on September 1, 2022 with NEPOOL leadership and to provide preliminary reactions. We may have additional input after ISO-NE discusses the draft 2023 Work Plan at the October 6, 2022 NEPOOL Participants Committee meeting.

The projects ISO-NE identifies in the draft Work Plan represent significant work across multiple fronts as the region continues progress toward the 21st century regional electric system that NESCOE called for in its Vision Statement – one that is clean, reliable, and affordable. We appreciate the significant grid-transformation work that ISO-NE staff has already undertaken and plans to pursue in the coming year.

Our feedback focuses primarily on priority matters including energy adequacy and future grid initiatives.

I. Energy Adequacy

New England has struggled with winter energy adequacy challenges for two decades. NESCOE joins NEPOOL in categorizing this issue as high priority in 2023 and supporting prioritization of work to identify durable solutions to persistent winter energy adequacy challenges.

We urge focus on the need to achieve a better understanding of the region's energy adequacy challenges during the winter months and to explore solution(s) to address such challenges. While ISO-NE and the region have taken productive steps to guard against energy shortfalls, including the 21-Day Energy Assessment Forecast and the Inventoried Energy Program (IEP), more work is required.

Since ISO-NE shared its draft Work Plan, it has provided further thinking on this critical issue to stakeholders, the Federal Energy Regulatory Commission (FERC), and the U.S. Department of Energy (DOE) through written communications and participation at the New England Winter Gas-Electric Forum convened by FERC.[1] Since these

[1] FERC New England Winter Gas-Electric Forum, Docket No. AD22-9-000. See also, *Letter from Gordon van Welie to Secretary Granholm, including a Draft ISO/EDC/LDC Problem Statement and Call to Action on LNG and Energy Adequacy*, August 29, 2022, at https://www.iso-ne.com/static-assets/documents/2022/08/isone_energy_security_letter_to_us_doe_and_statement_for_ferc_winter_forum_2022_08_29.pdf.

communications followed the draft Work Plan, NESCOE suggests ISO-NE translate those communications into Work Plan-style action items. To that end, we offer comments on the themes of, and the action items that emerged from, those communications.

- **Given the seriousness, breadth, and depth of the energy adequacy challenge, ISO-NE should categorize energy adequacy as a separate initiative.** The draft Work Plan lists energy adequacy as an operations anchor project. Energy adequacy is broader than an "operations" issue and the revised Work Plan should reflect that fact.

- **ISO-NE should update the draft 2023 Work Plan's energy adequacy components to bring clarity and allow common understandings about timeframes.** NESCOE urges timeframe discipline in all energy adequacy communications, including the 2023 Work Plan. All items in the final Work Plan that relate to energy adequacy should clearly indicate their relevant timeframe(s). Consistent reference to relevant timeframes will be help states, stakeholders, and the public better understand ISO-NE's communications.

  To that end, we offer the following as possible timeframe delineations for consistent reference going forward:

  - **Immediate-term** means the winter of 2022/2023.
  - **Short-term** means the subsequent winters with the Mystic Cost of Service contract (ending in 2024) and IEP (winters 2023/2024 and 2024/2025).
  - **Medium-term** means after the current Mystic Cost of Service contract ends on May 31, 2024 through the clean energy transition, as the grid of the future becomes prominent with a change in the generation fleet.
  - **Longer-term** means after the clean energy transition becomes prominent.
  - **Extreme Weather** means low-probability, high impact events at any point in time.

  If ISO-NE believes these suggested timeframes need adjustment, NESCOE suggests a regional discussion to define and settle on timeframes for consistent future reference.

- **ISO-NE should commence work on energy adequacy as soon as possible.** Energy adequacy needs are broadly considered to be urgent and meriting priority focus. The draft Work Plan seems to indicate that the region should begin energy adequacy conversations after ISO-NE completes the ongoing Operational Impacts of Extreme Weather Events analysis conducted in conjunction with the Electric Power Research Institute. NESCOE urges ISO-NE to identify what energy adequacy work can begin prior to the completion of that analysis that focuses on Extreme Weather, especially in connection with first four of the five timeframes noted above. To that end, please consider including work on items listed below.

- **In 2023, and for the foreseeable future, ISO-NE's Work Plan should include an annual analysis of data and associated recommendation(s) on any interim incremental winter action to protect reliability.** This past July, at the states' request, ISO-NE provided analysis and its recommendation as to whether New England needed to take incremental action to bolster reliability for the winter of

2022/2023.[2] This type of analysis should be part of ISO-NE's annual Work Plan until durable solutions to winter energy adequacy are in place. ISO-NE, states, and stakeholders should work together to define the scope and timing of the analysis to ensure it provides adequate information to the region on a timetable that allows action. Each year, ISO-NE should provide that analysis, and any confidential data the analysis rests on, to FERC.

- **The Work Plan should reflect the following action items ISO-NE discussed in recent communications and at the Gas-Electric Forum.**
  - **Exploring the development of a modernized Strategic Energy Reserve.** The New England Governors recently sought U.S. DOE support to modernize the strategic fuel reserve it has managed since 2002.[3] We appreciate ISO-NE's willingness to allocate resources to explore the development of a modernized strategic energy reserve to protect electric system reliability in the event of low probability, high impact weather events.[4]
  - **Laying necessary groundwork for possible Jones Act exemptions.** There may be acute needs to shore up fuel supplies in the immediate-term. Dedicating resources to early collaboration on possible targeted requests for Jones Act exemptions may allow New England to access domestic LNG by tanker in emergency conditions.
  - **Development of the longer-term reliability program ISO-NE referenced at the Gas-Electric Forum.** At the Forum, ISO-NE observed that the limited time ISO-NE would have had to develop a program for winter 2022/2023 led ISO-NE to focus the analysis it conducted in the July of 2022 on two existing programs: the winter reliability program and IEP. While ISO-NE concluded that neither program would provide incremental reliability for winter 2022/2023, ISO-NE observed that a new program would have helped.[5] To the extent this work is contemplated in the 2023 draft Work Plan, NESCOE suggests it should be explicit.

II. Future Grid Initiatives

NESCOE appreciates ISO-NE's work in furtherance of the foundational shift ahead to our future resource mix. In July 2019, in the context of the 2020 Work Plan, NESCOE

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[2] Winter 2022/23 Analysis, Presented to the NEPOOL Markets Committee, July 14, 2022.

[3] New England Governors Letter to Secretary Granholm, July 27, 2022, https://nepool.com/wp-content/uploads/2022/08/NPC_20220804_Composite5.pdf at page 59

[4] *Letter from Gordon van Welie to Secretary Granholm, including a Draft ISO/EDC/LDC Problem Statement and Call to Action on LNG and Energy Adequacy*, August 29, 2022, at https://www.iso-ne.com/static-assets/documents/2022/08/isone_energy_security_letter_to_us_doe_and_statement_for_ferc_winter_forum_2022_08_29.pdf. Mr. van Welie also echoed this sentiment at the Gas-Electric Forum.

[5] Specifically, Mr. van Welie noted that "what would provide value would be some new program that told every generator to fill up their tanks going into the winter and put somebody on the hook to buy 20 bcf through St. John… but to design such a thing and get it through the regulatory system and have it approved in time for winter was an impossibility." FERC New England Winter Gas-Electric Forum, Panel 4, at https://www.ferc.gov/media/webcast-panel-04-video-new-england-winter-gas-electric-forum.

asked that ISO-NE dedicate market development and planning resources to support states and stakeholders in analyzing and discussing potential future market frameworks that contemplate and are compatible with the implementation of state energy and environmental laws. Our interest was to explore these issues on a calendar of the region's making and not driven by an emergent issue or near-term filing deadline.

Thanks to the analysis ISO-NE has undertaken since then, including the Pathways to the Future Grid Study and the Future Grid Reliability Study (FGRS), we have a clearer picture of what the clean energy transition and the future grid might entail, and some of the challenges that will need to be addressed. NESCOE supports the work on these initiatives identified in the draft 2023 Work Plan and offers the following comments:

- **Discussions on acceptable governance structures for any possible Pathway approach will benefit from ISO-NE's legal analysis and associated conversations.** The states continue to have a collective interest in exploring the development of a Forward Clean Energy Market (FCEM).[6] We look forward to reviewing work by the Massachusetts Department of Energy Resources on an FCEM design,[7] which may further inform our thinking. We appreciate the region's recognition of the need for state input on acceptable governance structures. We continue to consider a range of governance options, from a state jurisdictional approach (single or multi-state) to a federal jurisdictional, ISO-NE tariff approach.

- **Continue to focus on market designs to provide sufficient revenue to existing clean energy resources needed for reliable system operation today and for the grid of the future**. This includes exploring market mechanisms that reduce reliance on capacity market revenues.

- **Continue the reliability-centric Future Grid Reliability Study as contemplated to better connect it to the market-centric Pathways Study in order to provide a fuller picture on how to transition today's grid to one that is compatible with state energy and environmental laws through a wholesale market design.** At the outset, the FGRS contemplated a Phase 2 "gap analysis" to identify whether the current market design would provide revenue sufficient to operate the system reliably in the future state. That analysis was to be followed by identifying approaches to address any gaps. We understand that ISO-NE is scoping Phase 2 and will share its proposal by early Q4 2022. We appreciate ISO-NE's continued allocation of resources to this prior NESCOE- and NEPOOL-supported process.

  We believe this request aligns with NEPOOL's interest in clarity about ISO-NE's plan to evolve wholesale markets and the electric grid to achieve decarbonization.

- **NESCOE supports allocating work plan hours to issues that may be identified in the Future Grid studies that may be more emergent or beneficial.** In addition to

[6] *NESCOE Observations on the Pathways Study*. May 6, 202, at https://nescoe.com/resource-center/pathways-observations-may-2022/.

[7] The Massachusetts Department of Energy Resources is currently undertaking work to develop a comprehensive market design proposal for a New England regional FCEM.

the planned forthcoming study work, we encourage ISO-NE to proactively identify and leverage opportunities to enhance planned market design changes in ways that are directionally consistent with needs identified in the various future grid studies. While it is important to see the Future Grid studies through completion, we urge ISO-NE not to wait for final studies to work with states and NEPOOL on items that may emerge in the near-term.

- **NESCOE affirms its prior request for ISO-NE to consider and develop standards or guidelines for right-sizing future transmission projects that may provide opportunities for efficient incremental transmission buildout.** Earlier this year, NESCOE asked ISO-NE to set aside resources in its 2023 Work Plan "to develop standards or guidelines for right-sizing future transmission projects, including asset condition and reliability projects."[8] This issue also appeared in NEPOOL's August 9, 2022 memo on its 2023 Priorities. This is an important emergent issue in light of the significant asset replacement projects in New England and the transmission investment anticipated to transition to the future grid.

III. Other Items

- **NESCOE urges ISO-NE to review and discuss with states and stakeholders several recommendations in the External Market Monitor (EMM) Annual Report and determine if they should be included in the 2023 Work Plan.** Specifically, NESCOE requests discussion of the following items for potential inclusion in the 2023 Work Plan, which the EMM identified as feasible in the short-term:
  - Modify allocation of "Economic" NCPC charges as this may be helpful to market liquidity.
  - Consider allowing firm energy imports from neighboring areas to satisfy second contingency requirements to possibly lower NCPC costs.
  - Utilize the lowest-cost configuration for multi-unit generators when committed for local reliability.

- **NESCOE supports the request in NEPOOL's 2023 Work Plan Priorities memo to set aside resources to initiate groundwork discussion on the scope of an initiative to integrate environmental justice considerations into regional electric system processes.** We appreciate the recognition of the need to integrate equity and environmental justice considerations in energy operations and infrastructure decisions, and the inherent acknowledgement of the need for a partnership between the states, ISO-NE, NEPOOL, and others to do so.

* * *

NESCOE looks forward to working with ISO-NE and others in the region on these issues and others in the 2023 Work Plan in the coming year.

[8] NESCOE, Memo to PAC on Right-Sizing Transmission Projects, April 11, 2022, at https://nescoe.com/resource-center/right-sizing_tx_projects/.

NEPOOL
NEW ENGLAND POWER POOL

To: ISO New England

From: Dave Cavanaugh – Chairman, NEPOOL Participants Committee & Vice-Chair, Publicly Owned Entity Sector
Christina (Tina) Belew – Vice-Chair, End User Sector
Sarah Bresolin – Vice-Chair, Alternative Resources Sector
Frank Ettori – Vice-Chair, Transmission Sector
Michelle Gardner – Vice-Chair, Generation Sector
Aleks Mitreski – Vice-Chair, Supplier Sector

Date: August 9, 2022

Subject: **NEPOOL's 2023 Priorities**

From among the many issues identified to each of the six Vice-Chairs of the Participants Committee by members of their respective Sector, the Officers collectively identified the following NEPOOL business priorities (provided below in no particular order). A high priority exists among multiple Sectors for each of these items and thus are presented here for consideration as ISO-NE management prepares the 2023-24 regional work plan.

- **ENERGY ADEQUACY/SECURITY CHALLENGE**

  Overall objective for this high-priority item is to achieve better understanding and greater consensus among regional stakeholders, the States and ISO of the region's energy adequacy challenges (particularly during the winter months) and to explore market-based solution(s) to address such challenge(s).

  In furtherance of this shared objective, NEPOOL believes it is critically important for stakeholders and the ISO to further discuss and assess the challenges together. Consistent with the stated objectives for the September 8 FERC-hosted New England Winter Forum, these discussions should include identification of any steps or analysis/information that may be needed to better understand and define the problem. Collective agreement on a problem statement is key to successfully moving forward as a region.

  With a better common understanding of our energy security/adequacy challenges, the region will then be better positioned to explore and consider together an effective long-term market-based solution(s) that is transparent to the marketplace and can be hedged.

  Some of the related questions/concerns that have been expressed on this item include:
    - Need a clear(er) definition of the problem. Is there agreement on the problem(s) or challenge(s) we are trying to solve for? (i.e., three-month winter fuel security

problem or year-round energy security challenge, or both, short-term or affected by future changes in the resource mix, or something different?)

- Assessment of whether additional information or tools are needed to better understand the challenges and develop effective solutions.
- There is a seeming lack of a comprehensive statement/plan from ISO on how to solve the problem as well as comments suggesting the potential efficacy or not of any market-based solution. What is the scope of potential solutions here?
- How does this fit into RCA and ancillary service efforts/enhancements?
- Concern that there might be another Mystic-like retention or other out-of-market actions.

➢ FCM ENTRY-RELATED IMPROVEMENTS

This priority item requests that as part of the 2023 Work Plan, ISO would work with stakeholders to review and adopt and/or develop proposed reforms to establish a better balancing of incentives for new entry in the Forward Capacity Market.

- ***3-Year Capacity Time Out*** – Request for ISO to work with stakeholders to review/evaluate current rules and consider elimination or modification of the 3-year time out rule while continuing to address the queue blocking issues that the time out rule was intended to mitigate.

NEPOOL agrees with the ISO's assessment that new generation timelines and approaches have changed since the 3-year time out rules were first developed. Given the "relatively modest" effort ISO anticipates to address this issue and the benefit it may provide to the marketplace by permitting projects to enter the capacity market only when they are ready to do so, NEPOOL requests that the ISO incorporate this assessment and potential modification into the 2023 annual work plan.

- ***FCM Financial Assurance Policy*** **–** Request for ISO to review/assess the current FCM FA requirements and implement reforms to address identified efficiencies/gaps (such as the ISO adopting CPV proposal or something similar).

NEPOOL appreciates ISO's reluctance to adopt certain rule changes that would place greater reliance on the CPS monitoring process (such as those included in the CPV proposal) but would like to explore with ISO-NE how the ISO may be able to achieve similar objectives, without such CPS-related changes, through a slightly different or modified approach that wouldn't be in the category of a "major lift."

PRIORITY ITEMS THAT ARE PART OF, OR RELATED TO, ONGOING REGIONAL EFFORTS/PROJECTS[1]

The priority items listed under this category are or could potentially be within the scope of ongoing or planned projects/efforts; projects that have either been initiated by the ISO voluntarily or prompted by FERC through pending rulemaking proceedings. NEPOOL appreciates that the Sector-identified priority items listed here are or will be part of those ongoing efforts. And although one or more of these items did not achieve a consensus position amongst the Sectors at this time, NEPOOL may revisit these items as a priority based on the results of ongoing/planned ISO initiatives and/or FERC compliance requirements.

- **Explore Incremental Improvements/Right-Sizing Transmission Projects** – Consider and develop standards or guidelines for right-sizing future transmission projects.

This request could/should be addressed or reassessed as a result of the Phase 2 of Extended-Term Transmission Studies initiative and/or FERC Order related to the Transmission NOPR (RM21-17). NEPOOL acknowledges that to the extent that specific issues of concern to certain Sectors or individual members are not addressed through the aforementioned initiatives, NEPOOL may be asked to re-visit/consider this item as a potential future NEPOOL priority.

- **Transmission Planning Transparency & Oversight of Costs** – Request that ISO-NE analyze and report on the following:
  - How to ensure highest impact, lowest cost solutions
  - Evaluation of alternatives
  - Oversight of transmission projects for design, scope and cost
  - How to ensure broadest benefit from transmission solutions.
  - How ISO-NE could work with the states on potential siting-related issues early in the process of evaluating transmission solutions.

Like the previous item, this request could also be addressed or reassessed as a result of the initiatives cited above, including through the ongoing NOPR-related effort.

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[1] While not identified as a new priority item herein, NEPOOL notes the continued importance of the **Future Grid Initiative**, which NEPOOL leadership, working closely with NESCOE and ISO-NE representatives, launched in 2020 to help the region prepare for and support New England's transition to a future grid. Through two parallel processes, this initiative was established for two key purposes: (1) to define and assess the future state of New England's regional power system (***Future Grid Reliability Study***); and (2) to explore and evaluate potential market frameworks that could be pursued to help advance the clean energy transition (***Pathways to the Future Grid***). Both of these efforts have materially advanced this year. Successfully moving forward with any particular alternative market framework(s) depends on the collaboration and consensus building within the region, particularly with and among the six New England States and NEPOOL members. NEPOOL looks forward to continued engagement with, and input from, the States (through NESCOE and NECPUC) and ISO-NE before deciding on next steps for the ***Pathways*** process.

- **FCM Retirement Reforms** – NEPOOL appreciates that the ISO will be tackling the retirement reform proposal that was approved by NEPOOL earlier this year[2] and that ISO is also planning to explore with stakeholders additional market reforms to enable retired resources to return to service under a broader set of conditions.[3]

In addition to the above, NEPOOL remains interested in hearing from ISO about potential inclusion of plans/projects in the 2023 Work Plan to continue to improve upon the rules relating to exit from the market.

- **Pay-For-Performance (PFP) Issues** – The list of questions/concerns with PFP is long -- is the Performance Penalty Rate (PPR) too high, do the stop loss and PPR rate at current levels work against each other and send inappropriate signals during scarcity conditions that lasts longer than an hour, should we revisit the definition of a Capacity Scarcity Condition, is the current construct frustrating retirement signals, and others.

NEPOOL looks forward to the release of ISO's anticipated Q3 2022 memorandum and subsequent Markets Committee discussions relating to ISO's assessment of PFP-related issues. Because it is unclear at this time whether or not additional PFP-related work will be considered as part of ISO's expected 2023 Work Plan, NEPOOL may revisit this item once more information is available and/or further dialogue is completed on this subject matter.

- **Request for Detailed Information on ISO's Overall Plan to support Clean Energy Transition** – Desire for better/clearer understanding of the ISO's overall plan to evolve wholesale markets and the electric grid to achieve decarbonization. As part of this Sector-identified priority item, there was a request for ISO to produce a detailed roadmap of the initiatives it believes will be necessary to achieve a reliable decarbonized grid, beyond the resource capacity accreditation reform and new day-ahead ancillary services initiatives already included in the ISO's Work Plan.

As ISO noted in its preliminary feedback on the larger list of Sector-identified priorities, "this work is underway and ongoing." NEPOOL appreciates the ISO's attention to and ongoing work related to this item, including ISO's recent publication/distribution of its *2022-2025 Roadmap to the Future Grid*, which identifies planned work over the next few years to adapt the markets and the power system for the evolving resource mix and clean-energy transition.

[2] During its February 3, 2022 meeting, the NEPOOL Participants Committee approved a participant-sponsored proposal to modify provisions of Market Rule 1 (Sections III.13.1.2.3, III.13.1.2.4 and III.13.8.1) to allow Retirement De-List Bids and Permanent De-List Bids the ability to decrease their originally submitted bid prices by up to 25% during the Static De-List Bid finalization window and to move the Internal Market Monitor's filing of finalized prices and elections to early November.

[3] Per its updated 2022 Annual Work Plan, ISO plans to begin NEPOOL stakeholder discussions on an alternative mothball option in Q4 of this year. *See* https://www.iso-ne.com/static-assets/documents/2022/04/2022_awp_update_for_04_07_22_pc.pdf.

- **Capacity Accreditation of Tie Benefits and HQICCs –** While the Resource Capacity Accreditation (RCA) effort is already a priority item within the existing Work Plan, the request here was to assure the RCA effort included an evaluation of the reliability contributions from tie benefits and HQICCs.

ISO stated in its written feedback to NEPOOL that: "*Evaluation of the reliability contributions from tie benefits and HQICCs in the RCA initiative would take place over the next year as part of the project.*"

- **Dynamic Line Ratings (DLR) –** FERC Order 881 prompted examination and reform of transmission line ratings in New England, resulting in ISO's compliance changes to implement ambient adjusted line ratings (AARs). However, Order 881 did not require the use of DLRs. With FERC earlier this year opening a Notice of Inquiry to examine whether the use of DLRs would improve the accuracy and transparency of transmission line ratings, the request here is for ISO to further consider with stakeholders whether DLR requirements would help with some of the congestion issues in the region.

With acknowledgement of the requisite priority of FERC compliance-related work, NEPOOL agrees with ISO's assessment that this request could be resolved or reassessed later based on AAR implementation and/or receipt of FERC's potential NOPR on DLRs.

OTHER ITEMS OF REQUESTED NEPOOL PRIORITY

The following items were identified by member representatives within one or more of the Sectors but did not achieve consensus among the Sector Vice-Chairs as items of the highest priority for NEPOOL as a whole. NEPOOL leadership does though encourage the ISO to consider these items on a going forward basis, especially if one or more such item(s) may help to address any of the aforementioned priorities. Additionally, NEPOOL may revisit these items as a potential priority in the future.

- **Overlapping Impact Study Result Transparency** – Request to publish publicly (with the appropriate CEII approval) overlapping impact test results, in exactly the same way that Feasibility Study and System Impact Study reports are available in the interconnection space.

NEPOOL appreciates the ISO's preliminary assessment that any changes to effectuate this request would require a relatively modest amount of effort. However, there appears to be a split among certain of the NEPOOL Sectors regarding both the benefits and potential downsides of public release of currently protected information from the overlapping impact test results. Some within NEPOOL continue to believe that publication would significantly improve the amount of information and transparency available to the marketplace, while a few other members have expressed some preliminary concern with the public release of certain market information. NEPOOL would appreciate any further insight from ISO on the potential pros and cons of publicly publishing results from overlapping impact tests.

- **Consideration of an additional performance mechanism** – Request that as part of the 2023 Work Plan, the ISO dedicates time and resources for further consideration of additional market design features that provide improved performance distinctions among resources holding a Capacity Supply Obligation (separate and distinct from scarcity event hours under PFP). It was suggested that such a mechanism could help to improve energy adequacy signals.

- **FCM Planning Horizons** – Request of ISO to dedicate resources to review the current three-year forward planning horizon and depending on outcome of assessment, consider potential alternative time horizons.

- **Potential Regulation Market Enhancements** – This requested effort would include ISO and stakeholder review, evaluation and consideration of the following issues and/or changes to the Regulation Market:
  - Implementing a co-optimization of the regulation market
  - Increasing the current caps of the regulation market
  - How is a unit that provides regulation treated during PFP events?
  - If an asset is regulating in an hour with day-ahead schedule, and energy prices in real-time increase over day-ahead, the NCPC will not cover the shortfall

- **Settlement Item on Reactive Power –** ISO-NE settlement system currently allocates Schedule 2 VAR/Reactive Power capacity cost payments for qualified reactive resources to identified Asset Owners monthly as part of its energy settlement. There is no ability for a Lead Market Participant to receive those payments directly. The request here is for ISO to consider changes to the allocation option in its settlement system for Schedule 2 VAR/Reactive Power capacity cost payments.

  Although this is not a NEPOOL-wide priority, the ISO has identified a limited in scope approach to this request:

  > "*Change the settlement system so that all Lead Market Participants are paid VAR Capacity Cost instead of Asset Owners, which they encourage the ISO to review as part of its customer service efforts. This is a relatively simple cost-allocation change that would require some minor IT and documentation changes*."

  Given the lighter lift with this contemplated approach, the NEPOOL Sector Vice-Chairs encourage the ISO to review addressing this request as part of its ongoing customer service efforts.

REQUESTS FOR ASSESSMENT BY IMM AND/OR EMM

While one or both of the following Sector-identified priority items may be worthwhile for inclusion in the 2023 Work Plan, there is general agreement among the NEPOOL Officers that these items would likely benefit from new or additional assessment by either the ISO's Internal or External Market Monitor. Also, because the scope of the DDBT-related request could, as ISO noted, "be affected by the Sealed Bid FCA request/assessment", NEPOOL appreciates the value in getting the sequencing right here with the two items. If this request is done prior, it may need to be modified based on the outcome of the Sealed Bid FCA request/assessment."

- **Dynamic Delist Bid Threshold (DDBT) Review/Assessment** – Based on bidding in the latest auction (FCA 17), more than 1500 MW sought to delist within 2 cents of one another. This large amount of delists across a very small price range at least indicative of an issue that should be reviewed. Upon further assessment by the IMM or EMM, the ISO should consider possible revisions to the current formula to add more bandwidth (e.g., multiplying the current formula by 1.5).

- **Further Evaluation/Consideration of Sealed Bid FCA** – Prompted by a desire among some of the NEPOOL members to move to a sealed bid Forward Capacity Auction to streamline mitigation of existing resources given significant competition under the DDBT demonstrated in past auctions, this request is for ISO to work with stakeholders to review and consider a sealed bid FCA.

As noted above, NEPOOL leadership is interested in the IMM (and/or EMM) conducting further assessment of the mitigation issues at play with both of these items.

REQUEST TO INITIATE GROUNDWORK DISCUSSION

- **Environmental Justice** – During the States' Energy Vision process, various stakeholders, including end users, raised the need to incorporate environmental justice considerations into regional decision-making. In their Advancing the Vision Report, the states subsequently asked the ISO to incorporate environment justice considerations into its decision-making. The initial request here is for ISO to detail any plans to address the states' ask concerning the interplay of environmental justice issues.

As a first step, NEPOOL leadership acknowledges the request of the states and agrees that it would be helpful, as a starting point, for an interested group of stakeholders to initiate preliminary discussions within NEPOOL, with the ISO, state representatives and others as to the proposed scope of such an initiative, including on issues relating to the overlap of environmental justice objectives and ISO jurisdictional authority. Initiation and completion of such discussions should help to lay the foundation for further consideration by ISO and NEPOOL.

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval and Pat Gerity, NEPOOL Counsel

DATE: September 29, 2022

RE: ISO New England Inc. ("ISO") 2023 Operating and Capital Budgets
New England States Committee on Electricity ("NESCOE") 2023 Budget

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At its October 6, 2022 meeting, the Participants Committee (the "NPC") will be asked to vote on the ISO's proposed 2023 operating and capital budgets (collectively, the "ISO Budgets") and on NESCOE's 2023 operating budget (the "NESCOE Budget"). We have included with this memorandum and will post with the composite for this meeting background materials regarding these budgets.

<u>The ISO 2023 Budgets</u>

The ISO Budgets were prepared according to the processes included in the Participants Agreement and in the Settlement Agreement with state agencies in FERC Dockets Nos. ER13-185 and ER13-192. The ISO presented its preliminary budgets to NECPUC on June 6 and at the June 21 NPC Summer Meeting. The ISO next presented the ISO Budgets to the NEPOOL Budget and Finance Subcommittee (the "Subcommittee") on August 11 and to the New England state agencies and attorneys general on August 12. Mr. Ludlow also provided an overview of the ISO Budgets at the September 1 NPC meeting and offered to answer any questions that NPC members may have on the ISO Budgets. Questions on the ISO Budgets provided by certain New England state regulators and consumer advocates, as well as the ISO's responses thereto, are posted on the ISO's website.

Included with this memorandum is a memorandum from Mr. Ludlow describing the changes that have been made to the ISO Budgets from the versions reviewed by the Subcommittee and provided previously to the NPC. That memorandum includes a link to the updated ISO Budgets presentation and a link to the comments from the New England state regulators and consumer advocates and the ISO's response to those comments. The ISO's September 29 memorandum regarding the allocation of its projected costs among the ISO Tariff Schedules is also included with this memorandum.[1]

The 2023 ISO operating budget, prior to true-ups, reflects an 11.7 percent increase over the 2022 operating budget. After accounting for the true-up mechanism in the ISO Tariff, the revenue requirement to fund the 2023 operating budget (i.e., the amount collected under the ISO administrative cost tariff) will

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[1] The memo addressing the Projected 2023 Revenue Requirement, including the final true-up for 2021 and a comparison to the 2022 Revenue Requirement, a Draft 2023 Revenue Requirement by activity, and Draft 2023 Rate Components, was circulated by the ISO to Participants Committee members and alternates and Budget & Finance Subcommittee members on September 28. A copy is included with this memorandum for your convenience.

increase by 4.4 percent over the amount projected to be collected in 2022. The ISO capital budget for 2023 is $33.5 million. This reflects a $1.5 million increase over the amount of the 2022 capital budget.

The following form of resolution can be used by the NPC on this matter:

> RESOLVED, that the Participants Committee supports the Year 2023 operating budget and capital budget proposed by the ISO, as presented at this meeting.

The NESCOE 2023 Budget

Ms. Heather Hunt, the Executive Director of NESCOE, joined the Subcommittee's August 11 meeting and informed the Subcommittee that NESCOE expected the NESCOE Budget for 2023 to be approximately $2,696,171. NESCOE's August 11 presentation to the Subcommittee was included with the materials for the September 1 NPC meeting and Ms. Hunt offered to answer any questions that NPC members may have on the NESCOE Budget. A revised summary presentation regarding the NESCOE Budget, which reflects the actual 2023 Schedule 5 Rate as calculated by the ISO ($0.00701 per kW-mo.), rather than an estimated rate, is included with this memorandum. The revised presentation is identical to the NESCOE August 11, 2022 presentation, with only slide 12 updated and marked to reflect the final 2023 Network Load factor and final Schedule 5 Rate and slide 2 updated to reflect the NPC's support and FERC filing of NESCOE's 5-year pro forma budget.

The following form of resolution can be used by the NPC in its consideration of the proposed 2023 NESCOE Budget:

> RESOLVED, that the Participants Committee supports the 2023 NESCOE budget, as proposed by NESCOE at this meeting, as the Year 2023 operating budget for NESCOE.

cc: R. Ludlow
C. Arnold
H. Hunt
NEPOOL Budget and Finance Subcommittee

memo

To: NEPOOL Participants Committee

From: Robert C. Ludlow, VP & CFO

Date: September 29, 2022

Subject: ISO New England's 2023 Proposed Operating and Capital Budgets

This 2023 operating and capital budgets (the "Budgets") update is intended to provide the NEPOOL Participants Committee with information regarding the changes that have been made to the ISO's 2023 proposed Budgets since the last review of the Budgets at the September 1, 2022 NEPOOL Participants Committee ("NPC") meeting.

Summary of Changes

The 2023 operating budget remains unchanged from the version presented to the NEPOOL Budget and Finance Subcommittee in August and to the NPC in September. Accordingly, the only updates to the budget presentation are to reflect the updated compensation survey data and that the Compensation and Human Resources Committee of ISO New England's Board of Directors approved the budgeted merit and promotional increase amounts. In summary, the 2023 operating budget, excluding the true-up, is an increase of 11.7% or $25.1M as compared to the 2022 operating budget. The 2023 operating budget, including the true-up, results in a 4.4% increase to the Revenue Requirement compared to 2022.

The 2023 overall capital budget of $33.5M has not changed from the amount presented at the August and September Budget and Finance and NPC meetings, respectively. Without impacting the overall budget, there were changes to certain capital projects that have been reflected in the updated budget presentation. The Forward Capacity Market Order 2222 and IT Asset Workflow Integration and Updates projects have moved from the planning phase to chartered, and, accordingly had changes in the 2022, 2023 and overall budget amounts. The currently chartered Physical Security Improvement Project has an updated 2023 and overall budget amount and an updated estimated completion date. Finally, the 2023 Other Emerging Work balance was adjusted to reflect the funding changes to the foregoing projects.

Materials

The August 11, 2022 budget presentation presented to the NEPOOL Budget and Finance Subcommittee has been updated to reflect the changes described above. The updated budget presentation can be found at the following link: https://www.iso-ne.com/static-assets/documents/2022/09/7_isone_2023_proposed_op_cap_budget_update_09_29_2022.pdf

The 2023 state agencies' written comments and the accompanying response can be found at the following link: https://www.iso-ne.com/static-assets/documents/2022/09/7_states_2023_budget_comments_isone_response.pdf

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Budget Presentation Slide Changes

The following pages have been updated in the budget presentation:

Operating Budget Compensation Slides, pages 87, 90, and 99

Capital Budget Slides, pages: 60, 61, 62, 151, 156, 157, 158, 178, and 180

Please let me know if you have any questions in advance of our meeting. I look forward to our discussion.

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memo

To: NEPOOL Budget & Finance Subcommittee and Participants Committee

From: Bob Ludlow and Cheryl Arnold

Date: September 28, 2022

Subject: Projected 2023 Revenue Requirement for ISO New England Administrative Cost Tariff Schedules

To help our Participants prepare their 2023 budgets and consistent with information provided in previous years, this memo includes a preliminary indication of ISO-NE's 2023 costs and related tariff schedules. Specifically, the memo includes (1) the estimated 2023 Revenue Requirement, including the final true-up for 2021 and a comparison to the 2022 Revenue Requirement (see Exhibit 1 below), (2) the Draft 2023 Revenue Requirement by activity (see Exhibit 2), and (3) the Draft 2023 Rate Components (see Exhibit 3). Exhibits 2 and 3 are attached and, in their final form, will be part of the ISO's budget filing with FERC. The cost assignment and allocation mechanisms that were utilized in the Draft 2023 tariff schedules were established as part of the settlement that has been in effect for the last twenty-one years.

Overall Change in Revenue Requirement

As shown in Exhibit 1 below, the overall Revenue Requirement has increased by $9.5 million year-over-year, from $216.1M for 2022 to $225.6M for 2023.[1] The change includes a $25.1 million increase in the revenue requirement before taking into account the change in prior year true-ups. Prior year true-ups resulted in a decrease of $15.7M. The 2022 tariff included a $1.1M revenue requirement increase for the final 2020 true-up, while the 2023 tariff will include a decrease of $14.6M as a result of the final 2021 true-up.

Draft Exhibit 1
ISO New England
Revenue Requirement By Tariff Schedule
2023 Estimated Amount vs. 2022 Filed Amount

	Sch 1	Sch 2	Sch 3	Total
2023 Revenue Requirement Before Prior Year True Ups	$ 49,273,547	$ 118,209,011	$ 72,722,598	$ 240,205,156
2022 Revenue Requirement Before Prior Year True Ups	45,082,953	105,115,206	64,872,524	215,070,683
$ Increase/(Decrease) from 2022 to 2023	**4,190,594**	**13,093,805**	**7,850,074**	**25,134,473**
% Increase/(Decrease) from 2022 to 2023	**9.3%**	**12.5%**	**12.1%**	**11.7%**
2023 Revenue Requirement Prior Year True Ups-Under/(Over) Collect	$ (3,063,761)	$ (7,987,289)	$ (3,537,695)	$ (14,588,745)
2022 Revenue Requirement Prior Year True Ups-Under/(Over) Collect	(701,273)	1,037,876	734,687	1,071,290
$ Increase/(Decrease) from 2022 to 2023	**(2,362,488)**	**(9,025,165)**	**(4,272,382)**	**(15,660,035)**
2023 Revenue Requirement Including Prior Year True-Ups	$ 46,209,786	$ 110,221,722	$ 69,184,903	$ 225,616,411
2022 Revenue Requirement Including Prior Year True-Ups	44,381,680	106,153,082	65,607,211	216,141,973
$ Increase/(Decrease) from 2022 to 2023	**1,828,106**	**4,068,640**	**3,577,692**	**9,474,438**
% Increase/(Decrease) from 2022 to 2023	**4.1%**	**3.8%**	**5.5%**	**4.4%**

[1] Minor variances may appear due to rounding among the various presentations and schedules for the 2023 Budgets.

Change in Revenue Requirement by Schedule

Before true-ups in 2023 and 2022, the 2023 Revenue Requirement reflects an overall increase of $25.1M or 11.7% over the 2022 Revenue Requirement. By tariff schedule, the changes are Schedule 1, a $4.2M or 9.3% *increase*; Schedule 2, a $13.1M or 12.5% *increase*; and Schedule 3, a $7.9M or 12.1% *increase*.

The Tariff Schedule 1 increase of $4.2M is attributable to:

- Increases that impact all three schedules including for: compensation, employee benefit costs, recruiting, retention, and succession planning; computer services and systems support, cyber security systems and resources, and power system modeling; resources in Participant Relations & Services, and External Affairs and Corporate Communications; and insurance policy increases.
- Also affecting all three schedules is depreciation expense increases for certain capital projects, including Security Information and Event Management Log Monitoring Replacement, New Security Operations Center, Amazon Web Services Cloud Foundation, E-mail List Server Technology Refresh, and Privileged Account Management Security Enhancements.
- Funding for Transmission Planning and Transmission Services resources to support long-term transmission planning related to the transition to a carbon-free power system, including further 2050 Transmission Study work, for North American Electric Reliability Corporation (NERC) standards compliance, and to support volume increases in the interconnection queue.

The Tariff Schedule 2 increase of $13.1M is attributable to:

- Funding for items that impact all three schedules as noted above in the explanation for Schedule 1.
- Depreciation expense increases for projects affecting all three schedules as noted above in the explanation for Schedule 1, and depreciation expense increases specifically affecting Schedule 2, related to the mid-2023 go-live of the nGEM platform projects[2] and the Replacement Locational Marginal Price Monitor project.
- Funding for Market Development resources to integrate renewable resources and new resource types, including large-scale storage resources and batteries into the market designs.
- Funding for work that affects Schedules 2 and 3, including Day-Ahead Ancillary Services market design and development, future grid studies for a clean-energy future, and a Participant Relations & Services resource to integrate several new initiatives and projects into market training and to begin the development of new training delivery methods.

The Tariff Schedule 3 increase of $7.9M is attributable to:

- Funding for items that impact all three schedules as noted above in the explanation for Schedule 1 and items that impact Schedules 2 and 3, as noted above in the explanation for Schedule 2.
- For Resource Capacity Accreditation (RCA) work to establish improvements to ISO-NE's accreditation processes in the Forward Capacity Market.
- Increases in Northeast Power Coordinating Council (NPCC) and NERC dues.
- Depreciation expense increases for projects affecting all three schedules as noted above in the explanation for Schedule 1, and depreciation expense increases for projects allocated entirely to Schedule 3, including the Forward Capacity Tracking System Infrastructure Conversion Part III and the Forward Capacity Market Cost Allocation & Accelerated Billing projects.

The ISO 2023 Revenue Requirement will be reviewed and voted on at the October 6, 2022 NPC meeting. Should you have any questions regarding the information provided in this memo, do not hesitate to contact us.

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[2] Upon completion of the nGEM Market Clearing Engine Implementation, scheduled for June 2023, the following projects will begin depreciating: CIMNET Simultaneous Feasibility Test with Data Transfer Enhancements, nGEM Value Added Development, nGEM Market Clearing Engine Implementation, nGEM Software Development Parts I and II, and nGEM Hardware Phase I and II.

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Line	Activity Code		Allocation	Self-Funding Tariff			
No.	No.	Description	Factor (1)	Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Administration-CEO**					
2	12651	Indirect Administrative Support	Total Dir Labor	$ 10,974,798	$ 2,365,069	$ 5,679,458	$ 2,930,271
3	12652	NEPOOL Committee Support	Total Dir Labor	3,045	656	1,576	813
4	12653	Adm/Finance/HR - Regional Committee Support	Total Dir Labor	225	48	116	60
5	12654	National Committee Support	Total Dir Labor	1,725	372	893	461
6	12657	Indirect Administrative Support for BCC	Total Dir Labor	1,195,864	257,709	618,859	319,296
7		Total		12,175,657	2,623,854	6,300,902	3,250,900
8							
9		**Finance**					
10	11601	Payroll Administration	Total Dir Labor	675,092	145,482	349,360	180,249
11	11701	Accounts Payable	Total Dir Labor	339,747	73,215	175,819	90,712
12	11702	Procurement	Total Dir Labor	467,485	100,743	241,923	124,818
13	11901	Settle for Power Transactions	Total Dir Labor	84,837	18,282	43,903	22,651
14	12001	Budgeting and Forecasting	Total Dir Labor	551,439	118,835	285,370	147,234
15	12005	Credit Administration	Total Dir Labor	466,602	100,553	241,467	124,583
16	12019	COVID-19 Related Expense	Total Dir Labor	3,260	703	1,687	871
17	12101	Ledger Closing, Financial Statements and Tax Reporting	Total Dir Labor	551,439	118,835	285,370	147,234
18	12201	Treasury and Cash Management	Total Dir Labor	2,478,015	534,012	1,282,373	661,630
19	92004	Depreciation Expense 2004 Assets	Alloc-Fixed	43,160	8,988	22,535	11,637
20	92005	Depreciation Expense 2005 Assets	Alloc-Fixed	773,169	163,467	402,125	207,577
21	92006	Depreciation Expense 2006 Assets	Total Dir Labor	568,947	122,608	294,430	151,909
22	92007	Depreciation Expense 2007 Assets	Total Dir Labor	156,427	33,710	80,951	41,766
23	92008	Depreciation Expense 2008 Assets	Total Dir Labor	1,808	390	936	483
24	92009	Depreciation Expense 2009 Assets	Total Dir Labor	1,535	331	794	410
25	92010	Depreciation Expense 2010 Assets	Total Dir Labor	2,380	513	1,232	635
26	92011	Depreciation Expense 2011 Assets	Total Dir Labor	-	-	-	-
27	92012	Depreciation Expense 2012 Assets	Total Dir Labor	80,432	17,333	41,624	21,475
28	92013	Depreciation Expense 2013 Assets	Total Dir Labor	851,098	183,412	440,443	227,243
29	92014	Depreciation Expense 2014 Assets	Alloc-Fixed	159,492	29,849	92,661	36,982
30	92015	Depreciation Expense 2015 Assets	Alloc-Fixed	11,486	2,475	5,944	3,067
31	92016	Depreciation Expense 2016 Assets	Alloc-Fixed	130,355	38,974	64,702	26,680
32	92017	Depreciation Expense 2017 Assets	Alloc-Fixed	442,680	65,976	314,410	62,293
33	92018	Depreciation Expense 2018 Assets	Alloc-Fixed	1,567,030	344,531	866,717	355,782
34	92019	Depreciation Expense 2019 Assets	Alloc-Fixed	3,438,109	725,483	1,849,458	863,168
35	92020	Depreciation Expense 2020 Assets	Alloc-Fixed	6,402,987	835,577	3,732,702	1,834,708
36	92021	Depreciation Expense 2021 Assets	Alloc-Fixed	7,825,467	1,071,096	4,644,629	2,109,742
37	92022	Depreciation Expense 2022 Assets	Alloc-Fixed	7,143,043	955,802	4,152,391	2,034,850
38	92023	Depreciation Expense 2023 Assets	Alloc-Fixed	1,276,396	137,716	700,334	438,347
39	99707	Amortization of Land Recovery	Alloc-Fixed	39,300	2,460	24,170	12,670
40	99995	NPCC/NERC Dues	Alloc-Fixed	7,296,418	-	-	7,296,418
41	99996	Operating Contingency	Total Dir Labor	700,000	150,850	362,250	186,900
42	99996	Operating Contingency	Total Dir Labor	2,000,000	431,000	1,035,000	534,000
43	99998	Payroll & Other Accruals	Total Dir Labor	16,040,630	3,456,756	8,301,026	4,282,848
44		Total		62,570,264	9,989,957	30,338,735	22,241,573
45							
46		**Facilities & Security**					
47	12664	Building Maintenance	Total Dir Labor	3,317,276	714,873	1,716,690	885,713
48		Total		3,317,276	714,873	1,716,690	885,713
49							
50		**Enterprise Risk Management**					
51	22704	Record Retention Services	Alloc-Fixed	106,371	35,422	35,422	35,528
52	22705	Corporate Scorecard	Alloc-Fixed	55,495	18,480	18,480	18,535
53	22706	Document Management Services	Alloc-Fixed	107,324	42,929	32,197	32,197
54	22710	Employee Development	Total Dir Labor	21,141	4,556	10,941	5,645
55	22714	Analysis	Total Dir Labor	339,347	73,129	175,612	90,606
56	22719	Human Performance Improvement	Total Dir Labor	13,392	2,886	6,930	3,576
57	22721	Corp Strategic Risk	Total Dir Labor	571,626	123,185	295,817	152,624
58	22726	Project Risk Mngmt Meeting	Total Dir Labor	23,784	5,125	12,308	6,350
59	23006	Business Continuity Planning	Total Dir Labor	240,553	51,839	124,486	64,228
60	25011	Corrective Action/Preventive Action	Alloc-Fixed	327,879	109,184	109,184	109,511
61	25014	EtQ Tools Dev & Support	Total Dir Labor	136,275	29,367	70,523	36,386
62	25015	Coord Tariff Chg Comm (TCC)	Total Dir Labor	5,285	1,139	2,735	1,411
63		Total		1,948,472	497,242	894,633	556,597
64							
65		**Human Resources**					
66	12661	Employee Affairs (Recreation Committee)	Total Dir Labor	54,948	11,841	28,436	14,671
67	12701	Recruiting/Interviewing	Total Dir Labor	1,090,732	235,053	564,454	291,225
68	12702	Intern Expense	Total Dir Labor	278,018	59,913	143,875	74,231
69	12801	Employee Relations	Total Dir Labor	1,676	361	868	448
70	12901	Benefit Administration	Total Dir Labor	1,442,674	310,896	746,584	385,194
71	12951	Compensation	Total Dir Labor	557,329	120,104	288,418	148,807
72	12961	HR - General	Total Dir Labor	1,307,136	281,688	676,443	349,005
73	12962	HR - Training	Total Dir Labor	1,280,546	275,958	662,682	341,906
74	13410	Power Training & Development	Total Dir Labor	869,781	187,438	450,111	232,231
75	13411	Markets Training & Development	Total Dir Labor	103,543	22,313	53,583	27,646
76	13412	People Training & Development	Total Dir Labor	288,964	62,272	149,539	77,153
77	13413	Business Skills Training & Development	Total Dir Labor	477,068	102,808	246,882	127,377
78	13414	Technology Training & Development	Total Dir Labor	843,082	181,684	436,295	225,103
79	13901	Performance Eval/Salary Review	Total Dir Labor	74,241	15,999	38,420	19,822
80		Total		8,669,737	1,868,328	4,486,589	2,314,820

Exhibit 2
Page 2 of 7

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Line	Activity Code		Allocation	Self-Funding Tariff			
No.	No.	Description	Factor (1)	Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Legal Department**					
2	12422	Interconnection Queue	Alloc-Fixed	103,141	-	-	103,141
3	12502	Board of Directors	Total Dir Labor	245,610	52,929	127,103	65,578
4	12508	Energy Markets / Complaints / Rule Changes	Alloc-Fixed	1,397,062	-	1,397,062	-
5	12513	Miscellaneous Labor Matters	Total Dir Labor	119,964	25,852	62,082	32,030
6	12514	NEPOOL Participants Committee	Total Dir Labor	135,001	29,093	69,863	36,045
7	12517	Administrative and Clerical Support	Total Dir Labor	577,591	124,471	298,903	154,217
8	12543	Independent Market Advisor	Alloc-Fixed	1,100,000	-	770,000	330,000
9	12559	General Corporate	Total Dir Labor	1,704,675	367,357	882,169	455,148
10	12587	Capacity Market Development	Alloc-Fixed	994,595	-	-	994,595
11	12588	Web Content Management	Total Dir Labor	727,694	156,818	376,582	194,294
12	12606	GC - NERC	Alloc-Fixed	600	270	60	270
13	12619	Compliance	Alloc-Fixed	165,026	66,010	66,010	33,005
14	12622	Open Access Transmission Tariff	Alloc-Fixed	322,938	322,938	-	-
15	12631	FERC Order 1000 (Legal Only)	Alloc-Fixed	371,308	-	-	371,308
16	12663	Public Information	Total Dir Labor	1,952,442	420,751	1,010,389	521,302
17	12669	Government Affairs	Total Dir Labor	1,999,182	430,824	1,034,576	533,781
18		Total		11,916,830	1,997,313	6,094,800	3,824,716
19							
20		**Internal Audit**					
21	15001	Indirect Management Duties	Total Dir Labor	209,476	45,142	108,404	55,930
22	15002	Personnel Management	Total Dir Labor	60,415	13,019	31,265	16,131
23	15003	Budget & Forecasting	Total Dir Labor	36,249	7,812	18,759	9,678
24	15004	Audit Follow-up Activities	Total Dir Labor	24,166	5,208	12,506	6,452
25	15005	Audit & Finance Committee	Total Dir Labor	113,013	24,354	58,484	30,174
26	15006	Internal Audit Business Process Update	Total Dir Labor	24,166	5,208	12,506	6,452
27	15007	Annual Audit Work Plan	Total Dir Labor	113,013	24,354	58,484	30,174
28	15011	Internal Audit Meetings	Total Dir Labor	36,249	7,812	18,759	9,678
29	15013	Indirect Adminstrative Support	Total Dir Labor	52,598	11,335	27,220	14,044
30	15014	GRC Tool Admin and Development	Total Dir Labor	105,985	22,840	54,847	28,298
31	15021	Performance Measurements	Total Dir Labor	36,249	7,812	18,759	9,678
32	15022	Vendor Contracts	Total Dir Labor	36,249	7,812	18,759	9,678
33	15023	Wire Transfers	Total Dir Labor	24,166	5,208	12,506	6,452
34	15028	Executive Compensation and Expense Reporting	Total Dir Labor	24,166	5,208	12,506	6,452
35	15110	Systems Development Reviews	Total Dir Labor	60,415	13,019	31,265	16,131
36	15133	Satellite Operations Reviews	Total Dir Labor	60,415	13,019	31,265	16,131
37	15137	Satellite IT Reviews	Total Dir Labor	60,415	13,019	31,265	16,131
38	15161	External Audit- Pension Audit	Total Dir Labor	99,509	21,444	51,496	26,569
39	15162	External Audit- Financial Audit	Total Dir Labor	156,365	33,697	80,919	41,749
40	15166	External Audit -Pricing Module Certification	Alloc-Fixed	24,166	-	24,166	-
41	15175	Ext Audit - Info Technology	Total Dir Labor	66,526	14,336	34,427	17,763
42	15176	External Audit - ISO Internet Vulnerability Assessment	Total Dir Labor	11,372	2,451	5,885	3,036
43	15186	External Audit - SSAE 18 Direct Support	Total Dir Labor	36,249	7,812	18,759	9,678
44	25702	External Audit - SSAE 18 Direct Management	Alloc-Fixed	518,014	-	518,014	-
45	28005	Fraud, Waste & Abuse Program	Total Dir Labor	54,563	11,758	28,236	14,568
46	28007	Contractor/Consultant Review	Total Dir Labor	26,243	5,655	13,581	7,007
47	28159	Audit - Oracle Licensing Compl	Total Dir Labor	113,280	24,412	58,622	30,246
48	28167	AUDIT-CLOUD COMPUTING	Total Dir Labor	113,280	24,412	58,622	30,246
49	28176	CIP Oversight, Monitoring, and Reporting Processes Review	Total Dir Labor	70,801	15,258	36,640	18,904
50	28179	NERC CIP V5.0 Mock Audit	Total Dir Labor	60,415	13,019	31,265	16,131
51		Total		2,428,186	406,434	1,518,188	503,564
52							
53		**COO-Adm**					
54	19001	NEPOOL Committee Support	Total OPS Labor	179,520	48,111	86,080	45,329
55	19002	Regional Committee Support	Total OPS Labor	7,550	2,023	3,620	1,906
56	19003	National Committee Support	Total OPS Labor	10,904	2,922	5,228	2,753
57	19005	Indirect Supervision/Clerical Support	Total OPS Labor	1,776,637	476,139	851,898	448,601
58	19009	Renewable Resource Integration	Alloc-Fixed	151,916	-	-	151,916
59		Total		2,126,526	529,196	946,826	650,505
60							
61		**System Operations & Market Administration**					
62	14404	NEPOOL Committee Support	SOA Labor	11,395	3,936	5,290	2,170
63	14405	Indirect Supervision/Clerical Support	SOA Labor	182,022	62,871	84,495	34,657
64	14407	Regional Committee Support	SOA Labor	11,395	3,936	5,290	2,170
65	14408	National Committee Support	SOA Labor	16,395	5,663	7,611	3,122
66	19101	NEPOOL Committee Support	MOA Labor	80,390	-	56,273	24,117
67		Total		301,598	76,405	158,958	66,235

DRAFT

Line	Activity Code		Allocation	Self-Funding Tariff			
No.	No.	Description	Factor (1)	Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Operations**					
2	14001	Generation Dispatch	Alloc-Fixed	4,153,473	-	3,488,917	664,556
3	14002	Transmission Operations	Alloc-Fixed	2,085,121	1,668,097	104,256	312,768
4	14304	Advanced Scheduling and Forecasting	Alloc-Fixed	2,068,352	103,418	1,633,998	330,936
5	14402	Operations Training	Alloc-Fixed	2,068,352	827,341	827,341	413,670
6	14413	Operations Support Training & Development	Alloc-Fixed	135,000	54,000	54,000	27,000
7	14563	National Committee Support	OPS Labor	6,844	1,913	3,789	1,141
8	14565	Employee Development	OPS Labor	26,981	7,544	14,936	4,500
9	14702	Procedure Documentation	Alloc-Fixed	72,216	28,886	28,886	14,443
10		Total		10,616,338	2,691,199	6,156,124	1,769,016
11							
12		**Operational Performance Trng and Integration**					
13	14402	Operations Training	Alloc-Fixed	424,451	169,780	169,780	84,890
14	14462	OSS - General Systems Operations Support	TSO Labor	422,747	136,843	202,115	83,788
15	14564	Indirect Supervision/Clerical Support	OPS Labor	988,947	276,510	547,481	164,956
16	14574	OPTI Continuing Training	Alloc-Fixed	845,504	338,202	338,202	169,101
17	14581	Application Testing and Development	Total Dir Labor	845,497	182,205	437,545	225,748
18	14583	Ops - Ad Hoc Analysis and Reporting	Total Dir Labor	422,747	91,102	218,772	112,873
19	14587	Ops - Other Internal Support Meetings	Total Dir Labor	422,747	91,102	218,772	112,873
20	15501	OA - Operations Analysis	Alloc-Fixed	422,747	63,412	295,923	63,412
21		Total		4,795,387	1,349,155	2,428,589	1,017,642
22							
23		**Reliability and Operations Compliance**					
24	14803	Regional Committee Support	OS Labor	76,576	38,288	-	38,288
25	14804	National Committee Support	OS Labor	100,621	50,311	-	50,311
26	14806	Employee Development	Alloc-Fixed	68,144	37,854	13,172	17,118
27	14807	NERC RSAW Update and Audit Prep	Alloc-Fixed	145,017	72,508	-	72,508
28	14808	Change Management	Alloc-Fixed	24,072	10,832	2,407	10,832
29	14809	Tariff Compliance	Alloc-Fixed	180,540	54,162	108,324	18,054
30	14812	NPCC MP Referral	Alloc-Fixed	60,180	24,072	24,072	12,036
31	14815	Identifications and Description of Internal Controls	Total Dir Labor	481,440	103,750	249,145	128,545
32	14816	Support NE Compliance Groups	Total Dir Labor	60,180	12,969	31,143	16,068
33	14817	AskISO Customer or Internal Inquiries	Total Dir Labor	60,180	12,969	31,143	16,068
34		Total		1,256,950	417,715	459,407	379,828
35							
36		**Operations Support Services**					
37	14301	Contract Administration and Scheduling	Alloc-Fixed	(60,000)	(6,000)	(42,000)	(12,000)
38	14453	National Committee Support	TSO Labor	20,420	6,610	9,763	4,047
39	14454	Indirect Supervision/Clerical Support	TSO Labor	22,094	7,152	10,563	4,379
40	14467	Nuclear Plant Liaison	Alloc-Fixed	13,687	-	-	13,687
41	14475	OSS - Frequency Response Work	Alloc-Fixed	16,769	16,769	-	-
42	14477	Participant project and outage coordination support	Alloc-Fixed	13,687	6,844	-	6,844
43	18361	Transmission Studies, Operations, OASIS Support	Alloc-Fixed	2,957,761	2,366,209	147,888	443,664
44	18381	Transmission Outage Application - Short Term	Alloc-Fixed	1,582,227	1,265,782	79,111	237,334
45	18382	Transmission Outage Application - Long Term	Alloc-Fixed	527,409	-	-	527,409
46		Total		5,094,055	3,663,365	205,326	1,225,364
47							
48		**Market Monitoring**					
49	16101	Market Power Monitoring and Mitigation	Alloc-Fixed	5,253,133	-	3,677,193	1,575,940
50	16102	Regulatory Activities	Alloc-Fixed	1,156	-	809	347
51	16115	Analysis & Internal Reports	Alloc-Fixed	348,871	-	244,210	104,661
52		Total		5,603,160	-	3,922,212	1,680,948
53							
54		**Market Administration & Auctions**					
55	21901	Day Ahead Price Monitoring	Alloc-Fixed	333,852	-	333,852	-
56	21902	Real Time Price Verification	Alloc-Fixed	333,852	-	333,852	-
57	21904	NEPOOL Committee Support	MA Labor	692	-	670	22
58	21907	Indirect Supervision/Clerical Support	MA Labor	584,503	-	566,033	18,470
59	21908	Employee Development	MA Labor	125,198	-	121,241	3,956
60	21909	Customer Support	MA Labor	429	-	416	14
61	21913	MA-Data Collection/Report Writing	Alloc-Fixed	166,926	-	166,926	-
62	21915	FTR/Auction Administration	Alloc-Fixed	292,120	146,060	146,060	-
63	21916	Forward Reserve Market - Administration	Alloc-Fixed	41,731	-	-	41,731
64	21917	Real Time Price Finalization	Alloc-Fixed	250,389	-	250,389	-
65	21951	FCM Annual Reconfiguration Auction Administration	Alloc-Fixed	83,463	-	-	83,463
66	21953	FCM Monthly Administration	Alloc-Fixed	125,194	-	-	125,194
67		Total		2,338,349	146,060	1,919,438	272,851

Exhibit 2
Page 4 of 7

DRAFT

Line No.	Activity Code No.	Activity Code Description	Allocation Factor (1)	Self-Funding Tariff Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**Market Analysis & Settlements**					
2	1701	Billing Statements - Energy	Alloc-Fixed	91,620	-	91,620	-
3	1702	Billing Statements - Transmission	Alloc-Fixed	109,503	109,503	-	-
4	1713	Billing Statements - ISO Tariff	Total Dir Labor	12,984	2,798	6,719	3,467
5	1714	Billable Tariff Re-billings	Total Dir Labor	1,225	1,225	-	-
6	1716	Winter Reliability Program	Alloc-Fixed	6,614	-	-	6,614
7	1717	Inventoried Energy Program	Alloc-Fixed	6,614	-	-	6,614
8	1718	Mystic COS	Alloc-Fixed	13,474	-	-	13,474
9	1719	FCM Daily	Alloc-Fixed	173,196	-	-	173,196
10	1722	NCC Trading FA	Alloc-Fixed	12,249	-	-	12,249
11	2047	Score Card	STLM Labor	3,185	471	1,551	1,162
12	2048	FCM	Alloc-Fixed	74,472	-	-	74,472
13	2049	Product Testing	Alloc-Fixed	16,658	-	13,327	3,332
14	2051	Legal Support	Alloc-Fixed	7,104	-	3,552	3,552
15	2005	Customer Service	STLM Labor	182,995	27,065	89,137	66,793
16	2007	Admin support - NEPOOL Committees	STLM Labor	245	36	119	89
17	2009	Indirect Supervision/Clerical Support	STLM Labor	844,597	124,916	411,403	308,278
18	2010	Employee Development	STLM Labor	195,319	28,888	95,140	71,291
19	2013	FTR Administration	Alloc-Fixed	36,011	-	36,011	-
20	2014	Billing Statements - NCPC	Alloc-Fixed	376,523	-	188,262	188,262
21	2020	Billing Disputes	Total Dir Labor	19,353	4,171	10,015	5,167
22	2021	Analysis & Reporting	Total Dir Labor	431,608	93,011	223,357	115,239
23	2024	ASM Regulation	Alloc-Fixed	27,927	-	-	27,927
24	2025	ASM Locational Forward Reserve	Alloc-Fixed	108,033	-	-	108,033
25	2026	Batch Processing	Total Dir Labor	33,806	7,285	17,495	9,026
26	2032	Billing	STLM Labor	41,155	6,087	20,047	15,022
27	2033	Market Analysis	Alloc-Fixed	172,646	-	172,646	-
28	2055	MAS - Market Monitoring Support	Alloc-Fixed	11,739	-	5,870	5,870
29		Total		3,010,853	405,456	1,386,269	1,219,128
30							
31		**Market Operations Support Services**					
32	3000	Hourly Settlements Support	Alloc-Fixed	302,125	-	151,063	151,063
33	3002	Monthly Settlements Support	Alloc-Fixed	215,804	107,902	-	107,902
34	3006	Customer Service	Alloc-Fixed	107,902	-	107,902	-
35	3008	Admin Support	Alloc-Fixed	193,212	-	193,212	-
36	3009	Indirect Supervision (Principal Analysts only)	Alloc-Fixed	151,063	-	151,063	-
37	3010	Employee Development	Alloc-Fixed	22,230	-	22,230	-
38	3012	FERC Data Request	Alloc-Fixed	5,395	-	5,395	-
39	3017	Project MAS (Market Analysis & Settlements)	Alloc-Fixed	323,706	80,926	80,926	161,853
40		Total		1,321,438	188,828	711,792	420,818
41							
42		**Market Services**					
43	16001	Participant/membership support	Alloc-Fixed	95,745	-	47,872	47,872
44	16006	Call Support (Ask ISO)	Alloc-Fixed	1,498,527	389,617	989,028	119,882
45	16414	Direct Customer Contact	MS Labor	26,510	-	23,859	2,651
46	16419	Asset Registration Implemented	Alloc-Fixed	333,852	-	333,852	-
47	16420	Asset Registration Review	Alloc-Fixed	208,657	-	208,657	-
48	16422	Claimed Capability Audits	Alloc-Fixed	542,509	-	542,509	-
49	16425	DR Registration Implemented	Alloc-Fixed	41,731	-	41,731	-
50	16432	New Generation Coordination and Registration	Alloc-Fixed	208,657	-	208,657	-
51	16434	QMS/CAPA Process and Procedure Updates	Total Dir Labor	292,120	62,952	151,172	77,996
52		Total		3,248,308	452,569	2,547,338	248,402
53							
54		**Participant Training Services**					
55	16021	Training Development	Alloc-Fixed	925,490	-	462,745	462,745
56	16024	Training Delivery	Alloc-Fixed	2,697	-	1,349	1,349
57	16436	Mkt Trng/Cus Serv Indirect Supervision	Total Dir Labor	450,669	-	450,669	-
58		Total		1,378,857	-	914,763	464,094
59							
60		**Planning Services**					
61	17101	Analysis	Alloc-Fixed	397,752	-	278,426	119,326
62	17131	Calculate Objective Capability	Alloc-Fixed	303,328	-	-	303,328
63	17403	TCA Application Review	Alloc-Fixed	101,358	-	-	101,358
64	17405	Energy Efficiency Forecast	Alloc-Fixed	34,195	-	-	34,195
65	17409	Environmental/Emissions Supp	Total Dir Labor	244,753	-	-	244,753
66	17501	FCA - Evaluate Existing Resource De-list Bids	Alloc-Fixed	88,283	-	-	88,283
67	17503	FCA - New Resource Qualification Support	Alloc-Fixed	982,836	-	-	982,836
68	17504	FCA - Perform Transmission / Topology Assessments	Alloc-Fixed	54,498	-	-	54,498
69	17505	FCA - Perform Existing Resource Qualification	Alloc-Fixed	108,991	-	-	108,991
70	17507	FCA - Auctions & Filings	Alloc-Fixed	1,074,696	-	-	1,074,696
71	17508	FCA - Annual Reconfiguration Auction Support/Reliability Reviews	Alloc-Fixed	163,484	-	-	163,484
72	18101	Develop Load Forecast	Alloc-Fixed	582,327	116,465	116,465	349,396
73	18121	Operations Forecast Support	Alloc-Fixed	239,343	47,869	47,869	143,606
74	18133	Solar Load Forecast Development	Alloc-Fixed	102,579	20,516	20,516	61,547
75		Total		4,478,423	184,850	463,276	3,830,297

Exhibit 2

DRAFT

Line	Activity Code		Allocation	Self-Funding Tariff			
No.	No.	Description	Factor (1)	Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**System Planning**					
2	18150	Regional Transmission Expansion Plan	Alloc-Fixed	421,969	316,477	105,492	-
3	18152	States Requests	Alloc-Fixed	223	111	56	56
4	18402	Transmission Planning/Economic Studies Initiative	Alloc-Fixed	1,190,521	-	595,261	595,261
5	18562	Project Management	Alloc-Fixed	475,641	475,641	-	-
6		Total		2,088,354	792,229	700,808	595,316
7							
8		**Transmission Planning**					
9	14715	Non DOE Funded/Unallowable	Alloc-Fixed	76,322	-	-	76,322
10	18201	Transmission System Assessment	Alloc-Fixed	3,549,228	3,549,228	-	-
11	18301	NEPOOL Administrative Support - Schedule 1 Tariff	Alloc-Fixed	129,840	129,840	-	-
12	18333	General SIS/FS	Alloc-Fixed	1,256,317	1,256,317	-	-
13	18334	Indirect Supervision/Clerical Support	Alloc-Fixed	799,017	799,017	-	-
14	18335	Regulatory Activities - NPCC	Alloc-Fixed	270,746	270,746	-	-
15	18336	National Activities	Alloc-Fixed	177,122	177,122	-	-
16	18337	TR - Regulatory Activities	Alloc-Fixed	10,826	10,826	-	-
17	18341	NERC Compliance	Alloc-Fixed	10,826	10,826	-	-
18	18344	TR - Transmission Planning Siting Support	Alloc-Fixed	10,824	10,824	-	-
19	18346	OATT and Oper. Agreement Dev., Adm. and Support	Alloc-Fixed	108,987	108,987	-	-
20	18350	States Future Planning Studies	Alloc-Fixed	190,565	190,565	-	-
21		Total		6,590,619	6,514,297	-	76,322
22							
23		**Program Management**					
24	801	Program Management - Administration	Total Dir Labor	806,813	173,868	417,526	215,419
25	1661	ISO Program Management	Alloc-Fixed	440,920	-	308,644	132,276
26	1665	Product and Test Mgmt.	Total Dir Labor	417,495	89,970	216,054	111,471
27	25002	PMO Support	Alloc-Fixed	882	265	309	309
28		Total		1,666,110	264,103	942,532	459,475
29							
30		**Advanced Technology Solutions**					
31	21201	Advanced Technology Solutions	Total Dir Labor	4,004,363	862,940	2,072,258	1,069,165
32	21203	Employee Development	Total Dir Labor	60,352	13,006	31,232	16,114
33	21207	Resource Capacity Accreditation	Total Dir Labor	2,200,267	-	-	2,200,267
34		Total		6,264,982	875,946	2,103,490	3,285,546
35							
36		**Market Development & Settlements Admin.**					
37	16607	National Committee Support	Total Dir Labor	87,359	18,826	45,208	23,325
38	19104	Indirect Supervision/Clerical Support	MOA Labor	422,767	-	295,937	126,830
39	21001	Market Development	Alloc-Fixed	1,246,821	-	623,410	623,410
40	21002	Administration	Total Dir Labor	562,036	121,119	290,854	150,064
41	21003	Employee Development	Total Dir Labor	480,145	103,471	248,475	128,199
42	21007	Budget/Forecast Support	Total Dir Labor	292,682	63,073	151,463	78,146
43	21010	MD - Day-Ahead Reserve Market	Alloc-Fixed	1,944,041	-	1,846,839	97,202
44	21011	Capacity Market	Alloc-Fixed	513,028	-	-	513,028
45	22401	Administration	Total Dir Labor	49,370	10,639	25,549	13,182
46	22402	Working Group Meetings and Support	Alloc-Fixed	49,373	-	24,687	24,687
47	22656	Energy, Reserve, and Regulation Markets	Alloc-Fixed	251,712	-	188,784	62,928
48	22658	Storage	Alloc-Fixed	239,604	-	191,684	47,921
49	22660	Energy Security	Alloc-Fixed	1,328,241	-	664,121	664,121
50	22661	Project: DER Participation	Alloc-Fixed	156,867	-	78,433	78,433
51		Total		7,624,048	317,128	4,675,444	2,631,476
52							
53		**Participant Relations & Services**					
54	22602	NEPOOL Committee Meetings & Support	Alloc-Fixed	430,163	-	215,082	215,082
55	22607	NEPOOL Committee Administration	Total Dir Labor	1,642,195	353,893	849,836	438,466
56	22612	Future Grid Study and Modeling	Total Dir Labor	1,849,823	-	739,929	1,109,894
57		Total		3,922,182	353,893	1,804,847	1,763,442
58							
59		**IT Management**					
60	6517	Employee Development - Hardware/Software	Total Dir Labor	138,756	29,902	71,806	37,048
61	6519	Indirect Supervision and Clerical Support	Total Dir Labor	4,879,674	1,051,570	2,525,232	1,302,873
62	6552	Security	Total Dir Labor	205,746	44,338	106,474	54,934
63	6556	Budget Preparation, Tracking & Forecast	Total Dir Labor	169,985	36,632	87,967	45,386
64	6557	Information Technology Committee	Total Dir Labor	407	88	211	109
65	22501	Change Management Support	Alloc-Fixed	289,276	130,174	130,174	28,928
66	22505	Administrative	Alloc-Fixed	460,896	156,705	152,096	152,096
67		Total		6,144,740	1,449,408	3,073,959	1,621,373

DRAFT

Line	Activity Code		Allocation	Self-Funding Tariff			
No.	No.	Description	Factor (1)	Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1							
2		**IT Infrastructure Support**					
3	6510	Desktop Support - Hardware	Total Dir Labor	489,937	105,582	253,543	130,813
4	6511	Desktop Support - Software	Total Dir Labor	958,524	206,562	496,036	255,926
5	6512	Host Computer - Hardware	Alloc-Fixed	2,880,590	-	2,160,442	720,147
6	6513	Host Computer - Software	Alloc-Fixed	6,071,084	-	4,553,313	1,517,771
7	6514	Networking - Hardware	Total Dir Labor	144,549	31,150	74,804	38,595
8	6516	Communications	Total Dir Labor	3,383,281	729,097	1,750,848	903,336
9	6619	IT - Infrastructure Coordination	Total Dir Labor	221,886	47,816	114,826	59,244
10	6602	Help Desk Support	Total Dir Labor	251,697	54,241	130,253	67,203
11	6615	Host Computer Monitoring	Alloc-Fixed	1,280,713	-	640,357	640,357
12	6616	Desktop Support	Total Dir Labor	432,286	93,158	223,708	115,420
13	6617	System Administration - Unix	Total Dir Labor	407,577	87,833	210,921	108,823
14	6618	System Administration - Windows	Total Dir Labor	793,262	170,948	410,513	211,801
15	6621	Network Support	Total Dir Labor	472,863	101,902	244,707	126,254
16	6622	CIP & Systems Compliance	Total Dir Labor	2,313,723	498,607	1,197,352	617,764
17	6623	Asset Management	Total Dir Labor	868,718	187,209	449,561	231,948
18	6624	Infrastructure Review & Planning	Total Dir Labor	266,251	57,377	137,785	71,089
19	6625	Infrastructure Patch & Vulnerability Mitigation	Total Dir Labor	226,777	48,870	117,357	60,549
20	6626	IT - Infrastructure Break-fix & Troubleshooting	Total Dir Labor	102,171	22,018	52,873	27,280
21	6627	IT - Infrastructure Support Request	Total Dir Labor	303,193	65,338	156,902	80,953
22	6628	IT - Infrastructure Cyber Security Support	Total Dir Labor	87,786	18,918	45,429	23,439
23	6629	IT - Infrastructure Refresh/Upgrade	Total Dir Labor	89,261	19,236	46,193	23,833
24	6630	IT - Infrastructure Operation Enhancement Effort	Total Dir Labor	242,333	52,223	125,407	64,703
25		Total		22,288,462	2,598,084	13,593,131	6,097,247
26							
27		**IT Cyber Security**					
28	6540	Security Compliance and Reporting	Total Dir Labor	3,574,405	770,284	1,849,755	954,366
29	6540A	Controls Assessment	Total Dir Labor	20,909	4,506	10,820	5,583
30	6540B	Virus/Malware Reporting and Response	Total Dir Labor	8,157	1,758	4,221	2,178
31	6540D	Intrusion Monitoring and Response	Total Dir Labor	1,416,998	305,363	733,297	378,339
32	6540E	System Compliance Enhancement	Total Dir Labor	14,775	3,184	7,646	3,945
33	6541	Security SW Tools Program	Total Dir Labor	651,154	140,324	336,972	173,858
34	6543	Critical Infrastructure Protection WG (NERC)	Total Dir Labor	55,573	11,976	28,759	14,838
35	6546	IT Audit Support	Total Dir Labor	21,969	4,734	11,369	5,866
36	6547	Cyber Security Training	Total Dir Labor	1,894	408	980	506
37	6548	CIP Compliance & Monitoring	Total Dir Labor	150,175	32,363	77,715	40,097
38		Total		5,916,009	1,274,900	3,061,535	1,579,574
39							
40		**IT Database & Analytics**					
41	6571	DBA Support - MOPS	Total Dir Labor	3,078,037	663,317	1,592,884	821,836
42	6591	Data Architect - MOPS	Total Dir Labor	305,606	65,858	158,151	81,597
43	6594	IT Data Analyst	Total Dir Labor	617,941	133,166	319,784	164,990
44	6595	IT WEB Application Support	Total Dir Labor	543,321	117,086	281,169	145,067
45	6596	IT Data Governance	Total Dir Labor	258,711	55,752	133,883	69,076
46	21706	Enterprise Software Support	Total Dir Labor	1,902,546	409,999	984,567	507,980
47	21801	Software Support - Settlements	Alloc-Fixed	390,149	-	312,119	78,030
48	21802	Software Support - Publishing	Alloc-Fixed	16,375	-	13,100	3,275
49	21803	Software Support - Finance	Alloc-Fixed	425,543	-	340,435	85,109
50	21804	Software Support - Mitigation	Alloc-Fixed	651,928	-	521,542	130,386
51	21805	Software Support - TSO	Total Dir Labor	662,615	142,794	342,903	176,918
52	21806	Software Support - Enterprise	Total Dir Labor	1,162,167	250,447	601,421	310,299
53	21807	Software Support - Planning	Alloc-Fixed	394,835	-	315,868	78,967
54	21808	Training Delivery to NON-IT	Alloc-Fixed	319,718	-	255,774	63,944
55	21809	IT Markets Software Maintenance	Alloc-Fixed	39,918	-	31,934	7,984
56	21811	Single Sign On Support	Alloc-Fixed	256,580	-	205,264	51,316
57	21812	GADS Support	Alloc-Fixed	116,614	-	93,291	23,323
58	21814	Manual Database Edit	Total Dir Labor	9,862	2,125	5,104	2,633
59	21816	CMS Support	Total Dir Labor	163,210	35,172	84,461	43,577
60	21818	Discoverer Support	Total Dir Labor	67,949	14,643	35,164	18,142
61	21824	FCTS Support	Alloc-Fixed	1,045,447	-	-	1,045,447
62	21825	eTariff Support	Alloc-Fixed	50,373	-	40,298	10,075
63	21830	Annual Software Maintenance for Enterpirse Wide Software	Total Dir Labor	161,668	34,839	83,663	43,165
64	21832	GDMA/Gateway Support	Alloc-Fixed	54,218	-	43,375	10,844
65		Total		12,695,330	1,925,198	6,796,156	3,973,977
66							
67		**IT Energy Management Systems**					
68	21600	Indirect Supervision and Administration	Total Dir Labor	143,669	30,961	74,349	38,360
69	21601	Power System Modeling	Total Dir Labor	107,785	23,228	55,779	28,778
70	21602	Applications Support	Total Dir Labor	241,374	52,016	124,911	64,447
71	21603	EMS Power System Applications Support	Total Dir Labor	649,817	140,035	336,280	173,501
72	21604	Dispatcher Training Simulatory Support	Alloc-Fixed	2,350,068	1,880,054	470,014	-
73	21605	DAM FTR/ARR Support	Alloc-Fixed	1,634,294	326,859	980,577	326,859
74	21606	Real-time Market Support	Alloc-Fixed	2,858,480	571,696	1,715,088	571,696
75	21607	Forecast Support	Alloc-Fixed	178,997	35,799	107,398	35,799
76		Total		8,164,484	3,060,649	3,864,395	1,239,440

Exhibit 2

DRAFT

Line No.	Activity Code No.	Activity Code Description	Allocation Factor (1)	Self-Funding Tariff Total (2)	Schedule 1	Schedule 2	Schedule 3
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1							
2		**IT Enterprise Applications Development**					
3	6518	Employee Development - Software	Total Dir Labor	32,800	7,068	16,974	8,758
4	21707	Application Analysis and Conceptual Design	Alloc-Fixed	26,579	-	21,263	5,316
5	21708	Application Design Evaluation and Selection	Alloc-Fixed	584,636	-	467,709	116,927
6	21709	Technology Evaluation and Selection	Alloc-Fixed	851,746	-	681,397	170,349
7	21710	Indirect Supervision and Administration	Alloc-Fixed	1,217,575	-	974,060	243,515
8	21711	EWR and CAPA Analysis	Alloc-Fixed	224,412	-	179,530	44,882
9		Total		2,937,748	7,068	2,340,933	589,747
10							
11		**IT Power System Modeling Management**					
12	21650	Indirect Supervision and Administration	Total Dir Labor	203,543	43,863	105,333	54,346
13	21651	Power System Modeling	Alloc-Fixed	1,879,580	751,832	751,832	375,916
14	21652	System Application Support	Alloc-Fixed	314,229	125,692	125,692	62,846
15	21654	NX9 Administration	Alloc-Fixed	580,609	232,244	232,244	116,122
16	21655	ICCP Support	Alloc-Fixed	1,149,245	459,698	459,698	229,849
17	21656	Transmission Project Management	Alloc-Fixed	30,644	24,515	6,129	-
18	21657	Model On Demand Admin	Alloc-Fixed	1,123,660	-	-	1,123,660
19	21661	MAS Software Dev and Support	Alloc-Fixed	23,915	-	-	23,915
20		Total		5,305,424	1,637,844	1,680,927	1,986,653
21							
22							
23		**Total ISO**		$ 240,205,156	$ 49,273,547	$ 118,209,011	$ 72,722,598

Exhibit 3

Draft 2023 Rate Components (1)

Tariff Schedule	Jan. 1, 2023
Schedule 1	
Network Load (per kW-hour)	$0.00028
Schedule 2	
TU Bids (Virtual Inc/Dec)	
Submitted	$0.00500
Cleared	$0.06000
FTR Bids	
Submitted	$2.01008
Cleared	$4.20539
TU's	
Block 1 - 1st 12,500	$0.69888
Block 2 - Next 27,000	$0.63535
Block 3 - Over 39,500	$0.57181
Volumetric	
Block 1 - 1st 250,000	$0.40259
Block 2 - Next 1,250,000	$0.36599
Block 3 - Over 1,500,000	$0.32940
Schedule 3	
R-T NCP Load Obligation	$0.26260
Export Rate	$0.55000

(1) From Exh 3, RCL-7, Sch. 3

NESCOE Pro Forma Budget
Proposed 2023

	2023
Salaries and Wages	
Salaries	1,311,718
Payroll Taxes	131,172
Health and Other Benefits	110,098
Retirement §401(k)	52,469
Total, Salaries and Wages	**1,605,457**
Direct Expenses - Consulting	
Technical Analysis	342,932
Legal (FERC)	342,933
Total, Direct Expenses, Consulting	**685,865**
General and Administrative	
Rent	-
Utilities	-
Office and Administrative Expenses	48,956
Professional Services	41,200
Travel/Lodging/Meetings	56,650
Total General and Administrative	**146,806**
Capital Expend. & Contingencies	
Computer Equipment	8,695
Contingencies	244,682
Capital Expend. & Contingencies	**253,377**
TOTAL EXPENSES	**2,691,505**
BUDGET	***2,696,171***

New England States Committee on Electricity

2023 Budget Presentation

NEPOOL Budget & Finance Subcommittee

August 11, 2022

NESCOE

REVISED October 2022 Participants Committee material.
Only changes to August material, noted as such, are as follows:
p. 12 to reflect actual 2023 Network Load factor and 2023 Schedule 5 Rate
p. 2 to reflect Participants Committee support and FERC filing of 5-year pro forma

Background: Budget Review

Term Sheet Provision: "… the annual review of its [NESCOE's] proposed budgets by at least the NEPOOL Participants Committee will be limited to considerations of accounting and reconciliation, so long as spending remains within the boundaries established by those frameworks….. NESCOE will develop an operating budget recommendation for each year in consultation with NEPOOL, the PTO Administrative Committee and ISO-NE within the boundaries of the then-approved five year budget framework …"

- ✓ Proposed 2023 budget conforms to:
  - Boundaries of 5-year pro forma (2023 - 2027) [new →] reviewed by Budget & Finance, supported by NPC on Sept. 1, 2022, and filed with the FERC (ER22-2812)
  - NESCOE commitment not to seek an increase over pro forma budget of more than 10% in any 1 year: 2023 proposed budget is less than 2023 5-year pro forma budget
- ✓ Following calendar year 2021, independent auditor concluded NESCOE books conform to generally accepted accounting principles

Background: Policy Priorities

Term Sheet Provision Governing Identification of Policy Priorities:

"Each year NESCOE will produce a ***Report to the New England Governors*** that will document its accomplishments from the preceding year and its projected policy priorities for the coming two years. This report will include a full accounting of spending by NESCOE during the preceding year and proposed budgets for each of the upcoming two years."

Consistent with Term Sheet, 2021 *Report to the New England Governors*:

- ✓ Reviewed work in 2021
- ✓ Projected policy priorities
- ✓ Provided spending from prior year
- ✓ Projected budget information for upcoming two years

Projected Policy Priorities

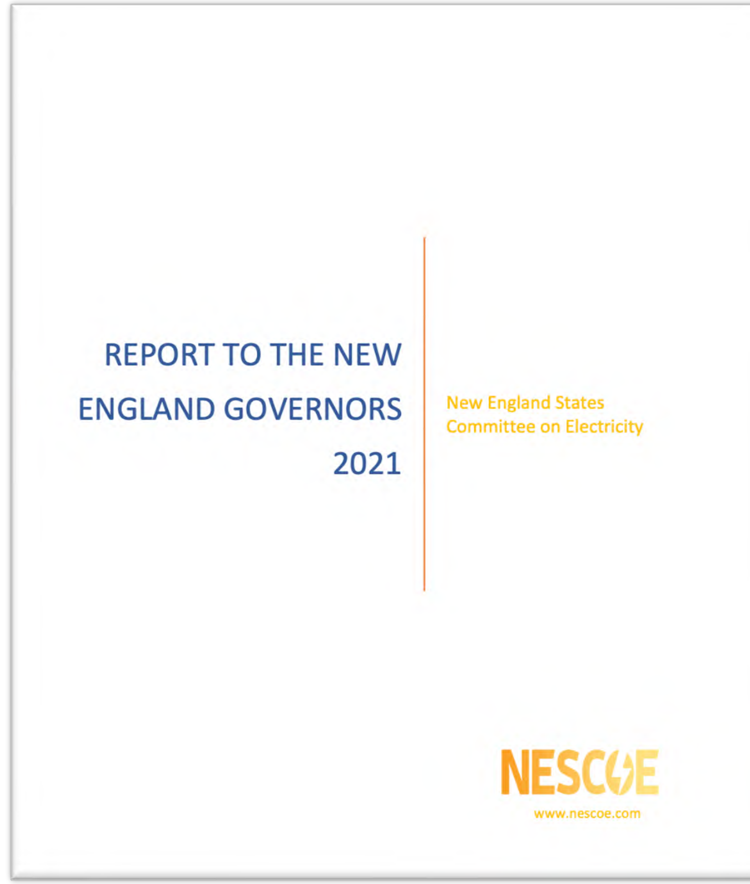
✓ NESCOE provided to the Governors the ***2021 Annual Report to New England Governors***

✓ Report simultaneously released to NEPOOL & ISO-NE & circulated to the Participants Committee

✓ NESCOE identified forward looking policy priorities at Section V, pages 15

Report in "Resource Center"

www.nescoe.com


REPORT TO THE NEW ENGLAND GOVERNORS 2021

New England States Committee on Electricity

NESCOE

www.nescoe.com

Projected Policy Priorities

- ✓ **Future Grid**. With ISO-NE and stakeholders, consider the contemplated Phase 2 Future Grid analysis to assess revenue sufficiency and system security in a gap analysis; advance the Pathways process, including governance approaches that provide an appropriate role for states.
- ✓ **Transmission**. Work with ISO-NE and stakeholders on tariff changes to enable states to consider options to address issues identified in the longer-term public policy-related transmission analysis; engage in FERC's reform of transmission planning, generator interconnection, and cost allocation processes, highlighting the critical need for states' appropriate, meaningful role in public-policy transmission planning and cost allocation.
- ✓ **Winter**. Continue to seek and assess timely analysis and recommendations from ISO-NE on near-term winter risks; assess means to value the contribution of resources needed for regional energy security/winter reliability; participate in ISO-NE's effort to assess potential operational implications of low probability/high impact extreme weather events and to identify a cost-effective approach to any mitigation; ensure consumer interests are chief among the metrics by which winter proposals are evaluated.

NESCOE Organization & Misc.

Employees

- ✓ Retain and attract diversity in academic training, skills; blend of private & public sector experience
- ✓ Assumes return to NESCOE's prior steady state employee level of six in light of sustained increase in workload volume; legal staff solicitation issued 2022

Office Space

- ✓ Terminated office space in Westborough, MA

Other Organization Matters

Technical Consultants

Technical consultants assist NESCOE in the regular course of business in analyzing ISO-NE studies and data.

Continue work with technical consultants to conduct independent analysis to inform state officials' decisions on key issues, including, for example:

- ✓ Wilson Energy Economics
- ✓ PeterGFlynn, LLC
- ✓ NewGen
- ✓ Supplement with other expertise, as needed

Legal Counsel

Litigation is not the primary means by which NESCOE seeks to accomplish its objectives & thus, greater resource and focus has historically, and thus far in 2022, been on technical consulting. Further, while NESCOE produces most legal pleadings and analysis internally, the frequency and type of litigation brought by others influences the extent to which NESCOE engages outside counsel.

- ✓ FERC Counsel: Phyllis G. Kimmel Law Office PLLC

5-Year Pro Forma

Proposed 2023 budget conforms to 2023 budget in 5-year Pro Forma Framework

✓ 2023 Projected Budget in 5-Year Pro Forma:	$2,696,171
✓ 2023 Proposed Budget:	$2,691,505
✓ 2022 Budget, for reference:	$2,485,156

In relation to 2022 Budget, 2023 Proposed Budget reflects:

- ✓ Return to prior steady state of six employees
- ✓ Inflationary pressures
- ✓ No office rent

5-Year Pro Forma, for reference

NESCOE
PRO FORMA BUDGET 2023-2027*

Expense Category	Year 16 (2023)	Year 17 (2024)	Year 18 (2025)	Year 19 (2026)	Year 20 (2027)
Salaries and Wages					
Salaries	1,311,718	1,377,304	1,446,169	1,518,478	1,594,401
Payroll Taxes	131,172	137,731	144,617	151,848	159,440
Health and Other Benefits	110,098	115,603	121,383	127,452	133,825
Retirement §401(k)	52,469	55,092	57,847	60,739	63,776
Total, Salaries and Wages	**1,605,457**	**1,685,730**	**1,770,016**	**1,858,517**	**1,951,443**
Direct Expenses - Consulting					
Technical Analysis	342,933	353,221	363,818	374,732	385,974
Legal (FERC)	342,933	353,221	363,818	374,732	385,974
Total, Direct Expenses, Consulting	**685,866**	**706,442**	**727,635**	**749,464**	**771,948**
General and Administrative					
Rent		12,000	12,360	12,731	13,113
Utilities		2,500	2,575	2,652	2,732
Office and Administrative Expenses	50,000	51,500	53,045	54,636	56,275
Professional Services	41,500	42,745	44,027	45,348	46,709
Travel/Lodging/Meetings	60,000	61,800	63,654	65,564	67,531
Total General and Administrative	**151,500**	**170,545**	**175,661**	**180,931**	**186,359**
Capital Expendiures & Contingencies					
Computer Equipment	8,666	8,926	9,194	9,470	9,754
Contingencies	244,682	252,022	259,583	267,371	275,392
Capital Expenditures & Contingencies	**253,348**	**260,948**	**268,777**	**276,840**	**285,145**
TOTAL EXPENSES**	**2,696,171**	**2,823,665**	**2,942,090**	**3,065,753**	**3,194,896**

*Projected 5% salaries and wages annual adjustment, and projected 3% annual adjustment on all other items. Line items and categories subject to increase greater than, or decrease from, amounts projected.
Any such changes will be subject to review, input, and recommendations by the NEPOOL Participants Committee (and/or its designees).
**At no time during this 5-year period will NESCOE seek a budget increase of more than 10% in any 1 year of more than 30% on a cumulative basis.

2023 Proposed Budget

	2023
Salaries and Wages	
Salaries	1,311,718
Payroll Taxes	131,172
Health and Other Benefits	110,098
Retirement §401(k)	52,469
Total, Salaries and Wages	**1,605,457**
Direct Expenses - Consulting	
Technical Analysis	342,932
Legal (FERC)	342,933
Total, Direct Expenses, Consulting	**685,865**
General and Administrative	
Rent	-
Utilities	-
Office and Administrative Expenses	48,956
Professional Services	41,200
Travel/Lodging/Meetings	56,650
Total General and Administrative	**146,806**
Capital Expend. & Contingencies	
Computer Equipment	8,695
Contingencies	244,682
Capital Expend. & Contingencies	**253,377**
TOTAL EXPENSES	**2,691,505**
BUDGET	***2,696,171***

2021 & 2022 Spending & Implications for 2023

Unspent funds in any year credited toward future year

2021 Total Spending:	$1,379,375*
2022 Spending to end of June:	$740,914
2022 Projected Year End:	$1,942,044 *

* Cumulative prior years' true up, including 2020, was reflected in the 2022 revenue requirement and rates. The 2021 true up will be reflected in the 2023 revenue requirement and rates (see next slide). Any 2022 true up will be reflected in the 2024 revenue requirements and rates.

2023 Projected Billing Rate

With thanks to ISO-NE for calculations -

2023 Budget:	$2,691,505
Less 2021 True Up:	($1,108,802)
Total Revenue Recovery:	$1,582,703

Updated September 2023 based on *actual* 2023 load factor:

Divided by Total Network Load: ~~231,453,876~~ 225,688,515

~~(total network load from 2022 ISO-NE tariff; no escalation or reduction used in calculation)~~

2023 Schedule 5 Rate ~~$0.00684~~ $0.00701 per kW-month

Thank you.

Questions?

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Eric Runge, NEPOOL Counsel

DATE: September 29, 2022

RE: Vote on HQICC and ICR Values for FCA17

At the October 6, 2022 Participants Committee meeting, you will be asked to support the following proposed sets of values: (i) Hydro-Quebec Interconnection Capability Credit values (the "HQICC Values"); and (ii) Installed Capacity Requirement ("ICR") values, and the related demand curves (collectively, the "ICR Values") to be used for Forward Capacity Auction 17 ("FCA17").[1] The Reliability Committee has recommended Participants Committee support for both sets of values with separate votes each at 63.95% in favor.

The HQICC Values and ICR Values for FCA17 were developed by the ISO, reviewed with the Power Supply Planning Committee, and reviewed with and voted on by the Reliability Committee. At its September 21, 2022 meeting, the Reliability Committee recommended in separate roll call votes that the Participants Committee support the HQICC Values and the ICR Values, with several opposing votes and abstentions.[2]

None of those opposed asserted that the ISO had failed to calculate the values in accordance with the existing Tariff provisions. Instead, most of the opposition seemed to be based on a concern that the existing methodology for calculating ICR and its components, including tie benefits, load reconstitution and the resulting HQICCs and Net ICR Values, might be defective and in need of reconsideration in the future. Some of those opposed suggested that the current methodology appears to be producing results that are not realistic or fully explicable. Additionally, Cross-Sound Cable Company opposed based on its long-standing objection to the lack of recognition of reliability value of Cross-Sound Cable in calculating tie benefits and the ICR.

[1] Background materials have been included with this memorandum. While the HQICC Values and ICR Values are interrelated, in the past separate issues have been raised with respect to one or the other, and accordingly they have been voted separately. The voting threshold for passing ICR-related resolutions is 60%.

[2] The individual Sector votes for the HQICC and ICR Values were Generation (8.35% in favor, 8.35% opposed, 2 abstentions), Transmission (16.70% in favor, 0.00% opposed, 0 abstentions), Supplier (0.00% in favor, 16.70% opposed, 8 abstentions), Publicly Owned Entity (16.70% in favor, 0.00% opposed, 0 abstentions), Alternative Resources (5.50% in favor, 11.00% opposed, 1 abstention), and End User (16.70% in favor, 0.00% opposed, 1 abstention).

The HQICC Values for FCA17 proposed by the ISO and recommended by the Reliability Committee are 1,001 MW for each month of the 2026-2027 Capacity Commitment Period (June through May).

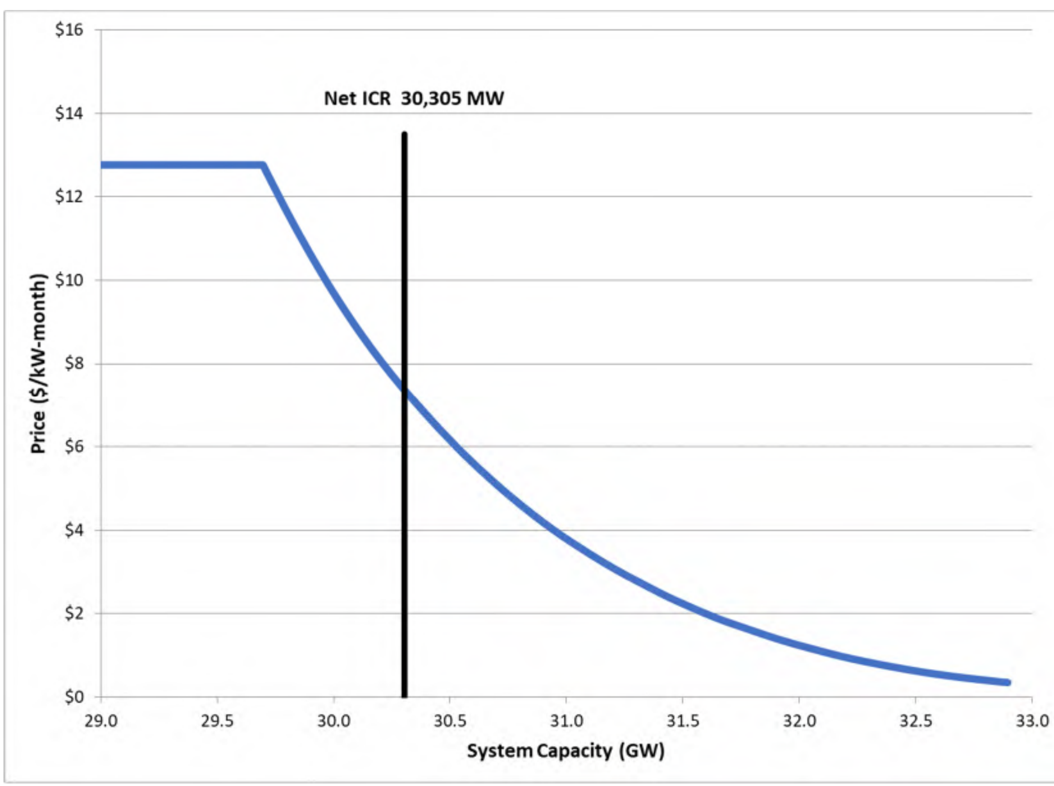
The ICR Values for FCA17 proposed by the ISO and recommended by the Reliability Committee are as follows:

ICR/LSR/MCL

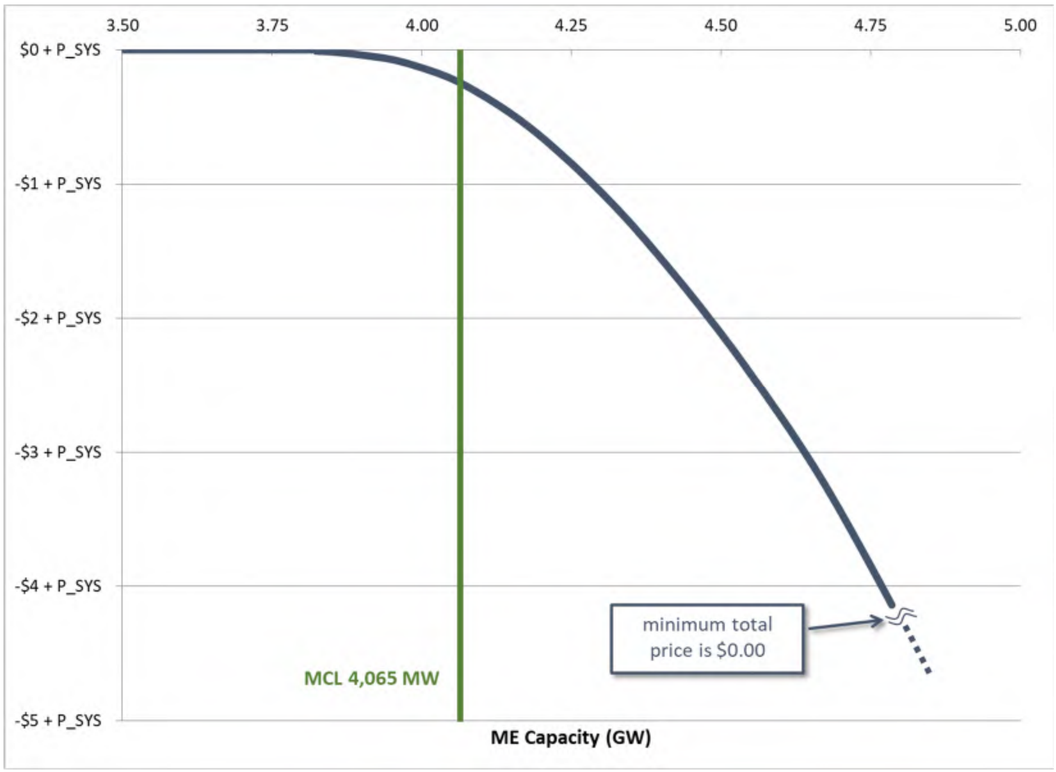
	2026-2027 Capacity Commitment Period ICR Values (MW)
Installed Capacity Requirement	31,306
Net Installed Capacity Requirement	30,305
Maine Maximum Capacity Limit	4,065
Northern New England Maximum Capacity Limit	8,595

Demand Curves

2026-2027 Capacity Commitment Period
System-Wide Demand Curve:



2026-2027 Capacity Commitment Period
Maine Capacity Zone Demand Curve:



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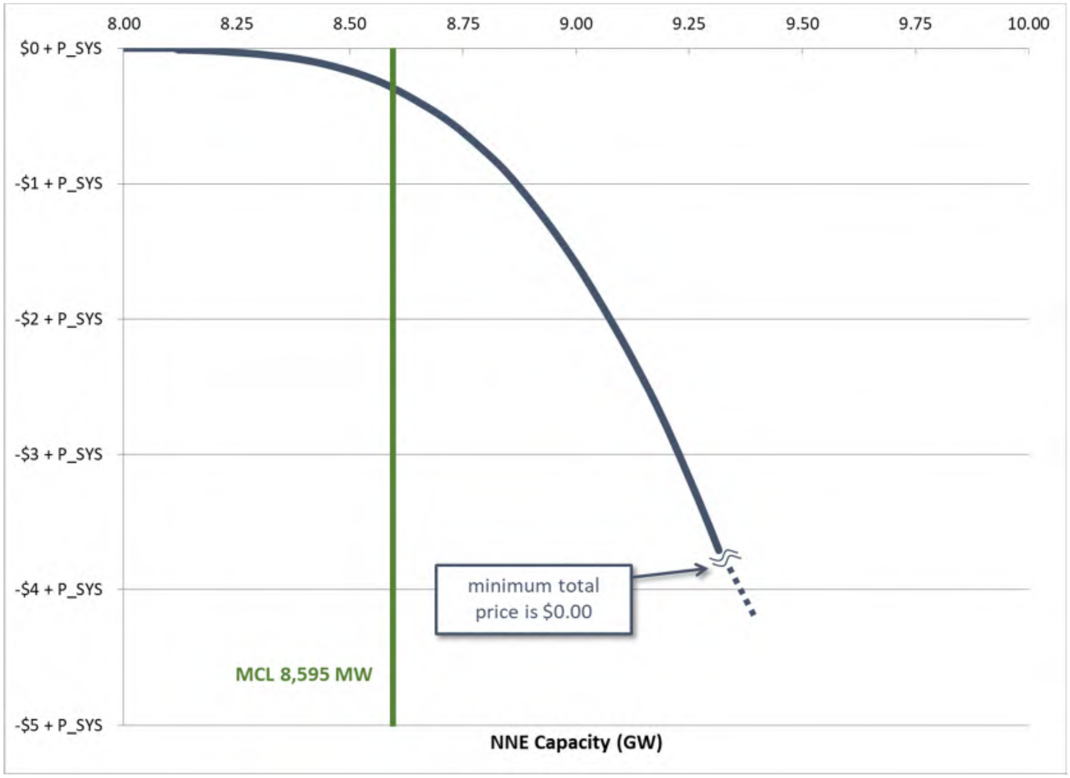
2026-2027 Capacity Commitment Period
Northern New England Capacity Zone Demand Curve:



The following resolutions, which require a minimum 60% Vote for approval, could be used for Participants Committee consideration of these items:

> RESOLVED, that the Participants Committee supports the FCA17 HQICC Values, as recommended by the Reliability Committee and as reflected in the materials distributed to the Participants Committee for its October 6, 2022 meeting, together with [any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

> RESOLVED, that the Participants Committee supports the FCA 17ICR Values, as proposed by the ISO and recommended by the Reliability Committee and as reflected in the materials distributed to the Participants Committee for its October 6, 2022 meeting, together with [any changes agreed to at the meeting and] such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee.

SEPTEMBER 20, 2022 | NEPOOL RELIABILITY COMMITTEE | COURTYARD BOSTON, MARLBOROUGH, MA

Installed Capacity Requirement (ICR)-Related Values for Capacity Commitment Period 2026-2027 Seventeenth Forward Capacity Auction (FCA 17)

NEPOOL Reliability Committee

Manasa Kotha and Fei Zeng

RESOURCE STUDIES AND ASSESSMENTS

Today’s Presentation

- Review the ICR-Related Values for FCA 17
- Answer any remaining questions that RC members may have regarding these values
- Request RC action on HQICC values and ICR-Related Values for FCA 17

Notes:

- The ICR, net ICR, Maximum Capacity Limit (MCL), the Marginal Reliability Impact (MRI) system and zonal Demand Curves, and the Hydro Quebec Interconnection Capability Credits (HQICCs) are collectively called the ICR-Related Values
- Transmission Security Analysis (TSA), Local Resource Adequacy Requirement (LRA) and Local Sourcing Requirement (LSR) will not be developed because there is no import-constrained Capacity Zone for FCA 17. For more information, please refer to the development of FCA 17 Capacity Zones presentation
- For details on ICR-Related Values development, please see ICR Reference Guide
- Assumptions that are used to calculate the FCA 17 ICR-Related Values are detailed in the September 7, 2022 ICR-Related Values presentation to the Reliability Committee
- Acronyms not defined are spelled out in the Appendix

FCA 17 ICR-Related Values Development Schedule

Date	Topic*
June 1	PSPC review of ICR-Related Values schedule
June 29	PSPC review of Capacity Zone determination and ICR-Related Values assumptions including assumptions for tie benefits study
July 28	PSPC review of tie benefits study results
August 25	PSPC review of proposed ICR-Related Values
September 7	RC initial review of proposed ICR-Related Values
September 20	RC review/vote of proposed ICR-Related Values
October 6	PC review/vote of proposed ICR-Related Values
By November 8	File ICR-Related Values with FERC

PROPOSED FCA 17 ICR-RELATED VALUES

Summary of FCA 17 Tie Benefits Study Results

Interface	FCA 17 Tie Benefits Amount (MW)
Maritimes	523
HQ Phase II (HQICCs)	1,001
Highgate	150
New York AC ties	426
Cross Sound Cable (CSC)	0
Total Tie Benefits	**2,100**

Results of the FCA 17 Tie Benefits Study are located at: https://www.iso-ne.com/static-assets/documents/2022/08/a02_review_of_fca17_tie_benefits_study_results.pptx

Comparison of FCA 17 & FCA 16 Tie Benefits

Interconnection	FCA 17 (MW)	FCA 16 (MW)	DELTA (MW) (FCA 17 minus FCA 16)
Maritimes	523	478	45
HQ Phase II	1,001	923	78
Highgate	150	142	8
New York AC ties	426	287	139
CSC	0	0	0
Total Tie Benefits	**2,100**	**1,830**	**270**

Note: FERC accepted the tie benefits for the 2025-2026 CCP associated with FCA 16 on December 21, 2021. See: https://www.iso-ne.com/static-assets/documents/2021/12/er22-378-000.pdf

Sensitivity Analysis and Observations

- The ISO identified several relevant assumption updates/changes in New York system, and conducted additional simulations to quantify their impacts on the tie benefits results
- The New York system relevant assumption updates/changes include:
  - An increase of import capability to New York Zone D from Chateauguay (Quebec) from 1,500 MW to 1,770 MW to reflect the Cedar Transmission Upgrade, which is expected to increase the tie benefits available to both New York and New England
  - Modifications in modeling certain resources
    - Modeling changes for some large energy limited hydro resources
    - Updated hourly profiles for wind and solar resources

Sensitivity Analysis and Observations, cont.

- A sensitivity analysis was conducted using:
  - FCA 16 tie benefit study New York's resource model
  - 1,500 MW for the import capability to Zone D from Chateauguay
- The total tie benefits of this sensitivity analysis is 1,830 MW, identical to the FCA 16 tie benefits
- In summary, the 270 MW increase of total tie benefits in FCA 17 is mainly attributed to the resource model changes of the New York system, and the increased import capability to Zone D from Chateauguay (~90 MW)

ISO Proposed FCA 17 ICR-Related Values for CCP 2026-2027 (MW)

2026-2027 FCA 17	New England	Maine	Northern New England
Peak Load (50/50) net of BTM PV	27,298	2,126	5,522
Peak Load (90/10) net of BTM PV	29,066	2,244	5,799
Existing Capacity Resources	32,797	3,642	8,308
ICR	31,306		
HQICCs	1,001		
Net ICR (ICR minus HQICCs)	30,305		
Maximum Capacity Limit		4,065	8,595

Notes:

- Details relating to the development of the FCA 17 ICR-Related Values are located at: https://www.iso-ne.com/static-assets/documents/2022/08/a02_proposed_icr_related_values_for_fca17.pptx
- The Existing Capacity Resources value reflects the existing resources with Qualified Capacity for FCA 17 at the time of the ICR calculation and reflects applicable retirements and terminations
- 50/50 and 90/10 peak loads which are net of behind-the-meter photovoltaic (BTM PV) include both transportation and heating electrification forecasts and are shown for informational purposes

Effect of Updated FCA 17 Assumptions on Net ICR

Assumption	2026-2027 FCA 17		2025-2026 FCA 16		Effect on Net ICR (MW)
Tie Benefits	426 MW New York		287 MW New York		-240
	523 MW Maritimes		478 MW Maritimes		
	1,001 MW Quebec (HQICCs)		923 MW Quebec (HQICCs)		
	150 MW Quebec via Highgate		142 MW Quebec via Highgate		
Total MW	2,100		1,830		
	MW	**WAEFORd (%)**	**MW**	**WAEFORd (%)**	
Generation Resources	29,383	6.2%	29,855	6.2%	30
Demand Resources	3,331	3.4%	3,667	2.3%	
Imports	84	0.3%	0	0.0%	
	50/50	**90/10**	**50/50**	**90/10**	
Gross Load Forecast net BTM PV	27,298	29,066	28,025	29,988	-1,130
BTM PV forecast change					-145
Load forecast uncertainty					-165
	MW		**MW**		
Net ICR	30,305		31,645		-1,340

Notes:

- Methodology: Using the model associated with the 2025-2026 FCA 16 ICR calculation, change one assumption at a time and note the change in net ICR
- The impact of each assumption change on Net ICR is not additive since they are evaluated one assumption at a time. The approach would not capture the compound effects of these assumption changes when modeled together
- Generation forced outage assumption is a weighted average (WA) of individual generator's 5-year average Equivalent Forced Outage Rate on Demand (EFORd) and Intermittent Power Resources assumed 100% available

Load Forecast Impact Follow-up from the September 7th RC

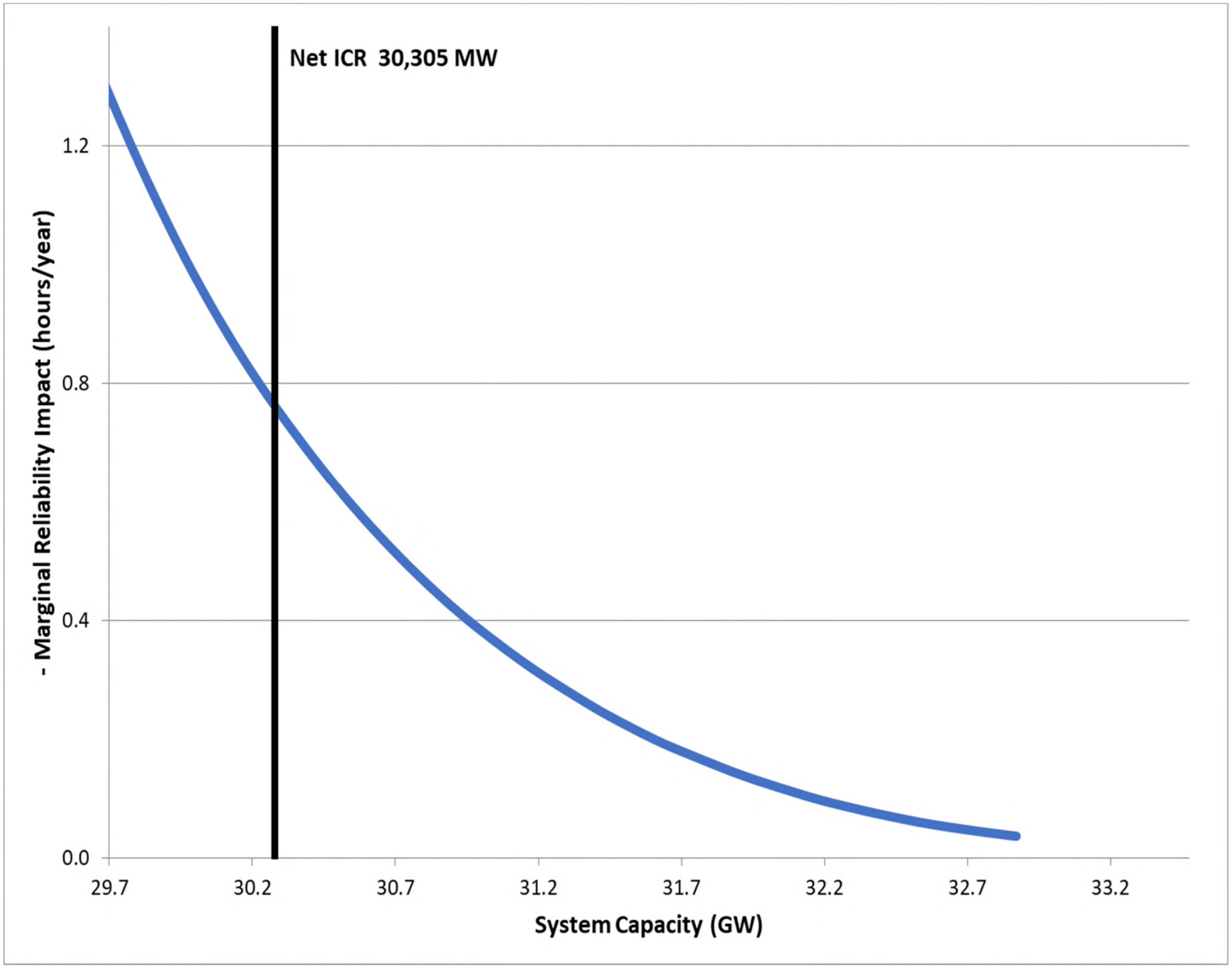
- The methodology used to reconstitute passive demand resources* (PDR), as defined in the Tariff (Section III.12.8), is working as expected, and is effectively capturing a recent trend of PDR taking on fewer obligations in recent FCAs
- The final 2022 load forecast was discussed at the [May 17, 2022 RC meeting]
  - Final PDR reconstitution is illustrated on slide 7
- The recent decreasing PDR trend is likely attributable to a combination of the following factors:
  - Increased expiration of EE in more recent FCA Capacity Commitment Periods
  - Declining claimable lighting savings (i.e., installations of CLFs and LEDs)
    - Due to both market saturation and rising lighting baselines
  - Growing focus on electrification as part of EE programs

* Historically, energy efficiency (EE) has comprised the vast majority of PDR

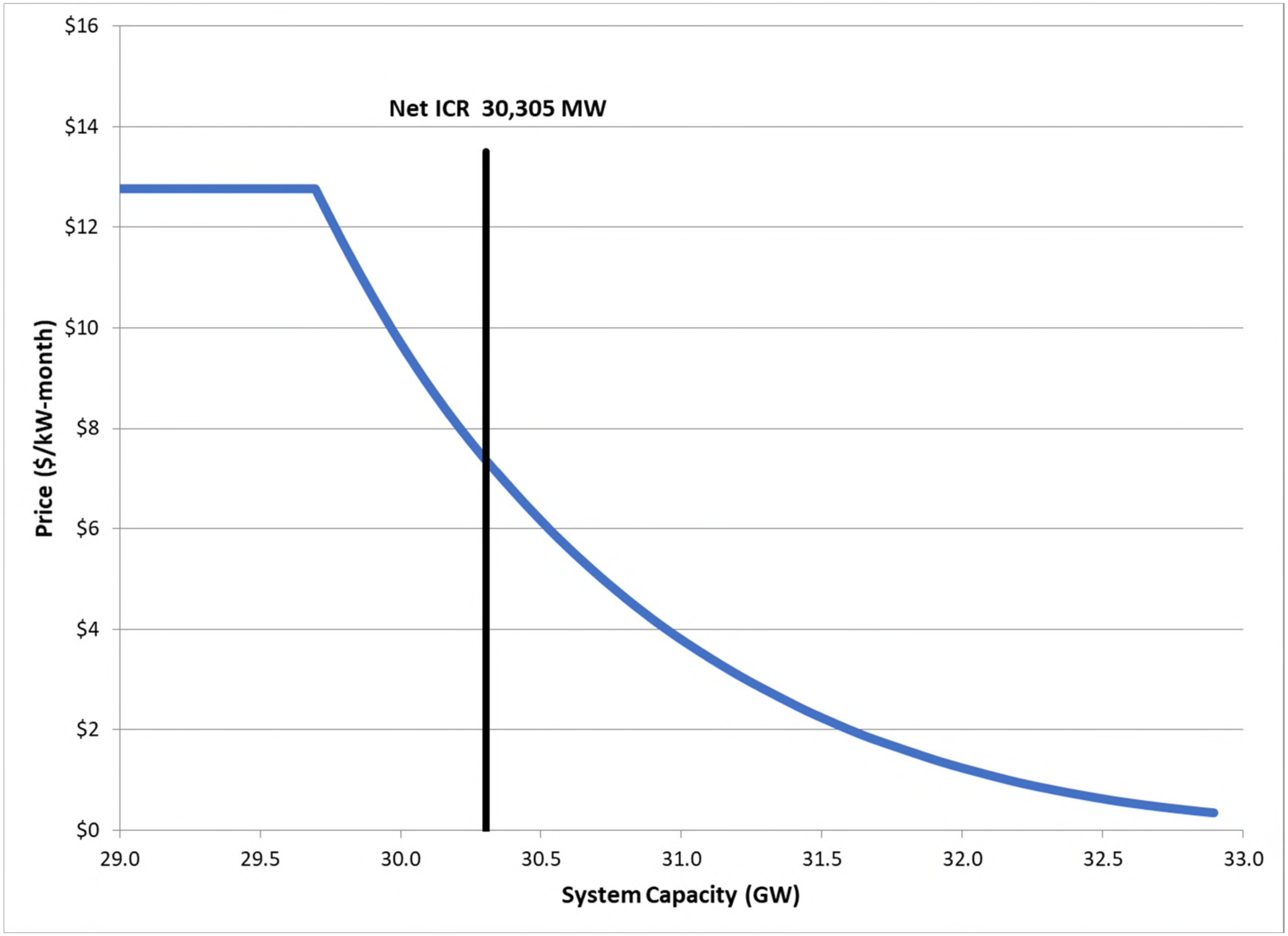
FCA 17 DEMAND CURVES

The FCA 17 MRI based Demand Curve Values are located at: https://www.iso-ne.com/static-assets/documents/2022/08/a02_fca_17_demand_curves.xlsx

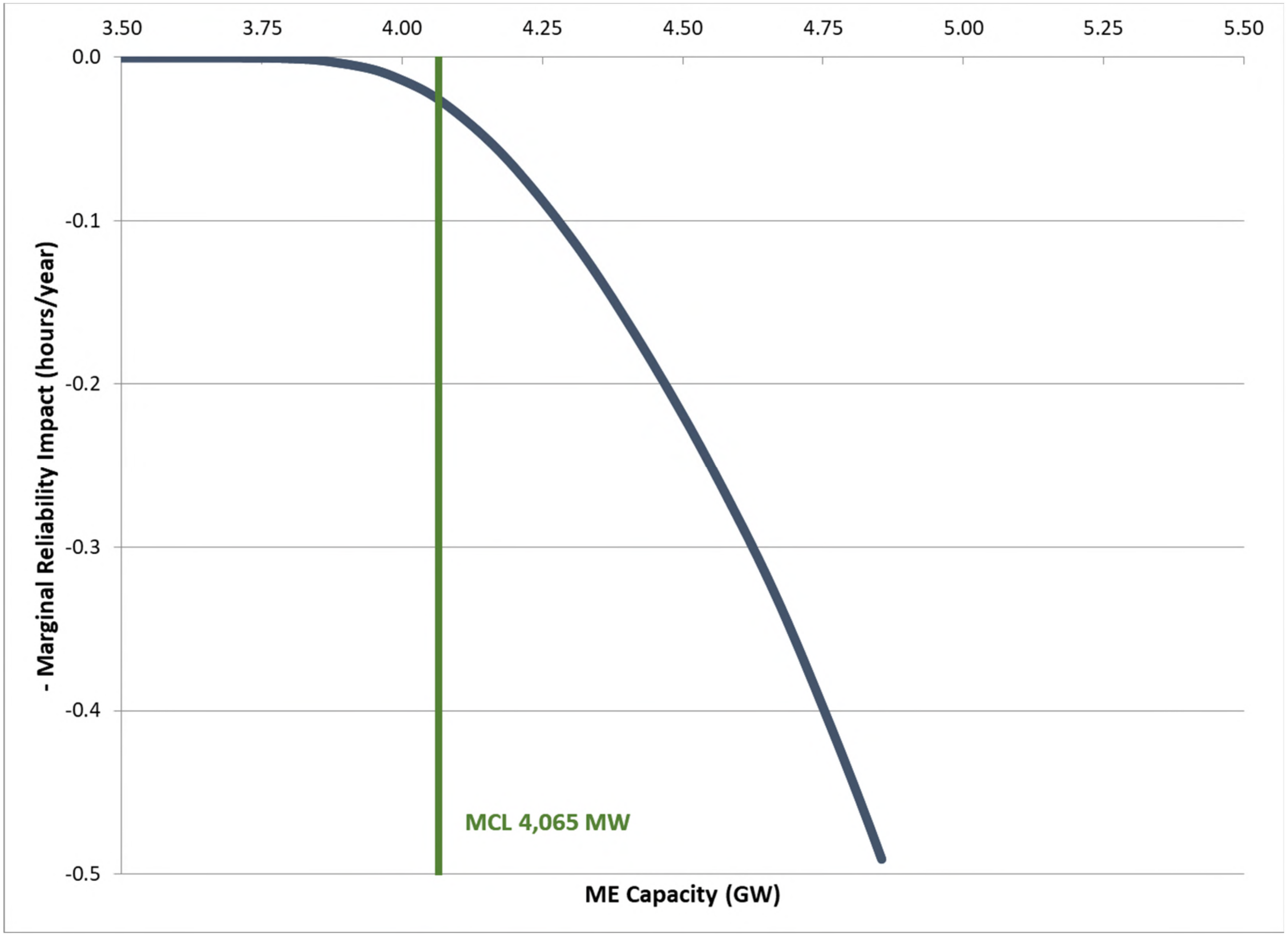
FCA 17 System-wide MRI Curve



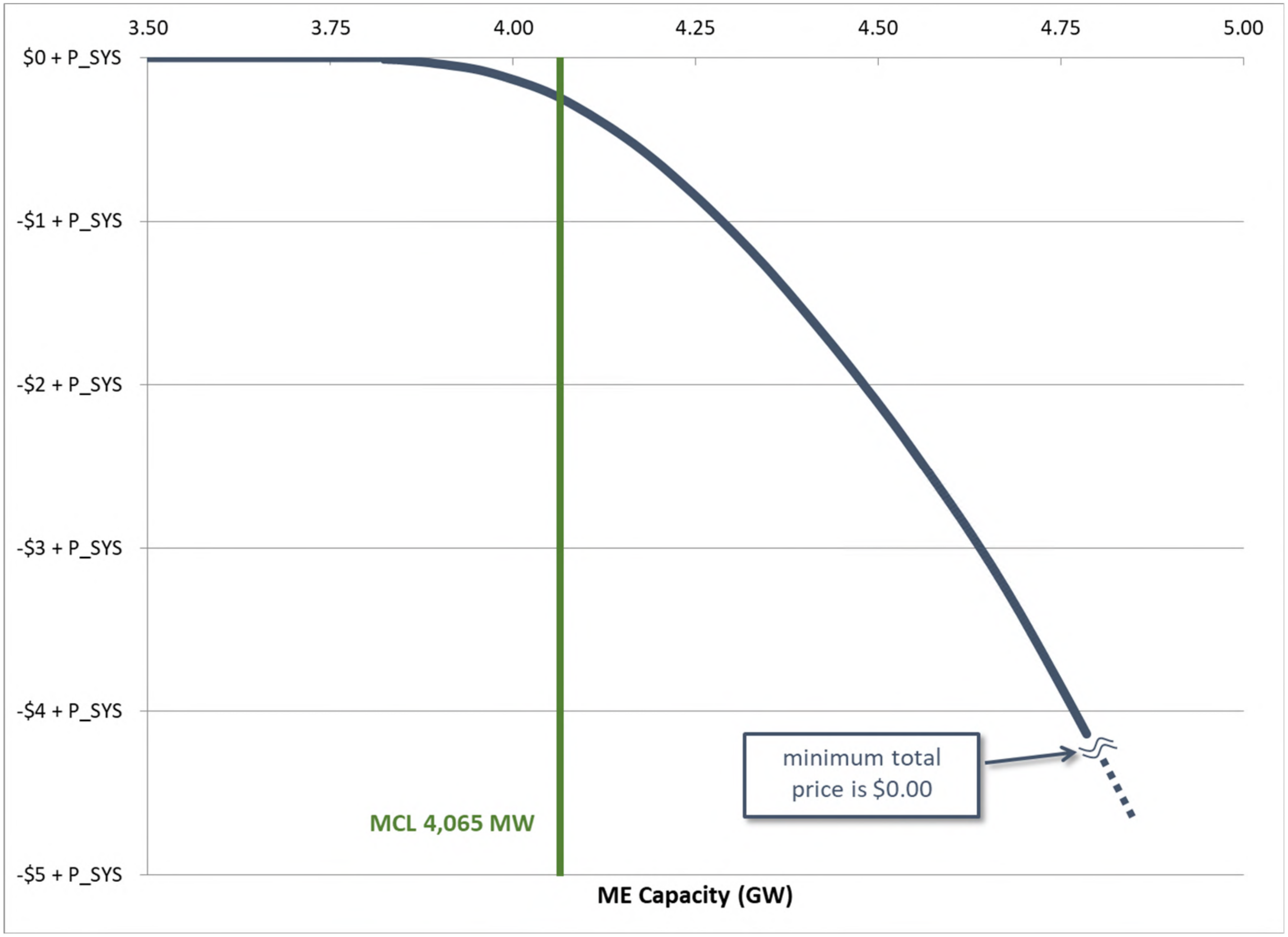
FCA 17 System-wide Demand Curve



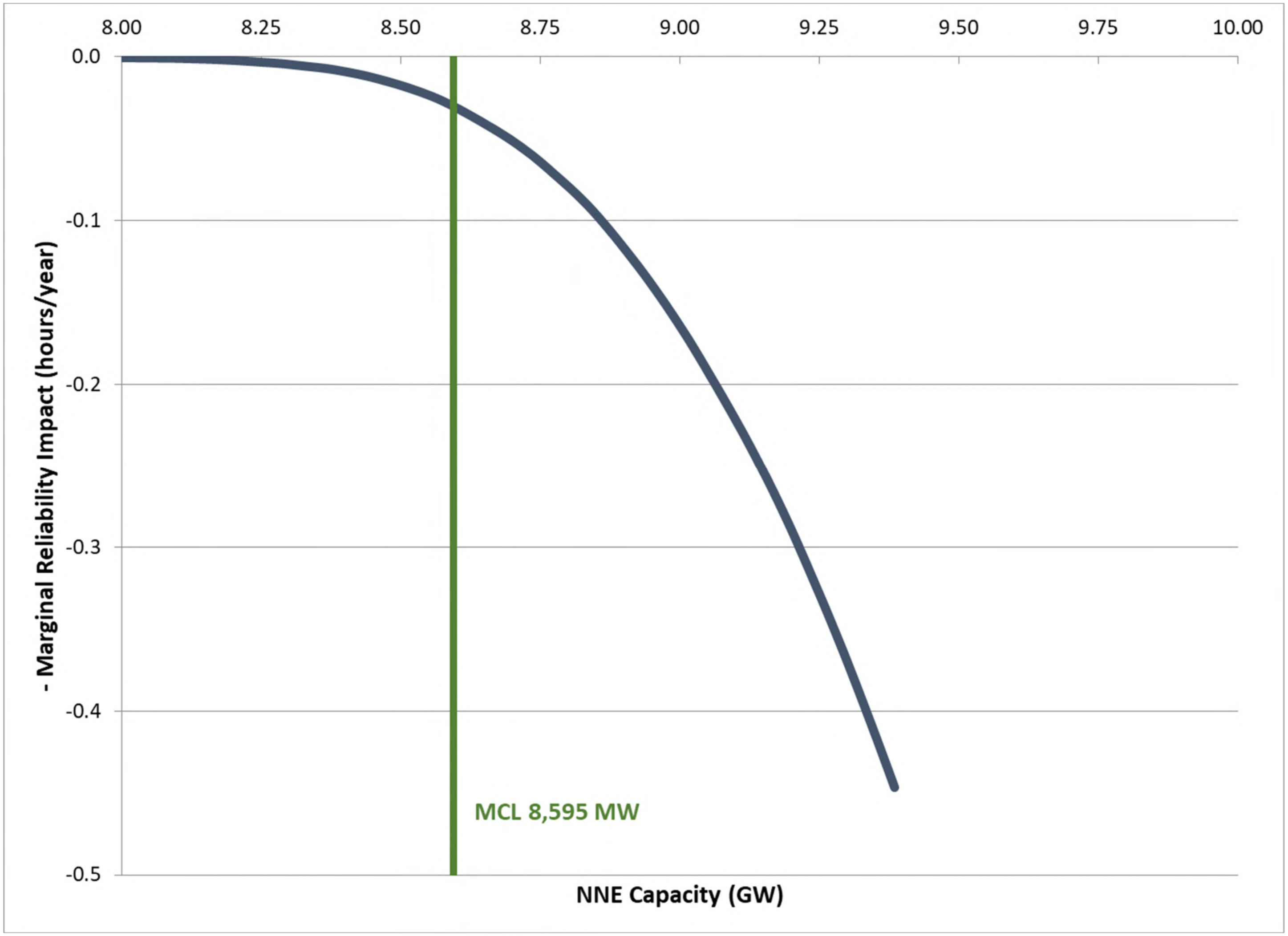
FCA 17 Maine MRI Curve



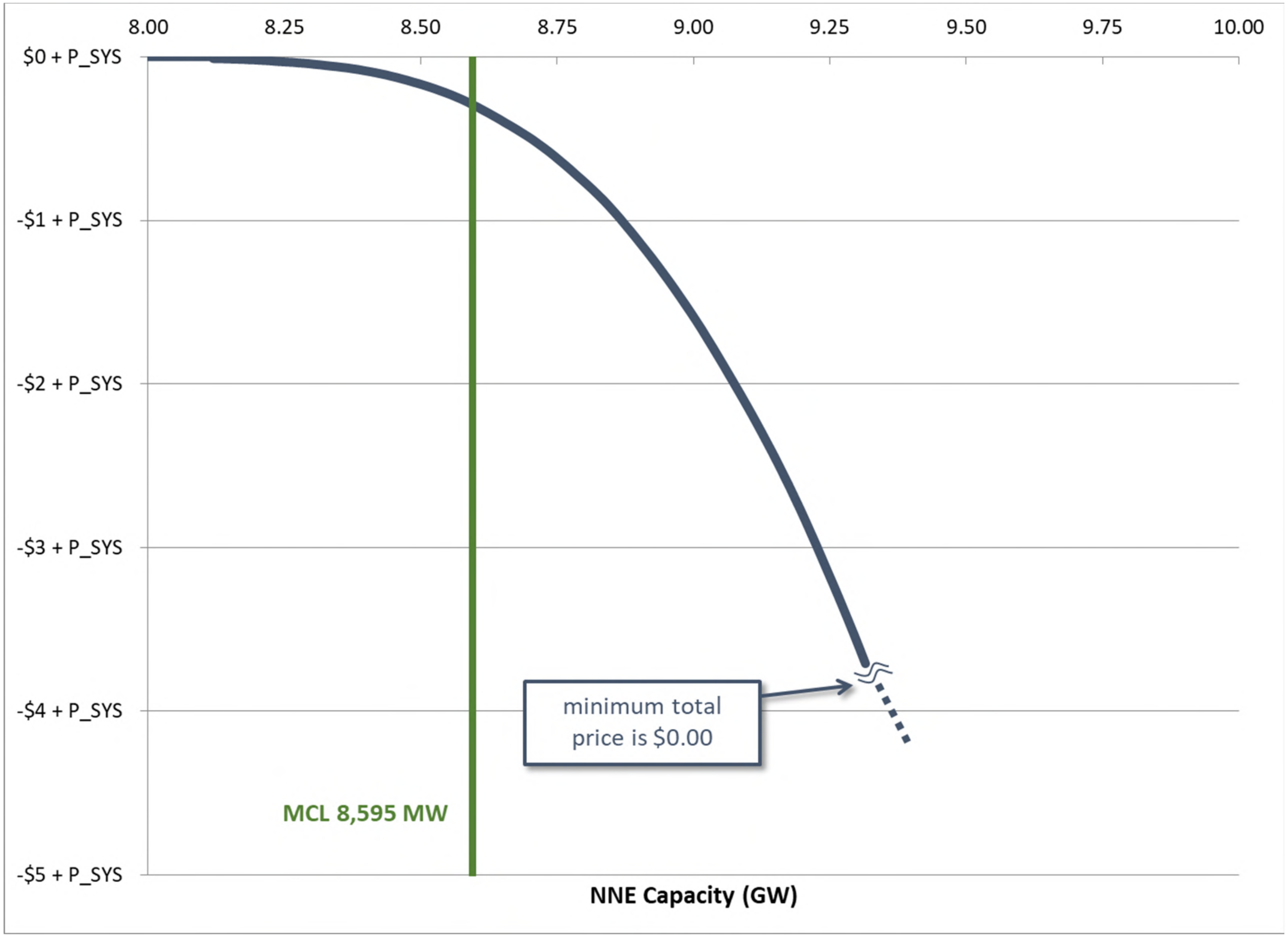
FCA 17 Maine Demand Curve



FCA 17 NNE MRI Curve



FCA 17 NNE Demand Curve



RELIABILITY COMMITTEE MOTIONS
FCA 17 ICR-RELATED VALUES

HQICC Motion

Resolved, the Reliability Committee recommends Participants Committee support for the following megawatt values that represent the Hydro-Québec Interconnection Capability Credit (HQICC) values for the seventeenth Forward Capacity Auction, which is associated with the 2026-2027 Capacity Commitment Period:

2026-2027 Capacity Commitment Period Month	HQICC Values (MW)
June	1,001
July	1,001
August	1,001
September	1,001
October	1,001
November	1,001
December	1,001
January	1,001
February	1,001
March	1,001
April	1,001
May	1,001

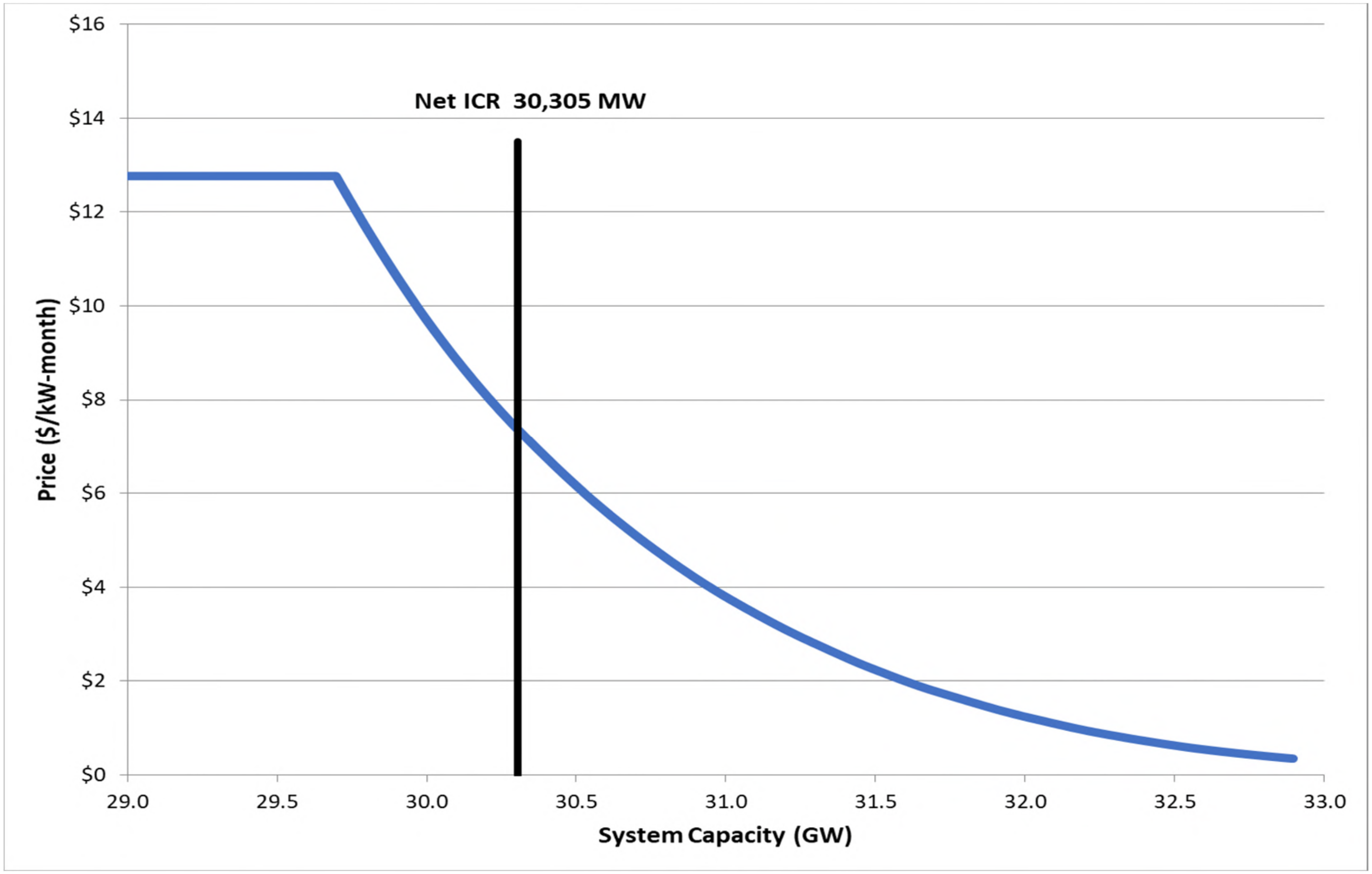
ICR/MCL/Demand Curves Motion

Resolved, the Reliability Committee recommends Participants Committee support for the following megawatt values that represent the New England Installed Capacity Requirement (ICR), Net Installed Capacity Requirement (Net ICR), Maine Maximum Capacity Limit (MCL), Northern New England MCL, and Capacity Demand Curves for the System and Capacity Zones based on the Marginal Reliability Impact (MRI) methodology for the seventeenth Forward Capacity Auction, which is associated with the 2026-2027 Capacity Commitment Period:

	2026-2027 Capacity Commitment Period ICR Values (MW)
Installed Capacity Requirement	31,306
Net Installed Capacity Requirement	30,305
Maine Maximum Capacity Limit	4,065
Northern New England Maximum Capacity Limit	8,595

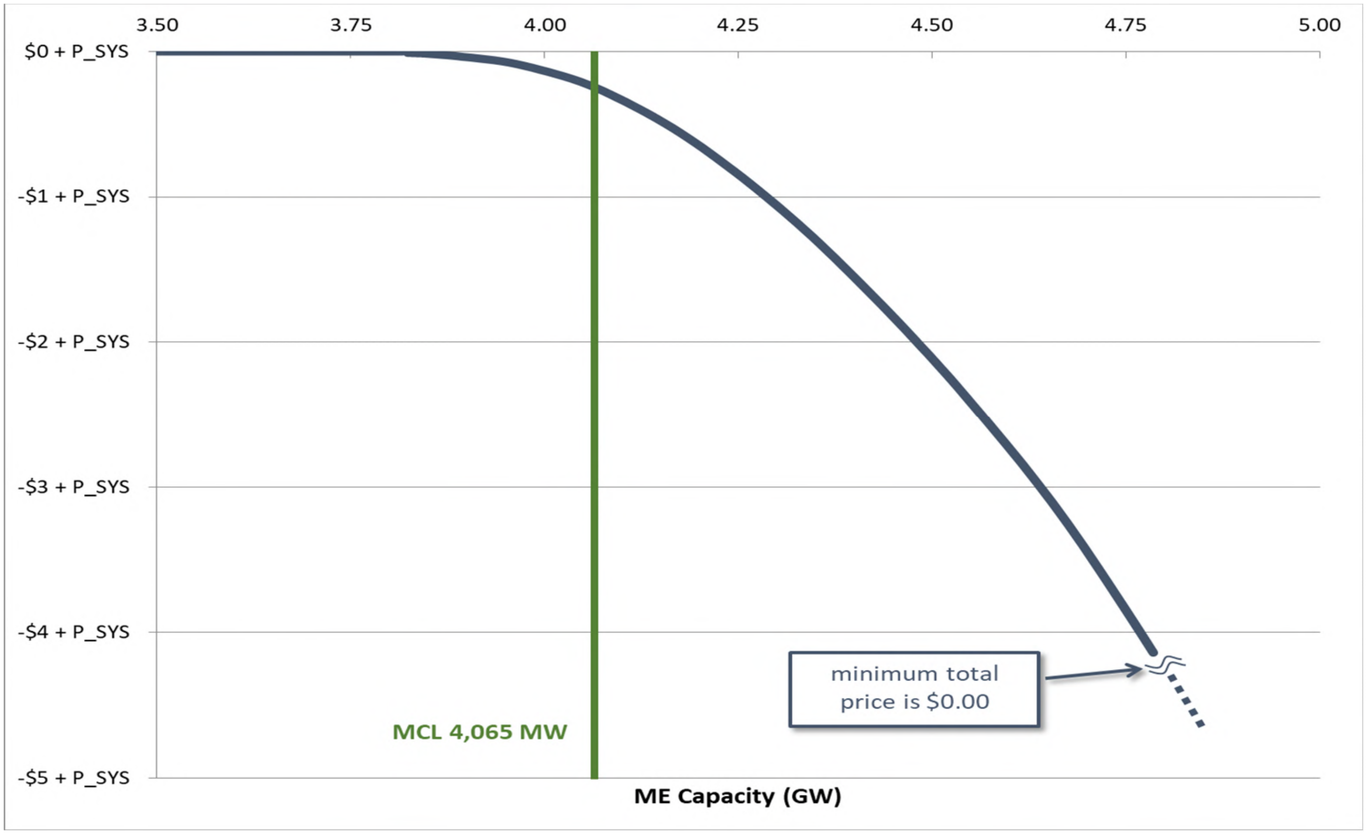
ICR/MCL/Demand Curves Motion, cont.

2026-2027 Capacity Commitment Period System-wide Demand Curve:



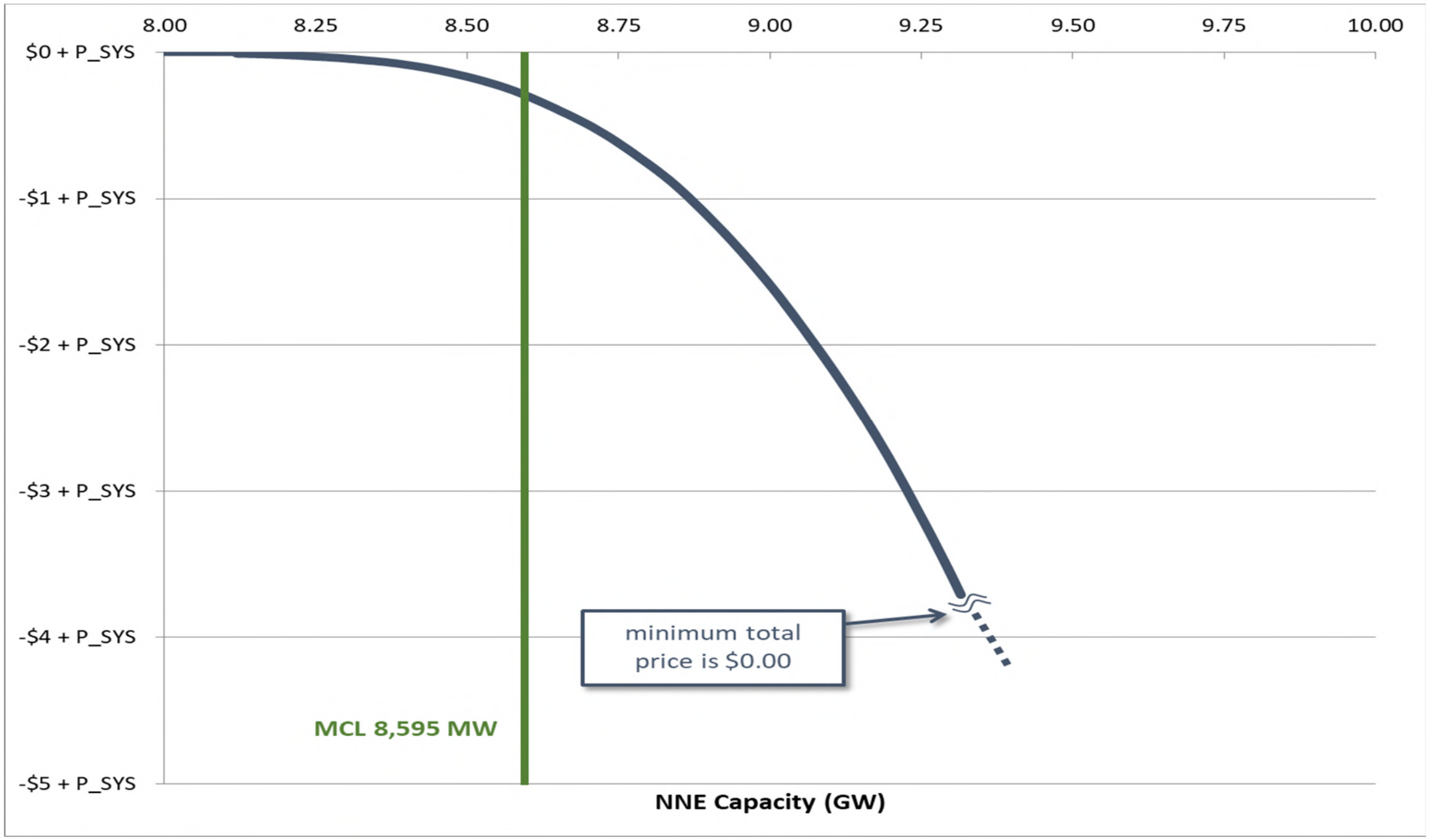
ICR/MCL/Demand Curves Motion, cont.

2026-2027 Capacity Commitment Period Maine Capacity Zone Demand Curve:



ICR/MCL/Demand Curves Motion, cont.

2026-2027 Capacity Commitment Period Northern New England Capacity Zone Demand Curve:



Questions

APPENDIX

*Acronyms for ICR-Related Values**

*Not all acronyms are used in this presentation

Acronyms

- ADCR – Active Demand Capacity Resource
- ALCC – Additional Load Carrying Capability
- APk – Gross peak load net of BTM PV
- ARA – Annual Reconfiguration Auction
- ART – Annual Reconfiguration Transaction
- BTM PV – Behind-the-meter Photovoltaic
- CCP – Capacity Commitment Period
- CDD – Cooling Degree Days
- CELT – Capacity, Energy, Loads and Transmission
- CSC – Cross Sound Cable
- CSO – Capacity Supply Obligation
- CT – Connecticut
- DR – Demand Resource

Acronyms, cont.

- EE – Energy Efficiency
- EFORd – Equivalent Forced Outage Rate on Demand
- FCA – Forward Capacity Auction
- FCM – Forward Capacity Market
- FERC – Federal Energy Regulatory Commission
- HQICCs – Hydro-Quebec Interconnection Capability Credits
- ICR – Installed Capacity Requirement
- ISO – ISO New England
- LRA – Local Resource Adequacy
- LSR – Local Sourcing Requirement
- MARS – Multi-Area Reliability Simulation
- MCL – Maximum Capacity Limit
- MRI – Marginal Reliability Impact
- NEMA – Northeast Massachusetts
- NEPOOL – New England Power Pool
- Net ICR – ICR minus HQICCs

Acronyms, cont.

- NNE – Northern New England
- NPCC – Northeast Power Coordinating Council
- OP-4 – Operating Procedure No. 4, Action During a Capacity Deficiency
- PAC – Planning Advisory Committee
- PC – Participants Committee
- PK – Peak (gross load forecast)
- PSPC – Power Supply Planning Committee
- RC – Reliability Committee
- RI – Rhode Island
- SEMA – Southeast Massachusetts
- SENE – Southeast New England
- SWCT – Southwest Connecticut
- TSA – Transmission Security Analysis
- VR – Voltage Reduction
- WEFORd – Weighted Equivalent Forced Outage Rated on Demand

memo

To: Participants Committee

From: Nicholas Gangi, Secretary, Reliability Committee

Date: September 21, 2022

Subject: Actions of the Reliability Committee from the September 20, 2022 Meeting

This memo is to notify the Participants Committee ("PC") of the actions taken by the Reliability Committee ("RC") at its September 20, 2022 meeting of the Reliability Committee. A quorum was established.

(Agenda Item 2.0) (66.67% Vote) Meeting Minutes

ACTION: APPROVED

Resolved, that the Reliability Committee approves the minutes of the following RC meeting as distributed to the committee for the September 20, 2022 meeting together with any changes agreed to at the meeting and such non-substantive changes as may be agreed to after the meeting by the Chair and Vice-Chair of the Reliability Committee:

- August 16-17, 2022 RC/TC Summer Meeting

Based on a voice vote, the motion passed with none opposed and no abstentions.

(Agenda Item 4.1) (66.67% Vote) 100 MW Orrington II BESS Project (QP 1015)

ACTION: APPROVED

Resolved, the Reliability Committee recommends that ISO New England Inc. determine that implementation of the 100 MW Orrington II BESS Project (QP 1015) - Proposed Plan Applications (PPAs) JUP-22-G03 and JUP-22-T03 from Jupiter Power (JUP) and VP-22-T05 from Versant Power (VP) as detailed in their August 16, 2022 and August 29, 2022 transmittals to ISO New England and distributed to the committee for the September 20, 2022 meeting, together with a recommendation letter from ISO New England, will not have a significant adverse effect on the stability, reliability or operating characteristics of the transmission

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841
413-535-4173
ngangi@iso-ne.com

receiving regional support and inclusion in Pool-Supported PTF Rates, the requested $24.992 million as eligible for Pool-Supported PTF cost recovery and with none of the costs associated with such upgrades being considered Localized Costs.

Based on a voice vote, the motion passed with none opposed and no abstentions.

(Agenda Item 7.0) (60.0% Vote) HQICCs and Installed Capacity Requirement and Related Values for Capacity Commitment Period (CCP) 2026/2027 (FCA 17)

ACTION: APPROVED

Resolved, the Reliability Committee recommends Participants Committee support for the following megawatt values that represent the Hydro-Québec Interconnection Capability Credit (HQICC) values for the seventeenth Forward Capacity Auction, which is associated with the 2026-2027 Capacity Commitment Period:

2026-2027 Capacity Commitment Period Month	HQICC Values (MW)
June	1,001
July	1,001
August	1,001
September	1,001
October	1,001
November	1,001
December	1,001
January	1,001
February	1,001
March	1,001
April	1,001
May	1,001

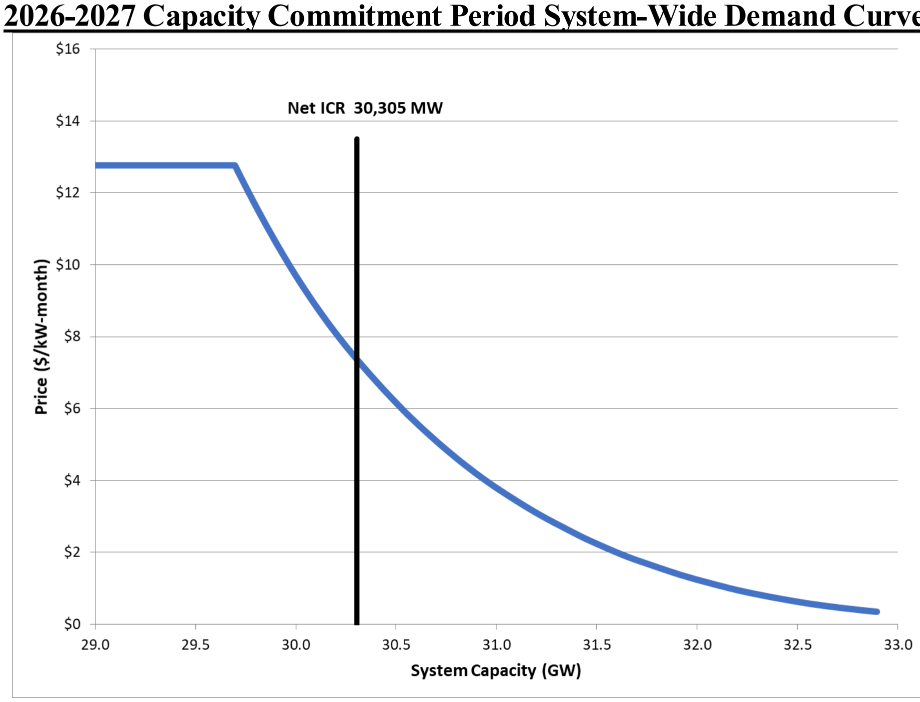
Based on a roll call vote, the motion passed with a vote of 63.95% in favor. The individual Sector votes were Generation (8.35% in favor, 8.35% opposed, 2 abstentions), Transmission (16.70% in favor, 0.00% opposed, 0 abstentions), Supplier (0.00% in favor, 16.70% opposed, 8 abstentions), Publicly Owned Entity (16.70% in favor, 0.00% opposed, 0 abstentions), Alternative Resources (5.50% in favor, 11.00% opposed, 1 abstention), and End User (16.70% in favor, 0.00% opposed, 1 abstention).

ACTION: APPROVED

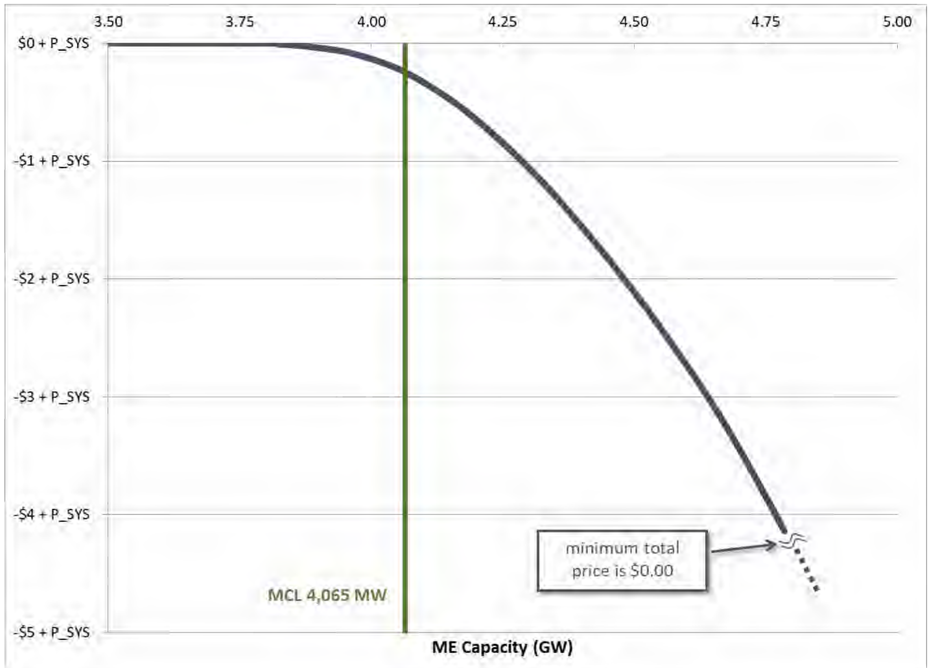
Resolved, the Reliability Committee recommends Participants Committee support for the following megawatt values that represent the New England Installed Capacity Requirement (ICR), Net Installed Capacity Requirement (Net ICR), Maine Maximum Capacity Limit (MCL), Northern New England MCL, and Capacity Demand Curves for the System and Capacity Zones based on the Marginal Reliability Impact (MRI) methodology for the seventeenth Forward Capacity Auction, which is associated with the 2026-2027 Capacity Commitment Period:

	2026-2027 Capacity Commitment Period ICR Values (MW)
Installed Capacity Requirement	31,306
Net Installed Capacity Requirement	30,305
Maine Maximum Capacity Limit	4,065
Northern New England Maximum Capacity Limit	8,595

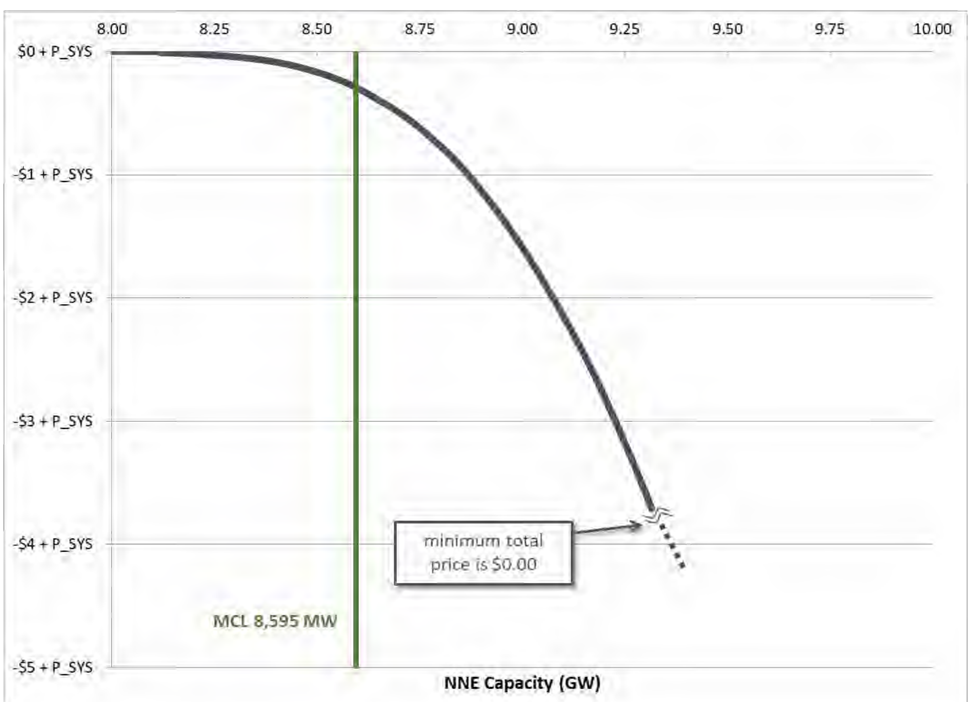
2026-2027 Capacity Commitment Period System-Wide Demand Curve:



2026-2027 Capacity Commitment Period Maine Capacity Zone Demand Curve:



2026-2027 Capacity Commitment Period Northern New England Capacity Zone Demand Curve:



Based on a roll call vote, the motion passed with a vote of 63.95% in favor. The individual Sector votes were Generation (8.35% in favor, 8.35% opposed, 2 abstentions), Transmission (16.70% in favor, 0.00% opposed, 0 abstentions), Supplier (0.00% in favor, 16.70% opposed, 8 abstentions), Publicly Owned Entity (16.70% in favor, 0.00% opposed, 0 abstentions), Alternative Resources (5.50% in favor, 11.00% opposed, 1 abstention), and End User (16.70% in favor, 0.00% opposed, 1 abstention).

MEMORANDUM

TO: NEPOOL Participants Committee Members and Alternates

FROM: Eric Runge and Rosendo Garza, NEPOOL Counsel

DATE: September 29, 2022

RE: ISO-NE's Storage as a Transmission-Only Asset (SATOA) Proposal

---

At the October 6, 2022 Participants Committee meeting, you will be asked to vote on a proposal to permit energy storage devices to participate as transmission-only assets, referred to herein as the "SATOA Proposal." Because the proposal revises Section I of the Tariff, Section II of the Open Access Transmission Tariff (OATT), the Transmission Operating Agreement (TOA), and Market Rule 1, the Transmission Committee (TC) and the Markets Committee (MC) vetted the SATOA Proposal. As more fully explained below, both the TC and MC have recommended that the Tariff changes under their jurisdiction be approved by the Participants Committee. Because there were many abstentions and some opposition to the SATOA Proposal by members of both Committees, this item has been included in the discussion agenda for the October 6 Participants Committee meeting.

This memorandum summarizes the SATOA Proposal and the stakeholder process to date, and includes the following materials:

- Attachment A1: Proposed Section I sheets
- Attachment A2: Proposed OATT sheets
- Attachment A3: Proposed TOA sheets
- Attachment A4: Proposed Market Rule 1 sheets
- Attachment B1: ISO-NE's TC voting memorandum (dated Aug. 10, 2022)
- Attachment B2: ISO-NE's MC voting memorandum (dated Sep. 7, 2022)
- Attachment C1: ISO's PowerPoint presentation provided at the August 16, 2022 TC meeting
- Attachment C2: ISO's PowerPoint presentation provided at the September 13–14, 2022 MC meeting

OVERVIEW OF THE SATOA PROPOSAL

The SATOA Proposal was developed by the ISO in response to some stakeholders' request to permit energy storage devices[1] to be considered as transmission-only assets. The ISO explained that it had two design principles in developing its proposal: (1) introduction of a SATOA cannot compromise reliability by inserting unmanageable operating burdens into the

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[1] As the ISO explained, the proposal is technology neutral. *See* Att. C1 at Slide 4.

control room; and (2) a SATOA cannot have a significant impact on the markets. The ISO proposed three requirements for any SATOA: (1) it must or will be connected to a Pool Transmission Facility (PTF) at a voltage level of 115KV or higher; (2) the ISO must approve the energy storage device for inclusion in the Regional System Plan (RSP) and RSP Project List as both a regulated transmission solution and a PTF pursuant to the regional system planning process in the OATT's Attachment K; and (3) the energy storage device can receive energy only from the PTF and store the energy for later injection to the PTF.

The SATOA Proposal provides that a SATOA may be evaluated and selected to address the needs of the system as identified in a Needs Assessment or Public Policy Transmission Study, among other things. The proposal also delineates the SATOA's evaluation and selection criteria. As explained in the ISO's materials, the SATOA would only operate, i.e., charge or discharge, under specified conditions to avoid or mitigate load-shedding when all available market actions have been exhausted.[2] The conditions the ISO could direct a SATOA to discharge will be detailed in operating procedures.[3]

As proposed, SATOAs would only be settled in the Real-Time Energy Market and not participate in any other settlements, making them ineligible to receive payments or charges related to Day-Ahead Energy, reserves, black start, or capacity (among others). The SATOA's energy produced while discharging or consumed while charging will be paid or charged at the Real-Time Locational Marginal Price. Thus, a SATOA will have a separate pricing node (or p-node) to minimize market impacts. The ISO indicated that no other market activity will be permitted on the SATOA's p-node.

Section I of the Tariff Additions

As part of the package of reforms, the SATOA Proposal would include two new defined terms in Section I, namely "Real-Time SATOA Obligation" and "Storage as Transmission-Only Asset." The proposed definitions can be reviewed in <u>Attachment A1</u>.

OATT and TAO Revisions

The SATOA Proposal would add a new subsection to Section II of the OATT. Specifically, the new subsection would detail the treatment of SATOAs, such as how the ISO would evaluate and select SATOAs, when a SATOA would operate, and the transmission service charges associated with SATOA operations. The remaining revisions proposed to Section II, including to several schedules and attachments, and to the TOA would be conforming changes.

More details concerning the changes to the OATT and TOA can be reviewed in <u>Attachment A2</u>, <u>Attachment A3</u>, <u>Attachment B1</u>, and <u>Attachment C1</u>.

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[2] *See also* <u>Att. A2</u>, Proposed Section II.51.2 (identifying the six reasons a SATOA would operate).

[3] The ISO indicated that it expects to revise aspects of Operating Procedures 4, 7, and 19, which will be brought through the stakeholder process at a later time. <u>Att. C2</u> at Slide 6.

Market Rule 1 Changes

The SATOA Proposal also includes revisions to the energy settlement rules in Market Rule 1. Specifically, this package of revisions proposes a new section to define a SATOA's participation in the markets, includes changes to ensure that real-time supply and demand are addressed when determining a Real-Time Locational Adjusted Net Interchange, adds new language to ensure that each Participant Transmission Owner accounts for a SATOA's charging and discharging, and provides metering requirements for SATOAs.

Attachment A4, Attachment B2, and Attachment C2 offer additional explanation to the proposed changes to Market Rule 1.

STAKEHOLDER PROCESS TO DATE

Because the SATOA Proposal included changes to Section I, Section II, the TOA, and Market Rule 1, the TC and MC reviewed and offered input to that Proposal. Additional information is provided herein regarding the outcome of each of the Committees' respective deliberations.

TC Review (Agenda Item 6.a)

The TC considered and provided feedback on the SATOA Proposal over the course of five meetings. At its August 17 meeting, the TC voted to recommend Participants Committee support for the SATOA-related revisions subject to its review, with 80.19% in favor and none opposed.[4] Although there was no opposition, there were numerous abstentions and some concerns raised generally about the potential for market impacts from the use of SATOAs.

MC Review (Agenda Item 6.b)

The MC considered and provided feedback on the SATOA Proposal over the course of three meetings. At its September 13, 2022 meeting, the MC considered the SATOA Proposal's revisions to Section I and Market Rule 1. Some members expressed concerns related to the potential for market impacts from use of SATOAs, but no amendments were offered. The motion to recommend Participants Committee support passed by show of hands vote, with four members opposed.[5]

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[4] Based on a roll call vote, the motion passed with a vote of 80.19% in favor. The individual Sector votes were Generation (19.81% in favor, 0.00% opposed, 2 abstentions), Transmission (19.81% in favor, 0.00% opposed, 0 abstentions), Supplier (19.81% in favor, 0.00% opposed, 3 abstentions), Publicly Owned Entity (0.00% in favor, 19.81% not in favor, 49 abstentions), Alternative Resources (19.58% in favor, 0.00% opposed, 1 abstention), and End User (1.17% in favor, 0.00% opposed, 1 abstention).

[5] At the September 13 MC meeting, the following oppositions and abstentions were recorded: two oppositions and two abstentions in the Generation Sector; two oppositions and four abstentions in the Supplier Sector; two abstentions in the Alternative Resources Sector; and three abstentions in the Publicly Owned Entity Sector.

Participants Committee Review

The SATOA Proposal's changes to Section I, Section II, including the schedules and attachments, and the TOA that the TC recommended the Participants Committee support require a 66.67% Vote. The revisions to Section I.2.2 and Market Rule 1 that the MC recommended the Participants Committee support require a 60% Vote. Accordingly, the following forms of resolutions may be used for Participants Committee action, voted either individually or in a single combined vote:

> RESOLVED, that the Participants Committee supports the SATOA Proposal as reflected in revisions to Section I, Section II of the Transmission, Markets and Services Tariff, and the Transmission Operating Agreement, as circulated to this Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Transmission Committee.
>
> FURTHER RESOLVED, that the Participants Committee supports the SATOA Proposal as reflected in revisions to Section I.2.2 and Market Rule 1, as circulated to this Committee in advance of this meeting, together with [any changes agreed to by the Participants Committee at this meeting and] such non-substantive changes as may be approved by the Chair and Vice-Chair of the Markets Committee.

I.2 Rules of Construction; Definitions

I.2.1. Rules of Construction:

In this Tariff, unless otherwise provided herein:

(a) words denoting the singular include the plural and vice versa;

(b) words denoting a gender include all genders;

(c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;

(d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;

(e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;

(f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;

(g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;

(h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;

(i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;

(j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or other late payment or charge, provided such payment is made on such next succeeding Business Day);

(k) words such as "hereunder," "hereto," "hereof" and "herein" and other words of similar import shall, unless the context requires otherwise, refer to this Tariff as a whole and not to any particular article, section, subsection, paragraph or clause hereof; and a reference to "include" or "including" means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of *ejusdem generis* shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned.

I.2.2. Definitions:

In this Tariff, the terms listed in this section shall be defined as described below:

Active Demand Capacity Resource is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward Capacity Market to fulfill a Market Participant's Capacity Supply Obligation pursuant to Section III.13 of Market Rule 1.

Actual Capacity Provided is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 of Market Rule 1.

Actual Load is the consumption at the Retail Delivery Point for the hour.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Real-Time Loss Revenue Charges or Credits are defined in Section III.3.2.1(m) of Market Rule 1.

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

Real-Time Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.7A of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Reserve Quantity For Settlement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as described in Section III.1.7.19 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of Market Rule 1.

Real-Time SATOA Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Synchronous Condensing NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or a Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses). A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load. A Network Customer's Monthly Regional Network Load shall be calculated in accordance with Section II.21.2 of the OATT.

remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Station-level Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Storage as Transmission-Only Asset (SATOA) is electric storage equipment that: (1) is connected to or to be connected to Pool Transmission Facilities in the New England Transmission System at a voltage level of 115 kV or higher; (2) the ISO approved to be included in the Regional System Plan and RSP Project List as a regulated transmission solution and Pool Transmission Facility pursuant to the regional system planning processes in Attachment K of the OATT; and (3) is capable of receiving energy only from the Pool Transmission Facilities and storing the energy for later injection to the Pool Transmission Facilities.

Storage DARD is a DARD that participates in the New England Markets as part of an Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Table of Contents

II.A. COMMON SERVICE PROVISIONS

II.1 Definitions

II.2 Purpose of This OATT

II.3 Market Rule 1

II.4 Ancillary Services

II.4.1 Scheduling, System Control and Dispatch Service

II.4.2 Reactive Supply and Voltage Control Service

II.4.3 Regulation and Frequency Response Service

II.4.4 Energy Imbalance Service

II.4.5 Ten Minute Spinning Reserve Service

II.4.6 Ten-Minute Non-Spinning Reserve Service

II.4.6A Thirty-Minute Operating Reserve Service

II.4.7 Blackstart Service

II.4.8 Generator Imbalance Service

II.4.9 Special Constraint Resource Service

II.5 Open Access Same-Time Information System (OASIS)

II.6 Local Furnishing and Other Tax-Exempt Bonds

II.6.1 Transmission Owners That Own Facilities Financed by Local Furnishing or Other Tax-Exempt Bonds

II.6.2 Alternative Procedures for Requesting Transmission Service -Local Furnishing Bonds

II.6.3 Alternative Procedures for Requesting Transmission Service – Other Tax-Exempt Bonds

II.7 Reciprocity

II.8 Billing and Invoicing; Accounting

II.8.1 Billing Procedure

II.8.2 Invoicing

II.8.3 Interest on Unpaid Balances

II.8.4 Customer Default

II.8.5 Study Costs and Revenues

II.8.6 Billing and Invoicing For Other Services and Transactions

II.45 Grandfathered Agreements

II.45.1 MEPCO Grandfathered Transmission Service Agreements (MGTSAs) over the New Brunswick/New England Interface

II.G. SYSTEM PLANNING, ADDITIONS AND MODIFICATIONS

II.46 General

II.47 Interconnection Procedures and Requirements

II.47.1 Interconnection of Generating Unit Under the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard

II.47.2 Generator Interconnection Proposal Review

II.47.3 Generator Right to Interconnection

II.47.4 Compliance with Schedule 11

II.47.5 Interconnection of Elective Transmission Upgrades

II.48 Interconnection Service Capabilities

II.48.1 Establishing CNR Capability and CNI Capability

II.48.2 Establishing NR Capability and NI Capability

II.48.3 Reductions to CNR Capability and CNI Capability

II.48.4 Reductions to NR Capability and NI Capability

II.H. OTHER TRANSMISSION PROVISIONS

II.49 Definition of PTF

II.50 Additions to or Upgrades of PTF

II.51 Treatment of SATOA

II.51.1 Evaluation and Selection of a SATOA

II.51.2 Operation of SATOAs

II.51.3 Transmission Service Associated with SATOA Operation

SCHEDULE 1 SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

SCHEDULE 1 IMPLEMENTATION RULE

APPENDIX A TO SCHEDULE 1 IMPLEMENTATION RULE BOSTON EDISON COMPANY SCADA

APPENDIX B TO SCHEDULE 1 IMPLEMENTATION RULE CENTRAL MAINE POWER COMPANY LOCAL CONTROL CENTER

SCHEDULE 2 REACTIVE SUPPLY AND VOLTAGE CONTROL SERVICE

SCHEDULE 3 REGULATION AND FREQUENCY RESPONSE SERVICE

SCHEDULE 4 ENERGY IMBALANCE SERVICE

SCHEDULE 5 TEN-MINUTE SPINNING RESERVE SERVICE

II.49 Definition of PTF

PTF or Pool Transmission Facilities are the transmission facilities owned by PTOs, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the TOA, rated 69 kV or above required to allow energy from significant power sources to move freely on the New England Transmission System, and include:

1. All transmission lines and associated facilities owned by PTOs rated 69 kV and above, except for lines and associated facilities that (i) were not built as Public Policy Transmission Upgrades and (ii) contribute little or no parallel capability to the PTF. The following do not constitute PTF:

    (a) Unless they were built as part of a Public Policy Transmission Upgrade,

    i. Those lines and associated facilities which are required to serve local load only,

    ii. Generator leads, which are defined as radial transmission from a generation bus to the nearest point on the PTF; or

    iii. Lines that are normally operated open.

    (b) Lines and associated facilities that are classified as MTF or OTF.

2. All Public Policy Transmission Upgrades that are comprised of transmission lines rated 115 kV or above, and associated facilities rated 115kV or above, owned by PTOs, and identified pursuant to Attachment K to the OATT shall constitute PTF.

3. Parallel linkages in network stations owned by PTOs (including substation facilities such as transformers, circuit breakers and associated equipment) interconnecting the lines which constitute PTF.

4. If a PTOs with significant generation in its transmission and distribution system (initially 25 MW) is connected to the New England Transmission System and none of the transmission facilities owned by the PTO qualify to be included in PTF as defined in (1), (2) and (3) above, then such PTO's connection to PTF will constitute PTF if both of the following requirements are met for this connection:

(a) The connection is rated 69 kV or above.

(b) The connection is the principal transmission link between the PTO and the remainder of the PTF network.

5. Rights of way and land owned by PTOs required for the installation of facilities that constitute PTF under (1), (2), (3) or (4) above.

The ISO shall review at least annually the status of transmission lines and associated facilities and determine whether such facilities constitute PTF and shall prepare and keep current a schedule or catalogue of PTF facilities.

The following examples indicate the intent of the above definitions:

Unless they were built as part of a Public Policy Transmission Upgrade, radial tap lines to local load are excluded.

Lines which loop, from two geographically separate points on the PTF, the supply to a load bus from the PTF are included.

Lines which loop, from two geographically separate points on the PTF, the connections between a generator bus and the PTF are included.

Radial connections or connections from a generating station to a single substation or switching station on the PTF are excluded, unless the requirements of paragraph (2) or (4) above are met.

Transmission facilities owned or supported by a Related Person of a PTO which are rated 69 kV or above and are required to allow Energy from significant power sources to move freely on the New England Transmission System shall also constitute PTF provided (i) such Related Person files with the ISO its consent to such treatment; and (ii) the ISO determines that treatment of the facilities as PTF will facilitate accomplishment of the ISO's objectives. If such facilities constitute PTF pursuant to this paragraph, they shall be treated as "owned" or "supported," as applicable, by a PTO for purposes of this OATT and the

II.50 Additions to or Upgrades of PTF

The possible need for an addition to or upgrade of PTF may be identified in connection with the planning process of Attachment K of this OATT, an application or request for service under this OATT, or a request for the installation of or material change to a generation or transmission facility, or may be separately identified by an ISO committee under the Participants Agreement, a Market Participant or the ISO. In such cases, a study, if necessary, to assess available transfer capability and, if necessary, a System Impact Study and a Facility Study, shall be performed by the affected PTO(s) in whose Local Network(s) the addition or upgrade would or might be effected or their designee(s), or the ISO, in the case of a System Impact Study, or the ISO's designee(s), with review of the study by the ISO if it does not perform the study. Studies to assess available transfer capability and System Impact Studies and Facilities Studies shall be conducted, as appropriate, in accordance with any affected PTO's Local Service Schedule of this OATT, or in accordance with the applicable methodology specified in Attachments C and D to this OATT, and the provisions of the Local Service Schedules to this OATT or the applicable provisions of Attachments I and J to this OATT shall apply, as appropriate, with respect to the payment of the costs of the study and the other matters covered thereby.

Responsibility for the costs of new PTF or any modification or other upgrade of PTF shall be determined, to the extent applicable, in accordance with Parts II.B and II.C and Schedules 11 and 12 to this OATT, including without limitation the provisions relating to responsibility for the costs of new PTF or modifications or other upgrades to PTF exceeding regional system, regulatory or other public requirements set forth in Section (3)(b) of Schedule 11 and Schedule 12 to this OATT.

II.51 Treatment of SATOA

A SATOA may only be evaluated and selected as a regulated transmission solution to address the needs of the system identified in a Needs Assessment or Public Policy Transmission Study in accordance with the regional system planning processes and requirements in Attachment K of the OATT, this Section II.51, and any other applicable requirements in the Tariff. A SATOA selected as the preferred solution to address an identified system need shall be classified as a Regional Benefit Upgrade or Public Policy Transmission Upgrade and meet the definition, criteria, and other requirements applicable to such upgrades.

II.51.1 Evaluation and Selection of a SATOA: In addition to the criteria, factors, and requirements in Attachment K of the OATT for evaluating transmission solutions and identifying a preferred solution, the ISO shall consider the following when evaluating whether a SATOA is the appropriate preferred solution to address needs of the system identified in the regional system planning process:

(a) the ability of the proposed SATOA to address the applicable system need in all hours that the need is determined to exist;

(b) the ability of the proposed SATOA to provide or absorb reactive power regardless of whether the SATOA is injecting or consuming real power;

(c) the aggregate amount of SATOAs in New England, which shall be limited to 300 MW of charging capability and 300 MWs of discharging capability;

(d) the total amount of SATOAs at a substation, which shall be limited to 30 MW of charging capability and 30 MW of discharging capability;

(e) a SATOA shall not be evaluated or selected as the preferred solution to address violations of IROL(s) or system needs related to an IROL;

(f) multiple SATOAs shall not be selected to address a single system need or multiple needs in the same area due to contingencies involving the same or similarly situated elements;

(g) a SATOA shall only be evaluated or identified as the preferred solution to resolve a system need that is a second contingency (N-1-1): a proposed SATOA shall not be evaluated or identified as the preferred solution to resolve an N-0 (all-lines-in) or N-1 (first contingency) system need; and

(h) any additional considerations unique to SATOAs that may support comparative evaluation to other solutions to the system need.

II.51.2 Operation of SATOAs: A SATOA shall operate, up to the capabilities of the device as proposed and selected during the process to evaluate and select transmission solutions, as necessary to, and only to:

(a) dynamically provide or absorb available reactive power while the SATOA is not injecting and not consuming real power to or from PTF;

(b) dynamically provide or absorb reactive power while the SATOA is injecting or consuming real power to or from PTF subject to the requirements in Section II.51.2 (c)-(f);

(c) maintain the required state-of-charge or maintenance of the SATOA;

(d) address the applicable system needs or concerns for which the SATOA was identified to address through a Needs Assessment, a Solutions Study, a Public Policy Transmission Study, the competitive solutions process in Attachment K of the OATT, or a combination thereof;

(e) support the New England Transmission System during system restoration; or

(f) as specified in the ISO New England Operating Documents, avoid or mitigate Load Shedding after all available Dispatchable Resources that can effectively provide relief to avoid or mitigate the Load Shedding have been dispatched.

The ISO New England Operating Documents shall specify the operating practices, limits, and audit requirements applicable to the SATOAs.

II.51.3 Transmission Service Associated with SATOA Operation: Transmission service charges, including charges for Ancillary Services, and charges assessed or revenues allocated under Schedules 1, 2, 3, and 5 of Section IV.A of the Tariff are not applicable to the operation of a SATOA.

ATTACHMENT F – APPENDIX E

RULES FOR DETERMINING INVESTMENT TO BE INCLUDED IN PTF

Section A – Transmission Lines*

Section B – Terminal Facilities*

Section C – Right of Way*

*The following provision shall apply to Sections A, B and C below:

Of those transmission facilities that are upgrades, modifications or additions to the New England Transmission System on and after January 1, 2004, only those that: (i) are rated 115kV or above, and (ii) otherwise meet the non-voltage criteria specified in Section II.49 of this OATT shall be classified as PTF. Those transmission facilities that were PTF on December 31, 2003, and any upgrades to such facilities that meet the definition of PTF specified in this OATT, shall remain classified as PTF for all purposes under the Transmission, Markets and Services Tariff.

Section A: Rules for Determining Transmission Line Investment to be Included in PTF

Pool Transmission Facilities (PTF) are the transmission facilities owned by PTO rated 69 kV or above required to allow energy from significant power sources to move freely on the New England transmission network, and include:

1. All transmission lines and associated facilities owned by the PTOs rated 69 kV and above, except:

    a. those which are required to serve local load only, thereby contributing little or no parallel capability to the transmission network,

    b. generator leads, which are defined as the radial transmission from a generator bus to the nearest point on the transmission network,

    c. lines that are normally operated open.

    d. those that are classified as MTF.

2. Terminal facilities (including substation facilities such as transformers, circuit breakers, and associated equipment) required to interconnect the lines which constitute PTF (see Section B).

3. If a PTO with significant generation in its system (initially 25 MW) is connected to the New England Transmission System and none of the transmission facilities owned by the PTO qualify to be included in PTF as defined in “1” and “2” above, then such PTO’s connection to PTF will constitute PTF if both of the following requirements are met for this connection:

will facilitate accomplishment of the ISO's objectives. If such facilities constitute PTF pursuant to this paragraph, they shall be treated as "owned" or "supported," as applicable, by a PTO for purposes of the OATT and the other provisions of the TOA, including the ability to include the cost associated with such PTF and any Transmission Support Expenses for support of PTF made by its Related Person in that PTO's Annual Transmission Revenue Requirements pursuant to Attachment F of the OATT.

Section B: Rules for Determining Terminal Investment to be Included in PTF

Terminal Investment is investment associated with the terminal facilities of electrical lines, including substation facilities such as transformers, circuit breakers, disconnects and airbreaks, bus conductor, related protection equipment and other related facilities (see paragraph 7).

1. The investment in terminal facilities shall be included where these facilities are identifiable and serve directly for terminating and/or switching PTF lines.

2. In cases where a line terminal is used in conjunction with both PTF and Non-PTF lines and/or facilities, it will be considered a PTF facility providing the terminal facility is at 69 kV or above and carries any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation. PTF equipment is any element of the transmission system in those parallel paths. Any equipment not in these parallel paths is Non-PTF.

3. Where line terminals are installed solely for Non-PTF facilities, and do not carry any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation, such terminal cost shall not be included in PTF.

4. A two-winding transformer which connects PTF facilities at both terminals along with any switcher which can be identified as pertaining solely to the transformer, will be included in their entirety as PTF.

5. An autotransformer or three winding transformer which connects PTF facilities at two (2) or more terminals, along with any switchgear which can be identified as pertaining solely to the PTF-connected terminals of the transformer, will be included in their entirety as PTF. An autotransformer or three winding transformer which is connected to PTF at only one terminal will not be PTF.

6. When a transformer supplies only Non-PTF facilities, the entire transformer installation, including the high side disconnect switch or circuit breaker and associated structures or tap lines shall be excluded from PTF except for the portion of line terminal facilities covered by paragraph 2.

7. Other facilities – the investment in that portion of a multi-use substation or switching station which is identifiable as serving a PTF function shall be included in PTF, while the investment in such facilities which are identifiable as serving a Non-PTF function shall be excluded. The investment in land, structures, ground mats, fences, ducts, lighting, etc., can often be identified and thus allocated. The investment in other facilities in the substation or switching station, excluding transformers, which are not identifiable as serving either a PTF

or a Non-PTF function and general overheads shall be allocated to PTF on the basis of the ratio of the investment in those facilities identified as PTF to the sum of the investments in the facilities which are identified as serving PTF and Non-PTF functions; the equipment cost of power transformers shall not be included in this calculation for determining the division of investment, since this would produce a distorted balance.

8. Alternate method of allocating the cost of terminal facilities – In those cases where the major portion of the investment has been lumped and utility plant records do not permit the accurate assignment of costs to specific terminals, the total investment may be prorated to PTF and Non-PTF according to the number of terminals serving PTF and Non-PTF facilities.

9. In cases where microwave facilities are used in whole or part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and Non-PTF functions served by the microwave facilities except where these facilities are otherwise supported under the Microwave Sharing Agreement dated June 1, 1970 among some of the New England utilities.

10. Generator unit transformers and generator circuit breakers shall be excluded from PTF, unless otherwise included by paragraphs 1 or 5.

11. In cases where remote control (Supervisory Control) and telemetering facilities are used in whole or in part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and Non-PTF functions served by these facilities.

12. The PTO Administrative Committee may designate appropriate facilities as PTF.

13. Flow limiting reactors, if operated normally bypassed, but capable of automatic insertion in a line to control flows in PTF facilities under certain operating conditions, shall be included in PTF.

14. Transmission level capacitor banks connected to a PTF eligible bus that may be normally operated open, but capable of being placed in service during adverse system events, shall be included in PTF.

15. Transmission level capacitor banks that are connected by the PTF by radial lines shall not be included in PTF.

16. Transformer-related costs, such as installation and other related costs that would not have been incurred but for the transformer, shall be treated in the same manner as the costs of the transformer.

17. SATOAs and associated facilities.

Section C: Rules for Determining PTF R/W Costs

ATTACHMENT O

NON-INCUMBENT TRANSMISSION DEVELOPER OPERATING AGREEMENT

NON-INCUMBENT TRANSMISSION DEVELOPER OPERATING AGREEMENT

TABLE OF CONTENTS

ARTICLE I. DEFINITIONS; INTERPRETATIONS

1.01. Definitions; Interpretations

ARTICLE II. TRANSMISSION FACILITIES

2.01. Transmission Facilities

2.02. New and Acquired Transmission Facilities and Transmission Upgrades

2.03. Merchant Facilities

2.04. Excluded Assets

2.05. Connection with Non-Parties

2.06. Review of Transmission Plans

2.07. Condemnation

ARTICLE III. OPERATING AUTHORITY

3.01. Grant of Operating Authority

3.02. [reserved]

3.03. Transmission Services and OATT Administration

3.04. Application Authority

3.05. The ISO's Responsibilities

3.06. NTD's Responsibilities

ARTICLE II
TRANSMISSION FACILITIES

2.01 **Transmission Facilities.** As to NTD, the transmission facilities over which the ISO shall exercise Operating Authority (as of the date the facilities are placed in service) in accordance with the terms set forth herein shall be:

(a) those facilities of NTD listed in Schedule 2.01(a) (hereinafter "NTD Category A Facilities"), as such list of facilities may be added to or deleted from in accordance with Sections 2.01(d) and 2.02 below;

(b) those facilities of NTD listed in Schedule 2.01(b) (hereinafter "NTD Category B Facilities"), as such list of facilities may be added to or deleted from, in accordance with Sections 2.01(d) and 2.02 below; and

(c) those transmission facilities of NTD within the New England Transmission System with a voltage level of less than 69 kV and all transformers that have no NTD Category A Facilities or NTD Category B Facilities connected to the lower voltage side of the transformer that are not listed on Schedule 2.01(a) and Schedule 2.01(b) (hereinafter "NTD Local Area Facilities"), provided that any excluded facilities of NTD listed on Schedule 4.01(d) shall not be NTD Local Area Facilities.

(d) The transmission facilities included on any of the lists of the NTD Category A Facilities or the NTD Category B Facilities contained in Schedule 2.01(a) and Schedule 2.01(b), respectively, may be redesignated on another of those two lists, deleted from such list, or redesignated as a NTD Local Area Facility without the necessity of an amendment to this Agreement, but only in the following manner:

(i) at the direction of a Governmental Authority with jurisdiction over the Transmission Facilities in question, provided that the ISO and NTD shall be provided prior written notice of such changes;

(ii) as agreed between the ISO and NTD; or

(iii) where the operational characteristics of a transmission facility have been materially modified (including a change from a radial transmission facility to a looped transmission facility that contributes to the parallel carrying capability of the New England Transmission System) in accordance with Section 2.01(e); provided that any such changes shall also be subject to ISO review consistent with Section 2.06.

(e) All transmission facilities to be redesignated as NTD Category A Facilities, NTD Category B Facilities, or Local Area Facilities or deleted from the lists in Schedule 2.01(a) and Schedule 2.01(b) in accordance with Section 2.01(d)(iii), and all transmission facilities to be added to the lists in Schedule 2.01(a) and Schedule 2.01(b) in accordance with Section 2.02 shall be classified in accordance with the following standards:

(i) NTD Category A Facilities shall consist of: all transmission lines with a voltage level of 115 kV and above, except for those 115 kV transmission facilities specifically designated as NTD Category B Facilities in accordance with Section 2.01(e)(ii); all transmission interties between Control Areas; all transformers that have NTD Category A Facilities connected to the lower voltage side of the transformer; all transformers that require an NTD Category A Facility to be taken out of service when the transformer is taken out of service; SATOAs connected to transmission facilities with a voltage level of 115 kV and above; and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such transmission lines, interties, and transformers.

(ii) NTD Category B Facilities shall consist of: all 115 kV radial transmission lines and all 69 kV transmission lines that are not interties between Control Areas; all transformers that have any NTD Category B Facilities and no NTD Category A Facilities connected to the lower voltage side of the transformer except to the extent such transformers are designated as NTD Category A Facilities in accordance with Section 2.01(e)(i); and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such NTD Category B Facilities.

(iii) NTD Local Area Facilities shall consist of all transmission facilities with a voltage level of less than 69 kV and all transformers that have no NTD Category A Facilities or NTD Category B Facilities connected to the lower voltage side of the transformer.

(iv) To the extent there is any dispute between the ISO and NTD as owner of a transmission facility concerning classification of such transmission facility under these standards, such disagreement shall be subject to the dispute resolution provisions of this Agreement, provided that the ISO's classification of a transmission facility under the standards shall govern pending resolution of the dispute.

Collectively, all NTD Category A Facilities, NTD Category B Facilities, and NTD Local Area Facilities shall hereinafter be referred to as the "Transmission Facilities," provided that "Transmission Facilities" shall not include Excluded Assets as defined in Section 2.04 of this Agreement or Merchant Facilities. The ISO shall maintain on its OASIS a posting of the current versions of Schedule 2.01(a) and Schedule 2.01(b), in each instance, reflecting each such change promptly after such change is made.

(f) The classifications set forth in this Section 2.01 are for operational purposes. Rate treatment of Transmission Facilities shall be governed by the ISO OATT, provided that filings for rate treatment under the ISO OATT shall be subject to Section 3.04 of this Agreement.

2.02 **New and Acquired Transmission Facilities and Transmission Upgrades.**

(a) Any New Transmission Facility or Transmission Upgrade shall be considered a "Transmission Facility" under this Agreement once it is included as "Proposed" in the RSP Project List and, unless otherwise agreed by the ISO and NTD, shall thereafter be added to Schedule 2.01(a) and/or (b), as applicable.

(b) Any Merchant Facility interconnected to or within the New England Transmission System shall not be the subject of this Agreement. Any Merchant Facility interconnected to or within the New England Transmission System constructed and placed in commercial operation after the Operations Date shall be subject to the authority of the ISO under a separate agreement in accordance with Section 2.03 and any applicable provisions of the ISO OATT.

Schedule 1.01

Schedule of Definitions

Acquired Transmission Facilities. Any transmission facility acquired within the New England Control Area by NTD after the Operations Date that meets the classification standards set forth in Section 2.02(a).

Additional Term. "Additional Term" shall have the meaning ascribed thereto in Section 10.01(a) of this Agreement.

Affiliate. Any person or entity which controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" shall mean the possession, directly or indirectly and whether acting alone or in conjunction with others, of the authority to direct the management or policies of a person or entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

Agreement. This Operating Agreement between the ISO and NTD, as it may be amended from time to time.

Ancillary Service. Those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the transmission system in accordance with Good Utility Practice.

Approved Outages. "Approved Outages" shall have the meaning ascribed thereto in Market Rule 1 of the ISO Tariff.

Best's. The A.M. Best Company.

Business Day. Any day other than a Saturday or Sunday or an ISO holiday, as posted by the ISO on its website.

Commercially Reasonable Efforts. A level of effort which, in the exercise of prudent judgment in the light of facts or circumstances known or which should reasonably be known at the time a decision is made, can be expected by a reasonable person to accomplish the desired result in a manner consistent with Good Utility Practice and which takes the performing party's interests into consideration.

RTO. An independent entity that complies with Order No. 2000 and FERC's corresponding regulations (or an entity that complies with all such requirements except for the scope and regional configuration requirements), as determined by the FERC.

Storage as Transmission-Only Asset ("SATOA"). "Storage as Transmission-Only Asset" or "SATOA" shall have the meaning ascribed thereto in Section I.2.2 of the ISO Tariff.

Schedule 22 Large Generator Interconnection Agreement. The interconnection agreement included in Schedule 22 of the ISO OATT.

Schedule 23 Small Generator Interconnection Agreement. The interconnection agreement included in Schedule 23 of the ISO OATT.

Scheduled Outages. "Scheduled Outages" shall have the meaning ascribed thereto in Market Rule 1 of the ISO Tariff.

Small Generating Facility. "Small Generating Facility" shall have the meaning ascribed thereto in the ISO OATT.

System Failure. Widespread telecommunication, hardware or software failure or systemic the ISO hardware or software failures that makes it impossible to receive or process bid information, dispatch resources, or exercise Operating Authority over the Transmission Facilities.

Tax or Taxes. All taxes, charges, fees, levies, penalties or other assessments imposed by any United States federal, state or local or foreign taxing authority, including, but not limited to, income, excise, property, sales, transfer, franchise, payroll, withholding, social security or other taxes, including any interest, penalties or additions attributable thereto.

Tax Return. Any return, report, information return, or other document (including any related or supporting information) required to be supplied to any authority with respect to Taxes.

Technical Committees. "Technical Committee" shall mean the stakeholder technical committees established pursuant to the ISO Participants Agreement.

Term. "Term" shall have the meaning ascribed thereto in Section 10.01 of this Agreement.

SCHEDULE 22

LARGE GENERATOR INTERCONNECTION PROCEDURES

TABLE OF CONTENTS

SECTION 1. DEFINITIONS
SECTION 2. SCOPE, APPLICATION AND TIME REQUIREMENTS.
2.1 Application of Standard Large Generator Interconnection Procedures.
2.2 Comparability
2.3 Base Case Data
2.4 No Applicability to Transmission Service
2.5 Time Requirements
SECTION 3. INTERCONNECTION REQUESTS
3.1 General
3.2 Type of Interconnection Services and Long Lead Time Facility Treatment
3.3 Utilization of Surplus Interconnection Service
3.4 Valid Interconnection Request
3.5 OASIS Posting
3.6 Coordination with Affected Systems
3.7 Withdrawal
3.8 Identification of Contingent Facilities
SECTION 4. QUEUE POSITION
4.1 General
4.2 Clustering
4.3 Transferability of Queue Position
4.4 Modifications
SECTION 5. PROCEDURES FOR TRANSITION
5.1 Queue Position for Pending Requests
5.2 Grandfathering
5.3 New System Operator or Interconnecting Transmission Owner
SECTION 6. INTERCONNECTION FEASIBILITY STUDY
6.1 Interconnection Feasibility Study Agreement
6.2 Scope of Interconnection Feasibility Study
6.3 Interconnection Feasibility Study Procedures

APPENDICES TO LGIP

APPENDIX 1 INTERCONNECTION REQUEST

APPENDIX 2 INTERCONNECTION FEASIBILITY STUDY AGREEMENT

APPENDIX 3 INTERCONNECTION SYSTEM IMPACT STUDY AGREEMENT

APPENDIX 4 INTERCONNECTION FACILITIES STUDY AGREEMENT

APPENDIX 5 OPTIONAL INTERCONNECTION STUDY AGREEMENT

APPENDIX 6 LARGE GENERATOR INTERCONNECTION AGREEMENT

APPENDIX 7 INTERCONNECTION PROCEDURES FOR WIND GENERATION

SECTION I. DEFINITIONS

The definitions contained in this section are intended to apply in the context of the generator interconnection process provided for in this Schedule 22 (and its appendices). To the extent that the definitions herein are different than those contained in Section I.2.2 of the Tariff, the definitions provided below shall control only for purposes of generator interconnections under this Schedule 22. Capitalized terms in Schedule 22 that are not defined in this Section I shall have the meanings specified in Section I.2.2 of the Tariff.

Administered Transmission System shall mean the PTF, the Non-PTF, and distribution facilities that are subject to the Tariff.

Adverse System Impact shall mean any significant negative effects on the stability, reliability or operating characteristics of the electric system.

Affected System shall mean any electric system that is within the Control Area, including, but not limited to, generator owned transmission facilities, or any other electric system that is not within the Control Area that may be affected by the proposed interconnection.

Affected Party shall mean the entity that owns, operates or controls an Affected System, or any other entity that otherwise may be a necessary party to the interconnection process.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Council shall mean the reliability council applicable to the New England Control Area.

Generating Facility shall mean Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities and shall not include a SATOA as defined in Section I of the Tariff.

Governmental Authority shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the System Operator, Interconnection Customer, Interconnecting Transmission Owner, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

Initial Synchronization Date shall mean the date upon which the Generating Facility is initially synchronized and upon which Trial Operation begins.

In-Service Date shall mean the date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Interconnecting Transmission Owner's Interconnection Facilities to obtain back feed power.

Interconnecting Transmission Owner shall mean a Transmission Owner that owns, leases or otherwise possesses an interest, or a Non-Incumbent Transmission Developer that is not a Participating Transmission Owner that is constructing, a portion of the Administered Transmission System at the Point

APPENDIX 6
LARGE GENERATOR INTERCONNECTION AGREEMENT

TABLE OF CONTENTS

Article 1	Definitions
Article 2	Effective Date, Term and Termination
Article 3	Regulatory Filings
Article 4	Scope of Service
Article 5	Interconnection Facilities Engineering, Procurement, and Construction
Article 6	Testing and Inspection
Article 7	Metering
Article 8	Communications
Article 9	Operations
Article 10	Maintenance
Article 11	Performance Obligation
Article 12	Invoice
Article 13	Emergencies
Article 14	Regulatory Requirements and Governing Law
Article 15	Notices
Article 16	Force Majeure
Article 17	Default
Article 18	Indemnity, Consequential Damages and Insurance
Article 19	Assignment
Article 20	Severability
Article 21	Comparability
Article 22	Confidentiality
Article 23	Environmental Releases
Article 24	Information Requirements
Article 25	Information Access and Audit Rights

THIS STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT (“Agreement”) is made and entered into this ____ day of ________ 20__, by and between ________________, a ________________ organized and existing under the laws of the State/Commonwealth of ________________ (“Interconnection Customer” with a Large Generating Facility), ISO New England Inc., a non-stock corporation organized and existing under the laws of the State of Delaware (“System Operator”), and ________________, a ________________ organized and existing under the laws of the State/Commonwealth of ________________ (“Interconnecting Transmission Owner”). Under this Agreement, the Interconnection Customer, System Operator, and Interconnecting Transmission Owner each may be referred to as a “Party” or collectively as the “Parties.”

RECITALS

WHEREAS, System Operator is the central dispatching agency provided for under the Transmission Operating Agreement (“TOA”) which has responsibility for the operation of the New England Control Area from the System Operator control center and the administration of the Tariff; and

WHEREAS, Interconnecting Transmission Owner is the owner or possessor of an interest in the Administered Transmission System; and

WHEREAS, Interconnection Customer intends to own, lease and/or control and operate the Generating Facility identified as a Large Generating Facility in Appendix C to this Agreement; and

WHEREAS, System Operator, Interconnection Customer and Interconnecting Transmission Owner have agreed to enter into this Agreement for the purpose of interconnecting the Large Generating Facility to the Administered Transmission System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this Standard Large Generator Interconnection Agreement, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used.

ARTICLE 1. DEFINITIONS

The definitions contained in this Article 1 and those definitions embedded in an Article of this Agreement are intended to apply in the context of the generator interconnection process provided for in Schedule 22 (and its appendices). To the extent that the definitions herein are different than those contained in Section I.2.2 of the Tariff, the definitions provided below shall control only for purposes of generator interconnections under Schedule 22. Capitalized terms in Schedule 22 that are not defined in this Article 1 shall have the meanings specified in Section I.2.2 of the Tariff.

Administered Transmission System shall mean the PTF, the Non-PTF, and distribution facilities that are subject to the Tariff.

Adverse System Impact shall mean any significant negative effects on the stability, reliability or operating characteristics of the electric system.

Affected Party shall mean the entity that owns, operates or controls an Affected System, or any other entity that otherwise may be a necessary party to the interconnection process.

Affected System shall mean any electric system that is within the Control Area, including, but not limited to, generator owned transmission facilities, or any other electric system that is not within the Control Area that may be affected by the proposed interconnection.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Environmental Law shall mean Applicable Laws or Regulations relating to pollution or protection of the environment or natural resources.

Federal Power Act shall mean the Federal Power Act, as amended, 16 U.S.C. §§ 791a *et seq*.

Force Majeure shall mean any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event does not include acts of negligence or intentional wrongdoing by the Party claiming Force Majeure.

Generating Facility shall mean Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities and shall not include a SATOA as defined in Section I of the Tariff.

Governmental Authority shall mean any federal, state, local or other governmental regulatory or administrative agency, court, commission, department, board, or other governmental subdivision, legislature, rulemaking board, tribunal, or other governmental authority having jurisdiction over the Parties, their respective facilities, or the respective services they provide, and exercising or entitled to exercise any administrative, executive, police, or taxing authority or power; provided, however, that such term does not include the System Operator, Interconnection Customer, Interconnecting Transmission Owner, or any Affiliate thereof.

Hazardous Substances shall mean any chemicals, materials or substances defined as or included in the definition of "hazardous substances," "hazardous wastes," "hazardous materials," "hazardous constituents," "restricted hazardous materials," "extremely hazardous substances," "toxic substances," "radioactive substances," "contaminants," "pollutants," "toxic pollutants" or words of similar meaning and regulatory effect under any applicable Environmental Law, or any other chemical, material or substance, exposure to which is prohibited, limited or regulated by any applicable Environmental Law.

ARTICLE 5. INTERCONNECTION FACILITIES ENGINEERING, PROCUREMENT, AND CONSTRUCTION

5.1 Options. Unless otherwise mutually agreed to between the Parties, Interconnection Customer shall specify the In-Service Date, Initial Synchronization Date, and Commercial Operation Date as specified in the Interconnection Request or as subsequently revised pursuant to Section 4.4 of the LGIP; and select either the Standard Option or Alternate Option set forth below, and such dates and selected option shall be set forth in Appendix B (Milestones). At the same time, Interconnection Customer shall indicate whether it elects to exercise the Option to Build set forth in Article 5.1.3 below. If the dates designated by Interconnection Customer are not acceptable to Interconnecting Transmission Owner, Interconnecting Transmission Owner shall so notify Interconnection Customer within thirty (30) Calendar Days. Upon receipt of the notification that Interconnection Customer's designated dates are not acceptable to Interconnecting Transmission Owner, the Interconnection Customer shall notify Interconnecting Transmission Owner within thirty (30) Calendar Days whether it elects to exercise the Option to Build if it has not already elected to exercise the Option to Build. In accordance with Section 8 of the LGIP and unless otherwise mutually agreed, the Alternate Option is not an available option if the Interconnection Customer waived the Interconnection Facilities Study.

5.1.1 Standard Option. The Interconnecting Transmission Owner shall design, procure, and construct the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades, using Reasonable Efforts to complete the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades by the dates set forth in Appendix B (Milestones). The Interconnecting Transmission Owner shall not be required to undertake any action which is inconsistent with its standard safety practices, its material and equipment specifications, its design criteria and construction procedures, its labor agreements, and Applicable Laws and Regulations. In the event the Interconnecting Transmission Owner reasonably expects that it will not be able to complete the Interconnecting Transmission Owner's Interconnection Facilities and Network Upgrades by the specified dates, the Interconnecting Transmission Owner shall to negotiate terms and conditions (including revision of the specified dates and liquidated damages, the provision of incentives, or the procurement and construction of all facilities other than the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades if the Interconnection Customer elects to exercise the Option to Build under Article 5.1.3). If the Parties are unable to reach agreement on such terms and conditions, then, pursuant to Article 5.1.1 (Standard Option), Interconnecting Transmission Owner shall assume responsibility for the design, procurement and construction of all facilities other than the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades if the Interconnection Customer elects to exercise the Option to Build.

5.2 General Conditions Applicable to Option to Build. If Interconnection Customer assumes responsibility for the design, procurement and construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades,

(1) the Interconnection Customer shall commit in the LGIA to a schedule for the completion of, and provide the System Operator evidence of proceeding with: (a) engineering and design of Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades, (b) procurement of necessary equipment and ordering of long lead time material, and (c) construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(2) the Interconnection Customer shall engineer, procure equipment, and construct the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades (or portions thereof) using Good Utility Practice and using standards and specifications provided in advance by the Interconnecting Transmission Owner;

(3) Interconnection Customer's engineering, procurement and construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades shall comply with all requirements of law to which Interconnecting Transmission

Owner would be subject in the engineering, procurement or construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(4) Interconnecting Transmission Owner shall review and approve the engineering design, equipment acceptance tests, and the construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(5) prior to commencement of construction, Interconnection Customer shall provide to Interconnecting Transmission Owner any changes to the schedule for construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades reflected in Appendix B (Milestones), and shall promptly respond to requests for information from Interconnecting Transmission Owner;

(6) at any time during construction, Interconnecting Transmission Owner shall have the right to gain unrestricted access to the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades and to conduct inspections of the same;

(7) at any time during construction, should any phase of the engineering, equipment procurement, or construction of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades not meet the standards and specifications provided by Interconnecting Transmission Owner, the Interconnection Customer shall be obligated to remedy deficiencies in that portion of the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades;

(8) the Interconnection Customer shall indemnify the Interconnecting Transmission Owner for claims arising from the Interconnection Customer's construction of Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades under the terms and procedures applicable to Article 18.1 (Indemnity);

(9) the Interconnection Customer shall transfer control of Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to the Interconnecting Transmission Owner prior to the In-Service Date;

(10) Unless Parties otherwise agree, Interconnection Customer shall transfer ownership of Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to Interconnecting Transmission Owner prior to the In-Service Date;

(11) Interconnecting Transmission Owner shall approve and accept for operation and maintenance the Interconnecting Transmission Owner's Interconnection Facilities and Stand Alone Network Upgrades to the extent engineered, procured, and constructed in accordance with this Article 5.2;

(12) Interconnection Customer shall deliver to Interconnecting Transmission Owner "as built" drawings, information, and any other documents that are reasonably required by Interconnecting Transmission Owner to assure that the Interconnection Facilities and Stand Alone Network Upgrades are built to the standards and specifications required by Interconnecting Transmission Owner; and

(13) Interconnection Customer shall pay Interconnecting Transmission Owner the agreed upon amount of [$ PLACEHOLDER] for Interconnecting Transmission Owner to execute responsibilities enumerated to Interconnecting Transmission Owner under this Article 5.2.Interconnecting Transmission Owner shall invoice Interconnection Customer for this total amount to be divided on a monthly basis pursuant to Article 12.

5.3 **Liquidated Damages**. The actual damages to the Interconnection Customer, in the event the Interconnecting Transmission Owner's Interconnection Facilities or Network Upgrades are not completed by the dates designated by the Interconnection Customer and accepted by the Interconnecting Transmission Owner pursuant to subparagraphs 5.1.2 or 5.1.4, above, may include Interconnection Customer's fixed operation and maintenance costs and lost opportunity

SCHEDULE 23

SMALL GENERATOR
INTERCONNECTION PROCEDURES

Attachment 1 – Glossary of Terms

Attachment 2 – Small Generator Interconnection Request

Attachment 3 – Certification Codes and Standards

Attachment 4 – Certification of Small Generator Equipment Packages

Attachment 5 – 10 kW Inverter Process

Attachment 6 – Interconnection Feasibility Study Agreement

Attachment 7 – Interconnection System Impact Study Agreement

Attachment 8 – Interconnection Facilities Study Agreement

EXHIBIT 1 - Small Generator Interconnection Agreement (SGIA)

Attachment 1

Glossary of Terms

10 kW Inverter Process – The procedure for evaluating an Interconnection Request for a certified inverter-based Small Generating Facility no larger than 10 kW that uses the section 2 screens. The application process uses an all-in-one document that includes a simplified Interconnection Request, simplified procedures, and a brief set of terms and conditions. See SGIP Attachment 5.

Administered Transmission System – The PTF, the Non-PTF, and distribution facilities that are subject to the Tariff.

Affected Party– The entity that owns, operates or controls an Affected System, or any other entity that otherwise may be a necessary party to the interconnection process.

Affected System – Any electric system that is within the Control Area, including, but not limited to, generator owned transmission facilities, or any other electric system that is not within the Control Area that may be affected by the proposed interconnection.

Affiliate – With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Applicable Laws and Regulations – All duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

At-Risk Expenditure – Money expended for the development of the Generating Facility that cannot be recouped if the Interconnection Customer were to withdraw the Interconnection Request for the Generating Facility. At-Risk Expenditure may include, but is not limited to, money expended on: (i) costs of federal, state, local, regional and town permits, (ii) Site Control, (iii) site-specific design and surveys, (iv) construction activities, and (v) non-refundable deposits for major equipment components. For purposes of this definition, At-Risk Expenditure shall not include costs associated with the Interconnection Studies.

Cluster Entry Deadline shall mean the deadline specified in Section 1.5.3.3.1.

Clustering shall mean the process whereby a group of Interconnection Requests is studied together for the purpose of conducting the Interconnection System Impact Study and Interconnection Facilities Study and for the purpose of determining cost responsibility for upgrades identified through the Clustering provisions.

Commercial Operation – The status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date – For a unit, the date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Standard Small Generator Interconnection Agreement.

Distribution System – The Interconnecting Transmission Owner's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which Distribution Systems operate differ among areas.

Distribution Upgrades – The additions, modifications, and upgrades to the Interconnecting Transmission Owner's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Small Generating Facility and render the transmission service necessary to effect the Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Fast Track Process – The procedure for evaluating an Interconnection Request for a certified Small Generating Facility that meets the eligibility requirements of section 2.1 and includes the section 2 screens, customer options meeting, and optional supplemental review.

Generating Facility – The Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities and shall not include a SATOA as defined in Section I of the Tariff.

STANDARD SMALL GENERATOR INTERCONNECTION AGREEMENT (SGIA)

12.10 Environmental Releases

12.11 Subcontractors

12.12 Reservation of Rights

Article. 13. Notices

13.1 General

13.2 Billing and Payment

13.3 Alternative Forms of Notice

13.4 Designated Operating Representative

13.5 Changes to the Notice Information

Article. 14. Signatures

Attachments to SGIA

Attachment 1 – Glossary of Terms

Attachment 2 – Description and Costs of the Small Generating Facility, Interconnection Facilities, and Metering Equipment

Attachment 3 – One-line Diagram Depicting the Small Generating Facility, Interconnection Facilities, Metering Equipment, and Upgrades

Attachment 4 – Milestones

Attachment 5 – Additional Operating Requirements for the New England Transmission System and Affected Systems Needed to Support the Interconnection Customer's Needs

Attachment 6 – Interconnecting Transmission Owner's Description of its Upgrades and Best Estimate of Upgrade Costs

Attachment 7 – Commercial Operation Date

ATTACHMENTS TO SGIA

Attachment 1	Glossary of Terms
Attachment 2	Description and Costs of the Small Generating Facility, Interconnection Facilities, and Metering Equipment
Attachment 3	One-line Diagram Depicting the Small Generating Facility, Interconnection Facilities, Metering Equipment and Upgrades
Attachment 4	Milestones
Attachment 5	Additional Operating Requirements for the New England Transmission System and Affected Systems Needed to Support the Interconnection Customer's Needs
Attachment 6	Interconnecting Transmission Owner's Description of its Upgrades, and Best Estimates of Upgrade Costs
Attachment 7	Commercial Operation Date

Attachment 1

Glossary of Terms

Administered Transmission System – The PTF, the Non-PTF, and distribution facilities that are subject to the Tariff.

Affected Party– The entity that owns, operates or controls an Affected System, or any other entity that otherwise may be a necessary party to the interconnection process.

Affected System – Any electric system that is within the Control Area, including, but not limited to, generator owned transmission facilities, or any other electric system that is not within the Control Area that may be affected by the proposed interconnection.

Affiliate – With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Applicable Laws and Regulations – All duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Standards – The requirements and guidelines of NERC, NPCC and the New England Control Area, including publicly available local reliability requirements of Interconnecting Transmission Owners or other Affected Systems.

At-Risk Expenditure – Money expended for the development of the Generating Facility that cannot be recouped if the Interconnection Customer were to withdraw the Interconnection Request for the Generating Facility. At-Risk Expenditure may include, but is not limited to, money expended on: (1) costs of federal, state, local, regional and town permits, (ii) Site Control, (iii) site-specific design and survey, (iv) construction activities, and (v) non-refundable deposits for major equipment components. For purposes of this definition, At-
Risk Expenditure shall not include costs associated with the Interconnection Studies.

Cluster Entry Deadline shall mean the deadline specified in Section 1.5.3.3.1.

Clustering shall mean the process whereby a group of Interconnection Requests is studied together for the purpose of conducting the Interconnection System Impact Study and Interconnection Facilities Study and for the purpose of determining cost responsibility for upgrades identified through the Clustering provisions.

Commercial Operation – The status of a Generating Facility that has commenced generating electricity for sale, excluding electricity generated during Trial Operation.

Commercial Operation Date – The date on which the Generating Facility commences Commercial Operation as agreed to by the Parties pursuant to Attachment 7 to the Standard Small Generator Interconnection Agreement.

Default – The failure of a breaching Party to cure its breach under the Small Generator Interconnection Agreement.

Distribution System – The Interconnecting Transmission Owner's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which Distribution Systems operate differ among areas.

Distribution Upgrades – The additions, modifications, and upgrades to the Interconnecting Transmission Owner's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Small Generating Facility and render the transmission service necessary to effect the Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Generating Facility – The Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities and shall not include a SATOA as defined in Section I of the Tariff.

SCHEDULE 25

ELECTIVE TRANSMISSION UPGRADE INTERCONNECTION PROCEDURES

TABLE OF CONTENTS

SECTION 1. DEFINITIONS

SECTION 2. SCOPE, APPLICATION AND TIME REQUIREMENTS

2.1 Application of Elective Transmission Upgrade Interconnection Procedures

2.2 Comparability

2.3 Base Case Data

2.4 No Applicability to Transmission Service

2.5 Treatment of Elective Transmission Upgrades for Transmission, Operations, and Scheduling Purposes

2.6 Time Requirements

SECTION 3. INTERCONNECTION REQUESTS

3.1 General

3.2 Type of Interconnection Services and Long Lead Time Facility Treatment

3.3 Valid Interconnection Request

3.4 OASIS Posting

3.5 Coordination with Affected Systems

3.6 Withdrawal

SECTION 4. QUEUE POSITION

4.1 General

4.2 Reserved

4.3 Transferability of Queue Position

4.4 Modifications

SECTION 5. PROCEDURES FOR TRANSITION

5.1 Queue Position for Pending Requests

5.2 Reserved

5.3 New System Operator or Interconnecting Transmission Owner

SECTION 6. INTERCONNECTION FEASIBILITY STUDY

6.1 Interconnection Feasibility Study Agreement

6.2 Scope of Interconnection Feasibility Study

6.3 Interconnection Feasibility Study Procedures

6.4 Re-Study

SECTION 7. INTERCONNECTION SYSTEM IMPACT STUDY

SECTION I. DEFINITIONS.

The definitions contained in this section are intended to apply in the context of the Elective Transmission Upgrade interconnection process provided for in this Schedule 25 (and its appendices). To the extent that the definitions herein are different than those contained in Section I.2.2 of the Tariff, the definitions provided below shall control only for purposes of Elective Transmission Upgrade interconnections under this Schedule 25. Capitalized terms in Schedule 25 that are not defined in this Section I shall have the meanings specified in Section I.2.2 of the Tariff.

Administered Transmission System shall mean the PTF, the Non-PTF, and distribution facilities that are subject to the Tariff.

Adverse System Impact shall mean any significant negative effects on the stability, reliability or operating characteristics of the electric system.

Affected System shall mean any electric system that is within the Control Area, including, but not limited to, generator owned transmission facilities, or any other electric system that is not within the Control Area that may be affected by the proposed interconnection.

Affected Party shall mean the entity that owns, operates or controls an Affected System, or any other entity that otherwise may be a necessary party to the interconnection process.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Council shall mean the reliability council applicable to the New England Control Area.

generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among areas.

Distribution Upgrades shall mean the additions, modifications, and upgrades to the Interconnecting Transmission Owner's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Elective Transmission Upgrade. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which the Elective Transmission Upgrade Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by the Commission or if filed unexecuted, upon the date specified by the Commission.

Elective Transmission Upgrade ("ETU") shall mean a new Pool Transmission Facility, Merchant Transmission Facility or Other Transmission Facility that is interconnecting to the Administered Transmission System, or an upgrade to an existing Pool Transmission Facility, Merchant Transmission Facility or Other Transmission Facility that is part of or interconnected to the Administered Transmission System for which the Interconnection Customer has agreed to pay all of the costs of said Elective Transmission Upgrade and of any additions or modifications to the Administered Transmission System that are required to accommodate the Elective Transmission Upgrade. An Elective Transmission Upgrade shall not include a SATOA as defined in Section I of the Tariff. An Elective Transmission Upgrade is not a Generator Interconnection Related Upgrade, a Regional Transmission Upgrade, or a Market Efficiency Transmission Upgrade.

Elective Transmission Upgrade Interconnection Agreement ("ETU IA") shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to an Elective Transmission Upgrade, that is included in this Schedule 25 to Section II of the Tariff.

Elective Transmission Upgrade Interconnection Procedures ("ETU IP") shall mean the interconnection procedures applicable to an Interconnection Request pertaining to an Elective Transmission Upgrade that are included in this Schedule 25 to Section II of the Tariff.

Emergency Condition shall mean a condition or situation: (1) that in the judgment of the Party making the claim is likely to endanger life or property; or (2) that, in the case of the Interconnecting Transmission

APPENDICES TO ETU IP

APPENDIX 1 INTERCONNECTION REQUEST FOR ELECTIVE TRANSMISSION UPGRADE

APPENDIX 2 INTERCONNECTION FEASIBILITY STUDY AGREEMENT

APPENDIX 3 INTERCONNECTION SYSTEM IMPACT STUDY AGREEMENT

APPENDIX 4 INTERCONNECTION FACILITIES STUDY AGREEMENT

APPENDIX 5 OPTIONAL INTERCONNECTION STUDY AGREEMENT

APPENDIX 6 ELECTIVE TRANSMISSION UPGRADE INTERCONNECTION AGREEMENT

APPENDIX 6
ELECTIVE TRANSMISSION UPGRADE
INTERCONNECTION AGREEMENT

TABLE OF CONTENTS

Article 1	Definitions
Article 2	Effective Date, Term and Termination
Article 3	Regulatory Filings
Article 4	Scope of Service
Article 5	Interconnection Facilities Engineering, Procurement, and Construction
Article 6	Testing and Inspection
Article 7	Metering
Article 8	Communications
Article 9	Operations
Article 10	Maintenance
Article 11	Performance Obligation
Article 12	Invoice
Article 13	Emergencies
Article 14	Regulatory Requirements and Governing Law
Article 15	Notices
Article 16	Force Majeure
Article 17	Default
Article 18	Indemnity, Consequential Damages and Insurance
Article 19	Assignment
Article 20	Severability
Article 21	Comparability
Article 22	Confidentiality
Article 23	Environmental Releases
Article 24	Information Requirements
Article 25	Information Access and Audit Rights
Article 26	Subcontractors
Article 27	Disputes

THIS ELECTIVE TRANSMISSION UPGRADE INTERCONNECTION AGREEMENT ("Agreement") is made and entered into this ____ day of ________ 20__, by and between ________________, a ________________ organized and existing under the laws of the State/Commonwealth of ________________ ("Interconnection Customer" with an Elective Transmission Upgrade Facility), ISO New England Inc., a non-stock corporation organized and existing under the laws of the State of Delaware ("System Operator"), and ________________, a ________________ organized and existing under the laws of the State/Commonwealth of ________________ ("Interconnecting Transmission Owner"). Under this Agreement the Interconnection Customer, System Operator, and Interconnecting Transmission Owner each may be referred to as a "Party" or collectively as the "Parties."

RECITALS

WHEREAS, System Operator is the central dispatching agency provided for under the Transmission Operating Agreement ("TOA") which has responsibility for the operation of the New England Control Area from the System Operator control center and the administration of the Tariff; and

WHEREAS, Interconnecting Transmission Owner is the owner or possessor of an interest in the Administered Transmission System; and

WHEREAS, Interconnection Customer intends to own, lease and/or control and operate the Elective Transmission Upgrade identified in Appendix C to this Agreement; and

WHEREAS, System Operator, Interconnection Customer and Interconnecting Transmission Owner have agreed to enter into this Agreement for the purpose of interconnecting the Elective Transmission Upgrade to the Administered Transmission System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein, it is agreed:

When used in this Elective Transmission Upgrade Interconnection Agreement, terms with initial capitalization that are not defined in Article 1 shall have the meanings specified in the Article in which they are used.

ARTICLE 1. DEFINITIONS

The definitions contained in this Article 1 and those definitions embedded in an Article of this Agreement are intended to apply in the context of the Elective Transmission Upgrade interconnection process provided for in Schedule 25 (and its appendices). To the extent that the definitions herein are different than those contained in Section I.2.2 of the Tariff, the definitions provided below shall control only for purposes of Elective Transmission Upgrade interconnections under Schedule 25. Capitalized terms in Schedule 25 that are not defined in this Article 1 shall have the meanings specified in Section I.2.2 of the Tariff.

Administered Transmission System shall mean the PTF, the Non-PTF, and distribution facilities that are subject to the Tariff.

Adverse System Impact shall mean any significant negative effects on the stability, reliability or operating characteristics of the electric system.

Affected System shall mean any electric system that is within the Control Area, including, but not limited to, generator owned transmission facilities, or any other electric system that is not within the Control Area that may be affected by the proposed interconnection.

Affected Party shall mean the entity that owns, operates or controls an Affected System, or any other entity that otherwise may be a necessary party to the interconnection process.

Affiliate shall mean, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Applicable Reliability Council shall mean the reliability council applicable to the New England Control Area.

Distribution System shall mean the Interconnecting Transmission Owner's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which distribution systems operate differ among areas.

Distribution Upgrades shall mean the additions, modifications, and upgrades to the Interconnecting Transmission Owner's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Elective Transmission Upgrade. Distribution Upgrades do not include Interconnection Facilities.

Effective Date shall mean the date on which the Elective Transmission Upgrade Interconnection Agreement becomes effective upon execution by the Parties subject to acceptance by the Commission or if filed unexecuted, upon the date specified by the Commission.

Elective Transmission Upgrade ("ETU") shall mean a new Pool Transmission Facility, Merchant Transmission Facility or Other Transmission Facility that is interconnecting to the Administered Transmission System, or an upgrade to an existing Pool Transmission Facility, Merchant Transmission Facility or Other Transmission Facility that is part of or interconnected to the Administered Transmission System for which the Interconnection Customer has agreed to pay all of the costs of said Elective Transmission Upgrade and of any additions or modifications to the Administered Transmission System that are required to accommodate the Elective Transmission Upgrade. An Elective Transmission Upgrade shall not include a SATOA as defined in Section I of the Tariff. An Elective Transmission Upgrade is not a Generator Interconnection Related Upgrade, a Regional Transmission Upgrade, or a Market Efficiency Transmission Upgrade.

Elective Transmission Upgrade Interconnection Agreement ("ETU IA") shall mean the form of interconnection agreement applicable to an Interconnection Request pertaining to an Elective Transmission Upgrade, that is included in this Schedule 25 to Section II of the Tariff.

Elective Transmission Upgrade Interconnection Procedures ("ETU IP") shall mean the interconnection procedures applicable to an Interconnection Request pertaining to an Elective Transmission Upgrade that are included in this Schedule 25 to Section II of the Tariff.

TRANSMISSION OPERATING AGREEMENT

Schedules

Schedule 1.01. Schedule of Definitions

Schedule 2.01(a). List of Each PTO's Category A Facilities

Schedule 2.01(b). List of Each PTO's Category B Facilities

Schedule 3.02(b). List of Interconnection Agreements with neighboring Control Areas and Tariff(s) Applicable to External Transactions

Schedule 3.02(d). List of Existing Operating Procedures

Schedule 3.09(a). Planning and Expansion – Participating Transmission Owner Rights and Obligations

1. PTOs Rights and Obligations to Build and Associated Conditions Including Cost Recovery

2. PTO Obligations

Schedule 3.09(b). List of Existing Planning Procedures

Schedule 3.11(b). List of Grandfathered Intertie Agreements

Schedule 3.11(c). List of Grandfathered Interconnection Agreements

Schedule 3.11(f) List of MEPCO Operating Documents

Schedule 4.01(d). PTO New England Transmission Facilities Not Subject to this Agreement

Schedule 11.01. Notices

Schedule 11.02. Superseded Agreements

Schedule 11.04. PTO Administrative Committee

Schedule 11.19(c). Additional Conditions Precedent

TRANSMISSION OPERATING AGREEMENT

This Transmission Operating Agreement (this "TOA" or this "Agreement"), dated as of February 1, 2005, is made and entered into by and among Bangor Hydro-Electric Company; Town of Braintree Electric Light Department; Boston Edison Company, Cambridge Electric Light Company, Canal Electric Company, and Commonwealth Electric Company; Central Maine Power Company; Central Vermont Public Service Corporation; Connecticut Municipal Electric Energy Cooperative; The City of Holyoke Gas and Electric Department; Florida Power & Light Company; Green Mountain Power Corporation; Massachusetts Municipal Wholesale Electric Company; New England Power Company; New Hampshire Electric Cooperative, Inc.; Northeast Utilities Service Company as agent for: The Connecticut Light and Power Company, Western Massachusetts Electric Company, Holyoke Power and Electric Company; Holyoke Water Power Company; and Public Service Company of New Hampshire; Norwood Municipal Light Department; Town of Reading Municipal Light Department; Taunton Municipal Lighting Plant; The United Illuminating Company; Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Company; Vermont Electric Cooperative, Inc; and Vermont Electric Power Company, Inc. (herein collectively referred to as the "Initial Participating Transmission Owners"), and the Initial Participating Transmission Owners along with the Vermont Public Power Supply Authority, Vermont Transco LLC and any other Additional Participating Transmission Owners (as defined in Section 11.05 of this Agreement), are collectively referred to herein as the "PTOs" and individually each is referred to as a "PTO"), and ISO New England Inc.("ISO"), a Delaware corporation (all PTOs and the ISO are collectively referred to herein as the "Parties").

WHEREAS, each of the PTOs owns and/or operates certain transmission facilities that are interconnected with the transmission facilities of certain other PTOs within the New England Transmission System or otherwise provides transmission service within the New England Transmission System;

WHEREAS, the ISO is a regional transmission organization ("RTO") authorized by the Federal Energy Regulatory Commission ("FERC") to exercise the functions required of RTOs pursuant to FERC's Order No. 2000 ("Order 2000") and FERC's RTO regulations;

WHEREAS, in accordance with the requirements of Order 2000, the ISO will be the transmission provider under the ISO Open Access Transmission Tariff (the "ISO OATT") of non-discriminatory, open access transmission services over the transmission facilities of the PTOs ("Transmission Service");

WHEREAS, the ISO OATT will be designed to provide for the payment by transmission customers for Transmission Service at rates designed to recover the revenue requirements of the PTOs in supporting the provision of such transmission service by the ISO under the ISO OATT;

WHEREAS, the ISO will be responsible for system planning within the ISO region subject to certain rights and obligations of the PTOs, all as set forth in this Agreement;

ARTICLE II

TRANSMISSION FACILITIES

2.01 **Transmission Facilities.** As to any PTO, the transmission facilities over which the ISO shall exercise Operating Authority in accordance with the terms set forth herein shall be:

(a) those facilities of such PTO listed in Schedule 2.01(a) (hereinafter "Category A Facilities"), as such list of facilities may be added to or deleted from in accordance with Sections 2.01(d) and 2.02 below;

(b) those facilities of such PTO listed in Schedule 2.01(b) (hereinafter "Category B Facilities"), as such list of facilities may be added to or deleted from, in accordance with Sections 2.01(d) and 2.02 below; and

(c) those transmission facilities of such PTO within the New England Transmission System with a voltage level of less than 69 kV and all transformers that have no Category A Facilities or Category B Facilities connected to the lower voltage side of the transformer that are not listed on Schedule 2.01(a) and Schedule 2.01(b) (hereinafter "Local Area Facilities"), provided that any excluded facilities of such PTO listed on Schedule 4.01(d) shall not be Local Area Facilities.

(d) As to each PTO, the transmission facilities included on any of the lists of the Category A Facilities or the Category B Facilities contained in Schedule 2.01(a) and Schedule 2.01(b), respectively, as of the Operations Date may be redesignated on another of these two lists, deleted from such list, or redesignated as a Local Area Facility without the necessity of an amendment to this Agreement, but only in the following manner:

(i) at the direction of a Governmental Authority with jurisdiction over the Transmission Facilities in question, provided that the ISO and all PTOs shall be provided prior written notice of such changes;

(ii) as agreed between the ISO and the PTO or PTOs owning the transmission facilities; or

(iii) where the operational characteristics of a transmission facility have been materially modified after the Operations Date (including a change from a radial transmission facility to a looped transmission facility that contributes to the parallel carrying capability of the New England Transmission System) in accordance with Section 2.01(e); provided that any such changes shall also be subject to ISO review consistent with Section 2.06.

(e) All transmission facilities to be redesignated as Category A Facilities, Category B Facilities, or Local Area Facilities or deleted from the lists in Schedule 2.01(a) and Schedule 2.01(b) in accordance with Section 2.01(d)(iii), and all transmission facilities to be added to the lists in Schedule 2.01(a) and Schedule 2.01(b) in accordance with Section 2.02 shall be classified in accordance with the following standards:

(i) Category A Facilities shall consist of: all transmission lines with a voltage level of 115 kV and above, except for those 115 kV transmission facilities specifically designated as Category B Facilities in accordance with Section 2.01(e)(ii); all transmission interties between Control Areas; all transformers that have Category A Facilities connected to the lower voltage side of the transformer; all transformers that require a Category A Facility to be taken out of service when the transformer is taken out of service; SATOAs connected to transmission facilities with a voltage level of 115 kV and above; and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such transmission lines, interties, and transformers.

(ii) Category B Facilities shall consist of: all 115 kV radial transmission lines and all 69 kV transmission lines that are not interties between Control Areas; all transformers that have any Category B Facilities and no Category A Facilities connected to the lower voltage side of the transformer except to the extent such transformers are designated as Category A Facilities in accordance with Section 2.01(e)(i); and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such Category B Facilities.

(iii) Local Area Facilities shall consist of all transmission facilities with a voltage level of less than 69 kV and all transformers that have no Category A Facilities or Category B Facilities connected to the lower voltage side of the transformer.

(iv) To the extent there is any dispute between the ISO and a PTO or PTOs owning a transmission facility concerning classification of such transmission facility under these standards, such disagreement shall be subject to the dispute resolution provisions of this Agreement, provided that the ISO's classification of a transmission facility under the standards shall govern pending resolution of the dispute.

(f) Collectively, all Category A Facilities, Category B Facilities, and Local Area Facilities shall hereinafter be referred to as the "Transmission Facilities," provided that "Transmission Facilities" shall not include Excluded Assets as defined in Section 2.04 of this Agreement or Merchant Facilities. The ISO shall maintain on its OASIS a posting of the current versions of Schedule 2.01(a) and Schedule 2.01(b), in each instance, reflecting each such change promptly after such change is made.

Schedule 1.01

Schedule of Definitions

Acquired Transmission Facilities. Any transmission facility acquired within the New England Control Area by one or more PTOs after the Operations Date that meets the classification standards set forth in Section 2.01(e).

Additional Participating Transmission Owners. "Additional Participating Transmission Owners" shall have the meaning ascribed thereto in Section 11.05 of this Agreement.

Additional Term. "Additional Term" shall have the meaning ascribed thereto in Section 10.01(a) of this Agreement.

Affiliate. Any person or entity which controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" shall mean the possession, directly or indirectly and whether acting alone or in conjunction with others, of the authority to direct the management or policies of a person or entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

Agreement. This Transmission Operating Agreement, as it may be amended from time to time.

Ancillary Service. Those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the transmission system in accordance with Good Utility Practice.

Approved Outages. "Approved Outages" shall have the meaning ascribed thereto in Section 3.08(a)(iv) of this Agreement.

ATC. Available Transfer Capability.

Backstop Transmission Solution. A solution proposed: (i) to address a reliability or market efficiency need identified by the ISO in a Needs Assessment reported by the ISO pursuant to Section 4.1(i) of Attachment K to the ISO OATT, (ii) by the PTO or PTOs with an obligation under Schedule 3.09(a) of the TOA to address the identified need; and (iii) in circumstances in which the competitive solution process specified in Section 4.3 of Attachment K to the ISO OATT will be utilized.

Back-up Control Center. The control center established by the ISO as a back-up to the ISO Control Center.

Back-up Control Center Lease. The lease for premises in Newington, Connecticut entered into by ISO New England Inc. and Rocky River Realty Company for an initial term ending July 31, 2005, and subject to the right of the tenant to four three-year extensions.

Public Policy Project. Any New Transmission Facility or Transmission Upgrade that is included in the ISO System Plan as a Public Policy Transmission Upgrade in accordance with Attachment K to the ISO OATT.

Publicly-Owned PTO. A "Publicly-Owned PTO" shall mean a PTO that is exempt, under Section 201(f) of the Federal Power Act, from the obligations and requirements of the Federal Power Act.

Qualified Transmission Project Sponsor. "Qualified Transmission Project Sponsor" shall have the meaning ascribed thereto in Section I.2.2 of the ISO Tariff.

Rating Procedures. "Rating Procedures" shall have the meaning ascribed thereto in Section 3.02(d) of this Agreement.

Regulation and Frequency Response Service. An Ancillary Service as defined in the ISO OATT.

Reliability Authority. "Reliability Authority" shall have the meaning established by NERC, as such definition may change from time to time, provided such definition of Reliability Authority shall not be inconsistent with the specific rights and responsibilities of the ISO and the PTOs under this Agreement.

Restoration Plans. The System Restoration Plan and all PTO Local Restoration Plans.

RFAP. "RFAP" shall have the meaning ascribed thereto in Section 6 of Schedule 3.09(a) to this Agreement.

RMR. Reliability must run resources.

RTO. An independent entity that complies with Order No. 2000 and FERC's corresponding regulations (or an entity that complies with all such requirements except for the scope and regional configuration requirements), as determined by the FERC.

Storage as Transmission-Only Asset ("SATOA"). "Storage as Transmission-Only Asset" or "SATOA" shall have the meaning ascribed thereto in Section I.2.2 of the ISO Tariff.

Schedule 22 Large Generator Interconnection Agreement. The interconnection agreement included in Schedule 22 of the ISO OATT.

Schedule 23 Small Generator Interconnection Agreement. The interconnection agreement included in Schedule 23 of the ISO OATT.

Scheduled Outages. "Scheduled Outages" shall have the meaning ascribed thereto in Sections 3.08(a)(ii) and 3.08(a)(iii) of this Agreement.

Small Generating Facility. "Small Generating Facility" shall have the meaning ascribed thereto in the ISO OATT.

Transmission Upgrade. Any upgrade to an existing Transmission Facility owned by any PTO that goes into commercial operation after the Operations Date

TRM. Transmission Reliability Margin.

TTC. Total Transfer Capability.

VAR. Volt-Amps Reactive.

Workers Compensation. Any financial award or settlement provided to employees or their dependents under state or federal law due to the occurrence of an employment-related accident, disease or injury.

Workers Compensation Insurance. The insurance, procured by the ISO in accordance with Section 9.05(a), covering losses that the ISO is subject to as an employer under state or federal worker's compensation laws.

Schedule 2.01(a)

Category A Facilities shall consist of all transmission lines listed as "Category A" in this Schedule and all transmission interties between Control Areas, all transformers that have listed Category A lines connected to the lower voltage side of the transformer; all transformers that require a listed line to be taken out of service when the transformer is taken out of service; SATOAs connected to transmission facilities with a voltage level of 115 kV and above; and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such transmission lines, interties, and transformers.
The list of Category A Facilities can be found at:

http://www.oatioasis.com/ISNE/index.html

Table of Contents

III.1 Market Operations.

III.1.1 Introduction.

III.1.2 [Reserved.]

III.1.3 Definitions.

III.1.3.1 [Reserved.]

III.1.3.2 [Reserved.]

III.1.3.3 [Reserved.]

III.1.4 Requirements for Certain Transactions.

III.1.4.1 ISO Settlement of Certain Transactions.

III.1.4.2 Transactions Subject to Requirements of Section III.1.4.

III.1.4.3 Requirements for Section III.1.4 Conforming Transactions.

III.1.5 Resource Auditing.

III.1.5.1. Claimed Capability Audits.

III.1.5.1.1 General Audit Requirements.

III.1.5.1.2 Establish Claimed Capability Audit.

III.1.5.1.3 Seasonal Claimed Capability Audits.

III.1.5.1.3.1 Seasonal DR Audits.

III.1.5.1.4 ISO-Initiated Claimed Capability Audits.

III.1.5.2. ISO-Initiated Parameter Auditing.

III.1.5.3 Reactive Capability Audits.

III.1.6 [Reserved.]

III.1.6.1 [Reserved.]

III.1.6.2 [Reserved.]

III.1.6.3 [Reserved.]

III.1.6.4 ISO New England Manuals and ISO New England Administrative Procedures.

III.1.7 General.

III.1.7.1 Provision of Market Data to the Commission.

III.1.7.19.2.3.1 Dispatched.

III.1.7.19.2.3.2 Non-Dispatched.

III.1.7.20 Information and Operating Requirements.

III.1.7.21 SATOA Participation in Markets.

III.1.8 [Reserved.]

…

III.1.7 General.

…

III.1.7.21 SATOA Participation in Markets: A Node will be established for each SATOA. A Market Participant's market activity, transactions, and actions taken at a SATOA's Node and a SATOA's participation in the New England Markets shall be limited to those necessary to consume or inject energy from or to PTF for any period, magnitude, and duration identified as necessary to: (1) address the applicable system needs or provide the transmission function for which the SATOA was selected as the preferred solution; or (2) as specified in the ISO New England Operating Documents, avoid or mitigate Load Shedding after all available Dispatchable Resources that can effectively provide relief to avoid or mitigate the Load Shedding have been dispatched.

III.3 Accounting And Billing

III.3.1 Introduction.

This Section III.3 sets forth the accounting and billing principles and procedures for the purchase and sale of services in the New England Markets and for the operation of the New England Control Area.

If a dollar-per-MW-hour value is applied in a calculation where the interval of the value produced in that calculation is less than an hour, then for purposes of that calculation the dollar-per-MW-hour value is divided by the number of intervals in the hour.

III.3.2 Market Participants.

III.3.2.1 ISO Energy Market.

For purposes of establishing the following positions, unless otherwise expressly stated, the settlement interval for the Real-Time Energy Market is five minutes and the settlement interval for the Day-Ahead Energy Market is hourly. The Real-Time Energy Market settlement is determined using the Metered Quantity For Settlement calculated in accordance with Section III.3.2.1.1.

(a) **Day-Ahead Energy Market Obligations** – For each Market Participant for each settlement interval, the ISO will determine a Day-Ahead Energy Market position representing that Market Participant's net purchases from or sales to the Day-Ahead Energy Market as follows:

> (i) **Day-Ahead Load Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Load Obligation for energy at each Location equal to the MWhs of its Demand Bids, Decrement Bids and External Transaction sales accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Load Obligation shall have a negative value.
>
> (ii) **Day-Ahead Generation Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Generation Obligation for energy at each Location equal to the MWhs of its Supply Offers, Increment Offers and External Transaction purchases accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Generation Obligation shall have a positive value.

(iii) **Day-Ahead Demand Reduction Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Demand Reduction Obligation at each Location equal to the MWhs of its Demand Reduction Offers accepted by the ISO in the Day-Ahead Energy Market at that Location, increased by average avoided peak distribution losses. Day-Ahead Demand Reduction Obligations shall have a positive value.

(iv) **Day-Ahead Adjusted Load Obligation** – Each Market Participant shall have for each settlement interval a Day-Ahead Adjusted Load Obligation at each Location equal to the Day-Ahead Load Obligation adjusted by any applicable Day-Ahead internal bilateral transactions at that Location.

(v) **Day-Ahead Locational Adjusted Net Interchange** – Each Market Participant shall have for each settlement interval a Day-Ahead Locational Adjusted Net Interchange at each Location equal to the Day-Ahead Adjusted Load Obligation plus the Day-Ahead Generation Obligation plus the Day-Ahead Demand Reduction Obligation at that Location.

(b) **Real-Time Energy Market Obligations Excluding Demand Response Resource Contributions** – For each Market Participant for each settlement interval, the ISO will determine a Real-Time Energy Market position. For purposes of these calculations, if the settlement interval is less than one hour, any internal bilateral transaction shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation for energy at each Location equal to the MWhs of load, where such MWhs of load shall include External Transaction sales and shall have a negative value, at that Location, adjusted for unmetered load and any applicable internal bilateral transactions which transfer Real-Time load obligations.

(ii) **Real-Time Generation Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation for energy at each Location. The Real-Time Generation Obligation shall equal the MWhs of energy, where such MWhs of energy shall have positive value, provided by Generator Assets and External Transaction purchases at that Location.

(iii) **Real-Time Adjusted Load Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Adjusted Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any applicable energy related internal Real-Time bilateral transactions at that Location.

(iv) **Real-Time Locational Adjusted Net Interchange** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange at each Location equal to the Real-Time Adjusted Load Obligation plus the Real-Time Generation Obligation plus the Real-Time SATOA Obligation at that Location.

(v) **Marginal Loss Revenue Load Obligation** – Each Market Participant shall have for each settlement interval a Marginal Loss Revenue Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any energy related internal Real-Time bilateral transactions at that Location that the parties to those bilateral transactions have elected to include in their Marginal Loss Revenue Load Obligation for the purpose of allocating Day-Ahead Loss Revenue and Real-Time Loss Revenue. Contributions from Coordinated External Transactions shall be excluded from the Real-Time Load Obligation for purposes of determining Marginal Loss Revenue Load Obligation.

(vi) **Real-Time SATOA Obligation** – Each PTO shall have for each settlement interval a Real-Time SATOA Obligation for energy at each Location equal to the sum of: (1) the MWhs of energy, where such MWhs of energy shall have positive value, provided by SATOAs at that Location; and (2) the MWhs of load, where such MWhs of load shall have a negative value, consumed by SATOAs at that Location.

(c) **Real-Time Energy Market Obligations For Demand Response Resources**

Real-Time Demand Reduction Obligation – Each Market Participant shall have for each settlement interval a Real-Time Demand Reduction Obligation at each Location equal to the MWhs of demand reduction provided by Demand Response Resources at that Location in response to non-zero Dispatch Instructions. The MWhs of demand reduction produced by a Demand Response Resource are equal to the sum of the demand reductions produced by its constituent Demand Response Assets calculated pursuant to Section III.8.4, where the demand reductions, other than MWhs associated with Net Supply, are increased by average avoided peak distribution losses.

(a) For external interfaces, the Metered Quantity For Settlement is the scheduled value adjusted for any curtailment, except that for Inadvertent Interchange, the Metered Quantity For Settlement is the difference between the actual and scheduled values, where the actual value is

(i) calculated as the five-minute telemetry value plus the difference between the hourly revenue quality meter value and the hourly average telemetry value, or

(ii) the five-minute revenue quality meter value, if five-minute revenue quality meter data are available.

(b) For Resources submitting five-minute revenue quality meter data (other than Demand Response Resources), the Metered Quantity For Settlement is the five-minute revenue quality meter value.

(c) For Resources with telemetry submitting hourly revenue quality meter data, the Metered Quantity For Settlement is calculated as follows:

(i) In the event that in an hour, the difference between the average of the five-minute telemetry values for the hour and the revenue quality meter value for the hour is greater than 20 percent of the hourly revenue quality meter value and greater than 10 MW then the Metered Quantity For Settlement is a flat profile of the revenue quality meter value equal to the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour. (For a Continuous Storage Facility, the difference between the average of the five-minute telemetry values and the revenue quality meter value will be determined using the net of the values submitted by its component Generator Asset and DARD.)

(ii) Otherwise, the Metered Quantity For Settlement is the telemetry profile of the revenue quality meter value equal to the five-minute telemetry value adjusted by a scale factor.

(d) For a Demand Response Resource, the Metered Quantity For Settlement equals the sum of the demand reductions of each of its constituent Demand Response Assets produced in response to a non-zero Dispatch Instruction, with the demand reduction for each such asset calculated pursuant to Section III.8.4.

(e) For Resources without telemetry submitting hourly revenue quality meter data, the Metered Quantity For Settlement is the hourly revenue quality meter value equally apportioned over the five-minute intervals in the hour.

III.3.2.2 Metering and Communication.

(a) Revenue Quality Metering and Telemetry for Assets other than Demand Response Assets

The megawatt-hour data of each Generator Asset, Tie-Line Asset, ~~and~~ Load Asset, and SATOA must be metered and automatically recorded at no greater than an hourly interval using metering located at the asset's point of interconnection, in accordance with the ISO operating procedures on metering and telemetering. This metered value is used for purposes of establishing the hourly revenue quality metering of the asset.

The instantaneous megawatt data of each Generator Asset (except Settlement Only Resources), ~~and~~ each Asset Related Demand, and each SATOA must be automatically recorded and telemetered in accordance with the requirements in the ISO operating procedures on metering and telemetering.

(b) Meter Maintenance and Testing for all Assets

Each Market Participant must adequately maintain metering, recording and telemetering equipment and must periodically test all such equipment in accordance with the ISO operating procedures on metering and telemetering. Equipment failures must be addressed in a timely manner in accordance with the requirements in the ISO operating procedures on maintaining communications and metering equipment.

(c) Additional Metering and Telemetry Requirements for Demand Response Assets

(i) Market Participants must report to the ISO in real time a set of telemetry data for each Demand Response Asset associated with a Demand Response Resource. The telemetry values shall measure the real-time demand of Demand Response Assets as measured at their Retail Delivery Points, and shall be reported to the ISO every five minutes. For a Demand Response Resource to provide TMSR or TMNSR, Market Participants must in addition report telemetry values at least every one minute. Telemetry values reported by Market Participants to the ISO shall be in MW units and shall be an instantaneous power measurement or an average power value derived from an energy measurement for the time interval from which the energy measurement was taken.

(ii) If one or more generators whose output can be controlled is located behind the Retail Delivery Point of a Demand Response Asset, other than emergency generators that cannot operate electrically synchronized to the New England Transmission System, then the Market Participant must also report to the ISO, before the end of the Correction Limit for the Data Reconciliation Process, a single set of meter data, at an interval of five minutes, representing the combined output of all generators whose output can be controlled.

(iii) If the Market Participant or the ISO finds that the metering or telemetry devices do not meet the accuracy requirements specified in the ISO New England Manuals and

ISO new england

memo

To: NEPOOL Transmission Committee

From: Brent Oberlin, Director, Transmission Planning

Date: August 10, 2022

Subject: Storage as a Transmission-Only Asset

The ISO is requesting a vote on the Storage as a Transmission-Only Asset proposal. The proposal seeks to satisfy stakeholder requests to allow storage to participate as a transmission asset. This proposal will enable storage to be considered as a solution in both the Solutions Study process and the competitive solution process to address system concerns identified in Needs Assessments and Public Policy Transmission Studies.

The Transmission Committee will take action on the following Tariff provisions:

Transmission, Markets, and Services Tariff Section I.2.2, definition of SATOA; Open Access Transmission Tariff (OATT) Section II.51; OATT Section II, Attachment O Sections 2.01(e)(i) and Schedule 1.01; Schedule 22, Section 1 and Appendix 6, Article 1; Schedule 23, Section 1 and Exhibit 1, Attachment 1; Schedule 25, Section 1 and Appendix 6, Article 1, and the Transmission Operating Agreement.

The specific proposal for the Transmission committee's consideration at its August 16-17th meeting has been presented in the meeting dates outlined below.

- April 14, 2022 agenda item #5: https://www.iso-ne.com/static-assets/documents/2022/04/a5_storage_as_transmission_only_asset.pdf
- May 31, 2022, agenda item #7: a7_storage_as_a_transmission_only_asset.pdf (iso-ne.com)
- June 28, 2022, agenda item #5: https://www.iso-ne.com/static-assets/documents/2022/06/a5_satoa_tariff_revisions_and_presentation.zip
- July 27, 2022, agenda item #5: https://www.iso-ne.com/static-assets/documents/2022/06/a5_satoa_tariff_revisions_and_presentation.zip
- August 16-17th, agenda item #14: https://www.iso-ne.com/event-details?eventId=149653

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841

memo

To: NEPOOL Markets Committee ("MC")

From: Greg Stoltzfus, Manager – Market Operations Support Services
Brent Oberlin, Director – Transmission Planning

Date: September 7, 2022

Subject: Settlement Treatment for Storage as a Transmission Only Asset ("SATOA") (WMPP ID: 166)

The ISO is requesting a vote on proposed revisions to Section I.2.2 of the Tariff, Sections III.3.2.1 and III.3.2.2 of Market Rule 1, and the addition of Section III.1.7.21 to Market Rule 1 to incorporate conforming energy settlement rules associated with a SATOA.

The proposal, as discussed at the NEPOOL Transmission Committee, will enable storage to be considered as a solution in both the Solutions Study process and the competitive solution process to address system concerns identified in Needs Assessments and Public Policy Transmission Studies. Related conforming changes are being considered by the MC to address SATOA's limited participation in markets and metering requirements.

Incorporating the consideration of energy storage devices as transmission facilities into the regional transmission planning process addresses requests from stakeholders, including NESCOE.

The proposal for the committee's consideration at its September 13-14, 2022 meeting has been presented previously to the Markets Committee at the meeting dates outlined below.

- June 7-8, 2022, agenda item #8
- August 9-10, 2022, agenda item #8

AUGUST 16-17, 2022 | STOWE, VT
NEPOOL TRANSMISSION/RELIABILITY COMMITTEES SUMMER MEETING

Storage as a Transmission-Only Asset

Final Follow-up and Draft Tariff Red-Lines

Revision 1 – slide 8 updated

Brent Oberlin

(413) 540-4512 | BOBERLIN@ISO-NE.COM

Project Title: Storage as a Transmission-Only Asset

WMPP ID: 166

Proposed Effective Date: July 2024

- Currently, the New England planning process and associated documents, such as the Tariff and the Transmission Operating Agreement, do not allow storage devices (storage) to be considered as a transmission asset when addressing identified needs and therefore storage is not available for treatment as a transmission asset eligible for Pool-Supported Pool Transmission Facility (PTF)
- Stakeholders have expressed their desire to have storage considered as a transmission asset
  - During the 2019 Competitive Transmission Solicitation Enhancements effort
  - As part of the 2021/2022 Boston 2028 RFP Lessons Learned process
  - At various ISO and NEPOOL meetings
  - FERC noted the ISO's commitment to consider "allowing storage to be considered transmission when addressing reliability concerns" in Docket No. ER22-733-000

Introduction: Storage as a Transmission-Only Asset

- The ISO is developing a process to allow for storage to be considered as a transmission asset. This would allow storage to be considered as a solution in both the Solutions Study process and the competitive solution process to address system concerns identified in Needs Assessments and Public Policy Transmission Studies
- Today's Transmission Committee (TC) discussion is intended to further discuss storage as transmission-only asset (SATOA), provide responses to previously discussed open items raised at the TC, and to discuss updated Tariff-redlines
- FERC filing is targeted for the end of the year to support future Solutions Studies and Requests for Proposal (RFP)

Background

- What is a SATOA?
  - A SATOA is an energy storage device connected to the PTF at 115 kV or higher which can inject stored power to address transmission system concerns
    - The storage medium will not be restricted to one particular technology. Batteries, air, water, large concrete blocks on cranes, etc. are all acceptable
- The ISO has identified some hurdles in undertaking this as a concept. To avoid issues identified, these two concepts will guide its proposal:
  - Introduction of a SATOA cannot compromise reliability by introducing unmanageable operating burdens into the control room
  - A SATOA cannot have a significant impact on the markets
- The proposed design takes these concepts into account

FOLLOW-UP ON PRIOR TC DISCUSSIONS

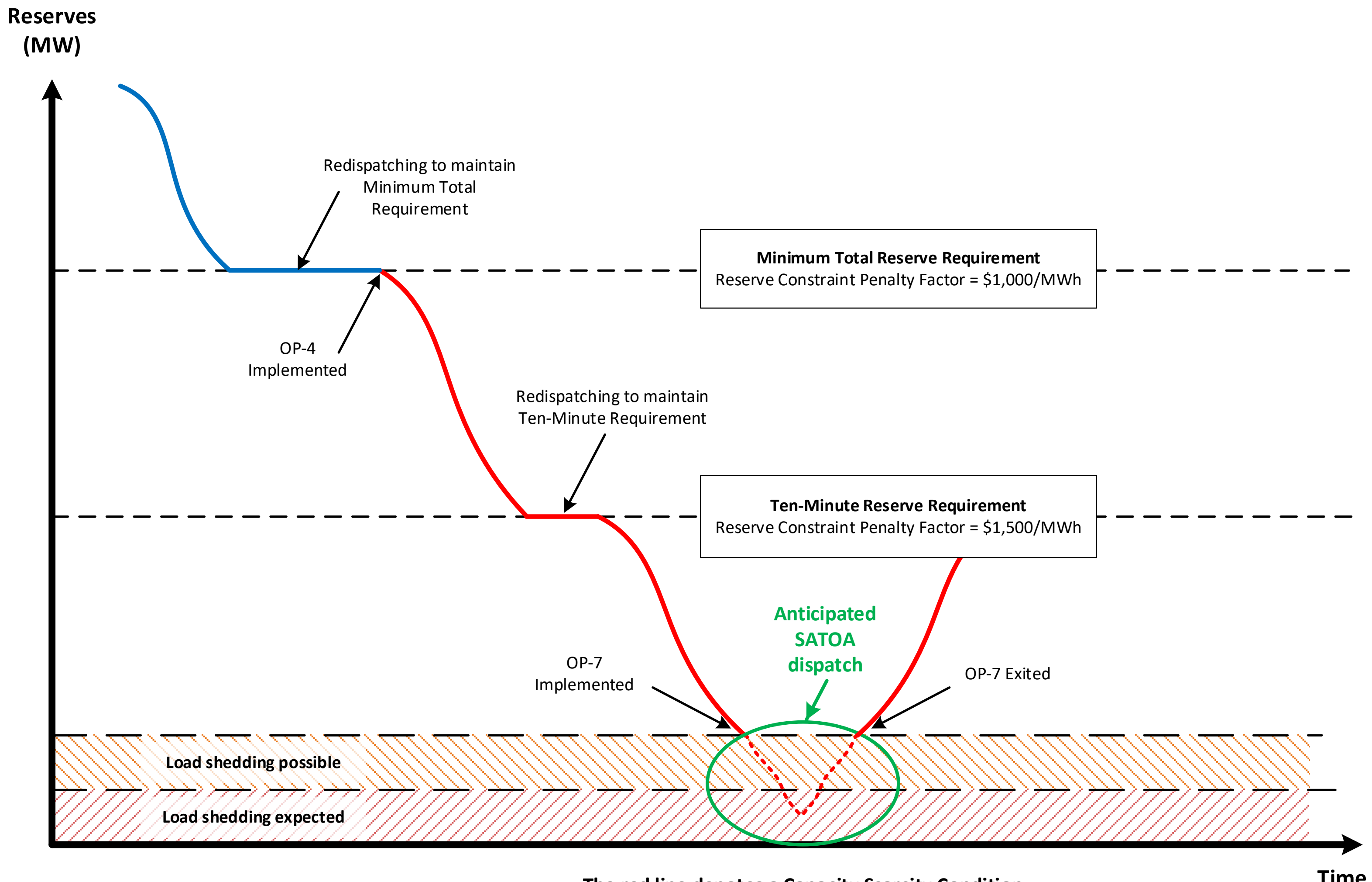
Follow-up from the July TC Meeting

- At the July TC meeting, questions were asked regarding the ability to co-locate resources with a SATOA
  - A resource can be installed at the same substation as a SATOA, including storage, and the additional resource is not subject to, nor considered in, the 300 MW/30 MW SATOA limitations
  - A resource cannot interconnect in such a manner that it uses any of the same facilities as the SATOA, such as inverters or step-up transformers
    - This issue had been previously considered by the ISO, and was prohibited in the definition: "(3) is capable of receiving energy only from the Pool Transmission Facilities and storing the energy for later injection to the Pool Transmission Facilities"
    - Co-locating facilities in this manner would cause concerns such as inverter sizing, equipment failure/longevity, maintenance, etc.

Follow-up from the July TC Meeting, cont.

- At previous TC meetings, a number of questions were asked regarding the use of a SATOA by Operations to prevent or reduce the amount of load shedding during a capacity deficiency
- The example on the next slide provides further clarity on the ISO's previous responses

Example: Reserve Deficiency (Capacity Scarcity Condition) and SATOA Dispatch



The red line denotes a Capacity Scarcity Condition

CHANGES TO DRAFT TARIFF LANGUAGE SINCE THE JULY TC MEETING

Section II.51.2(d)

- Stakeholders noted an inconsistency between language in the presentation discussing the use of a SATOA in FCM and PPA related analysis and the operational description provided in Section II.51.2(d)
- The ISO has revised Section II.51.2(d) to be consistent with the description provided regarding the use of a SATOA in FCM and PPA related analysis

(d) address the applicable system needs or concerns for which the SATOA was ~~selected as the preferred solution~~ identified to address through a Needs Assessment, a Solutions Study, a Public Policy Transmission Study, the competitive solutions process in Attachment K of the OATT, or a combination thereof;

Conclusion

- The ISO received stakeholder requests to consider energy storage devices as transmission facilities and seeks to meet that request with this proposal
- To ensure minimal impact on the ability to operate the system and the markets, limitations on the installation and use of SATOAs are necessary
- The ISO made limited changes (Section II.51.2(d)) to the draft Tariff language between the July TC meeting and today
- The ISO is requesting a vote on the proposed Tariff revisions
- The ISO is targeting a Q4 2022 FERC filing

Stakeholder Schedule for Storage as a Transmission-Only Asset

Proposed Effective Date – July 2024

Stakeholder Committee and Date	Scheduled Project Milestone
April 14, 2022 TC	Discussion of concepts
May 31, 2022 TC	Continued discussion of concepts
June 7-8, 2022 MC	Introduction of settlement conforming changes
June 28, 2022 TC	Review of proposed Tariff redlines
July 27, 2022 TC	Respond to questions, review incremental changes to Tariff redlines and discuss any proposed stakeholder amendments
August 9-10, 2022 MC	Discussion on Tariff changes to enable settlement of SATOAs, introduction of redlines, follow up on stakeholder questions
August 16-17, 2022 TC	Vote on proposal and any stakeholder amendments
August 23, 2022 B & F	Discussion of the proposed language changes related to the indirect link to Schedule IV.A
September 13-14, 2022 MC	Vote on the proposed Tariff revisions related to settlement provisions and any proposed amendments
Participants Committee October 6, 2022	Vote on the proposed Tariff revisions and any proposed amendments

Questions

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APPENDIX 1

Summary of Tariff-Related Revisions

Summary of Tariff-Related Revisions

- This effort requires revisions to a number of Tariff sections and related documents
  - Section I – Definitions added:
    - Real Time SATOA Obligation
    - SATOA

Summary of Tariff-Related Revisions

- Section II, Open Access Transmission Tariff, new Section II.51 added
  - Identifies SATOA as a solution to a Needs Assessment or a Public Policy Transmission Study
  - Section II.51.1 – provides additional evaluation factors and limits the use of a SATOA in planning
  - Section II.51.2 – discusses the use of a SATOA in operations
  - Section II.51.3 – limits the charges that are applicable to a SATOA
  - OATT Section II, Attachment F
    - Appendix E, Section B - Allows a SATOA to be considered as a PTF facility
  - OATT, Section II, Attachment O Non-Incumbent Transmission Developer Operating Agreement (NTDOA)
    - Section 2.01(e)(i) - Adds a SATOA as a Category A facility
    - Schedule 1.01 - Definition of SATOA added since it is now used in the NTDOA
  - Schedules 22, Section 1 and Appendix 6, Article 1 - prevents a SATOA from interconnecting via the generator interconnection process
  - Schedule 23, Section 1 and Exhibit 1, Attachment 1 - prevents a SATOA from interconnecting via the generator interconnection process
  - Schedule 25, Section 1 and Appendix 6, Article 1 - prevents a SATOA from interconnecting via the elective transmission upgrade process

Summary of Tariff-Related Revisions, cont.

- Section III, Market Rule (Tariff redlines to be discussed at the Markets Committee)
  - Section III.1.7.21 – new section added describes a SATOA's participation in the markets
  - Section III.3.2.1(b)(iv) – SATOA added to ensure that real time supply and demand are addressed
  - Section III.3.2.1(b)(v) – new section added to ensure that each PTO accounts for charging and discharging of the SATOA
  - Section III.3.2.2 – added SATOA to metering requirements
- Transmission Operating Agreement (TOA)
  - Section 2.01(e)(i) - Adds a SATOA as a Category A facility
  - Schedule 1.01 - Definition of SATOA added since it is now used in the TOA
  - Schedule 2.01(a) - SATOAs were added to the description of Category A facilities

APPENDIX 2

Proposed Tariff Red-lines that are Unchanged Since the July 27, 2022 TC Meeting

Proposed Tariff-Related Changes, Section I

Tariff Section	Tariff Change	Reason for Change
Section I.2.2	**Storage as Transmission-Only Asset (SATOA)** is electric storage equipment that: (1) is connected to or to be connected to Pool Transmission Facilities in the New England Transmission System at a voltage level of 115 kV or higher; (2) the ISO approved to be included in the Regional System Plan and RSP Project List as a regulated transmission solution and Pool Transmission Facility pursuant to the regional system planning processes in Attachment K of the OATT; and (3) is capable of receiving energy only from the Pool Transmission Facilities and storing the energy for later injection to the Pool Transmission Facilities.	Establishes the term for use in other Tariff sections

Proposed Tariff-Related Changes, Section II

Tariff Section	Tariff Change	Reason for Change
New section II.51 added	**II.51 Treatment of SATOA** A SATOA may only be evaluated and selected as a regulated transmission solution to address the needs of the system identified in a Needs Assessment or Public Policy Transmission Study in accordance with the regional system planning processes and requirements in Attachment K of the OATT, this Section II.51, and any other applicable requirements in the Tariff. A SATOA selected as the preferred solution to address an identified system need shall be classified as a Regional Benefit Upgrade or Public Policy Transmission Upgrade and meet the definition, criteria, and other requirements applicable to such upgrades.	Identifies SATOA as a solution to a Needs Assessment or a Public Policy Transmission Study

Proposed Tariff-Related Changes, Section II

Tariff Section	Tariff Change	Reason for Change
New section II.51.1 added	**II.51.1 Evaluation and Selection of a SATOA:** In addition to the criteria, factors, and requirements in Attachment K of the OATT for evaluating transmission solutions and identifying a preferred solution, the ISO shall consider the following when evaluating whether a SATOA is the appropriate preferred solution to address needs of the system identified in the regional system planning process: (a) the ability of the proposed SATOA to address the applicable system need in all hours that the need is determined to exist; (b) the ability of the proposed SATOA to provide or absorb reactive power regardless of whether the SATOA is injecting or consuming real power; (c) the aggregate amount of SATOAs in New England, which shall be limited to 300 MW of charging capability and 300 MWs of discharging capability; (d) the total amount of SATOAs at a substation, which shall be limited to 30 MW of charging capability and 30 MW of discharging capability; (e) a SATOA shall not be evaluated or selected as the preferred solution to address violations of IROL(s) or system needs related to an IROL; (f) multiple SATOAs shall not be selected to address a single system need or multiple needs in the same area due to contingencies involving the same or similarly situated elements; (g) a SATOA shall only be evaluated or identified as the preferred solution to resolve a system need that is a second contingency (N-1-1); a proposed SATOA shall not be evaluated or identified as the preferred solution to resolve an N-0 (all-lines-in) or N-1 (first contingency) system need; and (h) any additional considerations unique to SATOAs that may support comparative evaluation to other solutions to the system need.	Provides additional evaluation factors and limits the use of a SATOA in planning.

Proposed Tariff-Related Changes, Section II

Tariff Section	Tariff Change	Reason for Change
New section II.51.2 added	**II.51.2 Operation of SATOAs:** A SATOA shall operate, up to the capabilities of the device as proposed and selected during the process to evaluate and select transmission solutions, as necessary to, and only to: (a) dynamically provide or absorb available reactive power while the SATOA is not injecting and not consuming real power to or from PTF; (b) dynamically provide or absorb reactive power while the SATOA is injecting or consuming real power to or from PTF subject to the requirements in Section II.51.2 (c)-(f); (c) maintain the required state-of-charge or maintenance of the SATOA; (d) address the applicable system needs or concerns for which the SATOA was ~~selected as the preferred solution~~ identified to address through a Needs Assessment, a Solutions Study, a Public Policy Transmission Study, the competitive solutions process in Attachment K of the OATT, or a combination thereof; (e) support the New England Transmission System during system restoration; or (f) as specified in the ISO New England Operating Documents, avoid or mitigate Load Shedding after all available Dispatchable Resources that can effectively provide relief to avoid or mitigate the Load Shedding have been dispatched. The ISO New England Operating Documents shall specify the operating practices, limits, and audit requirements applicable to the SATOAs.	Discusses the use of a SATOA in operations. (Language in yellow discussed on slide 10.)

Proposed Tariff-Related Changes, Section II

Tariff Section	Tariff Change	Reason for Change
New section II.51.3 added	**II.51.3 Transmission Service Associated with SATOA Operation:** Transmission service charges, including charges for Ancillary Services, and charges assessed or revenues allocated under Schedules 1, 2, 3, and 5 of Section IV.A of the Tariff are not applicable to the operation of a SATOA.¶	Limits the charges that are applicable to a SATOA

Proposed Tariff-Related Changes, Section II

Tariff Section	Tariff Change	Reason for Change
Attachment F – Appendix E, Rules for Determining Investment to be Included in PTF, Section B, Terminal Investment	16. Transformer-related costs, such as installation and other related costs that would not have been incurred but for the transformer, shall be treated in the same manner as the costs of the transformer. 17. SATOAs and associated facilities.	Allows a SATOA to be considered as a PTF facility

Proposed Tariff-Related Changes, Section II

Tariff Section	Tariff Change	Reason for Change
Attachment O, Non-Incumbent Transmission Developer Operating Agreement, Section 2.10(e)(i)	(i) NTD Category A Facilities shall consist of: all transmission lines with a voltage level of 115 kV and above, except for those 115 kV transmission facilities specifically designated as NTD Category B Facilities in accordance with Section 2.01(e)(ii); all transmission interties between Control Areas; all transformers that have NTD Category A Facilities connected to the lower voltage side of the transformer; all transformers that require an NTD Category A Facility to be taken out of service when the transformer is taken out of service; SATOAs connected to transmission facilities with a voltage level of 115 kV and above; and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such transmission lines, interties, and transformers.	Adds a SATOA as a Category A facility
Attachment O, Non-Incumbent Transmission Developer Operating Agreement, Section Schedule 1.01	Storage as Transmission-Only Asset ("SATOA"). "Storage as Transmission-Only Asset" or "SATOA" shall have the meaning ascribed thereto in Section I.2.2 of the ISO Tariff.	Definition of SATOA added since it is now used in the NTDOA

Proposed Tariff-Related Changes, Section II

Tariff Section	Tariff Change	Reason for Change
Schedule 22 (Large Generator Interconnection Procedures): Section 1 (Definitions); and Appendix 6 (Large Generator Interconnection Agreement), Article 1 (Definitions)	**Generating Facility** shall mean Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities and shall not include a SATOA as defined in Section I of the Tariff.	Prevents a SATOA from interconnecting via the generator interconnection process
Schedule 23 (Small Generator Interconnection Procedures): Attachment 1 (Glossary of Terms); and Exhibit 1 (Small Generator Interconnection Agreement), Attachment 1 (Glossary of Terms)	**Generating Facility** – The Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities and shall not include a SATOA as defined in Section I of the Tariff.	Prevents a SATOA from interconnecting via the generator interconnection process

Proposed Tariff-Related Changes, Section II

Tariff Section	Tariff Change	Reason for Change
Schedule 25 (Elective Transmission Upgrade Interconnection Procedures): Section 1 (Definitions); and Appendix 6 (Elective Transmission Upgrade Interconnection Agreement), Article 1 (Definitions)	**Elective Transmission Upgrade ("ETU")** shall mean a new Pool Transmission Facility, Merchant Transmission Facility or Other Transmission Facility that is interconnecting to the Administered Transmission System, or an upgrade to an existing Pool Transmission Facility, Merchant Transmission Facility or Other Transmission Facility that is part of or interconnected to the Administered Transmission System for which the Interconnection Customer has agreed to pay all of the costs of said Elective Transmission Upgrade and of any additions or modifications to the Administered Transmission System that are required to accommodate the Elective Transmission Upgrade. An Elective Transmission Upgrade shall not include a SATOA as defined in Section I of the Tariff. An Elective Transmission Upgrade is not a Generator Interconnection Related Upgrade, a Regional Transmission Upgrade, or a Market Efficiency Transmission Upgrade.	Prevents a SATOA from interconnecting via the elective transmission upgrade process

Proposed Tariff-Related Changes, TOA

Tariff Section	Tariff Change	Reason for Change
Section 2.01(e)(i)	(i) Category A Facilities shall consist of: all transmission lines with a voltage level of 115 kV and above, except for those 115 kV transmission facilities specifically designated as Category B Facilities in accordance with Section 2.01(e)(ii); all transmission interties between Control Areas; all transformers that have Category A Facilities connected to the lower voltage side of the transformer; all transformers that require a Category A Facility to be taken out of service when the transformer is taken out of service; <u>SATOAs connected to transmission facilities with a voltage level of 115 kV and above;</u> and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such transmission lines, interties, and transformers.	Adds a SATOA as a Category A facility
Schedule 1.01	<u>Storage as Transmission-Only Asset ("SATOA"). "Storage as Transmission-Only Asset" or "SATOA" shall have the meaning ascribed thereto in Section I.2.2 of the ISO Tariff.</u>	Definition of SATOA added since it is now used in the TOA

Proposed Tariff-Related Changes, TOA

Tariff Section	Tariff Change	Reason for Change
Schedule 2.01(a)	Category A Facilities shall consist of all transmission lines listed as "Category A" in this Schedule and all transmission interties between Control Areas, all transformers that have listed Category A lines connected to the lower voltage side of the transformer; all transformers that require a listed line to be taken out of service when the transformer is taken out of service; SATOAs connected to transmission facilities with a voltage level of 115 kV and above; and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such transmission lines, interties, and transformers.	SATOAs were added to the description of Category A facilities

Settlement Treatment for Storage as a Transmission-Only Asset

Treatment of real-time energy obligations

Greg Stoltzfus

MANAGER, MARKET SUPPORT SERVICES

Project Title: Storage as a Transmission-Only Asset

WMPP ID: 166

Proposed Effective Date: July 2024

- The ISO received stakeholder requests to consider energy storage devices as transmission facilities and seeks to meet those requests with its Storage as a Transmission-Only Asset (SATOA) proposal
  - During the 2019 Competitive Transmission Solicitation Enhancements effort
  - As part of the 2021/2022 Boston 2028 RFP Lessons Learned process
  - At various ISO and NEPOOL meetings
  - FERC noted the ISO's commitment to consider "allowing storage to be considered transmission when addressing reliability concerns" in Docket No. ER22-733-000
- Changes to the planning process were discussed at the Transmission Committee (TC); the Markets Committee (MC) is discussing the associated settlement treatment
  - The TC voted in support of the associated planning process revisions at its August 17, 2022 meeting
- This presentation addresses stakeholder questions and describes conforming energy settlement rules to incorporate Pool Transmission Facility (PTF) energy injections and withdrawals by a SATOA

SATOA Proposal Summary

- A SATOA is an energy storage device connected to the PTF at 115 kV or higher which can inject stored power to address transmission system concerns
- The storage medium will not be restricted to one particular technology
- Details associated with the planning process were discussed at the TC
- A SATOA will have a market settlement only for the energy it injects and withdraws on the PTF to operate
- A SATOA will not otherwise participate in markets, and will not use bids/offers or be subject to economic dispatch

Transmission Facility Cost Recovery

- Since a SATOA is considered transmission, the cost of construction and operation are recovered through the Regional Network Service (RNS) rate
- Real-Time Energy costs and revenues resulting from a SATOA performing its transmission function will be reflected in a transmission owner's annual revenue requirement
  - Costs will be added to the owner's transmission revenue requirements
  - Revenues will be used to offset the owner's transmission revenue requirements
- Other than those described above, there will be no other payments made - such as Day-Ahead Energy, Reserve, Regulation, NCPC, Capacity, VAR, Black Start, etc.

FOLLOW-UP FROM STAKEHOLDER QUESTIONS

Follow-up from Stakeholder Questions

When will SATOAs operate?

- The conditions when the ISO could direct a SATOA to charge or discharge are defined in Section II.51.2* of the proposed Tariff language
  - Address the applicable system concern for which the SATOA has been identified to address through the planning process
  - Mitigate load-shedding when a SATOA may help and available market actions that can address the system concern have been exhausted (see example on slide 8)
  - In order to maintain required state-of-charge or maintenance of the SATOA
  - Allow use of a SATOA's capabilities during system restoration
  - Allow auditing of a SATOA's capabilities
- The ISO expects changes to Operating Procedures 4, 7, and 19
- Updates to Operating Procedures are expected to be brought to the NEPOOL Committees soon after a SATOA has been selected through the planning process

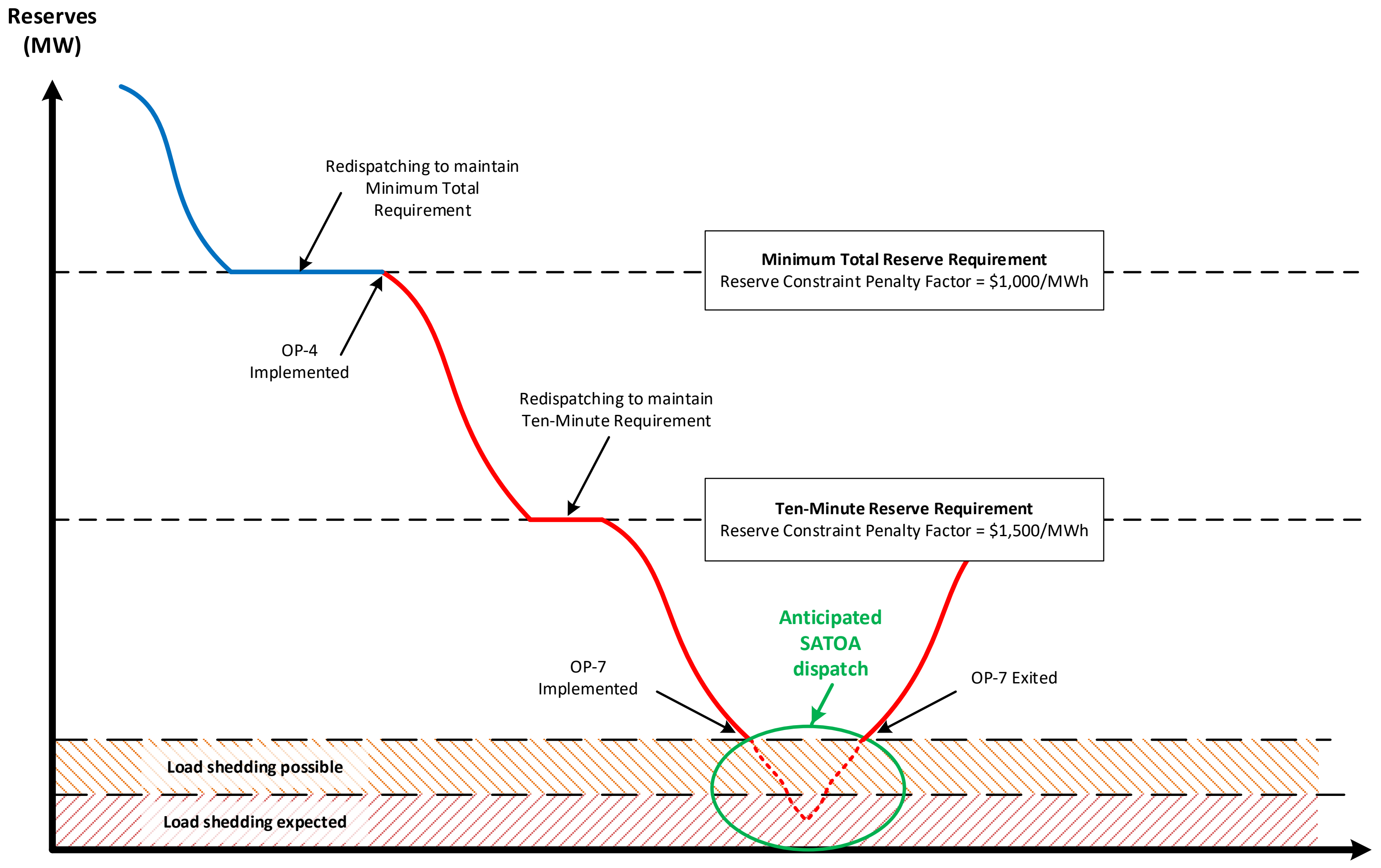
*Section II.51.2 was most recently discussed at the August TC meeting. See slide 22 of the presentation (file "SATOA August TC presentation_final_Rev1.pdf").

Follow-up from Stakeholder Questions

Please clarify what occurs under OP-7 vs OP-4 during a reserve deficiency.

- Changes to Operating Procedures 4 (OP-4) and 7 (OP-7) are anticipated to address the use of a SATOA, consistent with Section II.51.2, during a reserve deficiency
  – OP-4
    - Update reference to accounting for load shedding for post-contingent NERC recovery requirements to include the use of SATOAs in OP-7
    - This accounting occurs after all available market actions have been performed, is for reliability situational awareness, and does not affect reserve pricing
  – OP-7
    - Permit the use of a SATOA to prevent or reduce load shed when all available market assets have been dispatched
- The next slide shows the relationship between OP-4 and OP-7 for using a SATOA during a reserve deficiency

Example: Reserve Deficiency (Capacity Scarcity Condition) and SATOA Dispatch



The red line denotes a Capacity Scarcity Condition

SUMMARY AND NEXT STEPS

Summary of Tariff Revisions

- There are no changes to the Tariff revisions presented at the August meeting, which are located in the appendix
- Section I – General Terms and Conditions
  - Section 1.2.2 – new definitions added for Real Time SATOA Obligation and SATOA
- Section III – Market Rule 1
  - Section III.1.7.21 – new section added to define the limited participation of a SATOA in markets
  - Section III.3.2.1(b)(iv) – SATOA added to ensure that real time supply and demand are addressed
  - Section III.3.2.1(b)(v) – new section added to ensure that each PTO accounts for charging and discharging of the SATOA
  - Section III.3.2.2 – added SATOA to metering requirements

Conclusion

- The ISO received stakeholder requests to consider energy storage devices as transmission facilities and seeks to meet that request with its SATOA proposal
- Conforming energy settlement rules to incorporate PTF energy injections and withdrawals by a SATOA are needed
  - A SATOA will incur costs and receive revenues for charging and discharging in the Real-Time Energy settlement
  - These costs and revenues will be offset by increasing and reducing the SATOA's owner's annual revenue requirement
  - The costs of a SATOA will be recovered through the Regional Network Service rate
- The proposed effective date of these changes is July 2024

Stakeholder Schedule for Storage as a Transmission-Only Asset

Proposed Effective Date – July 2024

Stakeholder Committee and Date	Scheduled Project Milestone
April 14, 2022 TC	Discussion of concepts
May 31, 2022 TC	Continued discussion of concepts
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August 23, 2022 B & F	Discussion of the proposed language changes related to the indirect link to Schedule IV.A
September 13-14, 2022 MC	Vote on the proposed Tariff revisions related to settlement provisions and any proposed amendments
Participants Committee October 6, 2022	Vote on the proposed Tariff revisions and any proposed amendments

Questions

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APPENDIX

Proposed Tariff Changes

Proposed Tariff Changes, Section I

Tariff Section	Tariff Change	Reason for Change
Section I.2.2	**Real-Time SATOA Obligation** is defined in Section III.3.2.1(b) of Market Rule 1.¶	Establishes the term for use in settlement
Section I.2.2	**Storage as Transmission-Only Asset (SATOA)** is electric storage equipment that: (1) is connected to or to be connected to Pool Transmission Facilities in the New England Transmission System at a voltage level of 115 kV or higher; (2) the ISO approved to be included in the Regional System Plan and RSP Project List as a regulated transmission solution and Pool Transmission Facility pursuant to the regional system planning processes in Attachment K of the OATT; and (3) is capable of receiving energy only from the Pool Transmission Facilities and storing the energy for later injection to the Pool Transmission Facilities.¶	Establishes the term for use in other Tariff sections

Proposed Tariff Changes, Section III

Tariff Section	Tariff Change	Reason for Change
Section III.1.7.21	**III.1.7.21 SATOA Participation in Markets:** A Node will be established for each SATOA. A Market Participant's market activity, transactions, and actions taken at a SATOA's Node and a SATOA's participation in the New England Markets shall be limited to those necessary to consume or inject energy from or to PTF for any period, magnitude, and duration identified as necessary to: (1) address the applicable system needs or provide the transmission function for which the SATOA was selected as the preferred solution; or (2) as specified in the ISO New England Operating Documents, avoid or mitigate Load Shedding after all available Dispatchable Resources that can effectively provide relief to avoid or mitigate the Load Shedding have been dispatched.¶	New section added to define the limited participation of a SATOA in markets
Section III.3.2.1(b)(iv)	(iv) **Real-Time Locational Adjusted Net Interchange** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange at each Location equal to the Real-Time Adjusted Load Obligation plus the Real-Time Generation Obligation plus the Real-Time SATOA Obligation at that Location.¶	SATOA added to ensure that real time supply and demand are addressed

Proposed Tariff Changes, Section III

Tariff Section	Tariff Change	Reason for Change
Section III.3.2.1(b)(vi)	(vi) → **Real-Time SATOA Obligation** – Each PTO shall have for each settlement interval a Real-Time SATOA Obligation for energy at each Location equal to the sum of: (1) the MWhs of energy, where such MWhs of energy shall have positive value, provided by SATOAs at that Location; and (2) the MWhs of load, where such MWhs of load shall have a negative value, consumed by SATOAs at that Location.	New section added to ensure that each PTO accounts for charging and discharging of the SATOA
III.3.2.2(a)	(a) → **Revenue Quality Metering and Telemetry for Assets other than Demand Response Assets** The megawatt-hour data of each Generator Asset, Tie-Line Asset, ~~and~~ Load Asset, and SATOA must be metered and automatically recorded at no greater than an hourly interval using metering located at the asset's point of interconnection, in accordance with the ISO operating procedures on metering and telemetering. This metered value is used for purposes of establishing the hourly revenue quality metering of the asset. The instantaneous megawatt data of each Generator Asset (except Settlement Only Resources), ~~and~~ each Asset Related Demand, and each SATOA must be automatically recorded and telemetered in accordance with the requirements in the ISO operating procedures on metering and telemetering.	Added SATOA to metering requirements

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval and Samantha Regan, NEPOOL Counsel

DATE: September 29, 2022

RE: Request by NuPower for Waiver of GIS Operating Rules and GIS Agreement

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At the October 6, 2022 Participants Committee (the "PC") meeting, members will be asked to consider once again whether to waive certain NEPOOL Generation Information System ("GIS") requirements, this time in order to correct renewable energy Certificates for a generator for February and March this year. To provide the requested relief NEPOOL would need to waive provisions of both the GIS Operating Rules ("Rules") and the Amended and Restated Generation Information System Administration Agreement dated as of October 1, 2017, between APX, Inc. ("APX") and NEPOOL, as amended and extended (the "GIS Agreement"). The generator, NuPower Cherry Street FC, LLC ("NuPower"),[1] will offer an explanation why it believes its requested relief is appropriate at the October 6 meeting. NuPower states that, if this request is accepted, the value of the Certificates ($20,000 to $30,000) will be paid by third party buyers of the Certificates under NuPower's contract in the Connecticut LREC program.

By way of context, NuPower operates the Cherry Street Facility, which is a fuel cell facility located in Bridgeport, Connecticut. NuPower's emissions data and Connecticut Class I eligibility for the months of February and March 2022 were not reflected on its GIS Certificates when they were issued on July 15. NuPower attempted to rectify the problem via a request to the Connecticut Public Utilities Regulatory Authority that it recognize the Certificates as Connecticut Class I eligible, but its request was denied by that agency, keeping with its practice with similar requests in the recent past. The Authority noted that, in this situation, only NEPOOL can certify the Certificates as Class I and accordingly this was an issue between NuPower and NEPOOL.

NuPower then sought relief from the Markets Committee ("MC") pursuant to the MC's authority under Rule 3.8 to correct Certificates, arguing that the Certificates in question were issued erroneously because of a software error in the GIS. APX, the GIS Administrator, disputes that there was an error in the GIS software and believes the problem with the NuPower Certificates was due to user error. The MC referred NuPower's request to the GIS Operating Rules Working Group (the "Working Group") to develop additional evidence of whether there was a software error in the GIS that caused the errors in the NuPower Certificates. Indicating subsequently that it did not expect further evidence to be provided with respect to a software error in the GIS, NuPower requested instead that the Rules and the GIS Agreement be waived to rectify the errors in its February and March 2022 Certificates.

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[1] NuPower is not a NEPOOL Participant and is a Non-Participant Account Holder under the GIS Rules.

APX does not have the authority to correct the monthly generation data on the Certificates without both APX and NEPOOL waiving Section 4.2 of the GIS Agreement and Rule 1.4, which require APX to administer and operate the GIS in accordance with the Rules. APX, as the GIS Administrator, has under those provisions "the sole responsibility for the compilation, indexing, reasonable interpretation and implementation of the GIS Operating Rules." Since APX believes it has followed the Rules and GIS Agreement, it can correct NuPower's Certificates only if that Rule and Section of the GIS Agreement are waived.

APX indicates that it would be willing to waive the applicable requirements but only if NEPOOL, as the counterparty to the GIS Agreement, agreed to such a waiver and directed APX to correct the Certificates. In addition, APX has stated that it will not engage in discussions with NEPOOL about the requested waiver unless NuPower first retracts its previous statements regarding the claimed error in the GIS software.

When asked in August 2021 by another renewable energy generator, Stored Solar, LLC, to waive these applicable Rules and the GIS Agreement, the PC referred the matter to the MC for a recommendation first. The MC, in turn, referred the issue to the Working Group for recommendations on the request and suggestions on proposed criteria for NEPOOL to consider any future waiver requests. Before the MC acted on that direction from the PC, the producer found an alternative means of relief and withdrew its request for a waiver.

While the PC can act on NuPower's waiver request without any recommendation from the MC or the Working Group, the PC has already indicated its desire for a recommendation first from the MC in such circumstances. Similarly, while the MC can act on a waiver request without a recommendation from the Working Group, the MC has already indicated its preference for a Working Group recommendation first. Thus, for efficiency the PC can short circuit the process by directing the Working Group to recommend (1) criteria if any to apply to future requests for waiver of the Rules and GIS Agreement to correct erroneous certificates and (2) whether NEPOOL should grant the waivers here to correct NuPower's February and March Certificates (i.e. whether the criteria in item 1 are met in this instance). The PC can further direct that the MC make a recommendation here based on its consideration of any Working Group recommendation, or can have any Working Group recommendation delivered directly to the PC for action.

Whatever process is selected by the PC, NuPower has stated that it needs to have the Certificates corrected no later than the end of the year. There is time for the Working Group to consider this matter, for the MC to consider any recommendations from the Working Group on this matter, and for the PC to have a recommendation in time for a vote at its November or December meeting (depending upon when the Working Group meets and when the MC makes its recommendation). Of course, the PC could also vote on NuPower's waiver request at its October 6 meeting if it is prepared to do so.

Separately, APX requests amendments to the GIS Agreement to provide (1) NEPOOL the authority to waive the Rules to permit adjustments to Certificates without APX's consent; and (2) for APX either to charge NEPOOL for time APX must spend on waiver requests and requests for adjustments to Certificates under Rule 3.8 either at its standard rates or to charge that time against the 500 annual development hours included in the fee paid under the GIS Agreement. APX explains that it had not experienced these sorts of requests prior to the most recent extension of the GIS Agreement and had not included the considerable effort required to respond to those requests in its modified pricing structure agreed to at the time. NEPOOL may also want to consider revising the Rules to require the GIS Account Holder seeking a waiver of the Rules or an adjustment to its Certificates to pay NEPOOL for the costs associated with addressing that request. If members agree conceptually to those GIS Agreement changes, we would suggest that we work with the Participants Committee chair (or his designee(s)) and APX to prepare an amendment for the Participants Committee's consideration, not contingent on the NuPower request or its requested timeline.

The following alternative forms of resolution can be used for Participants Committee actions on NuPower's request:

> RESOLVED, that the Participants Committee refers to the NEPOOL GIS Operating Rules Working Group consideration of the request by NuPower Cherry Street FC, LLC to waive certain NEPOOL Generation Information System Operating Rules and sections of the Amended and Restated Generation Information System Administration Agreement dated as of October 1, 2017, between APX, Inc. and NEPOOL for a recommendation to [this Committee/The Markets Committee] on (1) criteria to apply in acting on this and future waiver requests and (2) the specific waivers sought by NuPower, all as discussed in the materials circulated for this meeting.
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> OR
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> RESOLVED, that the Participants Committee [grants] [denies] NuPower Cherry Street FC, LLC's request to waive certain NEPOOL Generation Information System Operating Rules and sections of the Amended and Restated Generation Information System Administration Agreement dated as of October 1, 2017, between APX, Inc. and NEPOOL as discussed in the materials circulated for this meeting.