NEPOOL
NEW ENGLAND POWER POOL
Sebastian Lombardi
Secretary

January 25, 2024

VIA E-MAIL

TO: **PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES**

RE: Supplemental Notice of February 1, 2024 Participants Committee Meeting

Pursuant to Section 6.6 of the Second Restated New England Power Pool Agreement, supplemental notice is hereby given that the February 2024 meeting of the Participants Committee will be held **in person on Thursday, February 1, 2024, at 10:00 am at the Renaissance Boston Waterfront Hotel, located at 606 Congress Street, Boston, MA 02210, in the Pacific Ballroom,** for the purposes set forth on the attached agenda and posted with the meeting materials at nepool.com/meetings/.

For those who otherwise attend NEPOOL meetings but plan to participate in the February 1 meeting virtually, please use the following dial-in information: **866-803-2146; Passcode: 7169224.** To join WebEx, click this link and enter the event password **nepool**.

FOR PARTICIPANTS, PARTICULARLY THOSE WHO DO NOT TYPICALLY RECEIVE INVOICES FROM ISO-NE, PLEASE NOTE THAT 2024 ANNUAL FEES WILL BE INCLUDED ON THE MONTHLY STATEMENTS TO BE ISSUED ON FEBRUARY 12, 2024. Participants that were members on January 1, 2024 will be assessed that Annual Fee, which must be paid, if the annual fee billing results in an invoice, on or before the close of business on Wednesday, February 14, 2024 in order to avoid penalties and interest. Please plan accordingly. If there are questions, you can reach out to Pat Gerity (860-275-0533; pmgerity@daypitney.com) or to ISO New England's Participant Support and Solutions (413-540-4220; askISO@iso-ne.com).

Looking ahead, the March Participants Committee meeting is scheduled for Thursday, March 7, 2024 and will be held in person. We will in future notices provide more detailed information regarding the location and arrangements for those seeking accommodations the evening before that meeting.

Respectfully yours,

/s/

Sebastian Lombardi, Secretary

FINAL AGENDA

1. To approve the draft minutes of the December 7, 2023 Participants Committee meeting. A copy of the draft minutes, marked to show the changes from the version circulated on January 23, 2024, is 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. Consent Agenda Item No. 3 has been removed and will be considered as Item 5A (see below).

3. To receive an update on activities of the Joint Nominating Committee and information from and about ISO Board member Michael Curran, one of the incumbent ISO Board of Directors who is eligible for re-election to the Board this year.

4. To receive an ISO Chief Executive Officer report. The February CEO report will be circulated and posted in advance of the meeting.

5. To receive an ISO Chief Operating Officer report. The February COO report will be circulated and posted in advance of the meeting. The January COO report was previously circulated and is posted on the NEPOOL and ISO websites.

5A. To consider, and take action, as appropriate, on revisions to Planning Procedure 5-6 (Interconnection Planning Procedure for Generation and Elective Transmission Upgrades). This item was removed from the Consent Agenda (Consent Agenda Item 3). Background materials and a draft resolution are included and posted with this supplemental notice.

6. To consider, and take action, as appropriate, on changes to Tariff §§ I.2.2 (Definitions) and III.9.3 (Forward Reserve Auction Offers), as recommended by the Markets Committee at its January 9, 2024 meeting, to update the Forward Reserve Offer Cap and delay the publication of the Forward Reserve Auction Offer data. Background materials and a draft resolution will be included and posted with the supplemental notice.

6A. To consider, and to take action if and as appropriate, on a request for a waiver of the NEPOOL Generation Information System (GIS) Operating Rules by Saco River Hydro, LLC. Background materials and a draft resolution are included and posted with this supplemental notice.

[continued on next page]

Protocols. The NEPOOL general business portions and plenary sessions of the meeting will be recorded, as are all the NEPOOL Participants Committee meetings. 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 participating in this meeting must 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.

COVID-19 Considerations. To safeguard the well-being of yourself and others, please refrain from attending a NEPOOL meeting in person if you have confirmed that you have COVID-19. If you suspect that you might have COVID-19, or if you have been exposed to COVID-19, please take the precautions recommended by the CDC. In any case, all are encouraged to be respectful of others' personal space, and to respect individual choices with respect to wearing or not wearing masks. Should you receive a COVID-19-positive test result within 10 days of attending a NEPOOL meeting in person, we'd kindly ask that you contact NEPOOL Counsel (pmgerity@daypitney.com) to report that result.

7. To receive a report on current contested matters before the FERC and the Federal Courts. The end of January litigation report will be circulated and posted in advance of the meeting. The January 11, 2024 Report is posted on the NEPOOL website.

8. To receive reports from Committees, Subcommittees and other working groups:

   - Markets Committee
   - Reliability Committee
   - Transmission Committee
   - Budget & Finance Subcommittee
   - Membership Subcommittee
   - Others

9. Administrative matters.

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

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PRELIMINARY

Pursuant to notice duly given, the 2023 annual meeting of the NEPOOL Participants Committee was held beginning at 10:00 a.m. on Thursday, December 7, 2023, at the Colonnade Hotel, Boston, Massachusetts. 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, either in person or by telephone.

Mr. David Cavanaugh, Chair, presided, and Mr. Sebastian Lombardi, Secretary, recorded. Mr. Cavanaugh welcomed the members, alternates and invited guests who were present. Members expressed their appreciation for Mr. Cavanaugh's leadership during his tenure and the grace with which he guided the Committee during the extremely challenging pandemic and afterward. Mr. Cavanaugh then addressed the Committee and remarked that any success achieved had been the direct result of the thoughtful and collaborative engagement among the Participants, together with ~~our~~ NEPOOL's partners at NESCOE, NECPUC and the ISO.

2023 NEPOOL ANNUAL REPORT

Mr. Cavanaugh referred the Committee to the 2023 NEPOOL Annual Report distributed at the meeting and posted on the NEPOOL website. Mr. Cavanaugh thanked the Day Pitney team and the Principal Committee Vice-Chairs ~~of each Sector and the Technical Committees~~ for their efforts assembling and completing the Annual Report. He encouraged members to review the Annual Report.

APPROVAL OF NOVEMBER 2, 2023 MEETING MINUTES

Mr. Cavanaugh then referred the Committee to the preliminary minutes of the November 2, 2023 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. Jon Lamson noted.

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 an abstention by Mr. ~~Jon~~ Lamson noted.

REMARKS BY FERC CHAIRMAN WILLIE PHILLIPS

Mr. Cavanaugh invited ISO Board Chair Ms. Cheryl LaFleur to introduce to the Committee FERC Chairman Willie Phillips, who was accompanied by his Critical Infrastructure and Resilience Advisor, Mr. Kal Ayoub. Ms. LaFleur warmly summarized Chairman Phillips'~~s~~ experience prior to joining the FERC, as well as the hallmarks thus far of his tenure as Chairman, and briefly introduced to Chairman Phillips the key issues facing, and work underway in, New England.

Chairman Phillips t~~T~~hanked ~~ing~~ Ms. LaFleur for her introduction. As a brief pause,[1] Chairman Phillips expressed his appreciation for the opportunity to speak in person to the

[1] As Chairman Phillips began his remarks, a group of Non-Participant representatives of the "No Coal, No Gas" campaign, who had not in advance requested or been invited to attend the meeting as required by the Committee Bylaws, entered the room with no advanced notice and requested the opportunity to listen to Chairman Phillips' remarks. Following a brief conversation with the Committee Chair, those representatives were invited by the Committee

Committee, notwithstanding the briskness of Boston in December (particularly in comparison to warm and sunny California where he had just been). He was grateful to build upon the efforts and experience of the June New England Winter Gas-Electric Forum (Forum) convened in Maine, by addressing NEPOOL directly. Chairman Phillips emphasized that the FERC continued to take very seriously the comments, remarks, and feedback received following the FERC Forum and appreciated the participation in that process. He stressed the importance to him of the issues facing New England, noting that his team, his office and his door was always open, encouraging members to come by and call on them.

Chairman Phillips acknowledged the critical role and importance he ascribed to the stakeholder process. He remarked that stakeholder groups like NEPOOL were critical to ensuring that wholesale electricity markets work for everyone and providing an opportunity for every sector's perspective to be heard, adding that an effective stakeholder process facilitated efforts to address, better understand and achieve some certainty with respect to the multitude of issues facing the grid system. The Chairman thanked those around the table for their active engagement in the process and specifically thanked NEPOOL leadership for the invitation and opportunity to speak to the Participants Committee. He put forward his commitment to be a Chairman focused on ensuring the reliability of energy delivery systems, affordability for all consumers and businesses, and planning for a sustainable energy future for all, including environmental justice communities. He proceeded in turn to address generally each of those areas.

Chair to remain in the room to listen to Chairman Phillips' remarks, and ultimately stayed in the room through those remarks and the remaining agenda items until the Committee was adjourned.

With respect to his commitment to system reliability and affordability, Chairman Phillips summarized ~~-~~the recently released joint statement he penned with NERC's CEO, noting his ongoing concerns with the reliability of New England's grid. He suggested that extreme weather of all kinds was restraining both the region's gas and electric systems. Referring also to the FERC/NERC final report on Winter Storm Elliot, he suggested that extreme weather events, with accompanying generator outages/losses, were becoming more the norm, if not predictable. He recounted a couple of examples of reliability-threatening, low pressure events on natural gas delivery pipelines that underscored for him the need to have an entity responsible for the reliability of the natural gas delivery system. That entity did not have to be the FERC, he said, but it would have to be an entity with the responsibility and authority to enact and enforce natural gas reliability standards. He pointed to Winter Storms Elliot and Uri ~~each serve~~ as sobering examples of how extreme weather events could have severe, adverse impacts on both the gas and electric systems, as well as on the well-being of the population as a whole.

Chairman Phillips urged New England's vigilance and proactive efforts in addressing how extreme weather and a changing resource mix impact winter reliability. Noting the region's reliance on natural gas resources and liquefied natural gas (LNG), and the potential, if not likely, effects of a prolonged cold spell, he was pleased that assessments for Winter 2023/24 projected a milder winter, but cautioned that hoping for or relying on milder winters could not be a sustainable plan for ensuring winter reliability. While the Chairman highlighted the ISO's expectation that, under normal conditions, adequate resources would be available for the upcoming winter and that the near-term energy security outlook may not be as dire as initially projected, he remained concerned about winter reliability in New England, for Winter 2023~~-~~/24 and beyond.

Looking ahead to potential solutions, Chairman Phillips opined that there were not simple solutions or easy fixes, nor could any one entity be relied upon to solve the problem. However, he expressed confidence that the critical players and best ideas would be found around the NEPOOL table, and all would have a role to play. He emphasized the importance of information availability, which would support well-informed decision-making. Identifying key sources of such information, he urged continued consideration and evaluation of the assumptions and methodologies underlying the region's assessments and studies. He was optimistic that NPCC's northeastern regional gas infrastructure study (including hydraulic modeling of gas systems in New England and New York) would help address some information gaps identified during the June Forum.

Turning to wholesale electric market design, Chairman Phillips noted the potential for Resource Capacity Accreditation (RCA) and other reforms to help address winter reliability issues by appropriately valuing the capacity of certain resources. He encouraged the region to consider such potential reforms in a holistic manner. He further encouraged the region, including the New England States (States), to ensure that the changing resource mix is implemented in a way that supports grid reliability. He noted concern with the impacts of the premature retirement of certain energy resources, including critical infrastructure like the Everett LNG facility, particularly during extreme weather events. Nonetheless, he applauded the efforts to implement ambitious clean energy goals, and emphasized that, in reaching for those goals, system reliability be kept top of mind.

Chairman Phillips spoke to the FERC's *Order 2023* interconnection reforms, which he characterized as a great first step on the "Transmission Reform Journey", as well as to FERC's long-term regional transmission planning rule efforts. Both of those efforts ~~a~~were intended to build upon developments in the various regions of the country and would be integral to preparing for the goals and a future 20-30 years down the road, by making necessary, critical and foundational decisions today.

Chairman Phillips then addressed environmental justice and equity (EJ). He articulated the industry's obligation to be sensitive to the cost and benefits of how energy is produced, procured and delivered. Noting that impacts had not historically been shared equally, he offered personal testimony to the challenges faced by EJ communities. He said it would be incumbent upon the industry moving forward to improve that balance so that the system planned for benefits all. He reported that the FERC hoped to issue in the near future an outward facing guidance document that would help utilities, advocates, and all those involved in the stakeholder processes better understand the FERC's expectation with respect to EJ communities, how to engage those communities, and how th~~e~~ose issues can be addressed in the stakeholder process.

In response to questions, he suggested that, to achieve a successful transition, many would have to be encouraged and lead, into what for them may be unfamiliar and uncomfortable territory, through education and changed behavior. Education would have to include a focus on the cost (both capital and human) of not taking certain steps/actions. He further challenged the members to work together to help ensure that the transition to a cleaner grid could be achieved~~,~~ reliably. He was also optimistic that the transition solution space would, with ~~the~~ appropriate adjustments, work with competitive wholesale markets, which he firmly believed added value when functioning properly.

When asked for thoughts on cost evaluation, Chairman Phillips referred to ongoing FERC proceedings addressing transmission costs. He believed there could be long-term savings, particularly given the impending need to replace aging infrastructure. He believed it more costly to reactively address aging infrastructure following operational failures, rather than proactively updating/upgrading that infrastructure. The benefits attendant to new projects, including economic, reliability, sustainability, and policy benefits, would all have to be considered, as well as the weighing of the costs of doing nothing.

There being no further questions, and on behalf of the Committee, Mr. Cavanaugh thanked Chairman Phillips for the generosity of his time and for his very thoughtful comments.

ISO CEO REPORT

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

Reacting to discussion from, and in reference to the Annual Report distributed earlier in, the meeting, Mr. van Welie stressed the importance of the values articulated in the Annual Report's theme – candor, respect and collaboration – as enhanced by "succeeding together". He suggested that the journey to refine and decarbonize the region's energy system could only be achieved through a collective, team effort, which in turn would rely on and be furthered by those values. He expressed his appreciation, not only for the express recognition afforded those values, but to the collaboration between the States, NEPOOL, and the ISO to support and achieve that outcome. He committed the ISO to those values.

Mr. van Welie recognized Mr. Cavanaugh for his "impeccable" leadership as NEPOOL Chair over the prior three years, complimenting him for how he helped NEPOOL navigate through the challenges it faced during his tenure as Chair. He looked forward to working with the next Chair, who he believed would likely face a similar series of challenges.

Finally, Mr. van Welie thanked Chairman Phillips and his staff for the thoughtful and substantive remarks offered earlier in the meeting. He was pleased how, from reliability, to cost and environmental justice, to gas-electric issues, the Chairman had addressed, and was affirmatively working on, many of the dimensions underlying the challenges facing the region.

ISO COO REPORT

Operations Highlights

Dr. Chadalavada referred the Committee to his December operations report, which had been circulated and posted in advance of the meeting. Dr. Chadalavada noted that the data in the report was through November 29, 2023, unless otherwise noted. The report highlighted: (i) Energy Market value for November 2023 was $378 million, up $118 million from the updated October 2023 value and down $275 million from November 2022; (ii) November 2023 average natural gas prices were 144% lower than October average prices; (iii) average Real-Time Hub Locational Marginal Prices (LMPs) for November ($35.96/MWh) were 48% higher than October averages; (iv) average November 2023 natural gas prices and Real-Time Hub LMPs over the period were down 40% and down 47%, respectively, from November 2022 average prices; (v) average Day-Ahead cleared physical energy during peak hours as percent of forecasted load was 100.6% during November (down from 101.6% reported for October), with the minimum value for the month of 95.2% on November 18; and (vi) Daily Net Commitment Period Compensation (NCPC) payments for November totaled $4.9 million, which was up $0.4 million from October 2023 and up $1.1 million from November 2022. November NCPC payments, which were 1.3%

of total Energy Market value, was comprised of $4.9 million in first contingency payments (up $0.4 million from October). There were no second contingency or voltage NCPC payments in November.

Dr. Chadalavada reported that November 2023 was colder than normal -- 6° F colder than November 2022 and 2° F colder than an average November in New England. Loads were slightly higher than November 2022, despite a significant increase in behind-the-meter photovoltaic (PV) installations and output (November 2023 averaged 3,900 MW of PV output, 600 MW more than 2022). He added that the pace of New England PV installations was averaging 600-800 MW per year. Tight system conditions were experienced on three days in November (the 6th, 29th and 30th), with each day having loads slightly higher than forecast, forced outages, and in a couple of instances, imports slightly below the Day-Ahead Energy Market level. On those days, there were binding reserve constraints, but not to the point where any capacity deficiency was forecasted.

Turing to upcoming planned transmission outages, Dr. Chadalavada noted two: (i) Line 312/393 (Northfield to Alps), which would be out of service from December 5 to December 10, and was expected to reduce in both directions the New York-New England interface limit to roughly 900 MW; and (ii) Line 369 (Seabrook-to-Timberswamp), which would be out of service from December 11 to December 16, potentially exposing New Hampshire and Maine to second contingency costs.

Dr. Chadalavada also reported that the Tariff revisions to make front-of-meter solar installations dispatchable under "do not exceed" (DNE) rules that account for the resources' variable output and any congestion on the transmission system was successfully implemented on December 5, 2023. He said that approximately 50-60 assets, totaling roughly 620 MW, were participating in the Solar DNE program, with 35-40 of those assets having put in place the necessary protocols to receive ISO dispatch instructions, and the remainder expected to submit, as permitted, plans to come into compliance before the expiration of the Tariff's compliance grace period. Implementation was smooth and comparable to implementation of the Wind DNE dispatch provisions. The ISO was pleased with the progress of solar assets' participation in the markets and the additional performance visibility that participation in the Solar DNE program provided to Control Room operators.

In response to questions, Dr. Chadalavada indicated that progress was being made with respect to PV load forecasting. He pointed to increased sampling of data sets, more accurate "machine learning", and better weighting of composite forecasts as contributing to that progress. Also, ISO adjustments had minimized what had previously been a consistent underforecasting bias. Several additional improvements were planned, including as the science would allow improvements to cloud cover forecasts, a key variable to PV forecasting. Dr. Chadalavada committed, with the benefit of additional experience and data, to come back to the Committee to review and discuss the performance of this ongoing effort.

New England 2023/24 Winter Outlook Update

Dr. Chadalavada then updated the Committee on the 2023/24 Winter Outlook. He reported that there was a 40-60% chance that temperatures would be above normal, and a 33-40% chance that, for southern New England, precipitation would be above normal (with an equal chance for above or below normal precipitation for northern New England). He noted that the Mystic cost-of-service agreement would continue through Winter 2023/24 and the Inventoried Energy Program (IEP) program would be in effect both for Winter 2023/24 and 2024/25. Winter demand for Winter 2023/24 was forecast to be roughly 250 MW to 350 MW (or 1.3% to 1.6%) higher than the prior winter. The ISO expected roughly 31 billion cubic feet (Bcf) of LNG to be available to thermal resources. Aggregate fuel-oil inventory was roughly 188 million gallons (48% of the max) and following commissioning earlier in the year, an~~d~~ additional 500 MW of dual-fuel capability/flexibility was available to the ISO. The Energy analysis for Winter 2023/24 remained unchanged from previous reports, with sufficient capacity and energy, with just a few possible but limited exceptions, generally available under both moderate and severe weather scenarios.

Addressing the IEP, Dr. Chadalavada estimated 2023/24's forward cost to be roughly $78 million, with total forward elections at 844,201 MWh. He noted an increase in the spot energy inventory elections, which had jumped since his November report, to an estimated 287,022 MWh. He added that, because spot participation would be compensated at $9.25/MWh on days meeting the IEP day threshold (an IEP Day), each IEP Day would add roughly $2.65 million to the overall program costs.

nGem Program Overview

Dr. Chadalavada then provided a long-anticipated high level overview of the next Generation Electricity Market (nGEM) program that General Electric (GE) had been developing for more than five years and would replace the existing GE platform being used by a number of the RTOs, including ISO-NE, MISO and PJM. nGem, he explained, would not replace the functionality of the ISO's current GE platform, but would introduce flexibility and new features, including a design that incorporates industry standard cyber security requirements, support for faster market rule implementation, improved test automation, and Kubernetes/containers-based technology that parses out and manages application code in smaller, more individually maintained chunks. nGem would be more easily monitored, maintained and standardized. He estimated New England would put up roughly $15 million towards initial development and total expected project cost over the next 10 years and its 20-year lifespan would run approximately $80-90 million.

Members thanked the ISO for the additional information and insight related to this enhanced market tool. In response to questions, Dr. Chadalavada further explained how the containerization of the platform would facilitate more expedited development, testing and implementation of market rule changes. He provided further context and examples of how nGem represented a significant improvement over previous platforms and tools.

ELECTION OF 2024 PARTICIPANTS COMMITTEE OFFICERS

Mr. Cavanaugh referred the Committee to the proposed slate of 2024 NEPOOL Participants Committee Officers circulated and posted in advance of the meeting. The following motion was duly made, seconded and unanimously approved, with an abstentions noted by the New Hampshire Office of Consumer Advocate and Mr. Lamson:

> WHEREAS, Section 4.6 of the Participants Committee Bylaws sets forth procedures for the nomination and election of a Chair and Vice-Chairs of the Participants Committee; and
>
> WHEREAS, pursuant to those procedures the individuals identified in the following resolution were nominated and elected for 2024 to the offices of Chair and Vice-Chair, as set forth opposite their names; and
>
> WHEREAS Section 7.1 of the Second Restated NEPOOL Agreement provides that officers be elected at the annual meeting of the Participants Committee.
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> NOW, THEREFORE, IT IS

RESOLVED, that the Participants Committee hereby adopts and ratifies the results of the election held in accordance with Section 4.6 of the Bylaws and elects the following individuals for 2024 to the offices set forth opposite their names to serve until their successors are elected and qualified:

Chair	Sarah Bresolin
Vice-Chair	Dave Cavanaugh
Vice-Chair	Michelle Gardner
Vice-Chair	Aleks Mitreski
Vice-Chair	Paul Roberti
Vice-Chair	Alan Trotta
Secretary	Sebastian Lombardi
Assistant Secretary	Pat Gerity

ESTIMATED BUDGET FOR 2024 NEPOOL EXPENSES

Mr. Tom Kaslow, Budget & Finance Subcommittee (B&F) Chair, reported that the B&F Subcommittee reviewed, at its November 28, 2023 meeting, the estimated budget for 2024 Participant Expenses, a copy of which was circulated and posted in advance of the meeting and is included as Attachment 2 to these minutes. He reported that there were no concerns or objections identified by Subcommittee members. Without further discussion, the following motion was duly made, seconded and approved unanimously, with an abstention noted by Mr. Lamson:

RESOLVED, that the Participants Committee adopts the estimated budget for NEPOOL expenses for 2024 as presented at this meeting.

FAP CHANGES – FCM DELIVERY FINANCIAL ASSURANCE

Mr. Kaslow then introduced proposed changes to the ISO Financial Assurance Policy (FAP) to update the provisions related to the FCM Delivery Financial Assurance requirements (the FCM Delivery FA Changes). He explained that the FCM Delivery FA Changes were intended to better align the financial assurance (FA) required with respect to FCM pay-for-performance (PFP) penalties with the potential risk of non-payment of those penalties. He reported that the FCM Delivery FA Changes were discussed by the B&F Subcommittee at its September 26, October 30 and November 28 meetings, with no Subcommittee member at those meetings objecting to the Changes. Following motion duly made and seconded, the Committee unanimously approved the following motion, with an abstention by Mr. Lamson noted:

> RESOLVED, that the Participants Committee supports the changes to the FAP related to the calculation of FCM Delivery Financial Assurance, as proposed by the ISO and as circulated to this Committee with the November 30, 2023 supplemental notice, together with such non-substantive changes as may be approved by the Chair of the Budget & Finance Subcommittee.

IMM 2022 ANNUAL MARKETS REPORT

Mr. David Naughton, ISO Internal Market Monitoring (IMM) Executive Director, referred members to the summary of the IMM's 2022 Annual Markets Report (2022 IMM Annual Report) circulated and posted with the materials for the meeting. He also highlighted an accompanying primer, entitled "An Overview of New England's Wholesale Electricity Markets" (Primer). He explained that the Primer was intended to be a resource to explain the underlying mechanics of New England Markets, while the 2022 IMM Annual Report focused on key trends, the drivers of those trends, and an evaluation of the overall competitiveness and performance of the Markets.

Turning to the performance of New England markets in 2022, he reported that, due to high natural gas prices, 2022's energy prices were the highest since standard market design (SMD) was implemented in 2003; the region's overall market costs were the highest experienced since 2008. Looking ahead to 2023, he anticipated that energy prices and overall costs would be significantly lower.

Next, Mr. Naughton presented the IMM's simulation of generator profitability, namely, how much hypothetical combined cycle and combustion turbine generators could have earned in the wholesale markets. Referring to a chart, he explained that the results indicated that revenues for hypothetical combined cycle and combustion turbine generators in 2022 were above their calculated Cost of New Entry (CONE). He explained that this was the first time since 2018 that the wholesale markets provided enough revenues to make it profitable for a new gas-fired generator in the region. The cold spells experienced in Winter 2022/23 contributed to this result. In response to a question, Mr. Naughton confirmed that the simulation model included Regional Greenhouse Gas Initiative (RGGI) costs but not those from the Commonwealth of Massachusetts' Global Warming Solutions Act.

Addressing virtual transactions, Mr. Naughton showed a trend in 2022 indicating a significant increase in virtual supply submissions and clearances between hours ending 9 through 17. Mr. Naughton explained the relationship between virtual supply and PV generation, especially on days with high solar output. Because most solar generation participates as settlement-only generation (SOG) and cannot participate in the Day-Ahead Energy Market, he explained that virtual supply offers replaced the price-taking SOGs that show up in Real-Time. Thus, he reasoned that virtual transactions add value to the market by helping converge Day-Ahead prices downward to Real-Time prices. Relatedly, he discussed virtual transaction profitability. He noted that NCPC charges impact the profitability of virtual transactions. Given the expected increase of intermittent generation, Mr. Naughton pointed to a long-standing IMM recommendation to improve the NCPC-related rules to reduce NCPC charges to virtual transactions.

Mr. Naughton then discussed reserve pricing under fast-start pricing. He observed a higher rate of non-zero reserve pricing when the reserve constraint is not binding, i.e., a physical reserve surplus exists, contrary to the purpose of reserve prices. To explain, he referred to an illustrative example showing that, on December 12, 2022, fast-start pricing generated reserve pricing for 85 minutes despite the reserve constraint binding for only 20 minutes. These points notwithstanding, Mr. Naughton opined that fast-start pricing generally supported better price formation in the Real-Time Energy Market by enabling fast-start generators to set the clearing price. In any case, he recommended that the ISO reassess the reserve pricing mechanism under fast-start pricing to address the frequency of non-zero reserve pricing when there is a physical reserve surplus.

Next, Mr. Naughton noted that energy market mitigation remained very low. He did, however, point out the December 24, 2022 mitigation event where an unusual step was taken to mitigate certain resources upward. Mr. Naughton explained that the FERC issued a show cause order, directing the ISO to review its mitigation rules. Following that review, the ISO filed a NEPOOL-supported proposal to eliminate the risk of upward mitigation, which as of the date of his report remained pending before the FERC. Mr. Naughton also stated that he supported a proposal to revise the Tariff provisions relating to the fuel price adjustment construct. That proposal was still being considered in the stakeholder process. Following this summary of energy market mitigation, he reviewed four recommendations for energy market mitigation design and responded to questions concerning two of the recommendations.

In the final portion of his presentation, Mr. Naughton commented on the Forward Reserve Market (FRM). He stated his concerns with the material offer price increase and related structural market power issues. He explained his recommendation for revisions to the

Forward Reserve ~~o~~Offer ~~c~~Cap and delaying the publication of FRM offer data, both making their way through the stakeholder process.

LITIGATION REPORT

Mr. Lombardi referred the Committee to the December 6 Litigation Report that had been circulated and posted before the meeting. He highlighted (i) the deadline for comments on the ISO's FCA18 Qualification Informational Filing set to end later that day, and (ii) the many joint ISO/NEPOOL filings that were pending FERC action, all the product of significant and recent efforts in the stakeholder process, including: the FCA19 schedule changes; FCM CONE and Net CONE updates; Energy Supply Offer Mitigation changes; Retirement/Permanent De-List Bid Price Flexibility changes; changes to the qualification rules for Distributed Energy Capacity Resources; and the compliance filing to make eligible to participate in the ~~Inventoried Energy Program (~~IEP~~)~~ pumped storage resources participating as Electric Storage Facilities.

COMMITTEE REPORTS

Markets Committee (MC). Mr. William Fowler, the MC Vice-Chair, reported that the next MC meeting was scheduled for December 12-14 in Westborough, MA. He indicated that key topics would include the RCA project, discussion on Analysis Group's report and key findings on alternative FCM commitment horizons, and various market rule enhancements and compliance-related changes.

Reliability Committee (RC). Mr. Robert Stein, the RC Vice-Chair, reported that, in addition to the December 12-13 joint meeting with the Markets Committee to consider RCA issues, the RC would itself meet on December 18-19. Key topics for the RC's two-day meeting would include, in addition to continuation of RCA discussions and consideration of a number of

Proposed Plan Applications and Transmission Cost Allocations, an introduction to the Regional Energy Shortfall Threshold (REST), a project to determine what level of reliability the region should strive to attain.

Transmission Committee (TC). Mr. Dave Burnham, the TC Vice-Chair, reported that the next TC meeting was scheduled in person in Westborough for December 21. Key topics would include longer/extended-term transmission planning and the ongoing FERC *Order 2023* compliance effort. With respect to *Order 2023* compliance, TC members could expect to see draft ISO-proposed Tariff redlines posted the following day and an additional TC meeting to be scheduled in early January to allow primarily for consideration of stakeholder amendments. He encouraged those with *Order 2023*-related amendments that had not already done so to reach out to him and the TC Chair, Ms. Emily Laine.

Budget & Finance Subcommittee. Mr. Kaslow reported that the next B&F Subcommittee meeting was scheduled for January 24, 2024.

Membership Subcommittee. Ms. Ashley Gagnon, Membership Subcommittee Chair, reported that the next Membership Subcommittee meeting was scheduled for December 11.

ADMINISTRATIVE MATTERS

Mr. Lombardi noted the possibility that January 4, 2024, then the date of the next regularly-scheduled Participants Committee meeting, might instead be used for the additional Transmission Committee discussion needed on amendments to the ISO's *Order 2023* compliance proposal. He encouraged members to stay tuned for further information and confirmation of the schedule for that day. Mr. Cavanaugh noted the membership orientation that would follow the meeting and encouraged members interested in additional information and insight on membership and stakeholder process issues to participate. He wished all a safe and joyful holiday season.

There being no other business, the meeting adjourned at 12:40 p.m.

Respectfully submitted,

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Sebastian Lombardi, Secretary

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES PARTICIPATING IN DECEMBER 7, 2023 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Advanced Energy United	Associate Non-Voting		Alex Lawton	
Ashburnham Municipal Light Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Associated Industries of Massachusetts	End User			Mary Smith (tel)
AVANGRID: CMP/UI	Transmission	Alan Trotta	Jason Rauch	Zach Teti (tel)
Bath Iron Works Corporation	End User			Bill Short (tel)
Belmont Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Block Island Utility District	Publicly Owned Entity	Dave Cavanaugh		
BlueWave Public Benefit Corp.	AR-DG	Mike Berlinski		
Boylston Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
BP Energy Company (BP)	Supplier			José Rotger
Braintree Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
Brookfield Renewable Trading and Marketing	Supplier	Aleks Mitreski		
Castleton Commodities Merchant Trading	Supplier			Bob Stein
Chester Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Chicopee Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
CLEAResult Consulting, Inc.	AR-DG	Tamera Oldfield		
Clearway Power Marketing LLC	Supplier			Pete Fuller
Concord Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
Connecticut Municipal Electric Energy Coop.	Publicly Owned Entity	Brian Forshaw (tel)		
Connecticut Office of Consumer Counsel (CT OCC)	End User		Jamie Talbert-Slagle	Jackie Litynski
Conservation Law Foundation (CLF)	End User	Phelps Turner (tel)	Priya Gandbnir	
Constellation Energy Generation	Supplier	Gretchen Fuhr	Bill Fowler	
CPV Towantic, LLC (CPV)	Generation	Joel Gordon		
Cross-Sound Cable Company (CSC)	Supplier		José Rotger	
Danvers Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Dominion Energy Generation Marketing, Inc.	Generation	Wes Walker (tel)		
DTE Energy Trading, Inc. (DTE)	Supplier			José Rotger
Durgin and Crowell Lumber Co., Inc.	End User			Bill Short (tel)
Dynegy Marketing and Trade, LLC	Supplier	Andy Weinstein		Bill Fowler
ECP Companies Calpine Energy Services, LP (Calpine) New Leaf Energy	Generation	Brett Kruse Liz Delaney	Andy Gillespie	Bill Fowler Alex Chaplin
EDF Trading North America, LLC	Supplier	Eric Osborn (tel)		
Elektrisola, Inc.	End User			Bill Short (tel)
Emera Energy Services	Supplier			Bill Fowler
Enel X North America, Inc.	AR-LR	Alex Worsley		
ENGIE Energy Marketing NA, Inc.	AR-RG	Sarah Bresolin	Joe Dalton	
Eversource Energy	Transmission	James Daly	Dave Burnham (tel)	Vandan Divatia
Excelerate Energy LP	Associate Non-Voting	Gary Ritter		
FirstLight Power Management, LLC	Generation	Tom Kaslow		
Galt Power, Inc. (Galt)	Supplier	José Rotger	Jeff Iafrati (tel)	
Garland Manufacturing Company	End User			Bill Short (tel)
Generation Bridge Companies	Generation	Bill Fowler		
Generation Group Member	Generation	Dennis Duffy	Abby Krich	
Georgetown Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Groton Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Groveland Electric Light Department	Publicly Owned Entity		Dave Cavanaugh	
H.Q. Energy Services (U.S.) Inc. (HQ US)	AR-RG	Louis Guibault (tel)	Bob Stein	
Hammond Lumber Company	End User			Bill Short (tel)

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN DECEMBER 7, 2023 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
High Liner Foods (USA) Incorporated	End User		William P. Short III (tel)	
Hingham Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Holden Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Holyoke Gas & Electric Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Hull Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Icetec Energy Services, Inc.	AR-LR	Doug Hurley		
Ipswich Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Jericho Power LLC (Jericho)	AR-RG	Ben Griffiths	Nancy Chafetz (tel)	Marji Philips
Jupiter Power	AR-RG		Ron Carrier (tel)	
Lamson, Jon	End User	Jon Lamson		
Littleton (MA) Electric Light and Water Department	Publicly Owned Entity		Dave Cavanaugh	
Littleton (NH) Water & Light Department	Publicly Owned Entity		Craig Kieney (tel)	
Long Island Power Authority (LIPA)	Supplier	Bill Kilgoar (tel)		
Maine Power LLC	Supplier	Jeff Jones (tel)		
Maine Public Advocate's Office	End User	Drew Landry		
Mansfield Municipal Electric Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Maple Energy LLC	AR-LR			Doug Hurley
Marblehead Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Mass. Attorney General's Office (MA AG)	End User	Ashley Gagnon	Jamie Donovan (tel)	
Mass. Bay Transportation Authority	Publicly Owned Entity		Dave Cavanaugh	
Mass. Department of Capital Asset Management	End User	Paul Lopes	Nancy Chafetz (tel)	
Mass. Municipal Wholesale Electric Company	Publicly Owned Entity	Matt Ide	Dan Murphy	
Mercuria Energy America, LLC	Supplier			José Rotger
Merrimac Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Middleborough Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Middleton Municipal Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Moore Company	End User			Bill Short (tel)
Narragansett Electric Co. (d/b/a RI Energy)	Transmission	Brian Thomson	Lindsay Orphanides (tel)	
Nautilus Power, LLC	Generation		Bill Fowler	
New Hampshire Electric Cooperative	Publicly Owned Entity			Brian Forshaw (tel)
New Hampshire Office of Consumer Advocate	End User	Donald Kreis		
New England Power (d/b/a National Grid)	Transmission	Tim Brennan	Tim Martin	
New England Power Generators Assoc. (NEPGA)	Associate Non-Voting	Bruce Anderson		Molly Connors (tel)
NextEra Energy Resources, LLC	Generation	Michelle Gardner	Nick Hutchings	
North Attleborough Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Norwood Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
Nylon Corporation of America	End User			Bill Short (tel)
Pascoag Utility District	Publicly Owned Entity		Dave Cavanaugh	
Pawtucket Power Holding Company LLC	Generation	Dan Allegretti	Kevin Telford	
Paxton Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Peabody Municipal Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
PowerOptions, Inc.	End User			Jackie Litynski
Princeton Municipal Light Department	Publicly Owned Entity	Matt Ide		
Reading Municipal Light Department	Publicly Owned Entity		Dave Cavanaugh	
RI Division (DPUC)	End User	Paul Roberti		
Rowley Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Russell Municipal Light Dept.	Publicly Owned Entity	Matt Ide		
Saint Anselm College	End User			Bill Short (tel)
Shell Energy North America (US), L.P.	Supplier	Jeff Dannels		
Shipyard Brewing LLC	End User			Bill Short (tel)

ATTACHMENT 1

PARTICIPANTS COMMITTEE MEMBERS AND ALTERNATES
PARTICIPATING IN DECEMBER 7, 2023 MEETING

PARTICIPANT NAME	SECTOR/ GROUP	MEMBER NAME	ALTERNATE NAME	PROXY
Shrewsbury Electric & Cable Operations	Publicly Owned Entity		Matt Ide	Dan Murphy
Sierra Club	End User	Casey Roberts (tel)		
South Hadley Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Sterling Municipal Electric Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Stowe Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Sunrun Inc.	AR-DG			Pete Fuller
SYSO Inc.	AR-DG	Doug Matheson		
Tangent Energy Inc.	AR-LR	Brad Swalwell (tel)		
Taunton Municipal Lighting Plant	Publicly Owned Entity		Dave Cavanaugh	
Templeton Municipal Lighting Plant	Publicly Owned Entity	Matt Ide		Dan Murphy
The Energy Consortium	End User		Mary Smith (tel)	
Vermont Electric Cooperative	Publicly Owned Entity	Craig Kieney (tel)		
Vermont Electric Power Company (VELCO)	Transmission	Frank Ettori		
Vermont Public Power Supply Authority	Publicly Owned Entity			Brian Forshaw (tel)
Versant Power	Transmission	Dave Norman (tel)		
Village of Hyde Park (VT) Electric Department	Publicly Owned Entity	Dave Cavanaugh		
Wakefield Municipal Gas & Light Department	Publicly Owned Entity		Matt Ide	Dan Murphy
Walden Renewables Development LLC	Generation			Abby Krich
Wallingford DPU Electric Division	Publicly Owned Entity		Dave Cavanaugh	
Wellesley Municipal Light Plant	Publicly Owned Entity		Dave Cavanaugh	
West Boylston Municipal Lighting Plant	Publicly Owned Entity		Matt Ide	Dan Murphy
Westfield Gas & Electric Department	Publicly Owned Entity		Dave Cavanaugh	
Wheelabrator North Andover Inc.	AR-RG		Bill Fowler	
Z-TECH LLC	End User			Bill Short (tel)

**ESTIMATED 2024 NEPOOL BUDGET COMPARED TO
2023 NEPOOL BUDGET AND 2023 PROJECTED ACTUAL EXPENSES**

Line Items	2023 Approved Budget	2024 Proposed Budget	2023 Current Forecast
NEPOOL Counsel Fees (1)	$4,350,000	$4,350,000	$4,350,000
NEPOOL Counsel Disbursements (1)	$ 30,000	$ 30,000	$ 30,000
Independent Financial Advisor Fees and Disbursements (2)	$ 48,000	$ 48,000	$ 47,000
Committee Meeting Expenses (1)	$ 900,000	$ 920,000	$ 720,000
Generation Information System (4)	$1,022,400	$1,086,700	$1,022,000
Credit Insurance Premium (3)	$ 799,000	$ 578,800	$ 484,700
NEPOOL Audit Management Subcommittee ("NAMS") Consultant (5)	$ 0	$ 0	$ 0
SUBTOTAL EXPENSES	$7,149,400	$7,013,500	$6,653,700
Revenue			
NEPOOL Membership Fees (3)	($2,300,000)	($2,300,000)	($2,300,000)
Generation Information System (4) (6)	($1,022,400)	($1,086,700)	($1,022,000)
Credit Insurance Premium (3) (7)	($ 799,000)	($ 578,800)	($ 484,700)
TOTAL REVENUE	($4,121,400)	($3,965,500)	($3,806,700)
TOTAL NEPOOL EXPENSES	**$3,028,000**	**$3,048,000**	**$2,847,000**

Notes

(1) 2024 proposed estimate provided by Day Pitney LLP, NEPOOL counsel.

(2) 2024 proposed estimate provided by Michael M. Mackles, NEPOOL's Independent Financial Advisor, and reflects responsibility for reviewing meeting and travel expenses.

(3) 2024 proposed estimate provided by ISO New England Inc. (ISO).

(4) Based on fee arrangement in Extension of and First Amendment to Amended and Restated Generation Information System Administration Agreement, pursuant to which the annualized fixed fee for 2024 is projected to be $1,047,400 for three months and $1,099,700 for nine months. Estimate assumes NEPOOL will not exceed 520 development hours for changes to GIS, and any additional development hours would impose additional charges on NEPOOL.

(5) If NEPOOL determines that an audit should be performed in 2024, funding for that audit will be addressed separately.

(6) GIS costs are paid by "GIS Participants" under Allocation of Costs Related to Generation Information System, which was approved by the NEPOOL Participants Committee on June 21, 2001 and amended by the NEPOOL Participants Committee on May 6, 2016.

(7) Credit insurance premium is paid by Qualifying Market Participants according to methodology described in Section IX of the ISO Financial Assurance Policy. The 2023 sales figure that was estimated using future pricing turned out to be higher than the actual pricing for the 2023 policy period, resulting in a lower actual premium than projected in the 2023 NEPOOL Budget.

CONSENT AGENDA

Markets Committee (MC)

*From the previously-circulated notice of actions of the MC's **January 9-11, 2024 meeting**, dated January 11, 2024.*[1]

1. Revisions to Market Rule 1 (Further *Order 2222* Compliance)

Support revisions to Market Rule 1 to designate the Distributed Energy Resource (DER) Aggregator as the entity responsible for providing metering information for its DER Aggregations (DERAs) and to provide DER Aggregators the option to choose a metering provider for DERAs providing energy injection and/or withdrawal service, as recommended by the MC at its September 12-13, 2023 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 approved with two opposed in the Alternative Resources Sector, and two abstentions in the End User Sector.

Reliability Committee (RC)

*From the previously-circulated notice of actions of the RC's **December 18-19, 2023 meeting**, dated December 19, 2023.*[2]

2. Revisions to OP-24 and Appendix B to OP-24 (Expansion of the number of facilities where fault clearing information (OP-24B data) is required to be provided on an annual basis)

Support revisions to ISO New England Operating Procedure (OP) No. 24 (Protection Outages, Settings and Coordination) and Appendix B to OP-24 (Transmission Relaying Characteristics),[3] as recommended by the RC at its December 18-19, 2023 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was approved unanimously.

3. REMOVED FROM CONSENT AGENDA; TO BE DISCUSSION ITEM #5A

Revisions to PP 5-6 (system modeling assumption updates, adopt IEEE Standard 2800, and improved IBR modeling requirements)

Support revisions to Planning Procedure 5-6 (Interconnection Planning Procedure for Generation and Elective Transmission Upgrades),[4] as recommended by the RC at its December 18-19, 2023 meeting, together with such further non-material changes as the Chair and Vice-Chair of the RC may approve.

The motion to recommend Participants Committee support was approved with one opposed and one abstention, each in the Generation Sector.

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

[2] RC Notices of Actions are posted on the ISO-NE website at: https://www.iso-ne.com/committees/reliability/reliability-committee/?document-type=Committee Actions.

[3] The recommended revisions to OP-24 and Appendix B to OP-24 include changes to: (i) expand the number of facilities where fault clearing information (OP-24B data) is required to be provided on an annual basis; and (ii) the data format in OP-24B to primarily cover single-line-to-ground faults and IPT status of breakers.

[4] The recommended revisions to PP 5-6 include changes to: (i) update system modeling assumptions to align with the operating conditions expected to result from the clean energy transition; (ii) describe the adoption of the new IEEE Standard 2800 (Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems); and (iii) improve modeling requirements for IBRs.

Michael J. Curran

Bio: Michael J. Curran joined the ISO New England Board in 2019. Curran spent the majority of his career in the financial services and investment community, including the Boston Stock Exchange, Inc., where he was chairman and CEO. Before joining the Boston Stock Exchange, he was managing director and chief operating officer of Kemper funds and international mutual funds for Zurich Scudder Investments. Curran most recently was chair of the Midcontinent Independent System Operator (MISO) Board of Directors. He is a graduate of Dickinson College.

ISO Board Service: Mike was elected to the Board on January 1, 2019. He serves on the Audit and Finance Committee, IT and Cyber Security Committee, and Markets Committee. He is the Chair of the Markets Committee. He has also served on the Joint Nominating Committee, Compensation and Human Resources Committee, and as Chair of the Audit and Finance Committee.

MEMORANDUM

TO: NEPOOL Participants Committee

FROM: Eric Runge, NEPOOL Counsel

DATE: January 25, 2024

RE: NPC Vote on Planning Procedure 5-6 Revisions

At the February 1, 2024 Participants Committee meeting, you will be asked to vote on proposed revisions to ISO Planning Procedure 5-6 ("PP5-6 Revisions"). At its December 19, 2023 meeting, the Reliability Committee recommended Participants Committee support for the PP 5-6 Revisions, with none opposed and two abstentions registered. Given this vote outcome at the Reliability Committee, this item was initially placed on the Consent Agenda for the February 1 meeting but was subsequently pulled for Participants Committee discussion at the request of Brookfield. The PP5-6 Revisions and related materials have been included with this memorandum.[1] Additional information from Brookfield may be provided in advance of the meeting and will be circulated and posted upon receipt.

The ISO is proposing to revise PP5-6 to: (i) update system modeling assumptions to align with the operating conditions expected to result from the clean energy transition; (ii) describe the adoption of the new IEEE Standard 2800 (Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems); and (iii) improve modeling requirements for inverter-based resources.

The following resolution could be used for Participants Committee consideration of the PP5-6 Revisions:

> RESOLVED, that the Participants Committee supports the PP5-6 Revisions, as circulated to the Participants Committee in advance of its February 1, 2024 meeting and as recommended by the Reliability Committee at its December 19, 2023 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.

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[1] The PP 5-6 Revisions, and the ISO's presentation on them, are also available at: https://www.iso-ne.com/static-assets/documents/100006/a13_1_pp_5_6.zip.

DECEMBER 19, 2023 | NEPOOL RELIABILITY COMMITTEE | DOUBLETREE HOTEL, WESTBOROUGH, MA

PP5-6 Interconnection Planning Procedure for Generation and Elective Transmission Upgrades

Updates for the Clean Energy Transition, Adoption of IEEE 2800 and Improvements to Modeling of Inverter-Based Resources

Brad Marszalkowski

LEAD ENGINEER | TRANSMISSION SERVICE STUDIES

Project Title: PP5-6 Updates

Proposed Effective Date: February 2023

- ISO New England is proposing updates to Planning Procedure 5-6 to:
  - Update system modeling assumptions to align with the operating conditions expected with the clean energy transition
  - Describe the adoption of the new IEEE Standard 2800 (Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems)
  - Improve modeling requirements for inverter-based resources

PROBLEM STATEMENTS AND SUMMARY OF ISO PROPOSALS

Problem Statements

- The system load-level scenarios currently used under PP5-6 no longer match the conditions of concern that will result from the clean energy transition
- New England needs to describe how the region will adopt IEEE 2800
- The modeling requirements for inverter based resources in PP5-6 no longer capture industry best practices

Summary of Proposals

- ISO is proposing updates to PP5-6 to:
  - Update system modeling assumptions to align with the operating conditions expected to result from the clean energy transition
  - Describe the adoption of the new IEEE Standard 2800 (Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems)
  - Improve modeling requirements for inverter-based resources

FEEDBACK SINCE NOVEMBER MEETING

ISO Responses to Feedback:

- **Feedback:** Steady state scenarios may be overly conservative for Energy Storage Systems in both daytime minimum and peak load scenarios
  - **ISO Response:**
    - Daytime minimum load scenario is meant to address when and if batteries have fully charged
    - FERC ESS will not be studied in the charging mode under peak load scenarios
    - Only ASO studies with PV and ESS components may be required to respect Peak Load scenarios with ESS charging
- **Feedback:** "Other Load levels and resource scenarios may be added at the discretion of the ISO where needed." This ISO discretion leads to unknowns for developers.
  - **ISO Response:**
    - Needed to ensure flexibility that benefits both developers and the ISO
- **Feedback:** Clarity requested about which scenarios apply to ASOs and which apply to FERC
  - **ISO Response:**
    - All scenarios will be able to be used by either ASO or FERC studies. Final selections will be up to the Tech Lead and project team.

ISO Responses to Feedback:

- **Feedback:** New EMT Model requirements add lead time and cost to model development and add increased potential for deficiency notices to be issued
  - **ISO Response:**
    - EMT Model requirement updates are needed to align with best industry practices
    - Will help to stream line entry into Clusters
    - Will help reduce the number of potentially non-viable projects
- **Feedback:** The ISO should develop a repository of useable EMT models for developers to choose from
  - **ISO Response:**
    - The ISO does not maintain which models are useable and follows best industry practice

FURTHER REFINEMENTS TO PROPOSED PP5-6 REDLINES

PP5-6 Incremental Updates Since November RC

PP5-6 Section	Procedure Change	Reason for Change
10.0 Additional Considerations for Generating Facilities that include Storage	The study of the discharging (i.e. generating) operating condition of a proposed electrical storage facility shall use the ~~same~~ study approaches described in this procedure except that it will not be studied as charging under any of the Peak Load scenarios listed in Section 3.6 unless it is a state-jurisdictional facility that is required to charge under mid-day load conditions. ~~as that used for a Generating Facility. The charging operating condition shall be studied under similar conditions to the conditions used when studying the discharging mode to ensure the charging operating condition does not introduce reliability criteria violations, diminish transfer capability or increase conditional dependence in accordance with the requirements of this Planning Procedure.~~	Recognize that requirements have been clarified in the procedure

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
Reliability Committee September 19, 2023	Initial Presentation
Reliability Committee October 24, 2023	Present PP5-6 Redlines
Reliability Committee November 14, 2023	Present incremental updates to PP5-6 Redlines
Reliability Committee December 18-19, 2023	Vote
Participants Committee February 1, 2024	Vote

Questions

bmarszalkowski@iso-ne.com

ISO NEW ENGLAND PLANNING PROCEDURE NO. 5-6

INTERCONNECTION PLANNING PROCEDURE FOR GENERATION AND ELECTIVE TRANSMISSION UPGRADES

EFFECTIVE DATE: ~~May 6, 2022~~

REFERENCES:

ISO New England Transmission, Markets and Services Tariff
- Section I.3.9 Review of Market Participant's Proposed Plans
- (Schedules 22, 23 and 25 of the Open Access Transmission Tariff)

ISO New England Planning Procedures
- Planning Procedure 3 (PP3): Reliability Standards for the New England Area Pool Transmission Facilities
- Planning Procedure 5-1 (PP5-1): Procedure for Review of Market Participant's or Transmission Owner's Proposed Plans
- Planning Procedure 5-3 (PP5-3): Guidelines for Conducting and Evaluating Proposed Plan Application Analyses
- Planning Procedure 9 (PP9): Major Substation Bus Arrangement Requirements and Guidelines
- Planning Procedure 10 (PP10): Planning Procedure to Support the Forward Capacity Market

ISO New England Operating Procedures
- Operating Procedure No. 12 – Voltage and Reactive Control
- Operating Procedure No. 14 – Technical Requirements for Generators, Demand Response Resources, Asset Related Demands and Alternative Technology Regulation Resources
- Operating Procedure No. 19 – Transmission Operations
- Operating Procedure No. 24 - Protection Outages, Settings and Coordination

ISO New England Transmission Planning Technical Guide

North American Electric Reliability Corporation (NERC) Reliability Standards
- TPL-001, Transmission System Planning and Performance Requirements
- FAC-001, Facility Interconnection Requirements
- FAC-002, Facility Interconnection Studies
- ~~FAC-013, Assessment of Transfer Capability for the Near-term Transmission Planning Horizon~~

- MOD-026, Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions
- MOD-027, Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions
- MOD-032, Data for Power System Modeling and Analysis
- PRC-024, Generator Frequency and Voltage Protective Relay Settings

NPCC Directory 1, Design and Operation of the Bulk Power System

Table of Contents

INTERCONNECTION PROCEDURE FOR GENERATION AND ELECTIVE TRANSMISSION UPGRADES

1.0 Introduction

The purpose of this procedure is to describe the scope of Interconnection Studies conducted pursuant to Schedule 22 ("Large Generator Interconnection Procedures" or "LGIP"), Schedule 23 ("Small Generator Interconnection Procedures" or "SGIP") and Schedule 25 ("Elective Transmission Upgrade Interconnection Procedures" or "ETU IP") of Section II of the ISO New England Transmission, Markets and Services Tariff (the "Tariff"). One objective of this document is to provide guidance which ensures that the Network Capability Interconnection Standard ("NCIS") is consistently applied in defining the scope and study assumptions for generator and ETU Interconnection Studies. While not all ETUs are eligible for Network Import Interconnection Service ("NIIS"), all are interconnected in a manner that, at a minimum, meets the requirements of the NCIS. A second objective of this document is also to provide guidance which ensures that the scope and study assumptions for preliminary nonbinding analyses for generators and certain External ETUs that are eligible to request interconnection under the Capacity Capability Interconnection Standard ("CCIS") are consistently applied.

Studies conducted in accordance with this procedure are also used to support applications made pursuant to Section I.3.9 ("Review of Market Participant's Proposed Plans") of the Tariff,~~.~~[1] including studies of proposed distributed energy resources that are processed under state interconnection procedures.[2]

This document (and the relevant documents referenced herein) describes the interconnection requirements and procedures for coordinated studies of new or materially modified existing Generating Facility and ETU interconnections and their impacts on affected system(s) as required by NERC FAC-001, Facility Interconnection Requirements. Those responsible for the reliability of affected system(s) of new or materially modified existing interconnections are notified in accordance with the "coordination with affected systems" provisions of the interconnection procedures.

The studies conducted in accordance with this procedure also serve to meet the requirements of NERC FAC-002, "Facility Interconnection Studies", to demonstrate that the proposed Generating Facility or ETU has been comprehensively studied to identify any reliability impact of the new interconnection, or materially modified existing interconnection, on affected system(s). As described in this document, studies shall include steady-state, short-circuit, dynamics and other studies, as necessary, to evaluate system performance under both normal and contingency conditions and to ensure that the proposed implementation will not cause non-compliance with the applicable NERC Standards including TPL-001, "Transmission System Planning Performance Requirements".

Studies that follow the guidance provided by this document will typically be sufficient to comply with Tariff requirements; however, that does not preclude the possibility that some situations may require additional analyses.

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[1] Additional information on the relevant planning procedures is found in Planning Procedures PP5-1 and PP5-3.
[2] Studies of proposed distributed energy resources (DER) are sometimes referred to as "affected system operator" studies.

1.1 Interconnection Standards

NCIS describes the minimum requirements to interconnect a proposed new Generating Facility in the New England Control Area, to interconnect an Eligible External ETU,[3] to materially change an existing Generating Facility, to materially change an Eligible External ETU, or to increase the capability of an existing Generating Facility or Eligible External ETU.

The NCIS is defined in the LGIP, the SGIP and the ETU IP of the Tariff.

The basic principle underlying the study approach to making the determination of no significant adverse impact is that the energy, incrementally injected by Generating Facilities or injected by virtue of the requested objective associated with an ETU, is allowed to be dispatched in an economic, security-constrained manner provided that there is no significant adverse impact on the reliability of the system, and that the ability to reliably and practicably operate the system is not compromised. Thus, when the new Generating Facility or ETU is added to the system models used in the study, energy injections from other Generating Facilities, external transactions, other interface transfers or ETUs generally may be reduced by an amount not more than the net energy injection associated with the new Generating Facility or ETU, adjusted for changes in system losses caused by the redispatch.

CCIS is defined in the LGIP, SGIP and ETU IP of the Tariff.[4]

1.2 Interconnection Studies

An Interconnection Study is an Interconnection Feasibility Study, an Interconnection System Impact Study, an Optional Interconnection Study or a re-study thereof. The scopes of these studies are described in the LGIP, SGIP and ETU IP of the Tariff. An Interconnection System Impact Study, or a re-study thereof, shall meet all of the requirements of this procedure. When the alternative Interconnection Feasibility study scope is elected, the analysis may consist of a limited subset of the analyses in this procedure, focusing on the issues that are expected to be most significant for the proposed Generating Facility or ETU.

1.3 Elective Transmission Upgrade Interconnection Requests

The approach used in the study of an Interconnection Request for an ETU will differ depending on the type of ETU.

When addition of a specific technology is identified in an ETU Interconnection Request, the study will take into account the type of the facility and the project's performance objective.

When a performance objective associated with a specific Generating Facility(s) is identified in an ETU Interconnection Request, the study will take into account both the generation and the objectives.

[3] External ETUs eligible for NIIS are controllable Merchant Transmission (MTF) or Other Transmission Facility (OTF). In this Planning Procedure, these External ETUs are referred to as "Eligible External ETUs."
[4] The details regarding the conduct of the CCIS test are contained in Planning Procedure PP-10

When a performance objective of increasing transfer capability between points is identified in an ETU Interconnection Request, the study, while meeting the requirements of Section 7 of this procedure, will address what is specified for:

- Transfer points (from/to)
- Transfer capability increase and direction(s) of flow

2.0 Requirements for Interconnection Studies

2.1 General Requirements

The Interconnection Studies of all Interconnection Requests for Generating Facilities and ETUs, conducted in accordance with Sections 3, 4, 5, 6 & 7 of this procedure, shall identify the minimum required upgrades to meet all of the following requirements:

- The proposed Generating Facility or ETU must satisfy the requirements of ISO New England Planning Procedure 3: "Reliability Standards for the New England Area Pool Transmission Facilities" (the "Reliability Standards") and NPCC Directory 1, "Design and Operation of the Bulk Power System" on a regional (i.e., New England Control Area) and sub-regional basis, subject to the conditions analyzed; and shall not compromise the ability of the system to meet NERC TPL-001: "Transmission System Planning Performance Requirements".

- The proposed Generating Facility or ETU must not diminish system transfer capability, whether limited by an individual constrained element or a relevant interface~~ – including those relevant interfaces evaluated in accordance with NERC FAC-013 "Assessment of Transfer Capability for the Near-term Transmission Planning Horizon"~~, below the level of achievable transfers during reasonably stressed conditions[5] and does not diminish the reliability or operating characteristics of the New England Area bulk power supply system and its component systems.

- For a proposed new Generating Facility in an exporting area, or ETU with a terminal in an exporting area, an increase in the transfer capability out of the exporting area is not required to meet this interconnection standard unless the transfer capability needs to be increased to allow the proposed new Generating Facility or ETU to operate at the requested maximum output even after the allowed redispatch described in this procedure.

- The proposed Generating Facility or ETU must not diminish system transfer capability, whether limited by an individual constrained element or a relevant interface, below the level of possible imports into an importing area during reasonably stressed conditions and does not diminish the reliability or operating characteristics of the New England Area bulk power supply system and its component systems.

- The addition of the proposed Generating Facility or ETU does not create a significant adverse effect on the ISO's or local Transmission Owner's ability to reliably operate and maintain the system. Creation of new constraints, particularly due to stability or dynamic

[5] Reasonably stressed conditions are defined in PP5-3 as "those severe load and generation system conditions which have a reasonable probability of actually occurring." Reference PP5-3 for additional information

voltage performance, may likely be deemed to be unacceptable, as this compromises the ability to operate the system, especially where the number of existing interfaces cannot be increased due to operating complexity. Creation of operating limitations, particularly those caused by short circuit contribution or equipment with limited voltage ratings are also likely be deemed unacceptable.

2.2 System Configuration

Analyses shall be performed with the existing system facilities and topology, with the addition of all Planned transmission projects (those with approved Proposed Plan Applications under Section I.3.9 of the Tariff) and with all relevant Generating Facilities and ETUs with active Interconnection Requests along with their associated upgrades in the Interconnection Queue ahead of the Generating Facility or ETU under study.[6]

In situations where some of the above projects have later in-service dates than the Generating Facility or ETU under study, the Interconnection Study may need to analyze the topology when the Generating Facility or ETU goes into service and the topology when all of the above projects are planned to be in service. In addition, sensitivity analysis shall be performed as appropriate for proposed transmission facilities that are relevant to the Interconnection Study for the Generating Facility or ETU under study.[7]

2.3 Load Levels

The following load levels may be utilized in Interconnection Studies: [8]

- Peak load: Load shall be at 100% of the projected ("90/10 forecast") peak New England Control Area load for the year the Generating Facility or ETU is projected to be in service
- Intermediate Load: 18,000 MW New England Control Area load
- Light Load: 12,500 MW New England Control Area load
- Nighttime Minimum Load: 8,000 MW New England Control Area load
- Daytime Minimum Load: 12,000 MW New England Control Area load

2.4 Resources[9]

For steady-state analysis, the maximum output for a Generating Facility shall be its summer Network Resource Capability ("NRC") value, its maximum output at fifty degrees Fahrenheit or higher. For stability analysis, the maximum output for a Generating Facility shall be its winter NRC value, its maximum output at zero degrees Fahrenheit or higher. For controllable ETUs, steady-state and stability

[6] Reference Section 2.1 of the ISO New England Technical Planning Guide for additional information
[7] Reference Sections 2.1.3, 2.1.4 and 2.1.5 of the ISO New England Technical Planning Guide for additional information
[8] Reference Section 2.2 of the ISO New England Technical Planning Guide for additional information
[9] Reference Section 2.3.1 of the ISO New England Technical Planning Guide for additional information on NRC and Section 2.3 for additional information on treatment of different types of resources

analysis shall be done with the maximum flow (in one direction if unidirectional or in each direction if bidirectional) described in the requested objective. Behind the meter (BTM) Distributed Energy Resources (DER) shall be modeled in steady state and stability analysis.[10]

2.5 Second Contingency Testing

Sufficient steady state and stability N-1-1 testing to assess performance relative to NERC, NPCC and ISO New England criteria shall be performed.[11]

2.6 Data Provision

The LGIP, SGIP and ETU IP specify data submittal requirements for the associated stages of each procedure. Starting with the submission of the Interconnection Request and before the completion of the System Impact Study, resources undergoing the Interconnection Procedures, shall submit all data through the Interconnection Request Tracking Tool (IRTT)[12]. NERC Standard MOD-032[13] requires that dynamic models be provided for Generating Facilities, HVDC lines, and other power electronic devices that are a part of the Bulk Electric System. ISO Operating Procedure OP-14 Section II.A.6 also requires dynamics models for Generating Facilities that are 5 MW or greater in size when ISO New England determines it to be necessary for the ISO to carry out its responsibility to reliably and efficiently operate the power system.

Appendix B describes the usability and acceptability requirements for PSS/E models for use in Interconnection Studies and in accordance with NERC Standard MOD-026 and MOD-027.

Resources undergoing the ISO Interconnection Procedures, shall submit the as-studied data through the Dynamics Data Management System (DDMS) and Short Circuit Data Management System[14] after the System Impact Study results have been accepted by the Interconnection Customer at the System Impact Study Results Meeting.

3.0 Steady-State Analysis

3.1 Steady-State Criteria

Steady-state analyses shall be performed to demonstrate compliance with applicable voltage and thermal loading criteria and shall identify any system upgrades required to satisfy these criteria.

3.2 Steady-State Stresses

Steady-state studies shall be performed with a dispatch of Generating Facilities, with flows on controllable ETUs, and with imports and exports such that it stresses power flows across applicable

[10] Reference Appendix K of the ISO New England Technical Planning Guide for additional information
[11] Reference Section 3.4 of the ISO New England Technical Planning Guide for additional information
[12] The IRTT system can be accessed from the ISO New England website at: http://www.iso-ne.com/system-planning/transmission-planning/interconnection-request-queue
[13] Refer to ISO New England Compliance Bulletin - MOD-032 – Model Data Requirements and Reporting Procedures for additional information on generator characteristics located at: http://www.iso-ne.com/participate/rules-procedures/nerc-npcc
[14] The DDMS and SDMS systems can be accessed via the SSO/SMD home page by selecting the Dynamic Data Management System application or Short Circuit Data Management System application. Instructions will be provided to Interconnection Customers during the interconnection process.

transmission lines or interfaces. A stressed line or interface shall, to the extent reasonable, be at or near their ratings or transfer limits.

A reasonable condition when power flows may not be at or near their transfer limits would exist when the maximum number of fully loaded Generating Facilities and ETUs that may reasonably be expected to be in service does not result in stressed power flows.

3.3 Steady-State Redispatch

The steady-state portion of an Interconnection Study typically includes an analysis of the transmission system without the proposed Generating Facility or ETU (pre-project case) and an analysis of the transmission system with the proposed Generating Facility or ETU in service (post-project case). The change to output of Generating Facilities and external controllable ETUs from the values in a pre-project case to the values in the post-project case is commonly referred as redispatch.

As a result of the addition of the proposed project, the maximum collective change in the output of other generation and changes to the flows of controllable external ETUs (the maximum redispatch) to meet the Reliability Standards must not exceed the capacity of the proposed Generating Facility or ETU, as measured by its intended high limit.

If the request for interconnection involves multiple generating units at a Generating Facility and the applicant for interconnection controls all the existing generating units at that Generating Facility, the applicant for interconnection shall specify the desired maximum output for the Generating Facility in the Interconnection Study Agreement and the design of the interconnection shall be based on this specified maximum output.

In addition, the following restricts the pre-contingency redispatch of Generating Facilities or external ETUs for first contingency (N-1) conditions:

- Redispatched Generating Facilities and redispatched ETUs and the new Generating Facility or ETU must be able to be automatically monitored and observed for purposes of system operation and unit commitment (for example a facility monitored and controlled by the System Operator via SCADA and security constrained economic dispatch), and,

- Generating Facility and ETU redispatch is not acceptable for limiting system constraints that occur on sub-transmission or lower voltage (less than 100 kV) facilities.

Second contingency (N-1-1) testing considers two initiating events that can occur close together in time. Following the first initiating event, system adjustments can be made in preparation for the next initiating event.[15] In the case of pre-second contingency Generating Facility or ETU runback and/or tripping after a first contingency to be secure for N-1-1 conditions:

- The runback and/or tripping that can be assumed to be achievable in 30 minutes following the first contingency shall utilize available replacement operating reserves consistent with ~~ISO-NE Planning Procedure No.~~ PP3.
- Generating Facilities and ETUs that are assumed to be runback or tripped (which may include the new Generating Facility or ETU) must be able to be automatically monitored and observed for purposes of system operation and unit commitment (for example a facility monitored and controlled by the System Operator via security constrained economic dispatch), and, Generating Facility and ETU runback or tripping is not acceptable for limiting system constraints that occur on sub-transmission or lower voltage (less than 100 kV) facilities, except as follows;
  - where the first and second contingencies are ~~for facilities connected at less than 100 kV~~not contingencies listed in PP3 and where the potential performance violation is for a facility ~~less than 100 kV~~that is not a Pool Transmission Facility, runback or tripping of non-market generation and/or Settlement Only Generators may also be assumed in the assessment. The assessment must confirm that such redispatch is operable[16] and does not introduce any other performance violations.

3.4 No Increase in Conditional Dependence

If no existing Generating Facility or ETU is required to be in service to avoid criteria violations for the conditions studied prior to placing the new Generating Facility or ETU in service, no existing Generating Facility or ETU can become required to operate as a condition for acceptable operation of the new Generating Facility or ETU for that study condition. If an existing Generating Facility or ETU is required to be in service to avoid criteria violations for the conditions studied prior to placing the new Generating Facility or ETU in service, the existing Generating Facility or ETU may continue to be modeled as required to avoid criteria violations, but such reliance shall not be increased. Generating Facilities and ETUs that continue to be required to be in service to avoid criteria violations for the conditions studied shall not be reduced, by redispatch in the study, below the level required for system reliability before the addition of the Generating Facility or ETU. Studies must examine relevant stressed existing Generating Facility and ETU outage conditions in addition to outages or reductions that have been considered as part of Generating Facility and ETU redispatch.

3.5 Post Contingency Resource Adjustments

No Generating Facility or ETU can be manually tripped or manually ramped down to relieve any first contingency facility loading in excess of the more limiting of either the Short Time Emergency Ratings or any other applicable Transmission Owner-specific emergency ratings. Manually ramping down Generating Facilities or ETUs to relieve first contingency overloads within the more limiting of the Short Time Emergency ratings or any other applicable Transmission Owner specific emergency ratings can only be applied to the Generating Facility or ETU under study, provided that the Generating Facility or ETU reduction is acceptable to the ISO. If a reduction in Generating Facility or ETU output is required in the

[15] Reference Section 3.4 of the ISO New England Technical Planning Guide for additional information
[16] For example, the constraints and generation output levels may need to be fully observable to, and controllable by, the operator and the implementation must be scalable and manageable in the context of reliable operating practice.

pre-project system in order to relieve overloads the same reduction shall be allowed in the post project case.

3.6 Steady-State Load Levels

Steady-state analysis shall be performed at the following load levels and in accordance with Table 3-1 below. Not all scenarios will be studied for every project. Scenarios will be selected as part of the project study scoping process:

- Analysis shall be performed at Peak Load with the Generating Facility or ETU operating at full capability.
  - Four scenarios may be analyzed:
    - An evening peak scenario characterized by high load, low solar, and energy storage available for discharging, while wind and conventional resources are available up to their full capability.
    - An evening peak scenario characterized by high load, no solar, and energy storage available for discharging, while wind and conventional resources are available up to their full capability[17]
    - A mid-day peak scenario, characterized by high load, high solar, and energy storage unavailable, while wind and conventional resources are available up to their full capability
    - A mid-day peak scenario, characterized by high load, high solar, and energy storage available for charging, while wind and conventional resources are available up to their full capability
  - ~~Two scenarios will be analyzed for stand alone battery energy storage systems, a low renewables scenario with storage in the discharging mode, and a high renewables scenario with storage in the charging mode~~
  - ~~Three scenarios will be analyzed for stand alone solar projects, a high renewables scenario without storage being dispatched, a high renewables scenario with storage being dispatched in the charging mode, and a low renewables scenario with storage in the discharging mode~~

- Analysis shall be performed at Intermediate Load with the Generating Facility or ETU operating at full capability in the cases where conditions such as the preservation of transfer capability are a concern.
  - Two scenarios may be analyzed:
    - A shoulder load scenario characterized by intermediate load, no solar, and energy storage available for charging, while wind and conventional resources are available up to their full capacity
    - A shoulder load scenario characterized by intermediate load, no solar, and energy storage available for discharging, while wind and conventional resources are available up to their full capacity
  - ~~Two scenarios shall be analyzed for stand alone Battery Energy Storage Systems, a no-solar scenario with storage charging, and a no-solar scenario with storage discharging.~~

[17] The evening peak with no solar scenario may be required if there are topology changes associated with the project

- Analysis shall be performed at Light Load as required by the ISO~~in cases when identified as required by the ISO~~to identify any upgrades that are required to allow the Generating Facility or ETU to operate at the requested output level while no other nearby generating facilities (that would contribute to any identified violations) are operating. ~~:~~

    - ~~When a proposed Generating Facility or ETU cannot start up and reach minimum output within two hours. Other Generating Facilities that may be dispatched at Intermediate Load shall also be assumed to be running, but may also be at minimum output except for units which can reach minimum output within 2 hours. Units that can start up and reach minimum output within 2 hours may be off in the Light Load analysis. Careful consideration of realistic operating conditions needs to be provided when simulating nuclear and hydro (run of river or ponding) facilities.~~
    ~~Regardless of the time taken to reach minimum output, a~~Analysis shall be ~~performed at Light Load to identify any upgrades that are required to allow the Generating Facility or ETU to operate at the requested output level while no other nearby generating facilities (that would contribute to any identified violations) are operating.~~
    - Two scenarios may be analyzed:
        - A light load scenario characterized by light load, high solar, and energy storage available for charging, while wind and conventional resources are available up to their full capacity
        - A light load scenario characterized by light load, no solar, and energy storage available for discharging, while wind and conventional resources are available up to their full capacity

- Analysis shall be performed at Minimum Load in cases where the Generating Facility or ETU, and its Interconnection Facilities and Network Upgrades, add a significant amount of charging current to the system or in areas where there are significant resources without significant voltage control.
    - ~~A Daytime Minimum Load scenario will be analyzed for stand alone solar projects~~
    - ~~Co-Located or Hybrid facilities will be required to analyze the combination of all scenarios listed under the different resources of which they are comprised~~
    - ~~A no-solar (nighttime) minimum load case will be run where there are topology changes due to upgrades from solar projects, or in cases where significant charging is added to the system (ie: long cables for off shore wind)~~
    - Two scenarios may be analyzed:
        - A Day-Time minimum load scenario characterized by minimum load, high solar, and energy storage unavailable, while wind and conventional resources are available up to their full capacity
        - A Night-Time minimum load scenario characterized by minimum load, no solar, and energy storage unavailable, while wind and conventional resources are available up to their full capacity[18]

- Co-Located or Hybrid facilities may be required to analyze the combination of all scenarios listed under the different resources of which they are comprised

[18] The night time minimum load scenario may be required if there are topology changes associated with the project.

- Other Load levels and resource scenarios may be added at the discretion of the ISO where needed.
- BTM-DERs and other non-Modeled assets will be modelled as dispatched at the resource availability level as shown in ~~the~~ table 3-1 below

Table 3-1 - Steady State Scenarios[19][20][21]

Available Scenarios/For Consideration	Solar Availability Across NE (Both Market and BTM)	Batteries/Stored Hydro Availability	Wind Availability	Conventional Resources Availability
Peak Load 90/10 (Gross) Low Solar*	26%	100% Discharging	100%	100%
Peak Load 90/10 (Gross) High Solar ~~(W/O Bat)~~	85%	0% OFF	100%	100%
Peak Load 90/10 (Gross) High Solar ~~(W/ Bat)~~*	85%	100% Charging	100%	100%
Peak Load 90/10 (NET = Gross) No Solar	0%	100% Discharging	100%	100%
Shoulder Load 18,000MW (NET = Gross)	~~No~~0%	100% Charging	100%	100%
Shoulder Load 18,000MW (NET = Gross)	~~No~~0%	100% Discharging	100%	100%
Light Load 12,500 (NET)	100%	100% Charging	100%	100%
Light Load 12,500 (NET = Gross)	0%	100% Discharging	100%	100%
N-Minload 8,000MW (NET = Gross)	0%	0% OFF	100%	100%
D-Minload 12,000MW (Gross)	100%	0% OFF	100%	100%

[19] Availability is interpreted as projects under their respective fuel types are able to be dispatched anywhere between a projects minimum power (PMIN) and the level listed multiplied by the projects maximum power (PMAX).

[20] Intermittent resources that are dispatched at a lower level than their max availability will not be assumed to be available for re-dispatching post N-1

[21] Gross is interpreted as prior to the addition of the DER, netting down of the load. As where Net is interpreted as the load post addition of the DER. For example, the daytime minimum load scenario lists 12000MW (Gross), if 5000MW of DER is added, the net load is then 7000MW. For the light load scenario with high solar, 12,500 (NET) is listed, if 5000MW of DER is added, the net load would be 7,500MW, so the scalable load would need to be scaled up commensurate to the DER added, to meet the required 12,500MW NET level. In the cases where NET=Gross is listed, this means there is no netting of the load due to the DER because there is no DER assumed.

4.0 Stability Analysis

4.1 Stability Criteria

Stability analyses shall be performed to demonstrate compliance with applicable criteria and shall identify any system upgrades required to satisfy these criteria.

4.2 Stresses in Stability Analysis

For normal contingency testing, power flows across applicable transmission lines or interfaces shall be at the most limiting of the existing stability or thermal (set using winter transmission equipment ratings, with appropriate margin, for light load testing) transfer limits.[22]

4.3 Stability Analysis Scenarios

Stability analysis shall consider reasonable combinations of all relevant Generating Facilities, ETUs and devices that would be expected to have significant interactions.

The Generating Facility or ETU under study as well as all local and relevant Generating Facilities and ETUs shall be modeled at full capacity. If all Generating Facilities and ETUs cannot be dispatched behind the limiting lines or interface, a reasonable number of combinations may need to be studied.

4.4 Stability Load Levels

Stability analysis shall be performed at the following load levels:

- Analysis shall be performed at Light Load with high levels of renewable generation online. Appropriate combinations of relevant Generating Facilities, distributed energy resources and ETUs shall be studied to ensure that stability is maintained for all reasonable conditions.
    - Two scenarios may be analyzed:
        - A light load scenario characterized by light load, high solar, and energy storage available for charging, while wind and conventional resources are available up to their full capacity
        - A light load scenario characterized by light load, no solar, and energy storage available for discharging, while wind and conventional resources are available up to their full capacity

- Analysis shall be performed at Peak Load when required by the ISO. The emphasis of the stability analyses performed at this load level is to confirm that the response has not significantly changed with the load level. It may also be used to assess changes in damping if the possibility of an oscillatory response is recognized in the light load analyses.

[22] Note: All units modeled as in service for a particular stability case shall be modeled at their full output, which may result in total transfers greater than the existing thermal transfer limit. More detail on modeling is available in PP5-3.

- Two scenarios may be analyzed:
    - An evening peak scenario characterized by high load, low solar, and energy storage available for discharging, while wind and conventional resources are available up to their full capability.
    - An evening peak scenario characterized by high load, no solar, and energy storage available for discharging. While wind and conventional resources are available up to their full capability[23]

- Analysis shall be performed at Minimum Load in cases where the Generating Facility or ETU, and its Interconnection Facilities and Network Upgrades, add a significant amount of charging current to the system or in areas where there are significant resources without significant voltage control.
    - Two scenarios may be analyzed:
        - A Day-Time minimum load scenario characterized by minimum load, high solar, and energy storage unavailable, while wind and conventional resources are available up to their full capacity
        - A Night-Time minimum load scenario characterized by minimum load, no solar, and energy storage unavailable, while wind and conventional resources are available up to their full capacity[24]

- Co-Located or Hybrid facilities will be required to analyze the combination of all scenarios listed under the different resources of which they are comprised

~~A no-solar (nighttime) minimum load case will be run where there are topology changes due to upgrades from solar projects, or in cases where significant charging is added to the system (ie: long cables for off shore wind)~~

- Other Load levels and resource scenarios may be added at the discretion of the ISO where needed.

- BTM distributed energy resources and other non-Modeled assets will be modelled as dispatched at the resource availability level as shown in the tables above

Table 3-2 Stability Scenarios[25][26]

Transmission Studies	Solar Availability Across NE (Both FERC	Batteries/Stored Hydro	Wind Availability	Conventional Resources Availability

[23] The evening peak with no solar scenario may be required if there are topology changes associated with the project
[24] The night time minimum load scenario may be required if there are topology changes associated with the project.
[25] Availability is interpreted as projects under their respective fuel types are able to be dispatched anywhere between a projects minimum power (PMIN) and the level listed multiplied by the projects maximum power (PMAX).
[26] Intermittent resources that are dispatched at a lower level than their max availability will not be assumed to be available for re-dispatching post N-1

	and Non-FERC)			
Peak Load 90/10 (Gross) Low Solar	26%	Discharging	100%	100%
Peak Load 90/10 No Solar	0%	Discharging	100%	100%
Light Load 12,500 (NET)	100%	Charging	100%	100%
Light Load 12,500 (NET = Gross)	0%	Discharging	100%	100%
N-Minload 8,000MW (NET = Gross)	0%	OFF	100%	100%
D-Minload 12,000MW (Gross)	100%	OFF	100%	100%

5.0 Short Circuit

Short circuit analyses[27] shall be conducted to demonstrate that short circuit duties will not exceed equipment capability and shall identify any system upgrades required to satisfy this criterion. The short circuit study base case shall include all generation and transmission projects that are proposed for the New England Transmission System and any Affected System and for which a transmission expansion plan has been submitted and approved by the applicable authority and which, in the sole judgment of the System Operator, may have an impact on the Interconnection Request. The base case shall include all generating facilities and ETUs (and with respect to (iii), any identified upgrades) that, on the date the study is commenced: (i) are directly interconnected to the New England Transmission System; (ii) are interconnected to Affected Systems and may have an impact on the Interconnection Request; and (iii) have a pending higher queued Interconnection Request to interconnect to the New England Transmission System and may have an impact on the Interconnection Request. A Generating Facility that has notified the ISO that it will retire will not be included in short circuit studies for timeframes beyond its retirement date.

6.0 Other Requirements

6.1 Voltage Control and Reactive Power Requirements

Where specified in Schedule 22, 23 or 25, Generating Facilities, ETUs and their associated Interconnection Facilities, that are capable of voltage control, are required to be capable of a composite power delivery at their maximum rated power output (maximum MW) at the Point of Interconnection (or at the high side of the station transformer, or at the Point of Interconnection if there is no station transformer, in the case of a non-synchronous Generating Facility) at both the power factor of 0.95 leading and 0.95 lagging. Further, all Generating Facilities equal to or greater than 5 MW will be required

[27] Reference Section 4.3 of the ISO New England Technical Planning Guide for additional information

to be capable of a composite power delivery at their maximum rated power output (maximum MW) at the Point of Interconnection[28] (or at the high side of the station transformer, or at the Point of Interconnection if there is no station transformer, in the case of a non-synchronous Generating Facility) at both the power factor of 0.95 leading and 0.95 lagging. The Interconnection Study shall verify this capability.

System Impact Study testing shall evaluate the compliance of the voltage control capability with the requirements of OP-14. For all generating facilities equal to or greater than 5 MW, the study will assume that the Generating Facility's responsiveness to voltage changes is active and in-service, unless the study identifies that such responsiveness cannot be activated (for example because of the pre-existing voltage control strategy for a distribution feeder).

While it shall be identified in the Interconnection Study if the voltage control strategy must be designed with the purpose of maintaining a scheduled voltage at the Point of Interconnection (or some other appropriate point), it shall be acceptable for the resource to dynamically control its terminal voltage under transient conditions, unless the Interconnection Study identifies a reliability issue that requires the resource be capable of controlling voltage at another point, such as the Point of Interconnection.

The power factor evaluation shall be conducted with the new Generating Facility or Eligible ETU modeled at unity terminal voltage and maximum rated power output. The maximum leading and lagging reactive power capabilities at maximum rated power output shall be taken from the associated facility "D-Curve" or similar specification. At both the maximum leading reactive output and at the maximum lagging reactive output, the real and reactive power losses in the step-up transformer(s) and other interconnection facilities, station service real and reactive load, as well any additional reactive contribution provided by project auxiliary reactive devices, shall be calculated. The resulting net real and reactive power at the Point of Interconnection (or the high side of the station transformer in the case of a wind generating facility) shall be required to meet the 0.95 leading and 0.95 lagging dynamic reactive power standards. Generating Facilities that operate in a combined mode (such as combined cycle generation) shall be evaluated on an overall combined basis.

System Impact Study testing shall evaluate the compliance of the voltage ride-through capability with the requirements of NERC PRC-024, Generator Frequency and Voltage Protective Relay Settings.

6.2 Governor Control/Frequency Response

System Impact Study testing shall evaluate the compliance of the new Generating Facility frequency response with the droop, deadband and overall response requirements of OP-14. Testing shall include an appropriate frequency changing event such as a large loss of load or generation.

System Impact Study testing shall evaluate the compliance of the frequency ride-through capability with the requirements of NERC PRC-024-1, Generator Frequency and Voltage Protective Relay Settings.

[28] The term "point of common coupling" is more commonly used for distribution-connected resources and will serve as the point of measurement for the purposes of this requirement for resources that are not interconnected pursuant to Schedule 23 (Small Generator Interconnection Procedures).

6.3 Shaft Torque (Delta P) Testing

Where there is a likelihood of large angular difference across an open transmission line, or of a large change in power flow when closing a transmission line, an Interconnection Study for a Generating Facility shall include determination of the largest change in power (Delta P) that the Generating Facility, and other Generating Facilities in proximity, could experience as the result of reclosing following an N-1 contingency. The value of Delta P shall be included in the Interconnection Study report. The Generating Facility or ETU shall be required to mitigate any unacceptable consequence of increased Delta P which they cause.

6.4 Subsynchronous Resonance and Subsynchronous Torsional Interaction Screening

An Interconnection Study for an HVDC facility or any project that includes a series-connected capacitor in Interconnection Facilities or Network Upgrades shall include screening for the potential of causing subsynchronous stresses on nearby generation. This screening shall examine N-1, N-1-1 and other potential contingent or operating conditions specified by the ISO. The results of this screening shall be included in the Interconnection Study report.

6.5 ~~PSCAD~~ Electromagnetic Transient Testing

~~A wind or~~Any inverter-based Generating Facility, including DER, an ETU that includes power electronics as part of the facility or a Generating Facility or ETU that includes power electronics as part of Interconnection Facilities or Network Upgrades shall provide a ~~PSCAD~~ Electromagnetic Transient (EMT) model(s) useable in PSCAD, of that equipment. The need for a ~~PSCAD~~ EMT model will be discussed at the Scoping Meeting for non-inverter based technology. ~~Based on the size of the project and its location in the electric system, the ISO will determine if a study of interactions, such as control interactions, with near-by equipment or an evaluation of equipment performance(for example under low short circuit conditions, if applicable to the proposed location) is required as part of the Interconnection Study~~. The ~~PSCAD~~ EMT study shall examine N-1, N-1-1 and other potential contingent or operating conditions specified by the ISO. Guidance regarding the requirements for PSCAD ~~EMT~~ model submittals and for ~~PSCAD~~ EMT testing is provided in Appendix C. [29]

These ~~PSCAD~~ EMT requirements shall not apply to wind or inverter based Generating Facilities that are not connected to the PTF and that are not subject to the requirements of Schedules 22 or 23 of the OATT, unless ISO New England identifies that the ~~PSCAD~~ EMT requirements are needed to be met by the Generating Facility for reliability reasons.

6.6 Operating Procedure Requirements

An Interconnection Study shall ensure that the Generating Facility or ETU satisfies the relevant equipment design requirements in Operating Procedures OP-12, OP-14 and OP-19.

6.7 IEEE 2800 Requirements

Non-synchronous resources participating in the first ISO-NE Cluster study, pursuant to FERC Order No. 2023, (and all subsequent clusters) must meet the requirements of Appendix F.

[29] Only state jurisdictional projects that are part of studies that will start after the initiation of the T~~t~~ransition C~~c~~luster Study pursuant to FERC Order No. 2023 will be required to meet section 6.5

7.0 Additional Considerations for Studies of ETUs

The appropriate study of an Interconnection Request for an ETU will differ depending on the type and objective of the ETU.

7.1 Eligible External ETUs

The scope of study of Eligible External ETUs is described in Section 2 of this procedure. The analysis of ETUs that have one or more terminals outside of the New England Control Area shall be coordinated with the other Control Area(s). The analysis at the point of injection to the New England transmission system shall be performed similar to the analysis of a Generating Facility connecting at that terminal. The impact of loss of the ETU when it is operating at full output shall be analyzed.

The analysis of a new Eligible External ETU shall include analysis with relevant existing external interfaces modeled with imports and exports at the maximum levels used in planning studies.

7.2 Internal Controllable ETUs

A controllable ETU could be a HVDC line or an AC line with a phase-angle regulator or other control device.

In a manner consistent with other parts of this procedure, the Interconnection Customer shall identify the generator dispatch or dispatches that will be used to provide the energy and/or capacity transmitted by the ETU at each terminal which is drawing power from the transmission system. The analysis shall identify the system upgrades required to maintain the reliability of the sending area in accordance with New England planning standards. This analysis shall be similar to the analysis that would be conducted if a new load was added at the point of withdrawal from the New England system.

The analysis at the point of injection to the transmission system shall be performed similar to the analysis of a Generating Facility connecting at that terminal. The analysis shall identify the system upgrades required to maintain the reliability of the receiving area.

The impact of loss of the ETU when it is operating at full output shall be analyzed.

7.3 Non-controllable ETUs Involving Specified Equipment Additions without Associated Specified Objectives

The analysis of a non-controllable ETU involving specified equipment additions without specified objectives shall be conducted consistent with the analysis of transmission additions pursuant to PP5-3.

7.4 ETUs Involving Specified Objectives

An ETU Interconnection Request may not always specify the equipment that it wishes to install. For example, a request may have the objective to increase the transfer limit across an interface by a certain amount. When an ETU Interconnection Request specifies an objective without specifying facilities, the study shall identify the solution necessary to satisfy the needs identified in the Interconnection Request and shall identify the transmission upgrades required. Section 3.1 of the Elective Transmission Upgrade

Interconnection Procedures states that the ISO, at its sole discretion, determines if a proposed objective is appropriate to propose in a single Interconnection Request.

8.0 Preliminary Nonbinding Overlapping Impact Studies

An Interconnection Customer with a Capacity Network Resource Interconnection Service ("CNRIS") Request or a Capacity Network Import Interconnection Service ("CNIIS") Request may request that the Feasibility Study or System Impact Study include a preliminary, non-binding, analysis to identify potential upgrades that may be necessary for the Interconnection Customer's Generating Facility or External ETU to qualify for participation in a Forward Capacity Auction ("FCA") under Section III.13 of the Tariff, based on a limited set of assumptions to be specified by the Interconnection Customer.

The preliminary, non-binding analysis shall use the same criteria and assumptions that are prescribed in the analysis of overlapping interconnection impacts in Planning Procedure 10: Planning Procedure to Support the Forward Capacity Market ("PP10"). The starting point for the base case to be used in the preliminary analysis shall be the latest developed base case that has been prepared, pursuant to PP10, for the analysis of New Generating Capacity Resources seeking to participate in an FCA.

The set of additional assumptions that may be specified by the Interconnection Customer are limited to additional transmission projects and/or generation projects with active Interconnection Requests under the L/SGIP that the Interconnection Customer requests to be added to the base case.

To the extent the Interconnection Customer requests a preliminary non-binding analysis of Overlapping Interconnection Impacts under the CCIS, a report shall contain the results of the requested preliminary analysis, along with an identification of potential upgrades that may be necessary for the Interconnection Customer's Generating Facility to qualify for participation in a FCA pursuant to Section III.13 of the Tariff.

An Interconnection Customer with an ETU Interconnection Request may specify as its performance objective a capacity transfer capability increase. As part of the Feasibility Study or the System Impact Study for this Interconnection Request, as requested by the Interconnection Customer; an analysis similar to a preliminary, non-binding analysis shall be performed to verify the increase in capacity capability. In this case, the study shall include all relevant Generating Facilities and ETUs with earlier queue positions and all Planned transmission projects.

9.0 Operational Considerations

As appropriate, the analysis shall include an assessment of the operating constraints of the proposed transmission and generation system without identifying the additional upgrades (beyond those identified pursuant to Section 2 of this procedure) necessary to reduce the operating constraints. The analysis shall determine the estimated magnitude of required redispatch of generation under typical and reasonably stressed conditions. If requested by the ISO, limited operating studies may be required to demonstrate viable operability of the proposed Generating Facility or ETU and provide some indication of the system conditions for which the Generating Facilities or ETU's operation may be restricted. The conditions to be considered in these studies shall be coordinated through the ISO. Examples of studies that may be expected include, but are not limited to:

- Examination of the operation of the proposed transmission or generating facilities over expected or suspected constrained conditions with examination of the limiting performance concern (for example thermal, voltage or stability issues). Hour-to-hour operability or performance over longer periods may be considered. Light, intermediate or peak load levels may be considered. Any increased need for operational oversight of the system, such as resource operating restrictions, atypical switching or the creation of additional procedures under outage conditions shall be noted.

- Determination if the system adjustments required to reliably serve the area of interest within 30 minutes following the first contingency change significantly, or are no longer effective, given the proposed change.

(Note: Extensive operating studies, separate from the Interconnection Studies, may be necessary prior to actual operation.)

10.0 Additional Considerations for Generating Facilities that include Storage

The study of the discharging (i.e. generating) operating condition of a proposed electrical storage facility shall use the ~~same~~ study approaches described in this procedure except that it will not be studied as charging under any of the Peak Load scenarios listed in Section 3.6 unless it is a state-jurisdictional facility that is required to charge under mid-day load conditions. ~~as that used for a Generating Facility. The charging operating condition shall be studied under similar conditions to the conditions used when studying the discharging mode to ensure the charging operating condition does not introduce reliability criteria violations, diminish transfer capability or increase conditional dependence in accordance with the requirements of this Planning Procedure.~~

Document History[30]

Rev. No.	Date	Reason
Rev 0	RTPC – 4/13/99	
Rev 1	RC – 2/13/01; PC 3/2/01	
Rev 2	Effective 2/1/05	Addition of overlapping impact language to PP to conform with recently approved updates to the ISO Tariff
Rev 3	RC 5/19/09; NPC 6/5/09; ISO-NE 7/7/09	
Rev 4	RC 7/19/10; NPC 8/6/10; ISO-NE 8/10/10	Administrative document changes to conform to Tariff terminology and to add back miscellaneous footnotes that were lost in prior versions.
Rev 5	RC 8/12/14; NPC 9/12/14; ISO-NE 9/15/14	Additions made to describe load level modeling.
Rev 6	RC 07/14/2015 NPC 08/07/2015	Additions made to address Elective Transmission Upgrades and add clarifications. Format updated to be consistent with Operating Procedures
Rev 7	RC 06/09/16 NPC 06/21/16	Additions made to conform with Interconnection Process Improvements filing (February 18, 2016)
Rev 8	RC 02/13/2018 NPC 03/02/2018	Additions to: (i) clarify alignment with other planning procedures, (ii) clarify certain provisions, (iii) clarify compliance with NERC standards, and (iv) clarify certain requirements for inverter-based generators.
Rev 9	RC 12/18/2020 NPC 02/06/2020	Correcting the title of PP5-1 in the References section.
Rev 10	RC 03/17/2020 NPC 04/02/2020	Update to loss-of-source interconnection design requirement in Appendix A.
Rev 11	RC 04/27/2022 NPC 05/05/2022	Additional guidance for Distributed Energy Resources

[30] This Document History documents action taken on the equivalent NEPOOL Procedure prior to the RTO Operations Date as well as revisions to the ISO New England Procedure subsequent to the RTO Operations Date.

Appendix A – General Transmission System Design Requirements for the Interconnection of New Generating Facilities and ETUs to the Administered Transmission System

All electrical facilities must be designed, built and operated in accordance with applicable NERC, NPCC, ISO New England (including Planning Procedure 9) and the Interconnecting Transmission Owners' standards, guidelines, criteria, or the equivalent. This document describes only the general transmission system design requirements for new Generating Facilities and ETUs to interconnect to the Pool Transmission Facilities (PTF). Additional technical and design requirements related to resource interconnection and operation may also apply.

Point of Interconnection

The following shall be applied to the design of a new Generating Facility (resource) or ETU interconnection:

1. All new Generating Facilities or ETUs shall be connected to the system at a new or existing station on the existing Administered Transmission System.
2. The station shall be designed to provide independent switching of each Generating Facility or ETU interconnection to the system and each transmission line terminating in the station. The intent is to design the interconnection in a manner that does not adversely affect the ability to maintain major components of the transmission system.
3. A ring bus or breaker-and-a-half connection shall be used at the point of Generating Facility or ETU interconnection with the transmission system. Transmission system needs and use may require a breaker-and-a-half arrangement. Alternative interconnection designs to Non-PTF facilities shall be considered where appropriate. Additionally, two circuit breakers placed in series may be required to mitigate the consequences of a stuck breaker that would otherwise result in an unacceptable system performance.
4. Transmission system circuit breakers shall not be used for synchronization of new Generating Facilities.

Interconnection Design – Loss-of-Source

The interconnection shall be designed such that, with all lines initially in service, there is no normal design contingency or common mode transmission system, station, or internal plant failure which could result in a net loss of more than 1,200 MW of resources, except in the case of an increase of no more than 2% above the maximum capability, in place at the time of the original incorporation of this provision into PP5-6 in June 2016, of an existing facility that already corresponded to a loss of more than 1,200 MW of resource for a normal design contingency.

Out of Step Protection

Each PTF connected synchronous generating resource shall be required to have out-of-step protection installed. This protection shall detect an out-of-step condition and trip the Generating Facility to protect the transmission system against adverse impact associated with the Generating Facility losing synchronism with the system. Additionally, the Transmission Owner and/or the ISO may require that supplementary supervisory detection be used in conjunction with the out-of-step protection when necessary to prevent unnecessary and undesirable out-of-step protection operation.

Transmission Circuit Breakers

All new 345 kV and, where identified as necessary, 230 kV and 115 kV, circuit breakers must meet the requirements of Planning Procedure 9.

Appendix B – Requirements of PSS/E Models

All power flow and dynamic models must be made available for use in the version of PSS/E that is in use by ISO New England and must accurately model all of the relevant control modes and characteristics of the equipment, such as:

- All available voltage/reactive power control modes
- Frequency/governor response control modes (which may be provided by a park controller)
- Low voltage ride through characteristics, if applicable
- Low frequency ride-through characteristics, if applicable
- Park controller or group supervisory functionality (e.g. for a wind farm)
- Appropriate aggregate modeling capability (e.g. for a wind farm)
- Charging or pumping mode, if applicable (e.g., for a battery energy storage device or pumped storage hydro Generating Facility)

Standard Dynamics Models
For all Interconnection Studies all models must be standard library models in PSS/E or applicable applications. Where applicable, the most up-to-date revision of the models must be used. User-written models will not be accepted.

User-Written Dynamics Models
A user written model is any model that is not a standard Siemens PSS/E library model. For all Interconnection Studies commencing before January 1, 2017, when no compatible PSS/E standard dynamics model(s) can be used to represent the dynamics of a device, accurate and appropriate user written models can be used, if accepted by ISO New England after testing.

User-written models for the dynamic equipment and associated data can be in either dynamic model source code (.lib) or dynamic model object code (.obj) or dynamic linked library (dll):

- User-written source code, object code, and parameters shall be updated for the latest PSS/E version in use and specified by ISO New England:
    a. Dynamics models related to individual units shall be editable in the PSS/E graphic user interface. All model parameters (CONS, ICONS, and VARS) shall be accessible and shall match the description in the model's accompanying documentation. Certain CONEC or CONET models may be acceptable.
    b. Dynamics models shall have all their data reportable in the "DOCU" listing of dynamics model data, including the range of CONS, ICONS, and VARS numbers. Models that apply to multiple elements (e.g., park controllers) shall also be fully formatted and reportable in DOCU.
    c. Dynamics models shall be capable of correctly initializing and run through the simulation throughout the range of expected steady state starting conditions without additional manual adjustments.
    d. Dynamics models shall be capable of allowing its accompanying element or elements to be switched out-of-service (including when the bus is disconnected) in the steady-state network without additional steps and without errors. Documentation of any special requirements for this condition shall be clearly defined in the model documentation.
    e. Dynamics models shall be capable of allowing all documented (in the model documentation) modes of operation without error.

f. A park controller model to control more than one generator (e.g., in a wind farm or photovoltaic park) shall be able to accurately control multiple equivalent generators. The relative reactive output of each generator shall be correctly representative of its representation of number of units and impedance data. The park controller shall be able to regulate a minimum of eight equivalent generator units.
g. Dynamic models shall be coded in such way that any internal changes of model variables or parameters incurred in one simulation run shall not be automatically passed on to the same models in subsequent simulation runs given both load-flow file and snapshot file are restored in the same PSS/E application.

- Models requiring allocation of bus numbers shall be compatible with the New England bus numbering system, and shall allow the user to determine the allocation of the bus numbers.
- Models shall initialize correctly and be capable of successful "flat start" and "ring down" testing using the following guideline (models shall be capable of meeting these requirements when operating at full rated (nameplate) power, and also at partial power within the physical operating range of the equipment, across a range of feasible reactive power output conditions and terminal voltages):
  a. 20 Second No-Fault Simulation (a/k/a "flat start"): This test consists of a 20 second simulation with no disturbance applied. The test will be considered to be passed if the following criteria are met:
     i. No generator MW change of 0.1 MW or more
     ii. No generation MVAR change of 0.1 MVAR or more
     iii. No line flow changes of 0.3 MW or more
     iv. No line flow changes of 0.3 MVAR or more
     v. No voltage change of 0.0001 p.u. or more
  b. 60 Second Disturbance Simulation (a/k/a "ring down"): This test consists of the application of a 3-phase fault for a few cycles at a key transmission bus, followed by removal of the fault without any lines being tripped. The simulation is run for 60 seconds to allow the dynamics to settle and will be considered to be passed if the following criteria are met:
     i. No generator MW change of 1 MW or more from pre-fault to steady-state post-fault conditions
     ii. No generator MVAR change of 1 MVAR or more, except for exciters with dead band control (typically IEEE Type 4) from pre-fault to steady-state post-fault conditions
     iii. No voltage change of 0.0001 p.u. or more, except in vicinity of exciters with dead band control from pre-fault to steady-state post-fault conditions
     iv. No undamped oscillations related to the addition of the new user-written model

User-written model(s) shall be accompanied by the following documentation:

- A user's guide for each model
- Appropriate procedures and considerations for using the model in dynamic simulations
- Technical description of characteristics of the model
- Block diagram for the model, including overall modular structure and block diagrams of any sub-modules
- Values, names and detailed explanation for all model parameters
- Text form of the model parameter values (PSSE dyr file format)
- List of all state variables, including expected ranges of values for each variable

Appendix C – Requirements of PSCAD Models

1.0 ~~PSCAD~~ EMT model requirement

As the penetration of inverter-based resources (IBR) and distributed energy resources (DER) continues to grow, EMT~~PSCAD~~ models are required to support current and future study efforts which are required to maintain a reliable power system. Models are required for one or more of the following reasons. Other specialty studies may also be performed from time to time.

- Integration of IBR into low system strength networks
- Sub-synchronous control interactions (plant-to-grid)
- IBR controls interactions (plant-to-plant and within the plant)
- IBR controls stability (large and small disturbance)
- IBR frequency and voltage ride-through capability and performance
- IBR short-circuit current analysis
- Power quality studies (e.g., harmonics, rapid voltage change)
- Black start and system restoration studies
- Benchmarking and verifying RMS positive sequence dynamic models

~~1.1 Weak System Analysis~~

~~In simple terms, when a device (such as a wind plant) connecting to a supporting transmission system (or collection of devices such as a cluster of wind farms) is large relative to the rest of the system, it has a relatively large dynamic influence on the system, and the system may be termed weak. "Weak" is a relative term, and typically does not have hard quantitative metrics associated with it.~~
~~It is not always initially clear when a system will become too weak to support generation. Conventional modeling tools such as PSSE may not be sufficiently detailed to represent the issues which will be encountered in actual equipment. Power electronic equipment provided by different manufacturers may respond differently to similar network conditions. Additionally, influences from nearby devices may or may not have a significant impact on a particular generator interconnection. Usually, if there is any consideration by planners that the network may be too weak to support additional generation, detailed studies are performed using electromagnetic transient type tools such as PSCAD.~~

~~1.2 Sub-synchronous Oscillation (SSO) Analysis~~

~~Series compensated transmission lines introduce the risk of SSO. SSO is a family of stability phenomena where the electrical resonance introduced by a capacitor causes the capacitor to exchange energy with either conventional generators, or renewable generators like wind.~~

~~In the case of conventional generators, these interactions are termed "Subsynchronous Resonance" or SSR (although more specific and formal definitions exist, and other phenomena are also studied in relation to conventional generation).~~

~~In the case of wind, these interactions are termed "Subsynchronous Control Interactions", or SSCI. SSCI is most probable when certain types of wind turbines are operated in very close proximity to series capacitors, particularly if there are no other parallel outlets for the wind energy ("radial" connections). If unchecked, SSCI can introduce oscillations onto the power system which can very quickly grow to~~

~~damaging levels. In the worst cases, it can lead to electrical instability which can trigger power system protection, damage wind turbines, or damage series capacitor equipment.~~

~~Many modern wind turbines are susceptible to SSCI, and therefore a direct connection to a series compensated line, or a connection which may (through outages) become radial or near-radial, requires careful study. An SSCI study is performed using very detailed electromagnetic transient type computer models such as PSCAD. These models shall represent the turbine controls in minute detail, and any possible network conditions requiring operation of the wind plant directly (or nearly directly) into a series capacitor shall be simulated to ensure the specific turbines chosen will be immune to SSCI phenomena. Conventional transient stability models such as PSS/E are unable to represent the SSCI phenomena due to inherent limitations in the model type.~~

~~Other power electronic devices such as HVDC ties also require consideration of SSO phenomena, and usually require electromagnetic transient based studies to evaluate this and other concerns.~~

~~1.3 Control Interaction Analysis~~

~~Power electronic based devices such as wind turbines, HVDC transmission systems, STATCOMs, and SVCs are highly controllable, and the controls may operate to perform specific functions within a wide range of timeframes and operating conditions. If two or more of these devices are in operation in close electrical proximity to each other, but have been designed and commissioned in isolation from each other, there is a potential for the controllers to interfere with each other, and the overall system performance could be degraded. Due to the level of detail required in the models to accurately represent the fast control loops used in these devices, electromagnetic transient models such as PSCAD are normally used to test for adverse control interactions.~~

~~1.4 Dynamic Performance Studies~~

~~For devices which are very influential in the system, represent unique designs, or of concern to the reliable operation of the grid, very detailed PSCAD models are sometimes requested to perform studies to test the general dynamic performance of the system. Specific control functions or stressed network conditions are sometimes tested for correct behavior. Typical devices which warrant PSCAD dynamic performance studies as part of routine connection processes include HVDC converters, SVCs, STATCOMs, and large renewable energy projects.~~

~~1.5 Other Studies~~

~~It is noted that there are many other types of studies which may require PSCAD models (e.g. harmonic studies), which are not described here. Such specific type of PSCAD model may be necessary as part of a System Impact Study and may vary depending on the specific analysis being done. If required, the appropriate modeling and analysis shall be specified as part of the individual system impact study.~~

2.0 ~~PSCAD~~ EMT Model Requirements

As mentioned above, specific model requirements for a ~~PSCAD~~ EMT study depend on the type of study being done. A study with a scope covering weak system interconnection, ride-through, voltage control and event response, and islanding performance (for example) would require a model which must meet the requirements stated in Appendix C-1~~has the following characteristics~~, and unless specified otherwise, this type of model is what is required.

~~2.1 Model Accuracy Features~~

~~For the model to be sufficiently accurate, it shall:~~

- ~~Represent the full detailed inner control loops of the power electronics. The model cannot use the same approximations classically used in transient stability modeling, and shall fully represent all fast inner controls, as implemented in the real equipment. It is possible to create models which embed the actual hardware code into a PSCAD component, and this is the best type of model.~~[31]
- ~~Represent all pertinent control features (e.g., external voltage controllers, plant level controllers, phase locked loops, etc). Operating modes that require system specific during the system impact study adjustment shall be user-accessible. In particular, plant level voltage control shall be represented along with adjustable droop characteristics.~~
- ~~Represent all pertinent electrical and mechanical configurations, such as filters and specialized transformers. There may be other mechanical features (such as gearboxes, pitch controllers, etc.) which shall be modeled if they impact electrical performance.~~
- ~~Have all pertinent protections that are relevant to network performance shall be modeled in detail for both balanced and unbalanced fault conditions. Typically this includes various OV and UV protections (individual phase and RMS), frequency protections, DC bus voltage protections, and overcurrent protection. There may be other pertinent protections that shall be included.~~

~~2.2 Model Usability Features~~

~~In order to allow study engineers to perform system analysis using the model, the PSCAD model must:~~

- ~~Have control or hardware options which are pertinent to the study accessible to the user. (For example, adjustable protection thresholds or real power recovery ramp rates) Diagnostic flags (e.g. flags to show control mode changes or which protection has been activated) shall be accessible to aid in analysis.~~
- ~~Be capable of running at a minimum time step of 20 microseconds, or no less than 10 microseconds if required by specific control parameters. Most of the time, requiring a smaller time step means that the control implementation has not used the interpolation features of PSCAD, or is using inappropriate interfacing between the model and the larger~~

~~[31] The model must be a full thyristor representation (preferred) if thyristors are used, or may use a voltage source interface that mimics thyristor switching (ie. A firing pulse based model). A three phase sinusoidal source representation is not acceptable. Models manually (ie. block-by-block) translated from MATLAB are often unacceptable because the method used to model the electrical network and interface to the controls may not be accurate. Note, however, that Matlab may be used to generate C code which is used in the real control hardware, and if this approach is used by the developer, the same C code may be directly used to create an extremely accurate PSCAD model of the controls. The controller source code may be compiled into DLLs if the source code is unavailable due to confidentiality restrictions.~~

~~network. Lack of interpolation support introduces inaccuracies into the model at higher time-steps.~~

- ~~Include user model guide and a sample implementation test case. Access to technical support engineers is desirable.~~

~~2.3 Model Efficiency Features~~

~~In addition, the following elements are required to improve study efficiency and enable other studies which include the model to be run as efficient as possible:~~

- ~~Initializes as quickly as possible (e.g. < 1-3 seconds) to user supplied terminal conditions.~~
- ~~Support multiple instances of the model in the same simulation.~~
- ~~Support the PSCAD "snapshot" feature.~~
- ~~Support the PSCAD "multiple run" feature.~~

3.0 Model Submission Report Requirements

Studies utilizing electromagnetic transient tools such as PSCAD rely heavily on model accuracy and quality to be conducted in a timely manner. Failures in model quality control or insufficient care in preparing site specific models can (and often does) result in long study delays. In order to allow ISO New England planning studies which may involve electromagnetic transient analysis to be conducted efficiently and accurately, PSCAD model submissions are required to be delivered along with a basic model submission report, outlined as follows:

3.1 Section 1: Statement of model compliance

In this section, a statement of model compliance is required which affirms ~~basic~~ conformance with the model requirements ~~stated above~~in Appendix C-1.

3.2 Section 2: Plant and Model Overview

In this section, details of what the plant consists of and how it connects to the ISO-NE system must be provided. This includes:

- A single-line diagram of the plant up to the POI
- Details of the POI (e.g. existing or new substation, voltage level, distance from the closest existing terminal stations on either side) including any other relevant configuration information
- In tabular format, details of the planned (or installed) inverter capability, generator step-up transformer (GSU), collector network, main power transformer (MPT),[32] gen-tie line, static and dynamic reactive devices (if any)

~~3.2~~3.3 Section ~~2~~3: Instructions for model use

In this section, a list of instructions for model use shall be included. This list shall include (at least):

- Directions for compiling and running the model
- Any special requirements for the model (e.g. simulation time-step, run-time settings, etc)
- Instructions on directory path settings if applicable, including a list of libraries, object files, or other files which may be required to run the model.

~~3.3~~3.4 Section ~~3~~4: List of plant-specific settings and description of control scheme

In this section, any control parameters which are specific to an individual plant must be stated. These parameters may include (among others):

- Ride-through thresholds and parameters
- Active power ramp rates following faults
- Plant-level voltage controller gains and time constants
- Interface parameters with non-turbine plant devices such as STATCOMs, if applicable
- Description of the planned (or installed) control schemes (such voltage, frequency, reactive power and/or power factor, runback etc.). The description should include:
  - The target of the control scheme
  - Overview of how it achieves its intended result
  - Parameters which directly impacts the performance, trigger levels, deadband etc.
  - Limitations of the control scheme

Where applicable, these parameters shall be matching with PSSE model settings, which studies are usually performed ahead of or in parallel to PSCAD studies.

~~3.4~~3.5 Section ~~4~~5: Basic performance testing at approximate connection location

In this section, a brief demonstration of model performance is required based on the location in the ISONE network where the plant will be connecting (POI).

Create Network Model

Using a provided PSSE network as a reference,[33] a small passive PSCAD model shall be built surrounding the POI which represents the correct short circuit MVA under system intact, fault, and under line outage conditions. As noted above, the presence of nearby devices can degrade performance, and this shall be born in mind, although detailed studies will follow (in other words, performance in simplified models may be better than performance when nearby devices are included, and design margin may be desirable). A short description of the SCMVA values resulting from the fault conditions considered shall be provided.

Apply Faults
Basic fault and contingency performance shall be tested to show plant recovery and stability under these approximated network conditions. Plant shall be capable of riding through faults with acceptable oscillations, and maintaining stable and accurate terminal voltage control. A set of representative plots shall be provided to demonstrate performance[34].

Important Note
These basic tests are requested to provide basic quality control and site-specific testing of the plant model. More detailed studies are required to analyze the phenomena described above, and the results of these studies may indicate problems which are not evident in these basic tests. For example, interactions with nearby devices will be impossible to test in a simple model without detailed models of the nearby devices available. Other issues may be found as more detailed system models and network conditions are tested.

~~3.4.1~~3.5.1 Detailed Instructions for the conduct of benchmarking analysis to confirm acceptable performance of the PSS/E model in comparison to the PSCAD model

PSS/E Simulation

1. The project shall be modeled at full output per the project's Interconnection Request.
2. Sufficient data channels shall be included in the snapshot file for reporting purposes. Example channel data would include bus voltages within the project and around the project's POI, line and transformer flows (both real and reactive), and LVRT status signal. Channel selection shall enable PSCAD modeling results to be directly compared against the PSS/E results.
3. Two fault simulations, each using a 6 cycle clearing time, at a bus close to the point of interconnection, for both pre-project (without the project modeled in-service) and post-project (with the project modeled in-service) :

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[32] For the purpose of this document, the MPT is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for dispersed power producing resources.

[33] Reference cases can be found at the following location on the ISO-NE website: http://www.iso-ne.com/system-planning/transmission-planning/ferc-form-no-715-reports

[34] Note: It will be possible for manufacturers to re-use basic model performance testing across multiple locations, provided:

- The site-specific model parameters are identical
- The SCMVA levels (for N-0 and N-1 conditions) used for the testing are the same or lower than those at the POI
- The inverter control topology and mechanical performance is expected to be identical

    a. With all lines in service
    b. With one line close to the point of interconnection out of service.
4. Plot scales shall be set appropriately for the reviewers to discern the entirety of the plotted signals, without clipping. Multiple signals may be plotted together in the same plot, as long as the signals are discernible from one another—otherwise, some of those signals should be separated out into multiple plot diagrams.

PSCAD Simulation

1. PSCAD simulation shall be performed under as similar conditions as possible to the PSS/E simulations discussed above, for the best possible comparison.
2. The Project and its associated auxiliary equipment shall be modeled with comparable parameters between the PSS/E and PSCAD modeling, with each model's parameters detailed in the summary report.
3. The PSCAD transmission system case model shall be created from the PSS/E case model, with sufficient buses included after forming the system equivalent to allow simulation of the line outage and fault conditions modeled in the PSS/E simulations discussed above.
4. Steady-state line outage scenarios shall be created similar to those in the PSS/E simulation. For each scenario, a short description of the SCMVA values resulting from the fault conditions considered shall be provided.
5. The PSCAD model shall initialize properly and that the same power flow and voltage conditions shall be observed between the PSCAD and PSS/E models.
6. Output channels shall be set up to capture similar data to that of the PSS/E simulations
7. Fault simulations using the same modeling as those for PSS/E shall be run
8. Comparison plot sets modeling the same data channels from PSS/E and PSCAD shall be developed.

Evaluation of Results

1. Comparison plots shall show similar results between PSS/E and PSCAD. If any significant differences are shown between the traces, sufficient explanation shall be included about why these differences should be considered acceptable.

Report

1. Statement of Model Compliance—a statement of model compliance is required which affirms basic conformance with the PSCAD model requirements
2. List of Plant-Specific Settings—data shall be included for both PSCAD and PSS/E models. Any control parameters which are specific to the plant must be stated. Where applicable, these parameters shall be matching with PSS/E model settings. These parameters may include (among others):
    a. Ride-through thresholds and parameters (e.g., undervoltage thresholds or fault-Q contribution limits)
    b. Active power ramp rates following faults
    c. Plant-level voltage controller gains and time constants
    d. Interface parameters with non-turbine plant devices such as STATCOMs
3. Results Documentation—Plots and related discussion regarding acceptability
    a. PSS/E
        i. Initialization Results
        ii. Flat Run (No Disturbance)
        iii. Fault simulation results

b. PSCAD
    i. Initialization Results
    ii. Power flow and voltage matching to PSS/E
    iii. Fault simulation plots comparison to PSS/E
c. PSS/E steady-state raw data (.RAW) data file and dynamics data (.DYR) file, in the latest version of PSS/E in use by ISO-NE, shall be included in the report. These files shall be ready to be incorporated into the base case and snapshot without further modifications. These files shall be also fully-compatible with the PSS/E model(s) designated (and if user-defined, provided to ISO New England) for the Project.

Appendix D – Detailed Considerations for the Study of an Inverter Based Generating Facility

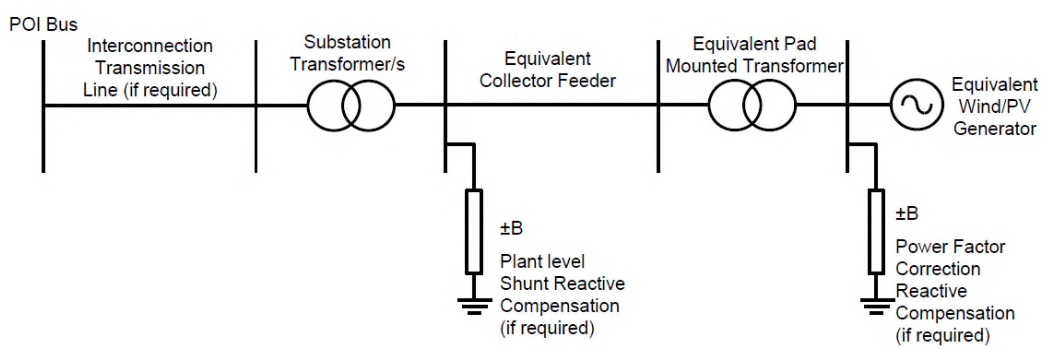
Typical Order of Study for an Inverter Based Generating Facility

1. Short Circuit Ratio calculation
2. Review of PSS/E-PSCAD benchmarking
3. PSCAD analysis of performance if Short Circuit Ratio is low
4. Review of performance of PSS/E model
5. Collector system/GSU tap setting/voltage control strategy calculation
6. Steady state reactive margin analysis
7. Initial dynamic fault testing
8. Full steady state testing to meet the requirements of this Planning Procedure
9. Full dynamic testing to meet the requirements of this Planning Procedure

Use of Aggregate Models for Collector-Based Generating Facilities

For the steady-state portion of the System Impact Study, including the detailed collector system analysis described below, a fully explicit model of the collector system, including all branch connections and step-up transformers shall be used.

For the stability portion of the System Impact Study, an equivalent model shall be used for each major feeder branch of the Generating Facility. The following figure provides a representation of the appropriate equivalent to be used.



Collector system/GSU tap setting/voltage control strategy calculation

A detailed evaluation using a fully explicitly modeled collector-based Generating Facility allows for analysis of voltage control strategies by showing the real and reactive power flow and losses across every element of the facility. Being able to monitor the terminal voltage at each individual generating unit makes it possible to ensure each unit remains within a reasonable voltage range to avoid tripping. All collector branches, junctions, individual high and low voltage busses (including the GSUs and generating units) shall be modeled using the configuration, network impedances, generating unit reactive capabilities and facility ratings for the project.

- The following voltage regulation modes should be reviewed as appropriate:
  - Generating units regulating voltage at a remote bus
  - Generating units regulating voltage at a Park transformer high side bus
  - Generating units regulating voltage at a Park transformer low side bus
  - Generating units regulating voltage at a fixed power factor

Step 1 – Reactive Power Capability

This step investigates the reactive power range of the overall Generation Facility and seeks to determine if the collector system design allows full reactive power capability. It also tries to determine what unit and station transformer taps allow for the largest reactive power injection range of the generating units.

- The POI may be modeled as a swing bus for this analysis. A fictitious machine may be placed at the swing bus to consume the Project output and to allow for adjustment of transmission system voltages.
- Testing is performed to determine if the generating units would violate any voltage trip settings given the full leading and lagging reactive power range of the generating units.
- The reactive power output of the generating units is ramped to the maximum leading negative MVAR and to the maximum lagging capability positive MVAR for various system voltages and transformer tap settings.
- If any bus voltage within the Project or collector system is outside of the specified range, the generating unit reactive power output for the wind park should be recorded along with the first bus that showed a voltage outside of the range. This information is used to determine which transformer tap settings result in the greatest usable reactive power range of the generating units as a way to pre-screen the testing required for Step 2.

Step 2 – Collector System Voltage Range

The goal of this testing is to develop a strategy to maintain sufficient margin to the generating unit trip settings and if possible maintain a preferred Generation Facility terminal voltage range (typically 0.95 to 1.05pu) for any transmission system voltage (typically 0.9 pu to 1.1 pu).

- Testing is performed at different plant output levels 0% to 100% output in 10% intervals with equal loading across all individual generating units.
- For each of the applicable control strategies described above, and optimum tap settings from Step 1, a voltage profile is created and the minimum and maximum voltages within the facility is recorded.

Step 3 – VAR impact to the System and Voltage Schedule Margin

- The goal of this testing is to identify a strategy that will minimize the reactive power demand from the system under normal conditions, but also provide VAR support under low voltage conditions and consume MVAR under high voltage conditions.
- To ensure there is proper margin with the scheduled voltage (as determined by ISO during the study), +/-2% from scheduled voltage is evaluated.

Appendix E – Procedures for Material Modification Determinations

This Appendix E provides implementation guidance in the application of the material modification procedures contained in Schedules 22, 23 & 25 of the OATT.

Different thresholds for determining Material Modification of a Generating Facility or ETU depend on the stage of the project:

1. After an Interconnection Request is received and before a Feasibility Study Agreement is executed
2. After the Feasibility Study Agreement is executed and before the Feasibility Study is completed
3. After the Feasibility Study is completed and before a System Impact Study has commenced
4. After the System Impact Study has commenced and before the System Impact Study is completed
5. After the System Impact Study, including evaluation of “as purchased data,” “as built/as tested data” and changes to existing facilities (e.g., equipment upgrade, replacement of failed equipment)
    - “As purchased data” is required to be submitted no later than 180 Calendar Days prior to the Initial Synchronization Date and shall be reviewed prior to the project being allowed to be synchronized to the New England system
    - “As built/as tested” is required to be submitted prior to the Commercial Operation Date and shall be reviewed prior to the project being allowed to become Commercial

1 (a). After an Interconnection Request is received and before a Feasibility Study Agreement is executed the following will be deemed material and require a new Interconnection Request

- Any increase to the energy capability or capacity capability output of a Generating Facility or ETU above that specified in an Interconnection
- A change from Network Resource (NR) Interconnection Service to Capacity Network Resource (CNR) Interconnection
- An extension of three or more cumulative years in the Commercial Operation Date, In-Service Date or Initial Synchronization Date of the Large Generating Facility or ETU unless provisions of Section 4.4.5 of the Schedules 22 or 25 are satisfied

1 (b). After an Interconnection Request is received and before a Feasibility Study Agreement is executed the following will not be deemed material

- Extensions of less than three (3) cumulative years in the Commercial Operation Date, In-Service Date or Initial Synchronization Date of the Large Generating Facility or ETU to which the Interconnection Request relates provided that the extension(s) does not exceed seven (7) years from the date the Interconnection Request was received by the System Operator
- A decrease of up to 60 percent of electrical output (MW) of the proposed project
- Modification of the technical parameters associated with the Large Generating Facility or ETU technology
- Modification of the Large Generating Facility or ETU step-up transformer impedance characteristics
- Modification of the interconnection configuration
- Modification of the Point of Interconnection (POI) based on information from the Scoping Meeting and identified within five (5) business days of the Scoping Meeting

2 (a) Changes after the Feasibility Study Agreement is executed and before the Feasibility Study is completed

- Once the Feasibility Study has started, it will be completed without making any changes except those based on study results that were not anticipated at the Scoping Meeting and are agreed to by the System Operator and the Interconnecting Transmission Owner. Other changes will be addressed in the System Impact Study.

2 (b). The following changes after the Feasibility Study Agreement is executed and before the Feasibility Study is completed will be deemed material and require a new Interconnection Request

- Any increase to the energy capability or capacity capability output of a Generating Facility or ETU above that specified in an Interconnection
- A change from NR Interconnection Service to CNR Interconnection
- An extension of three or more cumulative years in the Commercial Operation Date, In-Service Date or Initial Synchronization Date of the Large Generating Facility or ETU unless provisions of Section 4.4.5 of the Schedules 22 or 25 are satisfied
- Modification of the POI that is not based on unanticipated study results

2 (c). The following changes after the Feasibility Study Agreement is executed and before the Feasibility Study is completed will not be deemed material and will not require a new Interconnection Request

- Extensions of less than three (3) cumulative years in the Commercial Operation Date, In-Service Date or Initial Synchronization Date of the Large Generating Facility or ETU to which the Interconnection Request relates provided that the extension(s) does not exceed seven (7) years from the date the Interconnection Request was received by the System Operator
- A decrease of up to 60 percent of electrical output (MW) of the proposed project
- Modification of the technical parameters associated with the Large Generating Facility or ETU technology
- Modification of the Large Generating Facility or ETU step-up transformer impedance characteristics
- Modification of the interconnection configuration
- Modification of the POI based on study results that were not anticipated at the Scoping Meeting and are agreed to by the System Operator and the Interconnecting Transmission Owner
- Modification of settings of the project’s controls, such as wind farm voltage control scheme

3. Changes after the Feasibility Study is completed and before the System Impact Study has commenced

- ISO-NE will notify the Interconnection Customer 65 days before the study begins and allow the Interconnection Customer 60 days to refresh its data to the degree allowed under the same materiality standards for changes prior to execution of the System Impact Study Agreement
- Once the System Impact Study has started, it will be completed without making any changes except those based on study results that were not anticipated and are agreed to by the System Operator and the Interconnecting Transmission. Other changes will be addressed in the same way as changes made after the System Impact Study is complete.

4 (a). During the System Impact Study the following will be deemed material and require a new Interconnection Request

- Any increase the energy capability or capacity capability output of a Generating Facility or ETU above that specified in an Interconnection

- A decrease of the electrical output (MW) of the proposed project where the decrease would result in the transfer of an upgrade obligation to a later queued project
- A change from NR Interconnection Service to CNR Interconnection
- An extension of three or more cumulative years in the Commercial Operation Date, In-Service Date or Initial Synchronization Date of the Large Generating Facility or ETU unless provisions of Section 4.4.5 of the Schedules 22 or 25 are satisfied
- Modification of the POI and/or interconnection configuration that is not based on unanticipated study results

4 (b). During the System Impact Study the following may be deemed material and will require review after the System Impact Study is completed using the post System Impact Study criteria

- A decrease of the electrical output (MW) of the proposed project where the decrease would not result in the transfer of an upgrade obligation to a later queued project
- Modification of the technical parameters associated with the Large Generating Facility or ETU technology
- Modification of the Large Generating Facility or ETU step-up transformer impedance characteristics

4 (c). During the System Impact Study the following will not be deemed material and will not require a new Interconnection Request

- Extensions of less than three (3) cumulative years in the Commercial Operation Date, In-Service Date or Initial Synchronization Date of the Large Generating Facility or ETU to which the Interconnection Request relates provided that the extension(s) does not exceed seven (7) years from the date the Interconnection Request was received by the System Operator
- Modification of the POI and/or the interconnection configuration based on study results that were not anticipated and are agreed to by the System Operator and the Interconnecting Transmission Owner

5. Changes after the System Impact Study is completed

- A proposed project that has a completed System Impact Study, or an existing generating facility or ETU can request that a proposed change be evaluated to determine if the change is a Material Modification. If this happens, the proposed change will be evaluated using technical screening criteria. However, there may be proposed changes that have not been contemplated and might require additional analysis beyond the normal screening criteria
- The following will be deemed material and require a new Interconnection Request
    - Where the change(s) would either require significant additional study of the same Interconnection Request and could substantially change the interconnection design, or have a material impact (i.e., an evaluation of the proposed modification cannot be completed in less than ten (10) Business Days) on the cost or timing of any Interconnection Studies or upgrades associated with an Interconnection Request with a later queue priority date

5 (a). Screening Criteria for Changes in Dynamic Models or Voltage Control Schemes

- The following will not be deemed material and require a new Interconnection Request
    - There is no voltage or dynamic stability problem that may be adversely affected by the change to the project that is found in any base cases for the most severe N-1 and N-1-1 contingencies

  - The new models provide similar or better dynamic voltage and stability performance based on dynamic simulation of a few severe faults

5 (b). Screening Criteria for Short Circuit Impacts of Changes in Generation or ETU or Interconnection Facility Impedances

- The following will not be deemed material and require a new Interconnection
  - The total impedance is greater than that of the previously submitted unit(s) and X/R ratio is less than or equal to that of the previously submitted unit(s)
  - A short circuit study at only the interconnecting bus confirms that short circuit duty is less than or equal to that of the previously submitted unit(s)

5 (c). Screening Criteria for Stability Impacts of Changes in Generation or ETU or Interconnection Facility Impedances

- The following will not be deemed material and require a new Interconnection
  - The new models provide similar or better dynamic performance (better damping, smaller angular swing) based on dynamic simulation of a few severe faults

5 (d). Screening Criteria for Voltage Impacts of Changes in Generation or ETU or Interconnection Facility Impedances

- The following will be deemed material and require a new Interconnection Request
  - A change that will result in the Generating Facility or ETU not meeting the Tariff's power factor requirement
- The following will not be deemed material and require a new Interconnection
  - The change of impedance is small (less than 10% of the impedance used in the SIS), the power factor requirement is satisfied, and there is no pre-existing voltage problem

5 (e). Screening Criteria for PSCAD Changes to Generating Facilities or ETUs that Required a PSCAD model

- The following will not be deemed material and require a new Interconnection Request
  - The new models provide similar or better performance for the most severe N-1 and N-1-1 contingencies

Appendix F – IEEE 2800 Requirements

This Appendix E provides implementation guidance in the application of the material modification procedures contained in Schedules 22, 23 & 25 of the OATT.

- For the purposes of this appendix, figures 1,2 and 3 of clause 1.4 shall be adhered to

- This appendix defers to clause 3 of IEEE 2800-2022 for definitions, acronyms, and abbreviations

- Shall be compliant with clause 4 of IEEE 2800-2022
  - Shall be compliant with clause 4.1
  - Shall be compliant with clause 4.2
  - Shall be compliant with clause 4.3
  - Shall be compliant with clause 4.4
  - Shall be compliant with clause 4.7 items d-g
  - Shall be compliant with clause 4.9

- Shall be compliant with clause 5 of IEEE 2800-2022
  - Shall be compliant with clause 5.1
    - Default RPA shall be the POM
    - ICR and ICAR shall be defined as the Rated Active Power Output Rated Active Power Absorption as listed in the IBRs interconnection agreement.
    - Table 4 RPA Voltage Ranges will be defined based on the interconnection TOs requirements.
  - Shall be compliant with clause 5.2
    - Resources shall be enabled in voltage control mode by default
    - Response times under table 5 are adopted as the default
    - Proposed maximum step response timing will be subject to review during SIS to ensure no adverse impact during low system strength conditions

- Shall be compliant with clause 6 of IEEE 2800-2022
  - The default RPA for clause 6 is as written as the default in 6.1.1
  - Shall be compliant with 6.1.1
    - Both under and over frequency response shall be enabled to the fullest extent
    - Default parameters under table 7 are adopted
  - Shall be compliant with 6.1.2
    - Default parameters under table 8 are adopted

- Shall be compliant with clause 7 of IEEE 2800-2022
  - The Default RPA for clause 7 is as written for each sub clause within the standard

- Shall be compliant with 7.1
- Shall be compliant with 7.2.1
- Shall be compliant with 7.2.2.1
  - For resources that will cease to inject current in the permissive operation region, a notification to the ISO must be made.
- Shall be compliant with 7.2.2.2
  - IBRs shall by default be configured in reactive power priority mode
- Shall be compliant with 7.2.2.3.1
- Shall be compliant with 7.2.2.3.2
- Shall be compliant with 7.2.2.3.3
- Shall be compliant with 7.2.2.3.4
  - IBRs shall by default be configured in reactive current priority mode
- Shall be compliant with 7.2.2.3.5
  - Timing will be subject to review during SIS to ensure no adverse impact during low system strength conditions
- Shall be compliant with
  - Inverter-based resources are expected to ride through a post-fault dynamic voltage oscillation with the following envelope characteristics:
    - Upper and lower limits of 1.15 and 0.8 p.u. settling to between 1.05 and 0.90 p.u.
    - A frequency of oscillation between 0.25 Hz and 2 Hz in a synchronous reference frame
    - A damping ratio of 3% or better
- Shall be compliant with 7.2.2.5
- Shall be compliant with 7.2.2.6
  - Active power recovery time will by default be 1s. This will be confirmed and reviewed during the SIS to ensure no adverse impact during low system strength conditions
- Shall be compliant with 7.2.3
- Shall be compliant with 7.3
  - Fnom is 60, default values from table 15 shall be adopted

Exceptions:

- 4.5 is not adopted at this time
- 4.6 is not adopted at this time
- 4.7 items a-c are not adopted at this time
- 4.10 is not adopted at this time
- 4.11 is not adopted at this time
- 4.12 is not adopted at this time
- Capability to provide reactive power support when the primary energy source is not available as described in clause 5.1 is not adopted at this time
- 6.2 is not adopted at this time
- 7.4 is not adopted. Generators return to service after trip shall be coordinated with ISO-NE Control Room.
- Clauses 8, 9, 10, 11, and 12 are not adopted at this time

Clarifications:

- The measurement accuracy requirements of clause 4.4 are subject to coordination with all applicable ISO-NE Operating Procedures and NERC standards and the aforementioned will take precedence over compliance with this clause
- The default RPA is the POM as detailed in clause 4.2.1 unless otherwise specified within this Appendix F of PP5-6
- IBR's are not required to pre-curtail output in order to reserve under frequency response availability
- Resources tripping offline, going into blocking modes, or reducing power output outside of allowable ranges within clause 7 of this standard during SIS review will be treated as significant adverse impact, and mitigations will be required.
- Voltage disturbance oscillations and voltage excursions are defined differently under 7.2.2.4. Voltage excursions are separate events as where oscillations are not.
- Clause 5.1 shall be treated as a minimum reactive capability requirement for non-synchronous generation
- System Impact Study testing shall evaluate the compliance of the minimum reactive capability with the requirements of clause 5.1 of IEEE 2800.
- System Impact Study testing shall evaluate the compliance of the voltage and reactive power control with the requirements of clause 5.2 of IEEE 2800.
- System Impact Study testing shall evaluate the compliance of the active power and frequency response with the requirements of clause 6 of IEEE 2800.
- System Impact Study testing shall evaluate the compliance of the ride through capability with the requirements of clause 7 of IEEE 2800.

Appendix C-1. Electromagnetic Transient Modeling Requirements

In support of an Interconnection Request (IR) all equipment-level Electromagnetic Transient (EMT) models must be supplied by the respective Original Equipment Manufacturers (OEM) and combined into a plant-level model[1] by the Interconnection Customer (IC). These models must meet the requirements included in this checklist Sections A, B and C. Each checklist must be accompanied with an equipment Model Quality Attestation[2] (e-MQA) that is submitted by the respective OEM. Additionally, for each IR, the IC shall submit a single plant-level Model Quality Attestation (p-MQA)[2] above~~[2] above~~ that covers all equipment-level EMT models and other equipment[3] within the plant.

For the EMT models to be usable by ISO-NE, they must be in a format usable by the PSCAD™/EMTDC™ simulation tool. Any requirement within the checklist that is not met shall be documented with sufficient technical justification and will be subject to review.

Model Quality Attestation (MQA)[4]

Each IR (for which an equipment-level EMT model is provided) must be accompanied by an equipment Model Quality Attestation (e-MQA) from the respective OEM and a plant-level Model Quality Attestation (p-MQA) from the IC. An e-MQA and/or p-MQA shall be provided any time significant changes are made to the model[5] that may affect the performance of the plant. An e-MQA and p-MQA form is provided in Appendix C-1A and Appendix C-1B.

[1] A combination of system components (e.g. transformers, cables, auxiliary devices etc) and unit-level models provided by the inverter and plant-level controller OEMs to represent the expected behavior of the equipment

[2] https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline-EMT_Modeling_and_Simulations.pdf

[3] Examples of equipment include, but are not limited to, the following: gen-tie line, main power transformers, collector system, generator step-up transformer, coupling or scaling transformers, static reactive power devices, and any other equipment necessary

[4] MQA must be provided for the Planned, As-Purchased and As-Built project

[5] Significant changes include, but are not limited to, make and model of inverter or controller including software version, control parameters, plant configuration

Checklist for EMT Model

The following model submission summary table and model requirement checklist shall be submitted for each equipment-level EMT model.

EMT Model Submission Summary	
Interconnection Request ID	
Submission date:	
Revision Number:	
Equipment OEM:	
OEM Contact for model related questions	
Technology type: (eg. Wind, Solar, BESS, Fuel Cell etc.)	
Equipment Type[6]:	
Equipment Model:	
Hardware Firmware Version:	
EMT Model Release Version and Date:	
Model Documentation file(s) (Model User document etc.):	
Model Files supplied (e.g. DLL, lib, obj, txt etc.):	

[6] Examples of equipment include, but are not limited to, the following: ~~main power transformers, generator step-up transformer,~~ inverter models, plant-level controllers, dynamic ~~or static~~ reactive power devices, HVDC and any other applicable equipment

A. Model Accuracy Features[7]

In order to be sufficiently accurate, the model provided for each facility shall:

Requirement	Description	Y/N	Provide details if requirement not met or not applicable
1	Represent the full detailed inner control loop of the power electronics. Models cannot use the same approximations classically used in transient stability modeling and must fully represent all fast inner controls, as implemented in the real equipment. Models manually translated block-by-block from MATLAB or control block diagrams are unacceptable.A full power transistor (e.g. IGBT) representation is the preferred model. Models must embed the actual hardware code into a PSCAD component[8].		
2	An average source representation is strongly discouraged. However, if an average source representation is utilized (e.g., switching frequency greater than 40 kHz), it shall maintain full detail in the inner controls and DC side protection features. Sufficient technical justification must be provided on the usage of an average source representation.		
3	DC side protections, and any current, power or energy limitations that could ~~impact~~ affect plant ride-through shall be represented in the model. Modelling the DC side with an ideal voltage source is not acceptable if such a representation prevents the possibility of protection operation during external system events.		
4	Represent all pertinent control features as they are implemented in the real controls (e.g. customized PLLs, ride-through controllers, etc.) using actual hardware code.		
5	Represent Power Plant Controller (PPC) as implemented in the real controls and represent the specific controllers used in the plant. This includes automatic voltage regulation, specific measurement methods, and transitions into and out		

[7] The ISO-NE acknowledges the Electranix Technical Memo which was used to develop ISO-NE's EMT model requirements: http://www.electranix.com/wp-content/uploads/2022/09/PSCAD-Model-Requirements-Rev.-12-Sept-2022.pdf

[8] The controller source code may be compiled into DLLs or binaries if the source code is unavailable due to confidentiality restrictions.

Requirement	Description	Y/N	Provide details if requirement not met or not applicable
	of ride-through modes among others.Generic PPC representations are not acceptable.		
6	Communication and sample and hold delays between PPC and inverter must be modeled.		
7	Represent common plant controller functionality if there are multiple plants using the same technology or multiple technologies (eg. Hybrid BESS/PV). If supplementary or multiple voltage control devices (eg. STATCOM) are included in the plant, these should be coordinated with the PPC.		
8	Represent Sub Synchronous Oscillation (SSO) mitigation and/or protection including the ability to enable and disable SSO mitigation/protection, if applicable.		
9	Represent shunt capacitor and reactor banks and any dynamic reactive devices. The controls should be modeled if the equipment dynamically responds within 10 seconds following a disturbance.		
10	Represent all pertinent electrical and mechanical configurations, such as filters and specialized transformers. Mechanical features (such as gearboxes, pitch controllers, etc.) should be included in the model if they ~~impact~~ affect electrical performance. Any control or dynamic features of the actual equipment that may influence behaviour in the simulation period (up to 30 second post-disturbance) but are not represented or are approximated must be clearly identified.		
11	Have all pertinent protections modeled in detail for both balanced and unbalanced fault conditions. Typically, this includes various over-voltage and under-voltage protections (individual phase and RMS), frequency protections, DC bus voltage protections, and overcurrent protection among others. Any protection, which can influence dynamic behavior or plant ride-through in the simulation period (up to 30 second post-disturbance), must be included.		

Requirement	Description	Y/N	Provide details if requirement not met or not applicable
12	Accurately reflect behavior throughout the valid (MW and MVAr) output range from minimum power through maximum power.		
13	Model main power transformer[9] (MPT) and generator step up -saturation based upon transformer test reports available. If such data is not available, reasonable approximate data for transformer saturation shall be used and documented[10].		
14	Include detailed representation of any hardware or software filters for the wind turbine controllers, if necessary		
15	The specific implementation of frequency measurement equipment should be modeled. If actual equipment model is not available, a smoothed master library FFT or master library PLL shall be used.		
16	Be configured to match planned (or installed) site-specific equipment settings[11]. Any user-tunable parameters or options must be set in the model to match the equipment at the specific site being evaluated. It is unacceptable to use default parameters.		

B. Model Usability Features

In order to allow study engineers to perform system studies and analyze simulation results, the model provided for each facility shall:

Requirement	Description	Y/N	Provide details if requirement not met or not applicable
1	Have pertinent control or hardware options accessible to the user (e.g. adjustable protection thresholds, real power recovery ramp rates frequency or voltage droop settings, voltage control response time).Diagnostic flags (e.g. flags to show control mode changes or which protection has been activated) should		

[9] The MPT is the power transformer that steps up voltage from the collection system voltage to the nominal transmission/interconnecting system voltage for dispersed power producing resources.
[10] Data includes magnetization model, magnetizing current, air-core reactance, knee voltage of winding-limb, loop width and any other relevant information
[11] If POI SCR is unknown at the time of model submission, it is recommended to parametrize to a POI level SCR of 3 and X/R of 10 as an approximate representation of a weak system. If studies show a SCR lower than 3, additional model tuning may be required

Requirement	Description	Y/N	Provide details if requirement not met or not applicable
	be accessible to facilitate analysis and should clearly identify why a model trips during simulations.		
2	Be capable of accurately running for a time step of 10 µs or higher and not be restricted to operating at a single time step but within a range (eg. 10µs - 20 µs).Models requiring a smaller time step may mean that the control implementation has not used the interpolation features of PSCAD[12] or is using inappropriate interfacing between the model and the larger network. Smaller time step will be considered on a case-by-case basis.		
3	Be capable of initializing itself. Models shall initialize and ramp to full output without external input from simulation engineers. Any slower control functions which are included (such as switched shunt controllers or power plant controllers) must also accept initial condition variables if required[13].		
4	Accept external reference values. This includes real and reactive power reference values (for Q control modes), or voltage reference values (for V control modes) and utilize a single parameter for adjusting real power, and separately, a single parameter for adjusting voltage setpoints. Model must accept these reference variables for initialization, and be capable of changing these reference variables mid-simulation, i.e. dynamic signal references.		
5	Allow protection models to be disabled. Many studies result in inadvertent tripping of converter equipment, and the ability to disable protection functions temporarily provides study engineers with valuable system diagnostic information.		
~~6~~	~~Allow saturation on the main power transformer and the inverter step-up transformers to be disabled.~~		

[12] If power transistor switching frequency prevents accurate switching representation at 10 µs using interpolation, an average source approximation may be used. See Section A, Requirement 2 for more details.

[13] Note that during the first few seconds of simulation (eg. 0-2 seconds), the system voltage and corresponding terminal conditions may deviate from nominal values due to other system devices initializing, and the model must be able to tolerate these deviations or provide a variable initialization time.

Requirement	Description	Y/N	Provide details if requirement not met or not applicable
~~7~~6	Allow the active power capacity of the model to be scaled. This is distinct from a dispatchable power order and is used for modeling different plant capacities (e.g. if a portion of the plant is offline).		
~~8~~7	Allow the plant to be dispatched at any output within its operating range. If a minimum output is required, sufficient technical justification shall be provided. This is distinct from scaling a plant from one unit to more than one, and is used for testing plant behavior at various operating points.		

C. Model Efficiency Features

In order to improve study efficiency and model compatibility the following efficiency features are required. Note that no feature should compromise model accuracy. The model shall:

Requirement	Description	Y/N	Provide details if model does not meet requirements
1	Be compatible with Intel Fortran compiler versions 15 and higher and be compiled with Visual Studio 2015 or newer.		
2	Be compatible with PSCAD version 4.6.3 and higher.		
3	Initialize to user defined terminal conditions within five seconds of simulation time		
4	Support multiple instances of its own definition in the same simulation case.		
5	Support the PSCAD “snapshot” and “multiple run” feature.		
6	Allow replication in different PSCAD cases or libraries through the “copy” or “copy transfer” features.		
7	Not use or rely upon global variables in the PSCAD environment and not use multiple layers in the PSCAD environment, including ‘disabled’ layers		

Requirement	Description	Y/N	Provide details if model does not meet requirements
8	Inform the user through messages to the progress output device when the system conditions are beyond plant operational limits or otherwise not consistent with valid operating conditions for the plant.		
10	Show error/status codes[14]		
11	Clearly identify the OEM's EMT model release version and the applicable corresponding hardware firmware version.		

D. Accessible Parameters

All models shall allow modification to parameters typically requiring site-specific adjustments. Where applicable, these include:

- All applicable set-points including but not limited to(shall be adjustable before and during a simulation run):
  - Active and Reactive power
  - Voltage and Frequency
  - Power Factor
- Deadband, droop, delays (including communication delays) and slow outer loop controls for any applicable control system such voltage and frequency control
- Active power ramp rate adjustment
- Voltage and frequency protection settings
- Fault ride through activation and deactivation thresholds
- Active and reactive current injection/absorption settings during a fault
- Number of in-service inverters which can be adjusted before and during a simulation run
- Other parameters such as PI gains for inner/outer current/voltage control loops (including PLL, DC link current and voltage control, and any other control loops which can have an impact on system performance)

E. Model Documentation

At a minimum, the EMT model document shall include the following:

1. The specific equipment model(s) for which the provided document is valid

[14] Only those error/status codes which translate into a distinct electrical system response at the low voltage terminals of the unit, for example, normal, fault, stop, low or high voltage ride-through activation, unstable mode identification

2. Detailed description of all control schemes that respond to voltage or frequency disturbances on the system. These include but not limited to:
    a. Voltage and frequency control
    b. Power factor and/or reactive power control
    c. Priority modes and controls including description of voltage and frequency ride-through characteristics such as activation/deactivation thresholds, control mode during ride through etc.
    d. Protection schemes and settings for (but not limited to):
        i. Over-and-under-voltage protection
        ii. Over-and-under-frequency protection
        iii. Inter-trip or runback protection scheme
        iv. Any other relevant protections (e.g. frequency rate of change protections)
3. A table of all user-definable settings and status code outputs, range of acceptable values for each user-modifiable variable and a description of each entry's function. An image of the of model instance corresponding to the table must also be provided.
4. A table of all signals fed to the Power Plant Controller such as feedback from inverter, grid measurements, reference set-points etc., parameter unit (specify the base of all per unit parameters) and a description of each entry's function
5. A table of all trip signals and a description of each entry

Appendix C-1A. Equipment Model Quality Attestation (e-MQA) Form~~s~~

Respective OEM must complete the follow equipment Model Quality Attestation (e-MQA) form

Equipment Model Quality Attestation	
Interconnection Request ID	
Point of Interconnection	
Technology type (Wind, Solar, BESS, Fuel Cell etc)	
Equipment Type[1]	
Equipment OEM	
OEM Attester (Name)	
Equipment Model	
Equipment Software version	
Date of Attestation (mm/dd/yyyy)	
Attestation Revision Number	

Please provide any additional comments here including list of changes since last revision.

Attester Signature

I hereby certify that, to the best of my knowledge, the equipment-level Electromagnetic Transient (EMT) model provided in support of Interconnection Request _____________ has been parametrized to be site specific and meets the requirements listed in Appendix ~~X~~C

[1] Examples of equipment include, but are not limited to, the following: ~~main power transformers, generator step-up transformer,~~ inverter models, plant-level controllers, dynamic ~~or static~~ reactive power devices, HVDC and any other applicable equipment

Appendix C-1B Plant-level Model Quality Attestation (p-MQA) Form

The Interconnection Customer (IC) must complete the following plant-level Model Quality Attestation (p-MQA) form

Plant-level Model Quality Attestation			
Interconnection Request ID			
Technology type (Wind, Solar, BESS, Fuel Cell etc)			
Point of Interconnection (POI)			
SCR at POI[2]			
IC Attester (Name)			
Date of Attestation (mm/dd/yyyy)			
Attestation Revision Number			
Equipment OEMs	Equipment Type[3]	Equipment Model	Hardware Firmware version

Please provide any additional comments here including list of changes since last revision.

Attester Signature

I hereby certify that, to the best of my knowledge, the plant-level Electromagnetic Transient (EMT) model provided in support of Interconnection Request ______________ has been parametrized to be site specific and meets the requirements listed in Appendix ~~X~~C

[2] If POI SCR is unknown at the time of model submission, it is recommended to parametrize to a POI level SCR of 3 and X/R of 10 as an approximate representation of a weak system. If studies show a SCR lower than 3, additional model tuning may be required

[3] Examples of equipment include, but are not limited to, the following: gen-tie line, main power transformers, generator step-up transformer, inverter models, plant-level controllers, dynamic or static reactive power devices, HVDC and any other applicable equipment

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Sebastian Lombardi and Rosendo Garza, NEPOOL Counsel

DATE: January 25, 2024

RE: Proposed Revisions to the Forward Reserve Market (FRM) Rules

At the February 1, 2024 Participants Committee meeting, you will be asked to consider Tariff revisions to modify the Forward Reserve Offer Cap and to delay the publication of the Forward Reserve Auction Offer data. At its January 9-11, 2024 meeting, the Markets Committee considered and voted to recommend that the Participants Committee support an alternative Participant-sponsored proposal to the ISO's proposed revisions.

This memorandum provides an overview of the proposed revisions to the FRM rules and the associated stakeholder review process to date, including material developments since the Markets Committee considered and took action on this item.

Included with this memorandum are the following materials:

- Attachment A: ISO-NE's memorandum (dated January 25, 2024)
- Attachment B: LS Power's January 2024 PowerPoint presentation
- Attachment C: The Markets Committee-Recommended Proposed Tariff Redlines

BACKGROUND & OVERVIEW OF THE FRM REVISIONS

By way of brief background, through the FRM's auctions conducted for the summer and winter reserve periods, the ISO enters into forward obligations with resources to provide reserve capacity in Real-Time. In its *Spring 2023 Quarterly Markets Report*, the ISO's Internal Market Monitor (IMM) emphasized that the Forward Reserve Offer Cap is an important safeguard to limit the exercise of market power in those FRM auctions.[1] That IMM report concluded that the "current offer cap of $9,000/MW-month significantly overstate[d] a reasonable upper bound on competitive offers" and that the IMM's analysis indicated that a revised (lower) cap would constitute a "more reasonable reflection of the upper bound of competitive offers."[2] Moreover, the IMM expressed "concern[ ] that the publication of auction offer data may provide strategic

[1] Internal Market Monitor, ISO New England Inc., *Spring 2023 Quarterly Markets Report*, at 43 (Aug. 1, 2023), https://www.iso-ne.com/static-assets/documents/2023/08/2023-spring-quarterly-markets-report.pdf at 47.

[2] *Id.*

information to participants in the auctions" due to the frequency of the structurally-uncompetitive auctions and elevated pricing in the summer 2023 auction.[3]

Given this assessment with respect to the existing FRM rules, the ISO developed Tariff revisions to address the IMM's stated concerns. In the proposal considered and voted on by the Markets Committee, the ISO proposed to: (1) revise the definition of "Forward Reserve Offer Cap" by lowering the offer cap from $9,000/MW-month to $6,400/MW-month; and (2) add Tariff language stating that it will publish the Forward Reserve Auction Offer data one year after the FRA offer effective month.

NEPOOL MARKETS COMMITTEE CONSIDERATION

Since its October 2023 meeting, the Markets Committee reviewed and evaluated the ISO's proposal to modify certain of the FRM Tariff provisions. At its January 9, 2024 meeting, the Markets Committee voted on the ISO's proposal and one amendment to that proposal, which was offered by LS Power, through its Lead Market Participant, Jericho Power, LLC. The LS Power amendment considered by the Markets Committee modified the ISO's proposal by increasing the revised FRM offer cap from $6,400/MW-month to $7,200/MW-month.[4] That amendment passed at the Markets Committee, with a 79.09% Vote in favor.

The Markets Committee then considered and recommended for Participants Committee support a once-amended main motion, with a 66.6% Vote in favor,[5] referred here as the MC-Recommended FRM Proposal and described below. The ISO's un-amended proposal also was voted on by the Markets Committee but failed to achieve Committee support, with a 49.95% Vote in favor.[6]

[3] *Id.* at 52.

[4] Attachment B at 10; Attachment C. Note that the Markets Committee reviewed various Forward Reserve Offer Cap values, as LS Power presented. Attachment B at 8–9 (explaining how different adjustment to inputs could produce a higher Forward Reserve Offer Cap than ISO-NE's proposed number at the January Markets Committee meeting). Notably, the MC-Recommended FRM Proposal *does not* propose any modification to the ISO's proposal to delay publishing the Forward Reserve Auction Offer data.

[5] The individual Sector votes at the Markets Committee on the once-amended main motion were as follows: Generation – 16.7% in favor, 0% opposed, 1 abstention; Transmission – 0% in favor, 16.7% opposed, 3 abstentions; Supplier – 16.7% in favor, 0% opposed, 7 abstentions; Publicly Owned Entity – 16.7% in favor, 0% opposed, 22 abstentions; Alternative Resources – 16.5% in favor, 0% opposed, 3 abstentions; and End User – 0% in favor, 16.7% opposed, 0 abstentions.

[6] The individual Sector votes on ISO's unamended proposal were as follows: Generation – 0% in favor, 16.7% opposed, 1 abstention; Transmission – 16.7% in favor, 0% opposed, 0 abstentions; Supplier – 12.53% in favor, 4.18% opposed, 4 abstentions; Publicly Owned Entity – 1.67% in favor, 15.03% opposed, 19 abstentions; Alternative Resources – 2.36% in favor, 14.14% opposed, 3 abstentions; and End User – 16.7% in favor, 0% opposed, 0 abstentions.

DEVELOPMENTS SINCE THE MARKETS COMMITTEE JAN 9, 2024 VOTES

Following the Markets Committee's consideration and votes, the ISO continued to evaluate its proposal as well as the alternative supported by the Markets Committee, taking into account various stakeholder feedback received. As a result of that further evaluation, the ISO is now proposing a revised Forward Reserve Offer Cap value of $7,100/MW-month (rather than its earlier proposal of $6,400/MW-mo.).[7] In addition to the movement on the ISO's end, it is our understanding that LS Power, the Participant-sponsor of the MC-Recommended Proposal, has indicated that it too supports the ISO's revised FRM Offer Cap of $7,100/MW-month.

PROCESS FOR PARTICIPANTS COMMITTEE ACTION

Consistent with past practice and procedure, the Participants Committee will begin its consideration of this matter with the MC-Recommended Proposal. However, in light of the significant developments described above and in more detail within the accompanying materials, the Participants Committee will likely be asked, absent any objection, to amend and incorporate into the main motion the newly proposed Forward Reserve Offer Cap value of $7,100/MW-month in place of the previously recommended $7,200/MW-month value.

The following form of resolution may be used to initiate Participants Committee consideration at its February 1 meeting:

> RESOLVED, that the Participants Committee supports the revisions to Tariff Sections I.2.2 and III.9.3, as recommended by the Markets Committee at its January 9, 2024 meeting, and 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.

---

[7] Attachment A.

ISO new england

memo

To: NEPOOL Participants Committee Members and Alternates

From: ISO New England

Date: January 25, 2024

Subject: Forward Reserve Market Offer Cap – ISO Supported Amendment

Between October 2023 and January 2024, the ISO presented to the NEPOOL Markets Committee (MC) an updated Forward Reserve Market (FRM) Offer Cap.[1] Over the course of the MC discussions, the ISO refined its modeling and the resulting proposal. Following the January MC, the ISO has further considered stakeholder feedback regarding the representative asset parameters and performed further analysis to validate a reasonable alternative for deriving the asset parameters. As a result, the ISO now recommends incorporating a broader set of assets for purposes of modeling a representative asset and its estimated foregone energy and reserve revenues. With this memorandum, the ISO explains its support for a FRM Offer Cap value of $7,100/MW-month. The remainder of this memo explains the limited change in the ISO's analysis that supports the $7,100/MW-month value and the rationale.

The intent of the FRM Offer Cap is to reflect the upper bound of the estimated costs for a representative, installed unit to assume an obligation to provide Forward Reserves.[2] Updating the cap, as has been proposed by the ISO, better reflects the expected costs and revenues under current market conditions and, in practical terms, it reduces the upper bound of prices that Market Participants may include in their FRM offers, potentially reducing total FRM costs. Specifically with this updated proposal, the ISO would reduce the FRM Offer Cap from the currently effective $9,000/MW-month to $7,100/MW-month.

As discussed at the MC, to develop the estimates of foregone energy and reserve revenues, the ISO derived reasonable cost parameters for a representative asset (*i.e.*, its heat rate, capacity, startup costs, variable O&M costs, and emissions rates). Broadly, the ISO determined that natural gas units located in Connecticut provided the best basis for deriving these parameters based on the relevant asset characteristics and estimated costs.[3]

---

[1] This FRM Offer Cap update was undertaken at the recommendation of the Internal Market Monitor ("IMM"), in light of concerns over FRM structural competitiveness and recently elevated offer prices identified in the IMM's Spring 2023 Quarterly Markets Report. *See* ISO New England Internal Market Monitor, *Spring 2023 Quarterly Markets Report*, at 39–52 (Aug. 1, 2023) ("IMM Spring 2023 Quarterly Markets Report"), *available at* https://www.iso-ne.com/static-assets/documents/2023/08/2023-spring-quarterly-markets-report.pdf.

[2] IMM Spring 2023 Quarterly Markets Report at 9, 44, and 48.

[3] Connecticut was chosen as the representative asset's location because it was identified as the Load Zone with the vast majority of FRM and FRM-eligible units in New England.

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Previously, the ISO had performed its sampling to derive the asset parameters considering only assets that were *assigned forward reserve obligations during the two most recent forward reserve procurement periods*. The limited change the ISO now has incorporated in its updated analysis instead derives the asset parameters from all assets that are *eligible to participate in the FRM*.[4] In each case, the ISO's sampling method to derive reasonable asset cost and operating parameters is otherwise equivalent. The ISO proposes no changes to the other directly estimated cost components or to the structure for calculating the total cap value.

The rationale for considering all FRM-eligible units, instead of limiting consideration to assets recently participating in the FRM, is to avoid potentially understating the competitive population of existing units available to participate in the FRM. The concern otherwise is that the offer cap might be below some participating assets' — or potential competitive entrants' — actual cost of assuming a forward reserve obligation. This administrative constraint could limit auction participation and contestability, exacerbate concerns with structural competitiveness, and potentially result in the FRM auctions not procuring supply adequate to meet the requirements.

This alternative proposes a decrease from the FRM's current value of $9,000/MW-month. The direction of the change and magnitude aligns with the recommendation of the IMM.[5] Importantly, the FRM Offer Cap update has incorporated updated expectations for the number of Capacity Scarcity Condition hours, with a reduction from 12.8 hours to 5.4 hours, which aligns with the ISO's 2022 analysis for the MC.[6]

In summary, the ISO recommends the revised $7,100/MW-month FRM Offer Cap value in light of the above-described considerations, and based on the opportunity it has had to consider stakeholder feedback and conduct further analysis following the January MC.

---

[4] Specifically, this includes all natural gas units located in Connecticut capable of providing reserves within 30 minutes or less of being called upon.

[5] IMM Spring 2023 Quarterly Markets Report at 9, 49, and 51.

[6] *See generally* ISO New England Memorandum to NEPOOL Markets Committee, *Performance of Capacity Resources and Pay for Performance* (Sept. 7, 2022) (explaining conditions leading to fewer Capacity Scarcity Conditions), *available at* https://www.iso-ne.com/static-assets/documents/2022/09/a03_mc_2022_09_13-14_performance_of_capacity_resources_memo_rev1.pdf.

FRM Offer Cap Amendment

Ben Griffiths | Markets Committee | January 9-11 2024

About LS Power

LS Power is a development, investment and operating company focused on the North American power and energy infrastructure sector

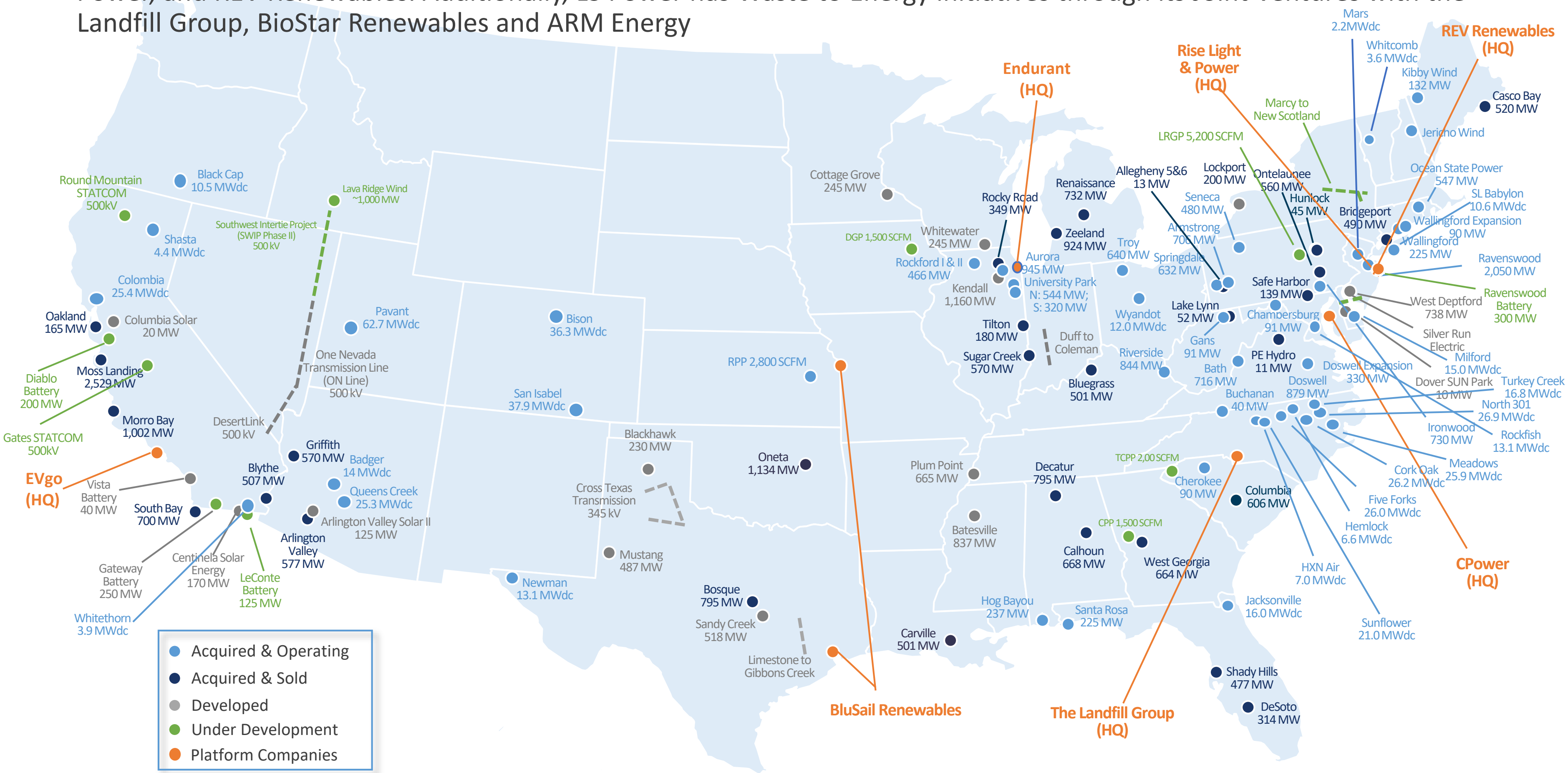
- Founded in 1990, LS Power has 280 employees across its principal and affiliate offices in New York, New Jersey, Missouri, Texas and California
- LS Power is at the leading edge of the industry's transition to low-carbon energy by commercializing new technologies and developing new markets.
  - **Utility-scale power projects across multiple fuel and technology types**, such as pumped storage hydro, wind, solar and natural gas-fired generation
  - **Battery energy storage**, market-leading utility-scale solutions that complement weather dependent renewables like wind and solar energy
  - **High voltage electric transmission infrastructure**, which is key to increasing grid reliability and efficiency, as well as carrying renewable energy from remote locations to population centers
  - **EVgo, the nation's largest public fast charging platform for electric vehicles** and first platform to be 100% powered by renewable energy
  - **CPower Energy Management**, the largest demand response provider in the country that is dedicated solely to the commercial and industrial sector
- Since inception, LS Power has developed, constructed, managed and acquired competitive power generation and transmission infrastructure, for which **we have raised over $47 billion in debt and equity financing.**
  - **Developed over 11,000 MW of power generation** (both conventional and renewable) across the United States
  - **Acquired over 34,000 MW of power generation assets** (both conventional and renewable)
  - **Developed over 660 miles of high voltage transmission**, with ~400 miles of additional transmission under development

Utilize deep industry expertise as owner/operator

LS Power Project Portfolio

Extensive development/operating experience across multiple markets and technologies

- With over $47 billion in equity and debt raised, LS Power has developed and acquired 120 Power Generation projects (renewable and conventional generation), 7 Transmission projects, and 5 Battery Energy Storage projects
- LS Power's Energy Transition Platforms includes CPower Energy Management, Endurant Energy, EVgo, Rise Light & Power, and REV Renewables. Additionally, LS Power has Waste to Energy initiatives through its Joint Ventures with the Landfill Group, BioStar Renewables and ARM Energy



Position Summary

- Setting a reasonable FRM offer cap is essential to a well functioning market
  - A too low offer cap may discourage resources from participating in FRM, which would increase the likelihood of the market clearing at its cap
- LS agrees with the IMM's suggestion that the current $9,000/MW-mo offer cap is too high, largely because PfP events are a lot less common than region anticipated in 2016
- LS also agrees that the FRM offer cap should be "based on an expectation of a reasonable upper-limit on the bid-in cost for a hypothetical forward reserve resource" [1]
- The ISO's estimation approach does *not* reflect a "reasonable upper-limit" on costs
  - Worse, changes made by ISO-NE in December lead to erroneous results
- Correcting flaws in the ISO analysis yields reasonable FRM Offer Cap estimates between $7,100 and $8,200/MW-month, compared to the ISO's final $6,400 value
- **Based on feedback, LS is revising its amendment and is now proposing to set the FRM Offer Cap at $7,200/MW-month**

1. 1. IMM 2023 Spring Quarterly Markets Report at 44; see also ER16-921 Filing Letter at 8: "the FRM offer cap will be **set reflecting the high end of the ISO's estimate of costs** for a representative, existing resource to assume an obligation to provide forward reserves"

ISO-NE's Foregone E&AS Revenue Estimates are in Error

- ISO-NE relies on a dispatch model (derived from the 2020 CONE analysis) to estimate foregone revenues from FRM participation
  - The dispatch model relies on certain unit parameters (e.g. Heat-rate, VOM, Start-up costs) to generate offers, dispatch profiles, and the foregone revenue estimates
- In December, ISO noted that it selected its heat-rate by estimating the 25th percentile of "all natural gas units to which forward reserve obligations have been assigned during the two most recent forward reserve procurement periods" (Dec MC presentation at Slide 7)
  - In effect, this is a conditional probability: the ISO takes its percentile having already filtered out all the non-FRM gas resources
- This means that **one-quarter of gas units that actually participate on a day-to-day basis** in the FRM would have higher foregone E&AS revenue than the ISO model indicates.
  - ISO acknowledges this: "Using parameters for actual assets, the dispatch model does yield some instances of … revenue higher than the proposed $2,070/MW-month" [1]
- By throwing out the costs of a quarter of the most efficient units it *actually relies on for the FRM*, units plausibly setting price in the FRM, the ISO is creating an unreasonable downward bias on the offer cap

1. ISO-NE Jan MC Presentation at 5

LS POWER

How to Remedy? Rely on ISO's original heat-rate estimate

- The ISO *could have done* one of two things to create un-biased estimates
  1. Take the minimum (or near minimum) heat-rate of units that were *actually designated* for FRM, instead of taking the 25th percentile
  2. Take the 25th percentile heat-rate of *all FRM eligible resources*, irrespective of their participation in the FRM market
- The ISO's *original* approach to estimating parameters for a reference unit **did not** rely on conditional probabilities, but instead picked a heat-rate based on a "representative, installed unit….representing the upper-end of opportunity costs….for relatively-efficient natural gas units" (Oct MC presentation at 8)
  – ISO's original approach aligned with IMM's selection of a "actual, relatively fuel-efficient, dual-fuel peaking resources in New England" (IMM Spring 2023 Report at 50)
- LS proposes to rely on the ISO's original, un-biased 9,575 Btu/kWh heat-rate estimate
  – Making on this one change to the ISO's dispatch model [1] increases the foregone E&AS revenue estimate to **$2,579/MW-mo** (a 25% increase over the ISO's $2,070)

1. https://www.iso-ne.com/static-assets/documents/100006/a07_mc_2023_12_12_14_frm_offer_cap_iso_dispatch_model.xlsx

LS POWER

Other changes would push the offer cap even higher

- ISO is relying on downward-biased estimates for VOM and start-up costs, too
  - LS is not proposing to account for these issues because no public estimates were released, but use of unbiased estimates would result in higher foregone revenues
- LS previously noted that the ISO's assumption that the indicative FRM resource must be located in Connecticut (which has a 5% tax on natural gas) is unreasonable. There are quick-start units, such as the Medway peakers, that are located outside of that state
  - Assuming the unit is located outside of CT, all else equal, yields an E&AS revenue estimate of **$2,524/MW-mo**
  - Pairing this location assumption with the un-biased HR assumption would increase the E&AS revenue to **$3,047/MW-mo**
- LS previously suggested that ISO should treat energy and reserve revenues as uncorrelated (as the IMM did in its revenue estimates)
  - IMM estimated E&AS revenues at **$3,233/MW-mo** [1]
- LS previously showed that forward-adjustments to historical prices may increase cap, too

1. IMM 2023 Spring Quarterly Markets Report at 50

LS POWER

Reasonable parametrizations suggest offer cap should fall in range of $7,100 and $8,200/MW-month

Updated Offer Cap ($/MW-Month)							
Item Number	Item Description	IMM E&AS Value	Lower HR + Unit Located outside CT	Lower HR	Unit Not Located in CT	ISO Value (Jan MC)	Item Units
1	**Foregone Revenue**						
1.1	Number of Reserve Shortage Hours	5.4	5.4	6.4	7.4	5.4	hours/year
1.2	Reserve Shortage Hour Reserve Revenue	1,990	1,990	1,990	1,990	1,990	$/MW-month
1.2(a)	*Minimum Total Reserve Req. Shortage Revenue*	*1,350*	*1,350*	*1,351*	*1,352*	*1,350*	$/MW-month
1.2(b)	*Ten-Minute Reserve Req. Shortage Revenue*	*640*	*640*	*640*	*640*	*640*	$/MW-month
1.3	Energy and Reserve Market Revenue	3,233	3,047	2,579	2,524	2,070	$/MW-month
Item 1 Subtotal	***Foregone Revenue Subtotal***	***5,223***	***5,037***	***4,569***	***4,514***	***4,060***	***$/MW-month***
2	**Penalties**						
2.1	Failure to Reserve (32.12%)*	1,678	1,618	1,468	1,450	1,304	$/MW-month
2.2	Failure to Activate (5.17%)**	270	260	236	233	210	$/MW-month
Item 2 Subtotal	***Penalty Subtotal***	***1,948***	***1,878***	***1,704***	***1,683***	***1,514***	***$/MW-month***
3	**Supplier Risk Premium** ([Item 1 subtotal + Item 2 subtotal]*15%)	***1076***	***1037***	***941***	***930***	***836***	$/MW-month
4	Total Offer Cap (Item 1 + Item 2 + Item 3)	8,246	7,952	7,214	7,127	6,410	$/MW-month
Item 4 Rounded	**Updated Forward Reserve Offer Cap**	8,200	8,000	7,200	7,100	6,400	**$/MW-month**

Amendment

- LS considers reasonable its suggestion that the FRM offer cap be set at $8,200 MW-mo
  - This cap estimate is based on IMM-derived values, after all
- However, in the spirit of compromise, LS proposes to revise its FRM offer cap amendment to reflect a reasonable lower bound of its four analytical different scenarios: **$7,200/MW-month**

- **Redlines are simple: a single value is changed**

Tariff Section	Description of Change	Reason for Change
I.2.2	Modify definition of Forward Reserve Offer Cap to "is ~~$9,000~~$7,200/megawatt-month."	Update offer cap

LS POWER

Questions?

Appendix: Additional Materials from December MC

Presented at November MC

Energy & (Non-Scarcity) Ancillary Service Revenues

- 50% difference in EAS revenue from IMM & ISO using conceptually similar approaches
  - ISO-NE estimates foregone E&AS revenues at **$2,170/MW-mo**
    - Estimate relies on the "CONE reset" dispatch models, several years of historic pricing data, and unit parameters based on a "more efficient unit" [1]
  - IMM estimated the same foregone revenues at **$3,233/MW-mo**; nearly 50% higher!
    - Energy estimated at $2,091/MW-mo based on the 90% percentile of observed summer energy revenues, over six summer seasons for a relatively new dual-fuel peaking resource [2]
    - Non-Scarcity Reserve Revenues estimated at $1,142/MW-mo based on 90% percentile value of available reserve revenue on observed over four summer seasons [2]
  - The difference in these two estimates, **$1,063/MW-mo**, is larger than the *entire* 15% risk premium offered by the ISO ($836/MW-mo)!
- [**Dec Update**: ISO-NE's estimate is now $2,070/MW-mo, $100 lower than previously estimated, which results in even larger differences in revenue estimates]

1. November MC presentation, Slides 20-24; Oct MC presentation, Slide 8 suggests HR of 9,575 BTU/kWh
2. IMM 2023 Spring Quarterly Markets Report at 50

LS POWER

Concern with ISO's current approach to calculating E&AS revenues

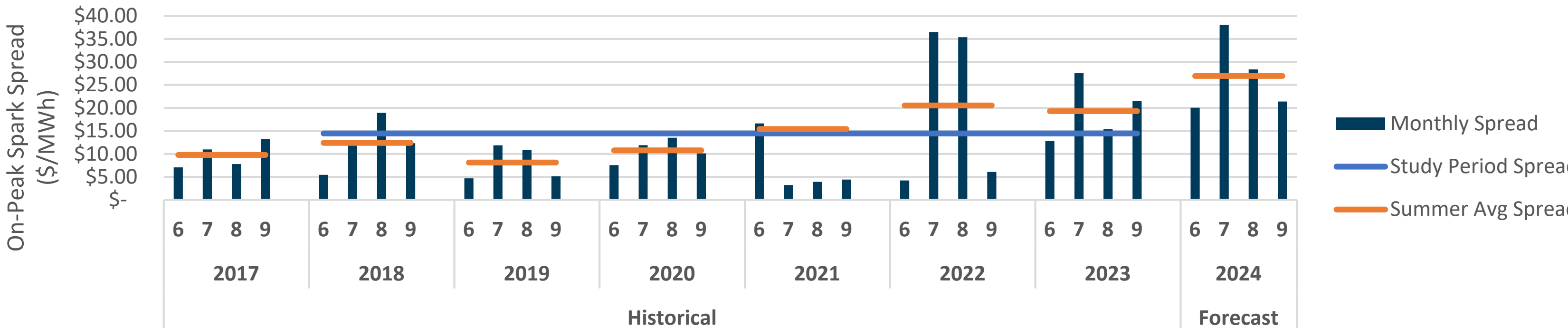
- The ISO is currently relying on a "lookback" approach to computing foregone E&AS revenues, based on observed pricing data from the 2018-2023 period
  - The IMM, using a conceptually similar approach found revenues would be 50% higher
- Last month, LS expressed concern that the ISO's approach to computing E&AS revenues will fail to capture salient differences between **(a)** past market performance and **(b)** current expectations for the upcoming summer seasons
- The ISO retorted that their historic approach "captures the high costs of summer 2022" and that "July 2022 and August 2022 prices exceed current futures prices"
  - LS readily agrees that current power forwards are *lower* than those in 2022
- But, foregone revenues aren't a function of the *absolute price* of commodities. Instead, revenues are based on *energy margin*, the spread between prices for power and gas
  - As shown on next slide, Summer 2024 has spreads 87% higher than the 2018-2023 average and 31% higher than Summer 2022.
- **Historic prices used by ISO are still *not* representative of future market conditions**

LS POWER

Presented at November MC

Forwards suggest higher spark spreads in Summer 2024

- FRM will likely be sunset starting March 2025, so any changes to the cap should reflect a reasonable upper-limit on offers for the June 2024 – February 2025 timeframe
- Historic prices used by ISO are *not* representative of future market conditions
  - Using <u>un</u>adjusted prices will lead to downward bias in revenue estimates and FRM cap because historical period had lower margin than forwards suggest for Summer 2024
- Chart below estimates on-peak spark spreads for each month in study period as well as based on current forward prices (as of 11/3/2023)
  - Recall, Spark Spread = [Avg On-Peak LMP] – [9.575 MMBtu/MWh HR] x [Avg Algonquin Price]
    - Historical sparks range from $4 to $36/MWh (avg = $14.44/MWh)
    - Forward sparks range from $20 to $38/MWh (avg = $26.96/MWh) → **87% higher**



LS POWER

Lack of correlation between reserves & energy revenues mean that values should be treated as independent

Presented at November MC

- While reserve prices and energy prices are correlated on an hour to hour basis, there is no real correlation between energy revenues and reserve revenues on a monthly basis
  - E.g., a generally low margin month from an energy perspective might have high reserve revenues due to the system tightening (but not hitting scarcity)
- A review of historical summer data from June 2017 to July 2023 shows the lack of relationship between energy and reserve prices. The correlation between
  - the (a) number of hours with positive reserve prices and (b) average DA LMP is -0.28
  - The (a) average combined TMNSR+TMOR price and (b) average DA LMP is +0.22
- As regressions, same variables yield R-squared value of 0.009 and 0.08 respectively
- **Separate estimates for energy and ancillaries, like IMM proposed, better reflects the lack of relationship**

LS POWER

Forward Reserve Obligation Charge is defined in Section III.10.4 of Market Rule 1.

Forward Reserve Offer Cap is $7,200~~9,000~~/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

Forward Reserve Resource is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

Forward Reserve Threshold Price is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

FTR Credit Test Percentage is calculated in accordance with Section III.B.1(b) of the ISO New England Financial Assurance Policy.

FTR Financial Assurance Requirements are described in Section VI of the ISO New England Financial Assurance Policy.

III.9 Forward Reserve Market

The Forward Reserve Market is a market to procure TMNSR and TMOR on a forward basis to satisfy Forward Reserve requirements.

III.9.1 Forward Reserve Market Timing.

A Forward Reserve Auction will be held approximately two months in advance of each Forward Reserve Procurement Period. The Forward Reserve Auction input parameters and assumptions will be evaluated, published and reviewed with Market Participants prior to the Forward Reserve Auction.

The Forward Reserve Procurement Periods shall be the Winter Capability Period (October 1 through May 31) or the Summer Capability Period (June 1 through September 30), as applicable.

The Forward Reserve Delivery Period shall be hour ending 0800 through hour ending 2300 for each weekday of the Forward Reserve Procurement Period excluding those weekdays that are defined as NERC holidays.

III.9.2 Forward Reserve Requirements.

The ISO shall conduct an advance purchase of capability to satisfy the expected Forward Reserve requirements for the system and each Reserve Zone as calculated by the ISO in accordance with the following procedures and as specified more fully in the ISO New England Manuals. The Forward Reserve requirements will be specified as part of the Forward Reserve Auction parameters and will be published and reviewed with Market Participants prior to each Forward Reserve Auction.

III.9.2.1 System Forward Reserve Requirements.

The Forward Reserve requirements for the New England Control Area will be based on the forecast of the first and second contingency supply losses for the next Forward Reserve Procurement Period and will consist of the following:

(i) One half of the forecasted first contingency supply loss will be specified as the minimum forward ten-minute reserve requirement to be purchased.

(ii) The minimum forward ten-minute reserve requirement described in subsection (i) will be increased if system conditions forecasted for the Forward Reserve Procurement Period indicate that the TMNSR available during the period would otherwise be insufficient to meet Real-Time

Operating Reserve requirements. The increase shall be calculated to account for: (a) any historical under-performance of Resources dispatched in response to a System contingency and (b) the likelihood that more than one half of the forecasted first contingency supply loss will be satisfied using TMNSR.

(iii) The minimum forward ten-minute reserve requirement plus one half of the second contingency supply loss will be specified as the minimum forward total reserve requirement to be purchased.

(iv) The minimum forward total reserve requirement described in subsection (iii) will be increased by an amount of Replacement Reserve as specified in ISO New England Operating Procedure No. 8.

The requirements specified above, further adjusted to respect the additional provisions described in Section III.9.2.2, represent the set of requirements that will be input into the Forward Reserve Auction.

III.9.2.2 Zonal Forward Reserve Requirements.

Zonal Forward Reserve requirements will be established for each Reserve Zone. The zonal Forward Reserve requirements will reflect the need for 30-minute contingency response to provide 2nd contingency protection for each import constrained Reserve Zone. The zonal Forward Reserve requirements can be satisfied only by Resources that are located within a Reserve Zone and that are capable of providing 30-minute or higher quality reserve products.

The ISO shall establish the zonal Forward Reserve requirements based on a rolling, two-year historical analysis of the daily peak hour operational requirements for each Reserve Zone for like Forward Reserve Procurement Periods. The ISO will commence the analysis on February 1 or the first business day thereafter for the subsequent summer Forward Reserve Procurement Period and on June 1 or the first business day thereafter for the subsequent winter Forward Reserve Procurement Period.

These daily peak hour requirements will be aggregated into daily peak hour frequency distribution curves and the MW value at the 95th percentile of the frequency distribution curve for each Reserve Zone will establish the zonal requirement.

In the event of a change in the configuration of the transmission system or the addition, deactivation or retirement of a major Generator Asset, Dispatchable Asset Related Demand or Demand Response Resource the rolling two-year historical analysis will be calculated in a manner that reflects the change in configuration of the transmission system or the addition, deactivation or retirement of a major Generator Asset, Dispatchable Asset Related Demand or Demand Response Resource as of the commencement date of the analysis provided that the following conditions are met:

(a) Change in Configuration of the Transmission System

Any change in the configuration of the transmission system must have been placed in service and released for dispatch on or before December 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before April 30 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent winter Forward Reserve Procurement Period.

If the change in the configuration of the transmission system consists of a new facility or upgrade of an existing facility, the facility must have operated at an availability level of at least 95% for the period beginning with its in service date and ending on January 31 prior to the summer Forward Reserve Procurement Period or ending on May 31 prior to the winter Forward Reserve Procurement Period.

(b) Addition, Deactivation or Retirement of a Major Generating Resource, Dispatchable Asset Related Demand or Demand Response Resource.

For the addition of a new Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource, the Resource must be placed in service and released for dispatch on or before December 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before April 30 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent winter Forward Reserve Procurement Period. For the deactivation or retirement of a Generator Asset, Dispatchable Asset Related Demand or Demand Response Resource, the Resource must have been removed from service on or before January 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent summer Forward Reserve Procurement Period or on or before May 31 for inclusion in the analysis for setting the zonal Forward Reserve requirements for the subsequent winter Forward Reserve Procurement Period.

The modified historical data set will be composed of actual data used in the operation of the reconfigured system and historical (pre-reconfiguration) data adjusted for the impact of the system reconfiguration. Pre-reconfiguration data will be revised by substituting values from the historical data set that are no longer valid with corresponding values used in the operation of the reconfigured system.

The zonal Forward Reserve requirements will be recalculated using the modified historical data set until the rolling two-year historical data set reflects a common system configuration.

III.9.3 Forward Reserve Auction Offers.

Forward Reserve Auction Offers for TMNSR and TMOR shall be (a) made on a $/MW-month basis, (b) made on a Reserve Zone specific basis, (c) made on a non-Resource specific basis and (d) shall be less than or equal to the Forward Reserve Offer Cap. Forward Reserve Auction Offers shall be submitted to the ISO by Market Participants. The Market Participants are responsible for complying with the requirements of this Section III.9 if the Forward Reserve Auction Offer is accepted. Notwithstanding the publication timeline specified in Section 3(a) of the ISO New England Information Policy, the ISO shall publish Forward Reserve Auction Offer data on the first day of the twelfth calendar month following the month during which the applicable supply offers were in effect, and not prior thereto.

III.9.4 Forward Reserve Auction Clearing and Forward Reserve Clearing Prices.

The Forward Reserve Auction shall simultaneously clear Forward Reserve Auction Offers to meet the Forward Reserve requirements for the system and each Reserve Zone using a mathematical programming algorithm. The objective of the mathematical programming based Forward Reserve Auction clearing is to minimize the total cost of Forward Reserve procured to meet the Forward Reserve requirements. The Forward Reserve Clearing Price for each Reserve Zone will reflect the cost to serve the next increment of reserve in that Reserve Zone based on the submitted offers. The Forward Reserve Auction algorithm substitutes higher quality TMNSR for lower quality TMOR to meet system or Reserve Zone Forward Reserve requirements when it is economical to do so provided that no constraints are violated.

The Forward Reserve Auction algorithm shall also utilize excess Forward Reserve in one Reserve Zone to meet the Forward Reserve requirements of another Reserve Zone or the system provided that the Forward Reserve can be delivered such that no constraints are violated. In addition, the Forward Reserve Auction shall apply price cascading such that the Forward Reserve Clearing Price for TMOR in a Reserve Zone is always less than or equal to the Forward Reserve Clearing Price for TMNSR in that Reserve Zone. If there is insufficient supply to meet the Forward Reserve requirements for a Reserve Zone, the Forward Reserve Clearing Price for that Reserve Zone will be set to the Forward Reserve Offer Cap.

M E M O R A N D U M

TO: NEPOOL Participants Committee Members and Alternates

FROM: Paul Belval, NEPOOL Counsel

DATE: January 25, 2024

RE: Request by Saco River Hydro for Waiver of GIS Operating Rules and GIS Agreement

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At the February 1, 2024 Participants Committee meeting, you may be asked to consider a request to waive certain NEPOOL Generation Information System ("GIS") requirements in order to change renewable energy Certificates for a generator for the first and second quarters of 2023. 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"). As further explained below, Saco River Hydro, LLC ("Saco River")[1] is seeking to have the first and second quarter Certificates for its Swans Falls project (the "Project") reclassified as Class I qualified under the Connecticut renewable portfolio standard ("RPS").

RELEVANT BACKGROUND & OVERVIEW

Saco River's Project has a total nameplate capacity of 0.82 MW and is registered in the ISO MSS. The Project was qualified as a Connecticut Class I RPS unit in 2005. Until last year, the Project was interconnected with Public Service Company of New Hampshire ("PSNH"). In February 2023, the Project dropped the interconnection with PSNH and was interconnected with Central Maine Power ("CMP"). As a result of the change in the interconnection, the Project was assigned a new asset ID number in the MSS, with CMP listed as the asset owner.

Because the Swan Falls Project had a new asset ID number in the MSS, APX, the GIS Administrator, needed a new confirmation of the Project's Class I status from the Connecticut Public Utilities Regulatory Authority ("PURA") aligning with the new ID, which it received in November 2023.[2] Because APX did not have that confirmation by July 10 (the deadline under the Rules[3]), the Project's first quarter Certificates were not denoted as Connecticut Class I qualified,

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[1] Saco River is not a NEPOOL Participant and is a Non-Participant Account Holder under the GIS Rules.

[2] APX noted that Connecticut PURA would have needed someone to contact it to inform them that the new asset ID was for the generator that was qualified as Class I in 2005, so that PURA could in turn inform APX that the Certificates for the new asset ID were Connecticut Class I qualified.

[3] GIS Operating Rule 2.3(a) states, "Any update provided after the fifth calendar day preceding any Creation Date shall not apply to the Certificates created on such Creation Date." The Creation Date for first quarter Certificates in any year is July 15, and the Creation Date for second quarter Certificates in any year is October 15.

and because APX did not have that confirmation by October 10, the project's second quarter Certificates also were not denoted as Connecticut Class I qualified. The total number of Certificates for the Project for the first two quarters was 1,260. The Project's Certificates will be denoted as Connecticut Class I qualified going forward, starting with the third quarter of 2023.

Through its waiver request, Saco River is seeking to have its first and second quarter Certificates be retroactively designated as Connecticut Class I qualified in the GIS. APX does not have the authority to change the RPS designation 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 administered correctly what is prescribed by the Rules and GIS Agreement, the only way it can change Saco River's Certificates as requested is if Rule 1.4 and Section 4.2 of the GIS Agreement are waived. APX has indicated that it would be willing to waive the applicable requirements but only if NEPOOL, as the counterparty to the GIS Agreement, agrees to such a waiver and directs APX to correct the Certificates.

The following resolution can be used for Participants Committee action on Saco River's request:

> RESOLVED, that the Participants Committee [grants] [denies] Saco River Hydro, 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.